ENERGIA CURA

Reference for Letter to L. Persily dated 1/26/10

EIA's *Weekly Natural Gas Storage Report* - Working natural gas in storage increased to 3,843 Bcf as of Friday, November 12, a new all-time record**.** The net injection was 3 Bcf, compared with last year's net injection of 21 Bcf and the 5-year average injection of 18 Bcf for the report week. This marks the second week in a row that the weekly net injection fell below the 5-year average. The Producing region storage levels are now 39 Bcf above last year's level, while the East region is 21 Bcf below last year's level. Working gas stocks in the West region lag behind last year's level by 6 Bcf.

ICIS -- Qatar to idle 66% of LNG capacity - 10 June 2010 06:51 GMT

Qatar, the world's largest producer of liquefied natural gas, will idle 66% of its export plants this year, reversing earlier plans and joining Russia in curtailing supply amid a global glut.

Bloomberg cited a report from New York-based consultant Poten & Partners as saying Qatar's two LNG projects, Ras Laffan and Qatar LNG, had an "unusually heavy" maintenance program during the past two months that shut six of 12 production units for several weeks. Another two units will undergo repairs this summer. Qatar has changed its approach from a January comment by Faisal Suwadi, then chief executive officer of QatarGas, that his company probably would not idle any LNG units for maintenance this year. Russian gas giant Gazprom, which supplies about a quarter of Europe's gas, cut its 2010 production goal yesterday because of reduced demand. Gazprom said it aims to produce 519.3 billion cubic metres of gas this year, scaling back an earlier forecast of 529 Bcm. "Gazprom is now revising down figures because of a lack of demand," head of the gas, condensate and oil production department Vsevolod Cherepanov, told reporters in Moscow. Qatar's decision to shut units even as it increases overall capacity underscores the challenge LNG producers face in balancing abundant supplies with long-term expectations of demand growth. "There have been more shutdowns globally than we have seen in the past, and LNG units are being shut," Andrew Pearson, an analyst at Edinburgh-based consultant Wood Mackenzie told Bloomberg. "Suppliers are trying to support the market on one hand, but on the other hand, holding the gas back for future months and years when the price is more attractive." US gas futures slumped 31% during the first three months of the year, fluctuated near $4 per million British thermal units during April, then rose 19% since 24 May, to close at $4.677 yesterday on the New York Mercantile Exchange. Gas for delivery in July 2011 was $5.384 per million Btu, a premium of 15% over the front-month contract. At the start of the year, the premium for July 2011 over gas for July this year stood at 6.6%. Gas prices have fallen during the past year as more nations boost exports and the US, the world's biggest consumer, increases domestic production from shale-gas deposits. Members of the Gas Exporting Countries Forum, which includes Russia, Iran and Qatar, failed to agree in April on an Algerian proposal to buttress prices by reducing spot sales. Qatari Minister of State for Energy Mohammed Sada said in March that his country did not plan to reduce output to support prices.

Foster Gas Report

Published: 10 June 2010 06:51 GMT | Last updated: 10 June 2010 06:51 GMT

Due to the growing domestic supply from shale gas, the U.S. did not become the liquefied natural gas (LNG) market many expected in the last couple of years, asserted BENTEK Energy, LLC in its latest report, *The LNG Market: New World Order*. U.S. shale gas has cut import needs, resulting in a global oversupply of LNG and lower world gas prices. The dramatic U.S. market dynamics have affected "every corner of the globe and every sector of the global gas industry," from supply to demand to transportation and prices, the report stressed. Worldwide LNG shippers have found "surprising demand growth" in emerging and traditional world markets, especially in Europe, which is relying more on LNG as an alternative to oil-indexed pipeline gas.

Furthermore, the LNG industry has effectively linked the rest of the global gas market much closer to the U.S. gas market. Major LNG players are buying stakes in U.S. shale, ensuring that changes in U.S. gas production affect not only U.S. gas prices, but also gas prices in other parts of the world.

“Not only is the U.S. effectively exporting its abundant shale gas by displacing LNG imports, it also is exporting its low gas prices, which is helping to drive up global gas demand,” the report observed. “Every new molecule of U.S. shale gas is sending ripples to markets in Europe, Asia and the Middle East.”

In the U.S., BENTEK sees a “weak outlook” for LNG imports over the next five years. The U.S. “will remain the most extreme market of last resort” and imports will remain largely a peaking supply source. U.S. LNG terminals are expected to operate at only 8% of total sendout capacity over the next five years. North America, in general, is projected to remain oversupplied with natural gas and subject to downward price pressure for the next five years. These market conditions, notably, “could lead” to U.S. LNG exports from several Gulf Coast terminals, BENTEK said.

BENTEK Energy LLC

November 18, 2010

CANADIAN NATURAL GAS IMPORTS TO U.S. PROJECTED TO DROP 30% BY 2015

Ruby Pipeline, Bison Pipeline and Marcellus shale to put “the big squeeze” on Canadian natural gas imports to the U.S.

EVERGREEN, CO – According to a new report from BENTEK Energy, LLC, Canadian producers face serious challenges as the continued growth of unconventional natural gas supplies and newly added pipeline infrastructure in the U.S. push Canadian imports out of the U.S. market. The Big Squeeze: Ruby, Canada and Marcellus examines the broad displacement of Canadian imports and its impact on the North American natural gas market, which will ultimately lead to curtailments in Canadian production.

“Marcellus shale volumes are now pushing Canadian imports out of the Northeast, and this trend will accelerate as new pipeline expansions drive additional U.S. gas supplies into Ontario,” said BENTEK Managing Director E. Russell (Rusty) Braziel. “In the West, the new Ruby and Bison pipelines will increase deliverability of the more economical Rockies gas to Western markets and the Midwest, respectively, while displacing gas back into Canada. Because of this, we anticipate gas imports to the U.S. to drop 2.0 billion cubic feet per day (Bcf/d) or 30% by 2015.” According to BENTEK, in the next few weeks Western Canadian supply currently bound for the Midwest markets on Northern Border Pipeline will face direct competition from Rockies supplies flowing east on the newly installed Bison Pipeline. By next summer, Rockies producers will have an additional 1.5 Bcf/d of westbound capacity on El Paso’s Ruby Pipeline bound for Malin, Oregon. These supplies will compete head-to-head with Canadian supply for PG&E’s Citygate, the premium market in the West. “We are looking for a 1.0 Bcf/d decline in Canadian production from 2010 to 2015, despite the growth of Canadian unconventional shale production in the Montney and Horn River plays of British Columbia,” continued Braziel. “The bright spot on the Canadian supply/demand horizon is a significant increase in Canadian natural gas demand, which will partially help offset the otherwise bearish outlook for Canadian gas prices.”

BENTEK forecasts an increase in gas usage due to the renewed focus on oil sands development in Alberta and increased power generation in Ontario as coal-fired power plants are replaced with natural gas power generation. The Big Squeeze: Ruby, Canada and Marcellus examines these issues in detail, including a five-year outlook of the expected market changes throughout North America. The report includes an in-depth look at the Canadian import outlook through 2015, including the impact of the Ruby and Bison pipelines and the supply increases expected from the Marcellus shale.

Associated Press

Oil companies increasingly eye natural gas - November 9, 2010

Pretty soon, Big Oil will be more like Big Gas. The major oil companies are increasingly betting their futures on natural gas, with older oil fields producing less crude and newer ones either hard to reach or controlled by unfriendly nations. They are focusing more than ever on natural gas because it burns cleaner than oil and is gaining traction as a fuel for transportation. The latest move came Tuesday, when Chevron made a $4.3 billion deal to buy up natural gas fields in the Northeast.

Until recently, Big Oil watched the rise of U.S. natural gas from the sidelines, and smaller companies drilled into underground layers of shale. New techniques allowed companies to drill parallel to the ground and hit previously tough-to-reach deposits, helping them tap ever larger bounties of shale gas.

"Production is screaming," said E. Russell Braziel, managing director of BENTEK Energy, which tracks natural gas prices in the U.S.

The U.S. now holds about 3.82 trillion cubic feet of natural gas in storage, about 10 percent more than the average over the past five years. And the industry keeps pumping more out of the ground.

AlterNet November 5, 2010

Why Is Obama Cuddling Up to Karl Rove and His Gas Drilling Friends?

Rove pronounced the movement for clean energy dead at a natural gas drilling conference. But a massive protest outside reveals just the opposite. In the days following Tuesday's election, President Obama's first peace offering to hardliners across the aisle was telling: "We've got, I think, broad agreement that we've got terrific natural gas resources in this country," he said. At the same time he was giving the thumbs-up for natural gas drilling, Karl Rove was doing the same, appearing as the keynote speaker at Pittsburgh's David Lawrence Convention Center for the DUG (Developing Unconventional Gas) East Coast conference on hydraulic fracturing for natural gas in the Marcellus Shale. On Wednesday, November 3, the main day of DUG programming, an estimated 500-800 people marched across the Rachel Carson bridge through downtown Pittsburgh, surrounding the convention center for a rally. As they crossed the historic bridge, they shouted "No fracking way," "Clean air, clean water," and "It used to be Frick and now it's Frack," (referring to Pennsylvania's coal and steel robber baron Henry Clay Frick). They played trombones and drums, carried 7-foot-high puppets, and held homemade signs, the most dramatic being a 12-foot-square banner reading, "The people have a constitutional right to clean air, pure water, and the preservation of the natural, scenic, historic and esthetic values of the environment -- Article 1, Section 27 PA Constitution." The consensus of the day was that the Marcellus is the most important shale in the country and Pennsylvania is the most important part of the Marcellus. Others, like John Pinkerton, President and CEO of Range Resources, who announced in October it would be selling off most of its Barnett Shale holdings in Texas to invest in the Marcellus, talked about the new frontier of the Marcellus. Tom Sherman, an analyst for Bentek LLC, an energy industry analysis firm, said, of Marcellus development, "It's not that we don't think West Virginia and New York are important. The point is that Pennsylvania's production and acreage is prolific and ample enough to drive the forecast on its own, regardless of what happens in West Virginia and New York."

President Obama might be feeling friendly to fracking. As reported by Mike Soroghan of Greenwire, fracking industry spokesmen found Obama's statements at his November 3rd press conference are consistent with positions of his State Department, which is looking to push the technology globally and the Energy Department also puts a lot of stock in shale gas production.

HART

October 15, 2010

Pa. Marcellus at 1.5 Bcf/d – Bentek

Marcellus production in Pennsylvania alone reached 1.5 Bcf/d this month, Bentek Energy director of origination and business development Andrew Bradford said yesterday at a roundtable discussion hosted by Hart Energy. Current levels of Marcellus and Eagle Ford production are outstripping projections issued just a year ago, Bradford added. With Marcellus output ramping up, Appalachian gas production could increase by 4 Bcf/d to total 7 Bcf/d in 2015, equivalent to 50pc of gas consumption in the northeast US, Bradford said. Pennsylvania will account for most of the incremental Marcellus output. Eagle Ford production could reach 4 Bcf/d by 2015, returning gross gas production in south Texas to 9 Bcf/d, Bradford said. While the region has ample transportation capacity towards the Houston Ship Channel and Henry Hub, the key challenge in the Eagle Ford is conversion of existing gathering networks to accommodate the expected growth in wet gas production, he added.

THE DAILY COMMODITIES

October 14, 2010

Liquid Gold

There's a growing divide in the North America gas industry. Liquids or non. The always hawkish energy eye of Colorado's Bentek Energy recently observed the growing effect of liquids-rich plays on the U.S gas production profile. Speaking at a National Energy Services Association forum last week, Bentek managing director Rusty Braziel noted just how critical liquid-rich gas plays are becoming. Said Braziel, "Some companies could sell their liquids and give the gas away for free and still make money."
This is an important point for anyone investing in natural gas. High-value liquids from plays like the Eagle Ford shale in Texas make producers in these areas somewhat insulated from gas prices. Even at low prices, producers can keep running these wells at a profit.

This flies in the face of conventional wisdom. Which suggests that "low prices should cure low prices" by forcing producers to shut in wells, ultimately decreasing output and raising bidding for the remaining supply.

My Billings Gazette

October 11, 2010

EPA's impending regs may decrease coal market

CASPER — Natural gas is poised to grab a portion of the electric utility market that for decades has been dominated by Wyoming coal. Driving this shift is the U.S. Environmental Protection Agency's actions to further restrict a number of industrial air pollutants, and a legal mandate to phase in rules curbing greenhouse gas emissions, which begin in January.

Advanced directional drilling and the ability to shatter deep rock formations to unlock shale gas have boosted domestic gas reserves by more than 35 percent in recent years, according to industry estimates.

Hundreds of rigs are drilling in shale gas plays such as the Marcellus in Pennsylvania and New York, the Haynesville in Louisiana and the Barnett in Texas. Industry analysts say it's reasonable to expect a significant resurgence of natural gas production in Wyoming and throughout the Rockies.

"The costs of those (production) activities are economic, at some prices. If gas stayed at $2 (per thousand cubic feet), probably not. But it's likely it will be in the $3 to $5 range," said Porter Bennett, president and CEO of Bentek Energy, which specializes in energy market analysis. According to the Energy Information Administration, the Rocky Mountain region can expect an 8 percent increase in natural gas production from tight sand formations by 2035.

Gas Daily

October 8, 2010

Gas output may increase even as capital shifts to high-btu plays

Natural gas production in the US could end up increasing even as exploration-and-production companies move capital away from pure gas drilling, an industry analyst said Thursday. Rusty Braziel, managing director of Bentek Energy, noted that several large producers, including heavyweights Chesapeake Energy and Devon Energy, have recently out-lined plans to shift their drilling focus toward gas plays that are also rich in hatural gas liquids and crude oil, such as the Eagle Ford Shale of South Texas.

"When these companies push more dollars into the higher-Btu plays, they are going to be drilling gas wells that they wouldn't otherwise be drilling," Braziel said on the sidelines of a National Energy Services Association forum in Bastrop, Texas. As a result, overall domestic gas production "stays up or increases."

platts

October 5, 2010

FERC Order 720: New Natural Gas Pipeline Postings Illuminate Intrastate Activity

The month of October 2010 marks a new chapter in the visibility of natural gas pipeline flows, capacity utilization and the dynamics of price formation. With the implementation of an important new Federal Energy Regulatory Commission (FERC) rule known as Order 720, buyers and sellers of natural gas now have unprecedented access to market supply, demand and storage data. Order 720 requires large intrastate pipelines, storage operators, local distribution companies and utilities to post natural gas flow and capacity data at the most significant points within those systems on publically accessible internet websites (also called electronic bulletin boards, or EBBs). Interstate pipelines have posted this information for a number of years, and the data has become the foundation for the analysis of natural gas market fundamentals. But until the implementation of Order 720, pipelines operating entirely within the boundaries of an individual state were exempt from this requirement. Utilization of the new intrastate and No-Notice data sources will significantly improve the quality of market participants' analytical research. As a result, energy traders, market makers, supply managers and investors will be able to step up the accuracy of their decision making in the natural gas arena. **With the implementation of this rule, data for several key intrastate markets such as the Houston Ship Channel, Katy, Waha and Carthage is now available for analysis.** Currently more than 60 intrastate pipeline systems are posting this vital flow and capacity data, including Enterprise Channel, Enterprise Texas, Energy Transfer Houston Pipeline, Energy Transfer Oasis, Atmos Pipeline, Kinder Morgan Storage, Crosstex LIG and Freeport LNG.

October 5, 2010

Analysis: Shale Gas Drilling Techniques Revolutionize Oil Shale Drilling

Evergreen, Colo.-based BENTEK Energy reports that horizontal drilling and hydraulic fracturing, which has revolutionized U.S. shale gas production and other unconventional plays, is also transforming the domestic crude oil industry. As a result, U.S. oil production is on the rise for the first time in 23 years. In its new report, The Rush to Unconventional Oil, BENTEK notes that technologies are being used to unlock oil from shales in a number of plays such as the Bakken and Niobrara shales in the Rockies region, the Bone Springs/Wolfberry, Granite Wash and Eagle Ford plays in and around Texas and the liquids-rich shales in the southwestern Marcellus. "These are extremely important developments for U.S. crude oil production," said E. Russell Brazil, BENTEK Energy managing director. "The growth trend in unconventional oil looks strikingly similar to what we saw in the early stages of natural gas shale production. And the development is being driven by attractive oil prices, which remain high relative to natural gas. "This has provided the economic incentive for many players in the upstream industry to turn to more oil-dominated exploration opportunities to realize higher returns for their drilling investment dollars." The transfer of shale drilling techniques from gas to oil has the further potential to increase revenue for producers. Not only will producers benefit from the revenue gains from adding oil and liquids to the production, they also will reap the advantages of drilling efficiencies that hold the promise of lower costs and higher production yields.

October 4, 2010

THE RUSH TO UNCONVENTIONAL OIL and OIL PRODUCTION

According to a new market analysis just released from BENTEK Energy, LLC, the horizontal drilling and hydraulic fracturing technology that has revolutionized natural gas production from shale's and other unconventional plays is beginning to transform the domestic crude oil industry. The new report, titled The Rush to Unconventional Oil, details how these technologies are being used to unlock oil from shale's in a number of plays such as the Backend and Niobrara shale's in the Rockies region, the Bone Springs/Wolfberry, Granite Wash and Eagle Ford plays in and around Texas and the liquids-rich shale's in the Southwestern Marcellus. The most explosive growth is coming from unconventional oil shale plays such as the Backend Shale in North Dakota. In the past year alone, the Backend oil production has rocketed up 79%, moving North Dakota into position as the nation's fourth largest oil producing state. Rocky Mountain oil production is expected to double in the next ten years. "These are extremely important developments for U.S. crude oil production," noted E. Russell (Rusty) Braziel, BENTEK Energy Managing Director. "The growth trend in unconventional oil looks strikingly similar to what we saw in the early stages of natural gas shale production. And the development is being driven by attractive oil prices, which remain high relative to natural gas. This has provided the economic incentive for many players in the upstream industry to turn to more oil-dominated exploration opportunities to realize higher returns for their drilling investment dollars." The report assesses the recent growth trend in U.S. oil production, which is up almost 10% over the past two years. Much of this growth has been in the deep waters of the Gulf of Mexico, which is now under a cloud due to the current moratorium and potential long-term regulatory changes expected as a result of the political fallout from the recent BP oil spill. However, the study indicates that growth in onshore unconventional crude oil production can be expected to offset deepwater declines over the next few years. "The transfer of unconventional drilling technology from natural gas to oil drilling has shown great promise thus far," Braziel noted. "Producers seem to be achieving similar drilling efficiencies, resulting in lower costs and higher production yields."

BENTEK's report warns that despite tremendous early success in a variety of unconventional oil plays, several of these new liquids-rich regions lack adequate gathering, processing and transportation infrastructure to move growing amounts of production to market. "Significant new investment will be required," Braziel said. "Which projects end up ultimately being built to serve these growing new onshore oil producing regions could dramatically change the U.S. energy landscape."

In conjunction with the release of The Rush to Unconventional Oil, BENTEK has also initiated the publication of a new series of monthly reports called the Oil Production Monitor series, which tracks regional crude oil drilling activities, permitting, well results, pipeline infrastructure developments, crude prices and forecasts of crude oil production. The Rockies Oil Production Monitor is available today, and includes The Rush to Unconventional Oil in an introductory subscription package.

REUTERS

October 4, 2010

Natgas prices must drop below $3 to curb production

Natural gas futures must fall well below $3 before producers begin to curb production, according to a Reuters poll, lower than the break-even price for drilling, reflecting a market still in flux from the advent of shale gas.

Henry Hub natural gas futures prices stuck below $4 per million British thermal units (mmBtu) for the past five weeks, the longest stretch below that mark in a year. Traders are searching for evidence that marginal drillers may finally begin to idle rigs. But according to a Reuters poll, the conventional wisdom that a price of $3.50 to $4.00 gas would curb production has grown outdated since 2009, when prices collapsed in September, to an average of $3.46.

Now, prices would need to drop to a sustained level of $2.73 per mmBtu before companies are likely to stop drilling new wells, according to the average of 14 analysts surveyed by Reuters. The highest estimate was $3.50; the lowest was $1.75. Break-even costs for drilling in the Haynesville and Marcellus, two of the most prolific shale plays located in Louisiana and Pennsylvania are below $4/mmBTU. Gas prices below $3 for a long period would certainly curb drilling programs for dry gas but costs for liquids-rich gas in plays like the Eagle Ford and Granite Wash [shales] are lower than $3.

Forbes.com

September 27, 2010

It's Time For The U.S. To Export Natural Gas

Just a few years ago the rule of thumb was that the United States was running low on big new natural gas fields and that to meet demand (currently running at 63 trillion cubic feet a year) we would need to start importing ever larger quantities of liquified natural gas, or LNG. It was that reckoning that led companies like Cheniere Energy and Sempra Energy to navigate the sea of NIMBYism and build LNG import terminals. Then came the shale gas revolution. The Barnett, Haynesville, Eagle Ford, and Marcellus shales promise enough gas to supply the nation for 100 years, if they can be drilled safely.

Now, facing low prices of $3.80 per mmbtu and a glut of supply, natural gas producers are curbing their investments in drilling up new fields. Penn Virginia, Marathon Oil, Noble Energy and Apache Corp all are slowing gas drilling. The scene is so dire for gas drillers that Dave Roberts, head of exploration at Marathon Oil Corp telling investors he doubts the gas biz “is going to get better any time soon and maybe within the span of my career.”

platts **September 24, 2010**

Asia Pacific demand to stay heart of LNG business 2010-15

Demand for LNG in the Asia Pacific region is forecast to grow by 7.8 Bcf/d from 2010 to average 25.4 Bcf/d in 2015, with the region remaining the heart of the LNG business, US-based energy analyst Bentek said in a report released Thursday. Bentek added that demand growth would be driven largely by China and India, with additional requirements from the recovering economies of Japan, South Korea and Taiwan, as well as emerging markets in Bangladesh, Pakistan, Thailand, Singapore and the Philippines. "China and India are markets with immense demand potential that are hindered by infrastructure constraints that will only be partially addressed by 2015," the report said, with both countries registering a combined demand of 8.1 Bcf/d by 2015. Domestic gas production increases in India and China only posed a "small risk" to LNG imports, and Bentek added that while it expected both countriesto increase domestic production of unconventional gas, this would not be enough to displace significant volumes of LNG imports. China's commitment to increase the use of gas in its energy mix will prove the major driver behind its demand growth over the next five years. With 4 Bcf/d of new import capacity slated to come online from 2010-2015 and numerous long-term contracts slated to start deliveries, domestic gas price hikes mandated by the country's leading economic agency, the National Development and Reform Commission, would help to support increasing LNG imports. "Japan will remain the world's largest importer over 2010-2015," Bentek said, adding: "Japanese demand will remain effectively flat through 2015, given limited economic growth and shifts to nuclear and less costly fuels."

Foster natural gas Report ... FROM WASHINGTON **September 24, 2010**

LACK OF DEMAND IN U.S. FOR LNG DUE TO DOMESTIC SUPPLY OF SHALE GAS HAS SHIFTED THE DYNAMICS OF THE WORLD MARKET; PREDICTS LOW U.S. LNG IMPORTS OVER THE NEXT FIVE YEARS AND THE GULF TURNING TO EXPORTING

Due to the growing domestic supply from shale gas, the U.S. did not become the liquefied natural gas (LNG) market many expected in the last couple of years, asserted BENTEK Energy, LLC in its latest report, *The LNG Market: New World Order*. U.S. shale gas has cut import needs, resulting in a global oversupply of LNG and lower world gas prices. The dramatic U.S. market dynamics have affected “every corner of the globe and every sector of the global gas industry,” from supply to demand to transportation and prices, the report stressed. Worldwide LNG shippers have found “surprising demand growth” in emerging and traditional world markets, especially in Europe, which is relying more on LNG as an alternative to oil-indexed pipeline gas. “The global LNG market has become more dynamic and flexible with a multitude of new participants,” the report noted. Furthermore, the LNG industry has effectively linked the rest of the global gas market much closer to the U.S. gas market.

Major LNG players are buying stakes in U.S. shale, ensuring that changes in U.S. gas production affect not only U.S. gas prices, but also gas prices in other parts of the world. “Not only is the U.S. effectively exporting its abundant shale gas by displacing LNG imports, it also is exporting its low gas prices, which is helping to drive up global gas demand,” the report observed. “Every new molecule of U.S. shale gas is sending ripples to markets in Europe, Asia and the Middle East.”

WORLD GAS INTELLIGENCE

September 15, 2010 - Imagine US LNG Exports

The US Department of Energy (DOE) decision last week to allow Cheniere to export up to 803 billion cubic feet (16 million tons) per year of gas for 30 years from its Sabine Pass site in Louisiana could be a first step in revolutionizing North America's still largely isolated gas industry -- and a big step toward higher North American gas prices and perhaps even global gas price linkage. The DOE authorization effectively covers two of the four 3.5 million ton/yr liquefaction trains Cheniere has said it hopes to build at Sabine Pass, already home to a 4 Bcf/d (32 million ton/yr) regas terminal, with existing rights to re-export LNG from other countries. Top US shale gas producer Chesapeake has tentatively committed to take one train of liquefaction capacity, enough to prepare 500 million cubic feet per of its domestic US gas for export (WGI Jun.9,p5). "We believe the US has needed an export terminal since the beginning of 2007," says Bentek Energy analyst Kelly Bennett. "We don't see demand growing enough to absorb the significant amount of production expected to go online, and to raise prices to a level high enough that producers would want to keep going." Bentek forecasts US production growth of another 5 Bcf/d by 2015. "Having a true export terminal in the Gulf of Mexico could really influence the Henry Hub price," Bennett adds. In the initial DOE ruling, Cheniere was authorized to export only to countries with free trade agreements with the US. While clearly restrictive, even this limited clearance could allow significant exports, particularly as the list of qualified countries includes Singapore and Canada -- which both have LNG hub ambitions that would allow re-export to other Asian and European locations -- as well as others including Australia, Chile, Mexico, Oman and Peru (WGI Aug.27'08,p8). Cheniere is now seeking authorization to export gas to all countries except those few subject to a US trade ban. That clearance would also cover volumes from another two trains. To read the complete article, please visit: www.energyintel.com.

OPIS
OIL PRICE INFORMATION SERVICE September 14, 2010

Ethane frac spread faces downward pressure, study says

The ethane frac spread, or the spread between natural gas and ethane, faces downward pressure going forward as shale plays across North America stand to increase total ethane production, says a market report. Weak frac spreads are bad news for planners of pipeline and marine transportation projects that involve shipping Marcellus Shale ethane long distances to petrochemical markets, located mostly at the U.S. Gulf Coast. The frac spread is a primary driver that underlies the economics of these projects. From 2006 to the present, the spread has averaged a robust 20.9cts/gal, and on occasion has leapt to 60cts/gal, says the Sept. 9 report from Bentek Energy. But over the next five years, the difference between the Marcellus Shale gas price and the Mt. Belvieu ethane price could average just 1-0cts/gal, the report says. Strong NGL prices have seen producers shift toward shale plays with high NGL content, increasing their production, especially of ethane. Almost 100% of ethane is used in the petrochemical market where NGLs have long been the preferred feedstocks versus more expensive naphtha and gas oils from refinery output streams. Over the past year, about 80% of all U.S. ethylene cracker feedstocks were NGLs. However, Bentek says that it is highly likely that ethane production from shale plays will increase faster than the petrochemical industry's ability to absorb it. Thus, ethane prices will decline relative to other NGLs, compressing the ethane frac spread.

OIL&GAS FINANCIAL JOURNAL **September 17, 2010**

Intrastate Pipe Data Will Give Market 'Missing Puzzle Piece'

The FERC order (Order 720) requiring many intrastate pipelines, storage operators, local distribution companies and utilities to post natural gas flow and capacity data at the most significant parts within their systems is due to be implemented Oct. 1. The addition of the intrastate information to existing market data will provide an unprecedented and crucial level of visibility into natural gas market supply and demand dynamics across North America. Interstate pipelines have posted natural gas flow and capacity data for many years. Although the data has provided a highly accurate depiction of the flow of natural gas across North America, without intrastate information, the whole picture of gas movement has remained incomplete. Now that we'll have the missing puzzle piece, our industry will see a much more comprehensive view of the natural gas market. The final rule, which was issued in November 2008, established new posting requirements under Section 23 of the Natural Gas Act (NGA) that call for all interstate and certain major non-interstate pipelines to post on their publicly accessible websites daily operational information, such as scheduled volume information and design capacity for certain receipt and delivery points (see Daily GPI, Nov. 21, 2008).

The order defined a major non-interstate pipeline as a pipe that is not classified as a natural gas company under the NGA and delivers annually more than 50 Bcf/year during a three-year period. Non-interstate pipes with deliveries at this level contribute to price formation, according to the Federal Energy Regulatory Commission (FERC). The FERC initiative also requires qualifying non-interstate pipelines to post daily specific scheduled flow information at each receipt or delivery point with a design capacity of 15 MMcf/d or more.

BENTEK Energy LLC **September 1, 2010**

FERC ORDER 720 TO REVOLUTIONIZE NATURAL GAS MARKET TRANSPARENCY BY UNLOCKING ACCESS TO INTRASTATE FLOW DATA

Pipelines, utilities, storage facilities and other systems operating within state boundaries are required to post natural gas flow and capacity data. EVERGREEN, CO (September 1, 2010) – On October 1, 2010, the Federal Energy Regulatory Commission (FERC) is scheduled to implement Order 720, requiring many intrastate pipelines, storage operators, local distribution companies and utilities to post natural gas flow and capacity data at the most significant points within those systems. According to analysts at BENTEK Energy, the addition of intrastate information will provide an unprecedented and crucial level of visibility into natural gas market supply and demand dynamics across North America.

“Interstate pipelines have posted natural gas flow and capacity data for many years,” noted E. Russell (Rusty) Braziel, Managing Director of BENTEK Energy. “Although this data has provided a highly accurate depiction of the flow of natural gas across North America, without intrastate information, the whole picture of gas movement has remained incomplete. Now that we’ll have the missing puzzle piece, our industry will see a much more comprehensive view of the natural gas market.” Additional rules of Order 720 include the posting of what is known as “No-Notice” data by interstate pipelines. No-Notice services give shippers on certain pipeline systems the ability to receive natural gas without the necessity of scheduling (nominating) the gas. The requirement under Order 720 for interstate pipelines to post No-Notice data has been in effect for several months, and approximately 30 interstate pipelines are providing the information.

“Utilization of the new intrastate and No-Notice data sources will significantly improve the quality of market participants’ analytical research,” Braziel said. “As a result, energy traders, market makers, supply managers and investors will be able to step up the accuracy of their decision making in the natural gas arena.”

THE WALL STREET JOURNAL.

Coal Gets Burned By Low Gas Price - August 26, 2010

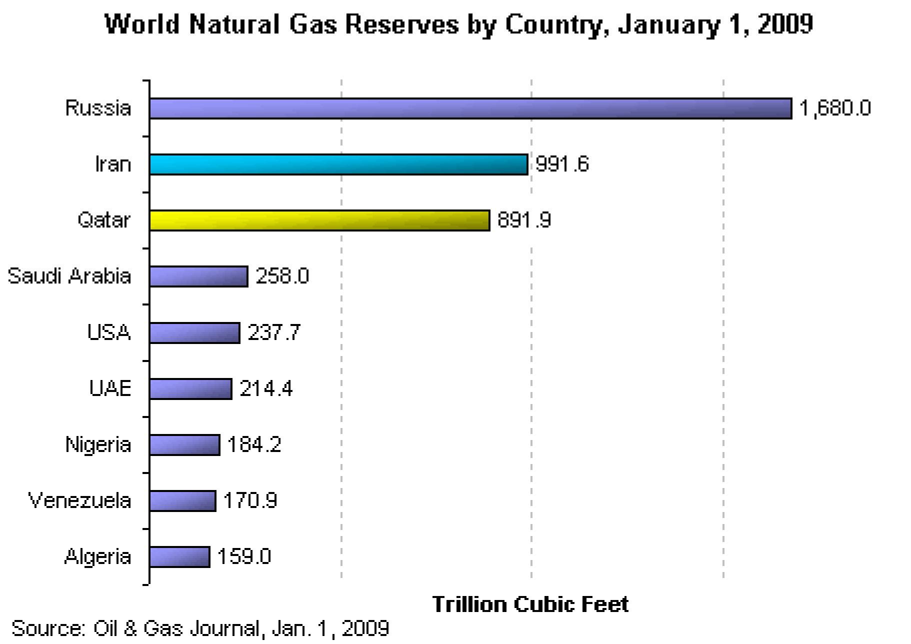
Fall in the Cost of One Resource Used to Fuel Power Plants Is a Drag on the Other. A slump in prices of natural-gas futures is having a knock-on effect in the U.S. coal market. Gas prices have fallen so far, trading Wednesday at a five-month low of less than $4 a million British thermal units, that gas-powered plants are able to capture a bigger share of the market. That is sapping demand for coal and driving down prices of Central Appalachian coal futures. The front-month contract settled at $60.05 a ton Wednesday on the New York Mercantile Exchange, down 15% since reaching a 20-month high of $70.87 a ton Aug. 5. September gas ended Wednesday down 4.2% at $3.871 a million BTUs. Eastern coal prices had climbed steadily since February before the recent pullback but remained well below record levels above $140 a ton reached in mid-2008. Plants that run on coal from the largest U.S. coal basin in Wyoming tend not be affected by natural-gas prices because of the low cost of Western coal.

Competition between coal and natural gas—known in the industry as fuel switching—was rare before last year and happens today mostly in the eastern U.S. Natural-gas production has boomed with the development of shale-rock formations across the U.S., and producers haven't shown signs of pulling back even as prices have declined. At the same time, supplies of eastern coal have tightened because of tougher environmental regulations, higher production costs and dwindling reserves.

OIL&GAS FINANCIAL JOURNAL ***Qatar has the largest non-associated natural gas field in the world and is the world's largest liquefied natural gas exporter***

Overview

According to *Oil & Gas Journal*, Qatar's proven natural gas reserves stood at approximately 890 trillion cubic feet (Tcf) as of January 1, 2009. Qatar holds almost 15 percent of total world natural gas reserves and is the third-largest in the world behind Russia and Iran. The majority of Qatar's natural gas is located in the massive offshore North Field, the world's largest non-associated natural gas field. The North Field is a geologic extension of Iran's South Pars field, which holds an additional 450 Tcf of recoverable natural gas reserves.



Sector Organization

As in the oil sector, Qatar Petroleum (QP) plays a dominant role in Qatar's natural gas sector, leading upstream production and playing an important role in downstream projects. Qatar's focus on natural gas development tends to be large-scale projects linked to LNG exports or the promotion of downstream industries that utilize natural gas as feedstock. Therefore, foreign company involvement has favored international oil companies with the technology and experience in integrated mega-projects, including ExxonMobil, Shell, and Total.

Qatar's LNG sector is dominated by Qatar LNG Company (Qatargas) and Ras Laffan LNG Company (RasGas). RasGas is 70 percent-owned by QP and 30 percent-owned by ExxonMobil, while the Qatargas consortium includes QP, Total, ExxonMobil, Mitsui, Marubeni, ConocoPhillips, and Shell. The LNG companies handle all upstream to downstream natural gas transportation themselves, while the Qatar Gas Transport Company (known as "Nakilat", which means "carriers" in Arabic) is responsible for shipping Qatari LNG.

Production and Consumption

Qatar continues to expand natural gas production. In 2008, Qatar produced approximately 2.7 Tcf of natural gas, or more than five times the amount produced in 1995. The expected increase in natural gas production will fuel the growing natural gas requirements of domestic industry, LNG export commitments, piped natural gas exports through the Dolphin pipeline, and several large-scale gas-to-liquids (GTL) projects. Qatar's natural gas consumption in 2008 was approximately 715 billion cubic feet (Bcf).

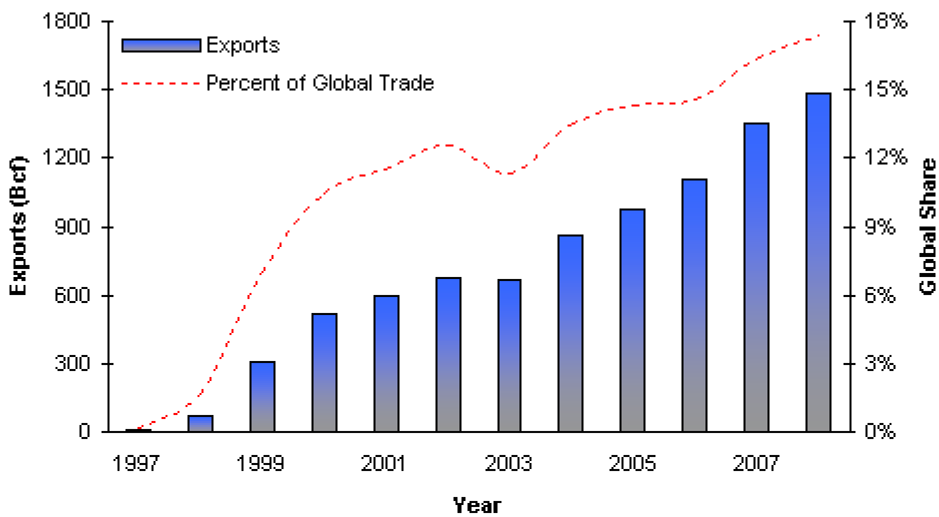
North Field

The North Field is key to Qatar's natural gas development and production plans. In 2005, Qatari government officials placed a moratorium on additional natural gas development projects at the North Field to allow time to study field development optimization. The moratorium did not affect projects approved or underway before the moratorium, allowing Qatar to continue its growth in natural gas production. According to *FACTS Global Energy*, by 2012 the North Field is expected to produce 20 Bcf/d.

LNG

Qatar is the world's leading LNG exporter. In 2008, Qatar exported nearly 1.4 Tcf of LNG. Of this amount, approximately 425 Bcf (8.7 million tons [MMt]) went to South Korea, 400 Bcf (8.2 MMt) to Japan, 300 Bcf (6.2 MMt) to India, 165 Bcf (3.4 MMt) to Spain, and 3 Bcf (less than 0.1 MMt) to the United States.

Qatar's LNG Exports, 1997-2008



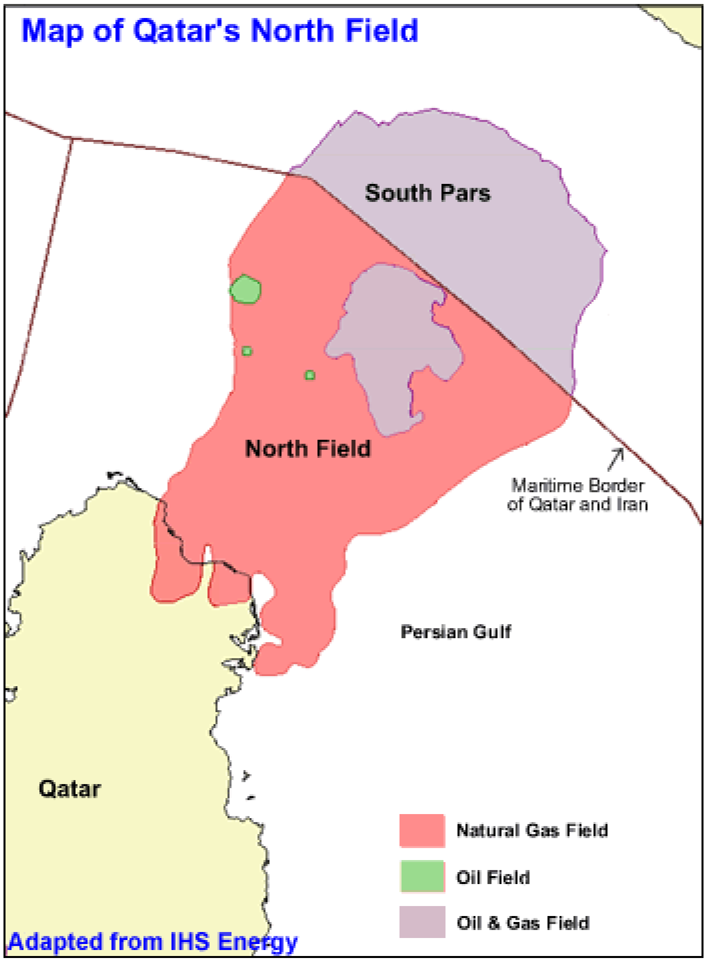
Source:1997-2007 EIA; 2008 FACTS Global Energy

Qatar has two major LNG operations, RasGas and Qatargas, with 11 trains online and a total LNG liquefaction capacity of 2.7 Tcf/y (53 MMt/y). Three of these trains were added in 2009. Qatargas 2, trains 4 and 5 were brought online in April and September (respectively). Combined, the trains will produce approximately 780 Bcf/y of LNG (15.6 MMt/y]), 44 million barrels per year (bbl/y) of condensate (6 MMt/y), and 12.5 million bbl/y of propane and butane (1.7 MMt/y). Rasgas 3, Train 6 was brought online in late October 2009 and has an LNG liquefaction capacity of 380 Bcf/y (7.8 million MMt/y).

RasGas 3, Train 7 is expected to come online in 2010. Qatargas 3, Train 6, with a liquefaction capacity of 390 Bcf/y of LNG (7.8 MMt/y) is planned to begin operations in 2010. Qatargas 4, Train 7, with the same liquefaction capacity, is planned to begin operations in 2011.

Exports

During 2008, Qatar exported over 2 Tcf of natural gas, about 70 percent of which was liquefied natural gas (LNG). Qatar currently exports about 2 Bcf/d of natural gas to the UAE through the Dolphin pipeline.



Qatar's LNG Infrastructure, November 2009			
Unit	**Liquefaction Capacity**	**Start-up**	**Primary Market(s)**
RasGas Facilities			
Trains 1& 2	2 x 3.2 MMt (320 Bcf)	Aug. 1999	South Korea
Train 3	4.7 MMt (230 Bcf)	Feb. 2004	India
Train 4	4.7 MMt (230 Bcf)	Aug. 2005	Europe
Train 5	4.7 MMt (230 Bcf)	Mar. 2007	Europe & Asia
Train 6	7.8 MMt (380 Bcf)	Oct. 2009	China
Train 7	7.8 MMt (380 Bcf)	2010	China
QatarGas Facilities			
Trains 1-3	3 x 3.2 MMt (480 Bcf)	Dec. 1996	Japan & Spain
Train 4	7.8 MMt (380 Bcf)	Apr. 2009	UK
Train 5	7.8 MMt (380 Bcf)	Sep. 2009	UK
Train 6	7.8 MMt (380 Bcf)	2010	US
Train 7	7.8 MMt (380 Bcf)	2011	China & North America
Source: RasGas, Qatargas, media reports			

Dolphin Project

Qatar is the supplier for the Dolphin Project, which connects the natural gas networks of Qatar, the United Arab Emirates, and Oman with the first cross-border natural gas pipeline in the Gulf Arab region. The pipeline currently exports 2 Bcf/d from Qatar, and has a capacity of 3.2 Bcf/d. Increased supplies from Qatar are uncertain until the North Field moratorium issue is resolved.

Gas-to-Liquid

Gas-to-liquids (GTL) technology uses a refining process to turn natural gas into liquid fuels such as low-sulfur diesel and naphtha, among other products. In January 2009, industry sources reported the Oryx GTL plant (QP 51 percent, Sasol-Chevron GTL 49 percent) was fully operational, producing approximately 30,000 bbl/d of GTL. The Oryx project uses about 330 MMcf/d of natural gas feedstock from the Al Khaleej field. Depending on the resolution of the North Field moratorium, Oryx GTL may choose to expand production capacity of the plant in the future. The Pearl GTL project (QP 51 percent, Shell 49 percent) is expected to use 1.6 Bcf/d of natural gas feedstock to produce 140,000 bbl/d of GTL products as well as 120,000 bbl/d of associated condensate and LPG. Currently, the plant is expected to start up at the end of 2010, followed by a ramping up of production in 2011. The Pearl project will be the first integrated GTL operation in the world, meaning it will have upstream natural gas production integrated with the onshore conversion plant.

ICIS October 18, 2010

IN THE early part of this decade, there was a boom in the building of terminals and bubble-topped barges to carry liquefied natural gas, known as LNG, around the globe. The ultimate target at the time was put squarely on the gas-deficient US market. The lead time on LNG projects in gas-rich places such as Qatar, the world's largest LNG exporter, Nigeria, Russia, Algeria, Yemen and Norway had 2009 highlighted on industry calendars as the coming-out party for the super-cooled version of natural gas as a global force. However, over the past few years, the US natural gas supply picture has radically reversed as new drilling technology in tight-rock shale formations has unleashed a flood of supply, leading to this year's unprecedented storage builds.

Staring down the historic overhang in US natural gas, LNG players shelved new capacity and sped up maintenance at existing production trains, slowing LNG traffic globally. But industry observers are predicting that that pent-up production of LNG will start to appear on the market in 2010 and shape natural gas pricing, an all-important power fuel and feedstock for the chemical industry, beginning this year. "We had expected to see the LNG wave of 2009, but that didn't occur," says Teri Viswanath, director of energy research for Credit Suisse in Houston, Texas, US. "These projects are a decade in the making. But there were concerns of bringing on a supply stream into a market with very little [in the way of] buyers." In the first nine months of 2009, LNG imports to the US totaled 352.9bn cubic feet (bcf) (10bn m^3), according to the latest data from the US **Energy Information Administration (EIA)**. That level was 23% higher than the period in 2008, but almost half the 691.5bcf that hit US shores in 2007.

The US shale gas revolution has affected the entire energy sector, but might have shaped LNG decision-making as much as any market. Bob Ineson, head of the North American gas group at IHS Global Insight's **Cambridge Energy Research Associates (CERA)**, says the emergence of unconventional gas in the US caused "the great hiatus" in the LNG market over last three or four years. Investment decisions to build new LNG [facilities] were scarce, as in zero," he says. The slowdown in LNG ships to the US coincided with gas gushing out of the ground in the continental US. "To put the order of magnitude around that, from the beginning of 2007 to the middle of 2008, US [natural gas] production increased by 7bcf/day," Ineson explains. "That's equivalent to 100% of UK production." Then the world economy faltered, leading into 2009, wiping out massive amounts of industrial demand, while commodity prices cratered. The perfect storm of negative factors that suppressed LNG activity in 2009 will not stop cargoes sailing in 2010.

Viswanath says conservative forecasts put the 2010 increase in global LNG supply at 4bcf/day. Half of that will head for the US. That outlook would double US LNG imports from 1bcf/day to 2bcf/day, according to Viswanath. The EIA's expectation is slightly lower, predicting an import total of 1.7bcf/day this year. The government agency attributed its forecast to "the expected completion of additional global LNG supply projects, although the start-up dates for supply additions have historically been subject to delay. "Our outlook assumes that production does back off and drilling activity does slow and that gets us to a slightly higher price environment than we had this year," he says. "We are not in the camp that says we are going to be at $6.00-7.00 by the end of 2010."

In the Atlantic Basin, LNG cargo prices are based on the futures prices on the New York Mercantile Exchange (NYMEX)'s Henry Hub pipeline point in the US and National Balancing Point (NBP) in the UK. Simon Ellis, head of LNG markets for the global news and pricing agency **ICIS Heren**, says spot LNG cargoes are typically priced into the US and European markets at a slight premium to futures benchmarks. The flexibility of LNG to extend gas supply beyond the insulated continental pipeline markets has some suggesting that LNG could be the catalyst for uniformity in Atlantic basin pricing. "There is an awful lot of re-gasification capacity on both sides of the Atlantic, so there is quite a substantial potential to move gas back and forth and keep the markets across the Atlantic in some kind of rough convergence," says Ineson. The futures-based pricing scenario is opposite to the long-term LNG contracts in Asia and in some parts of Europe that are linked directly to oil prices, because of its standing as a liquid global index amid no concrete regional gas benchmarks.

Crude-correlated contracts are dominating LNG cargoes priced from the recently announced projects in Australia and Papua New Guinea. Chinese state energy giant Sinopec has arisen as a buyer in the **PNG project in Papua New Guinea**, directed by US oil and gas major ExxonMobil. ExxonMobil is also part of the massive Australian Gorgon LNG project that is being lead by US major Chevron, as well as partner the Anglo-Dutch major Shell. Multi-decade deals have already been announced with major Korean and Japanese LNG buyers such as Japan's Osaka Gas and Tokyo Gas, and South Korea's **CS Caltex**. ExxonMobil has been lining up its resources to capitalize on the increased profile for natural gas in the coming decades, especially in its LNG moves. The US major, also the world's largest publicly traded company, anticipates that global LNG demand will climb by roughly 4%/year in the next 20 years. By 2040, ExxonMobil has predicted that LNG will account for 15% of the world's natural gas demand. But in the meantime, oversupply plagues the global natural gas markets. That has the US in the position of port of last resort with its LNG infrastructure far outweighing the capacity of any other destination.

OIL&GAS FINANCIAL JOURNAL

LNG Outlook 2010

The current outlook for LNG is probably more uncertain than it has been for many years. This is the result of several factors, among which are:

- The speed with which LNG demand, particularly in North America, Spain, and the UK, has developed.
- The inherently slow response time of LNG supply to the sharply increased demand signals
- 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 and construction contractors and sophisticated machinery suppliers. This has led to a sharp “demand pull” inflation on capital costs. Costs are not only much higher than expected, but the potential for cost overruns and construction delays has increased. It is not clear how severely this has affected plans of the many projects that are under active consideration.
- The sharp increase in world energy prices. The effect of these higher prices on gas demand and on interfuel competition is not well understood.

- The uncertainties raised by environmental concerns. Pressures to limit coal utilization may tend to favor gas-fired power generation despite higher gas prices. This is a particularly important issue in China, where absent government policy intervention, high-priced 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 the countries will play in LNG supply between now and 2020.
- And last, but not least, the fact that LNG demand is inherently sensitive to small changes in world gas supply-demand balances. Where LNG is the "swing" source of gas supply for a gas importing country, small changes in its indigenous gas supply or demand magnify the effect on its LNG imports.

These uncertainties make it unrealistic to expect any forecast—no matter how well done—accurately to predict specific LNG trade flows out to 2020. This article, however, summarizes a recently completed projection—in three scenarios—of world LNG trade to 2020 done by Jensen Associates for the California Energy Commission.

More conservative

If one can generalize about most published world and regional gas forecasts, they tended to become more optimistic about gas demand in the 1990s as the enthusiasm for gas-fired combined cycle power generation took hold. Then, supply problems in North America and the North Sea 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 gas supply to imported LNG. During this period, demand estimates tended to remain high, and LNG tended to substitute for some of the projected loss of indigenous natural gas. But there was a growing recognition that supply was the principal determinant of the growth of world LNG trade. Now, in a more common forecast pattern, estimates reduce the amount of gas for future power generation and are more conservative about LNG trade.

At the same time that forecasts were adjusting to supply constraints, the rapid increase in world energy prices threatened to blunt the growth of overall energy demand and alter the balance between fuels in interfuel competition. This added an additional conservative element to the forecasts. The two major governmental organizations that publish world energy forecasts—the International Energy Agency and the US Energy Information Administration—both publish projections of future world gas supply and demand. A review of their projections over the past several years reveals a trend towards reduced expectations for total world gas demand and for interregional gas trade. For EIA, it is possible to compare its expectations of total world gas consumption for 2020 in both its International Energy Outlook 2002 (IEO2002) and its IEO2006. Total consumption shows a decline of 7.4% between the forecasts made 4 years apart.

For the IEA, a comparison of total consumption for 2040 (IEA does not project 2020 in both documents) is possible for its World Energy Outlook 2002 (WEO2002) and its WEO2006. Its total consumption projections decline 7.8%. But indicating the sensitivity of trade to the new, higher priced environment, its projection of interregional gas trade declines by 22.4%. This pattern of declining gas demand and LNG trade forecasts over time is significant. It suggests that some LNG demand estimates 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 our 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 a "high" scenario.

It is important to recognize that our projections are on the low side compared to many public projections of future LNG trade. Their conservatism results from two underlying assumptions. We accept the IEA's and EIA's view that higher prices have reduced expectations of gas demand and world gas trade. But we are impressed that many of the LNG supply problems—high costs, technological challenges, and geopolitical concerns—may slow the process of making supply available.

Escalating costs

For an extended 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. But this perception of steadily falling costs for LNG has been dashed in recent years. The surge in demand for LNG that began in the late 1990s has taxed the capabilities of experienced engineering-procurement-construction (EPC) contractors and 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 EPC contractors 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 4-year design and construction period for most LNG plants, the plants scheduled to come on line over the next 4 years might be described as the “order book.”

Click here to enlarge image

Fig. 1 shows the order book has more than doubled since 2002 from the period 1991 to 2001, graphically illustrating the pressures on the suppliers. It is extremely difficult to get reliable estimates of what is happening to costs at present. What is apparent is that there is a wide dispersion in costs for liquefaction plants that are currently under construction. There are also a number of “problem trains” that have dramatically higher costs than one might expect from trends in historic cost patterns. It is difficult to separate the special problems that have escalated construction costs of these plants from the current pressures on costs that are applicable to construction costs 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/tonne of liquefaction capacity. A reasonable range of costs for these projects in 2000 construction environment might have been $250-300/tonne. Current costs for those projects—assuming no problems—would probably be more than double those levels. Both Snohvit and Sakhalin II experienced very large cost overruns, but both are Arctic projects and seem to have experienced “learning curve” problems. The Iranian bid is for a project whose government is under international sanctions and has difficulty getting competitive bids from experienced EPC contractors.

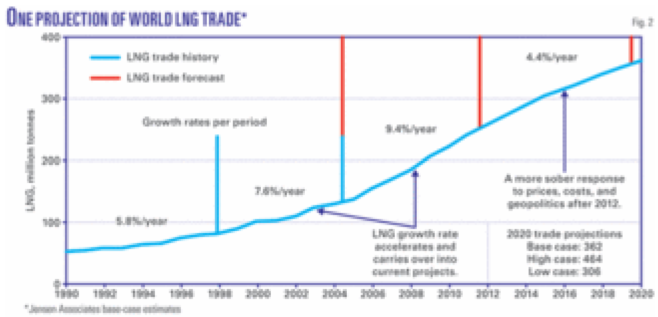
It is always dangerous to assume that “cost shock” levels are permanent and will persist throughout the period of a long-term forecast. But it is very difficult to determine what a more stable long-term cost structure might look like.

What is apparent, however, is that the current high-cost environment has reduced the order level for new LNG liquefaction capacity that might be expected to come on line in 2012 or later. If this pattern persists, new capacity expected to become available beyond 2012 will be in doubt.

If the burst in new orders 2002-06 has set the stage for a surge of new LNG capacity 2010-12, the current ordering pattern suggests a dip in new capacity beyond 2012.

The forecasts

In all three scenarios, 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 starting point for the reference case was the gas projections in IEA's WEO2006. Although it provided a basis for the overall projections, the forecast made use of many other sources to arrive at its final estimates.



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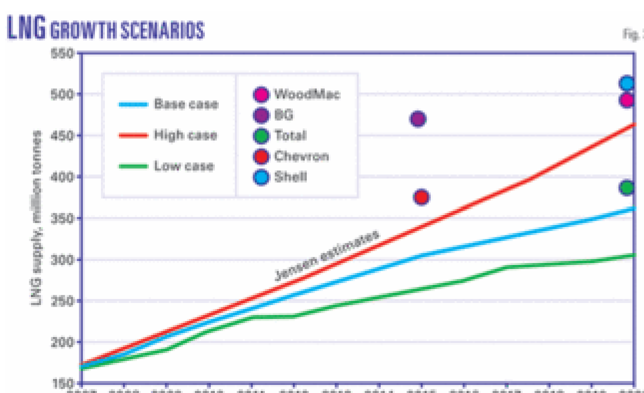
The base-case estimate for 2020 is 362 million tonnes (Fig. 2); the scenario range is 306-464 million tonnes.



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It is important to note that this forecast is more conservative than most others (Fig. 3). Its conservative estimates reflect two basic assumptions:

1. It adopts the view of IEA and EIA that high prices have moderated the demand for natural gas and reduced the potential requirements for interregional gas trade.
2. It does not foresee early resolution to the industry's cost, geopolitical, and arctic technology problems.

Whence supplies? World reserves of natural gas are very large and appear more than adequate to support gas exports far into the future. But many of those reserves are where economics, technology, or geopolitics raise questions about how quickly they will become commercially available.

Some portion of the reserves are already committed to markets, either for domestic consumption or contracted for export through pipeline or LNG infrastructure. Other gas is "deferred" because it is involved in oil production, either for reinjection, in gas caps in producing fields, or "long reserves" (dissolved gas that will not be produced until far into the future when the oil is recovered).

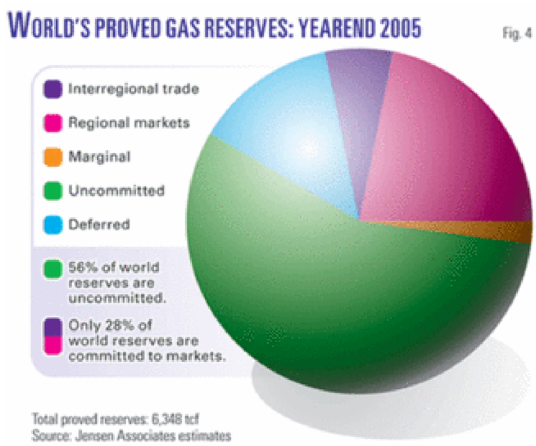
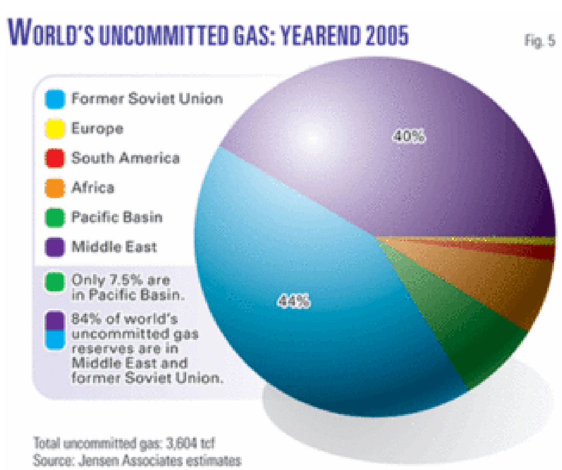
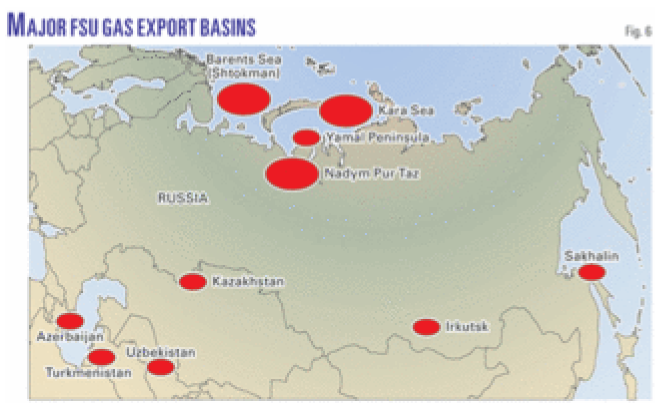


Fig. 4 shows our estimated market status breakdown of world gas reserves as of yearend 2005. Fully 54% of the world's reserves are currently uncommitted. While not all of the gas is available for current exports because producers reserve some of it to back up existing pipeline and LNG export contracts, uncommitted gas is the major source of new projects. Undiscovered resources will also become available at some time in the future, as will the deferred gas, as its involvement in oil production changes.

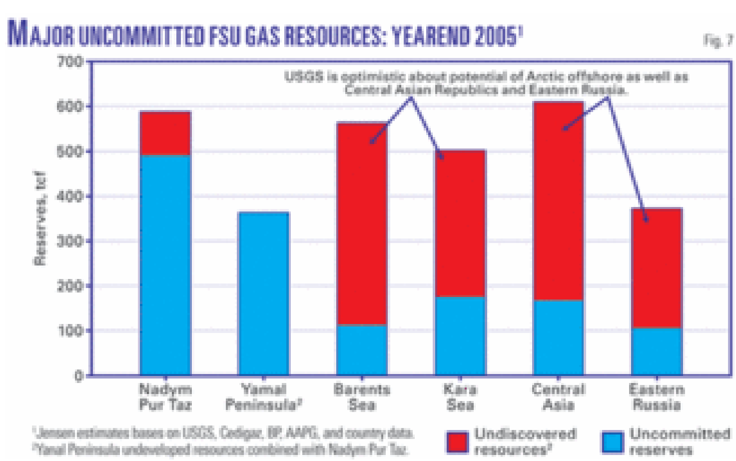
Eighty-four percent of the world's uncommitted reserves, however, as well as much of the undiscovered resource base are in the Middle East and the former Soviet Union (FSU; Fig. 5). It is significant that the FSU has historically exported entirely by pipeline, while the Middle East has exported its interregional volumes as LNG. We expect that future FSU exports will remain predominantly via pipeline and Middle East exports predominantly via LNG.



The start-up of Russia's Sakhalin II project next year will represent that country's first entry into LNG export. Sakhalin island is proving to be hydrocarbon-rich and is well situated to serve Pacific Basin LNG markets. But the question of how much of that resource is ultimately used to support LNG exports raises complex Russian geopolitical issues. Russian gas projects in Sakhalin and Eastern Siberia have been developed, not by Gazprom, as in the West, but with participation of international oil companies. Shell has operated Sakhalin II, ExxonMobil Sakhalin I, and a BP affiliate the Kovykta field near Irkutsk. The Russian government used severe cost overruns on Sakhalin II and environmental issues to reopen its licensing agreement with Shell. Following very difficult negotiations, Shell ultimately relinquished control of the project to Gazprom (OGJ Online, Dec. 21, 2006). Subsequently, Russia reopened the licensing agreement with a BP subsidiary for Kovykta. These moves suggest that the Russia wants to reexert centralized control over East Siberian and Sakhalin reserves. The country appears to be trying to develop a coordinated internal gas transportation grid from which it can serve both domestic and export markets. It has shown an interest in a pipeline system that would link Sakhalin and East Siberian reserves with its West Siberian reserves that serve Eastern and Western Europe. Such a system would give Russia the choice of LNG or pipeline exports as well as destination flexibility to serve Atlantic basin or Pacific basin markets.



But it is in the West where some of the Russian policy questions have the greatest potential impact on world LNG markets. In West Siberia, the Nadym-Pur-Taz region has been the workhorse of the Russian gas industry. Russia has three other, as yet undeveloped, major potential producing regions that hold much of the uncommitted gas: offshore Barents Sea containing the super giant Shtokman field; Yamal Peninsula; and offshore Kara Sea (Figs. 6 and 7).

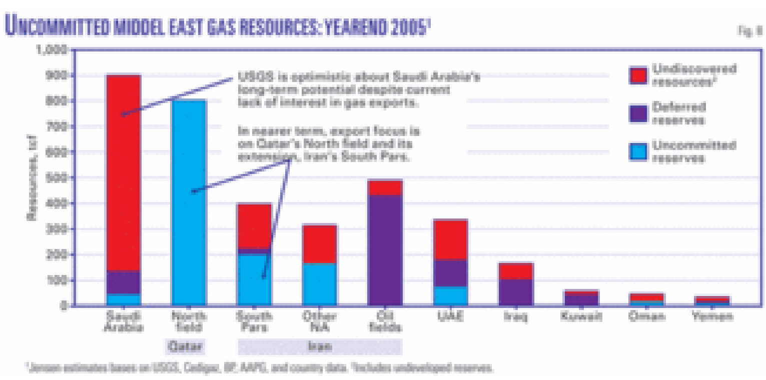


Nadym-Pur-Taz contains the world's second and third largest gas fields—Urengoi and Yamburg. But these two fields, together with another super giant—Medvezhye—are in advanced stages of depletion at a decline rate estimated at 2 bcfd/year.[1] In 2002 Gazprom brought another supergiant—Zapolyarnoye—on line to maintain production rates. But Russia appears to want to tap the other major undeveloped producing basins before undertaking significant further market expansion. These new reserves are likely to be costly and, in the case of the Arctic offshore fields, technically difficult.

For a time, it appeared that Russia favored a pipeline from the Yamal Peninsula to Western Europe as the next step. Russia has alienated some of its major European customers, however, both through supply interruptions to the Ukraine (that were perceived by some as politically motivated) and Russian refusal to allow independent Russian producers access to Gazprom's pipelines, a third-party access policy 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.

Emergence of North American 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 that could supply an LNG export facility as well as be extended south to St. Petersburg, where it could supply both Russia's new Nordstream Pipeline under the Baltic and also a small proposed LNG facility at Primorsk. More recently, Russia seems to have cooled somewhat on the idea of a Murmansk LNG export facility, although it still is interested in the Shtokman pipeline connection to the Baltic. It has not given up on the Yamal option, however. Development of Shtokman faces a technological challenge because of its Arctic offshore location. Several international oil companies were attempting to join with Gazprom to develop Shtokman. Although the Russian government at one point rejected their overtures, they appear to be back on the table with the signing of an agreement with Total (OGJ Online, July 13, 2007) and StatoilHydro (OGJ Online, Oct. 26, 2007). The uncertainties involving Russia's gas export plans have a substantial impact how Atlantic basin LNG develops. If Russia decides to concentrate on pipeline exports, which it knows best, and if the European customers grow more comfortable with Russian 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.

The Middle East accounts for 40% of both the world's proved reserves and its uncommitted reserves. But 61% of the region's uncommitted gas is in a single gas field shared between Qatar (the North field) and Iran (South Pars). If one adds in the uncommitted gas elsewhere in Iran, those two countries account for nearly 90% of the Middle East's uncommitted gas (Fig. 8).

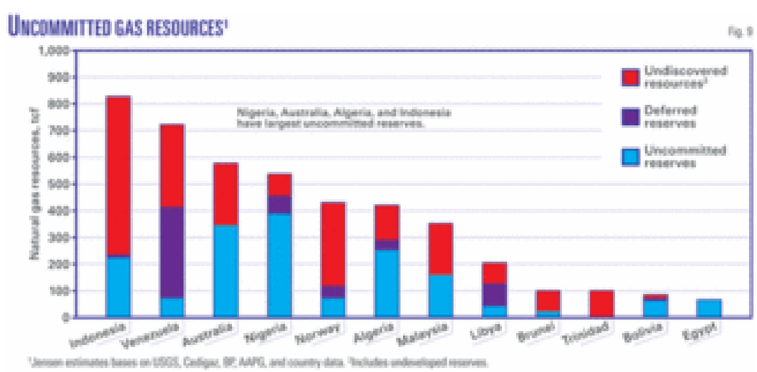


Qatar began its first LNG exports in 1997 and has elected an aggressive policy of LNG expansion since that time. It is expected to account for nearly 40% of the entire world's increase in capacity 1996-2011.

Qatar has adopted a “wait and see” policy for further LNG expansion beyond that point, however, both to digest the consequences of its rapid growth and better to understand how the complex 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 United Arab Emirates (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 US Geological Survey is very optimistic about undiscovered gas resources in Saudi Arabia, but that country has not yet found that gas nor shown any interest in gas exports. As long as Qatar maintains its decision against expansion beyond 2011, further Middle East LNG growth 2011-20 will have to come largely from Iran. That country 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 gas for reinjection into its complex oil fields. It is developing South Pars on the basis of 20 (perhaps as much as 23, if the gas proves to be there) production blocks of about 1 bcfd each. Five of the first eight blocks 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. Five LNG projects have been proposed for subsequent North Field blocks, as well as several that would utilize other Iranian gas fields.

The issue of whether 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. Although 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.

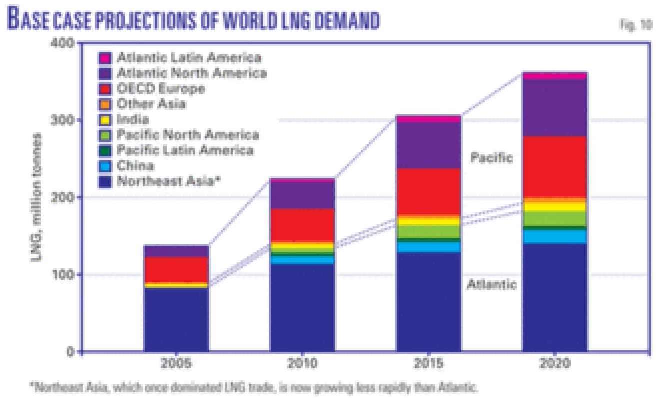


Other countries have significant available reserves for LNG export Fig. 9. But geopolitical issues that inhibit LNG development are not unique to Russia and the Middle East. Bolivia, Libya, Nigeria, and Venezuela have substantial gas reserves and potential LNG projects under consideration. But each of them faces geopolitical problems in developing new LNG projects.

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

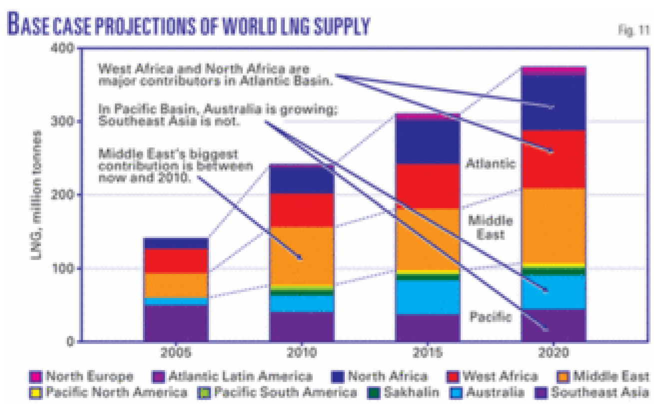
Regional implications

The base case envisions a world LNG demand growing to 362 million tonnes by 2020 from 138 million tonnes in 2005. While Atlantic basin markets will grow much more rapidly over the period than the Pacific basin markets, they still will not surpass the Pacific over the forecast period (Fig. 10).



The three biggest importing regions—Northeast Asia, OECD Europe, and the North American Atlantic Coast—among them account for more than 80% of world trade. Despite their potential importance, China and India account for only 5% and 3%, respectively.

Qatar dominates LNG supply additions out to 2011but has adopted a "wait and see" policy for further expansion beyond that point. While it is probable that Qatar will revisit that conservative policy at some point, it is speculative to include further Qatar supply beyond 2011 (Fig. 11).



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. Indonesia, which was the world's largest LNG supplier as recently as 2005 until being surpassed by Qatar, shows virtually no growth in the forecast. The country is grappling with the desire to use more of its gas domestically, and we expect it to limit export growth to new projects. On the other hand, Australia emerges as the second largest supplier after Qatar by 2015, followed closely by Nigeria.

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LNG's unexpected, unconventional shift

What a difference three years makes. In 2007, the liquefied natural gas (LNG) industry was characterised by burgeoning demand and tight supply. The dynamic had created a sellers' market that was expected to remain the status quo for the foreseeable future. What was not foreseen was the biggest global recession since the 1930s and the rapid expansion of shale-gas resources in North America. As a result of these factors, demand expectations for LNG have slumped as record amounts of new supply capacity come on stream. This has created a near-term excess and a favourable environment for buyers. But with few supply projects taking final-investment decisions (FID) in 2007 and 2008, and the ability to sanction new projects becoming increasingly difficult, market control is expected to revert to suppliers over time.

Over the past three years, global LNG demand has continued to rise, but at a far slower pace than predicted, largely because of supply constraints. Forecast demand for 2010 has dropped by 14% – equivalent to 37m tonnes a year (t/y) – to 220m t/y in Wood Mackenzie's most recent outlook, compared with the view in 2007 (see Figure 1).

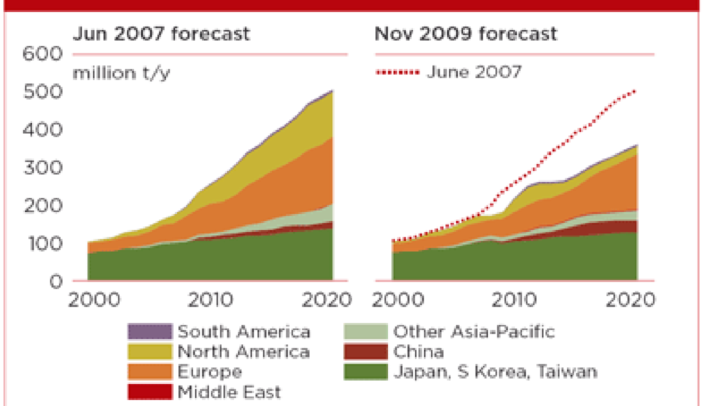


Figure 1: Global LNG demand forecast

Source: Wood Mackenzie LNG Tool

The difference between the two widens over time, with today's prediction of 360m t/y in 2020 being 28% (144m t/y) lower than the 2007 forecast. This radical shift has primarily been driven by two fundamental developments:

•Global economic crisis – the global recession severely affected the gas/LNG sector. Lower output across many industrial sectors subdued gas demand and resulted in hub prices falling by over 50% in 2009. As well as the immediate effect, deferred investment decisions stemming from difficulties in securing finance and general economic uncertainty are also adversely affecting the longer-term outlook for LNG demand; and:

•North American supply response – over the past decade, US LNG-import capacity has increased more than tenfold, to exceed 100m t/y. The new capacity was developed on the premise of a widely predicted gap between indigenous supply and demand. Despite intensive efforts to increase domestic production at the start of the decade, the overall supply picture for North America (US, Canada and Mexico) was one of slow growth or stagnation. In the absence of pipeline alternatives, developers scrambled to build re-gasification terminals to secure a new wave of LNG supply.

However, unconventional gas production in the US has accelerated at an unprecedented rate over the past three years. Shale gas has been particularly prolific, with production increasing by over 5bn cubic feet a day (cf/d) – equivalent to 40m t/y of LNG – since the beginning of 2007. This has had a material effect on US gas prices and drastically reduced the outlook for LNG demand in North America. In response, suppliers have started to remarket long-term volumes originally targeted at the US to other markets.
Unsurprisingly, North America's forecast LNG demand shows the greatest change, dropping by two-thirds over the 2010-20 period compared with the outlook in 2007. Europe's projected demand has also been severely hit, falling by over a third, as have the established northeast Asian LNG markets of Japan, South Korea and Taiwan, albeit to a lesser extent. But despite the generally pessimistic outlook, some markets are buoyant and have exceeded expectations. China, while undoubtedly affected by the economic crisis, has weathered the global recession better than most. GDP exceeded 8% a year in 2009 and is expected to remain buoyant as the global economy recovers. Projected demand of 9.7m t/y for 2010 is 1.2m t/y higher than forecast in 2007. But by 2020, it is forecast to reach 32m t/y, 43% (14m t/y) greater than previously expected.

Bullish Chinese outlook

This more bullish outlook is driven by the amount of new LNG supply China has contracted since 2007. Between 2007 and 2009, China signed long-term supply agreements (binding and non-binding) for the delivery of 22m t/y beyond 2015. As well as securing supply for its own domestic needs, China played an important role in allowing several new projects to achieve FID. It has also benefited from the decline in the long-term appetite for LNG in the US, with almost half of the new contracted supply being Qatari volumes originally targeting the US. China certainly has more upside potential. But with the push to promote indigenous production, including unconventional gas resources, and the start up of piped imports – from Turkmenistan and Myanmar (Burma), and potentially from Russia – LNG will face increased competition. Given its various supply options and the raft of Pacific-basin projects vying for market share, China should be in a strong position to leverage its buying power to procure future LNG supplies at competitive prices.

Five new countries have started importing LNG since 2007. Supplies to Brazil, Chile and Canada started as expected (see Table 1).

Table 1: New LNG importers since 2007

Since 2007 (April)	By 2013	Potential by 2020	Wild cards
Argentina	**Dubai**	Canary Islands	**Albania**
Brazil	Germany	Croatia	**Bahrain**
Canada	Netherlands	Cyprus	**Bulgaria**
Chile	Pakistan	Indonesia	**Colombia**
Kuwait	Singapore	Ireland	**Morocco**
	South Africa	Israel	**Panama**
	Thailand	Jamaica	**Romania**
		New Zealand	**Sri Lanka**
		Malaysia	**Ukraine**
		Philippines	**Vietnam**
		Poland	
		Uruguay	

Bold, red countries were not included in the outlook in 2007

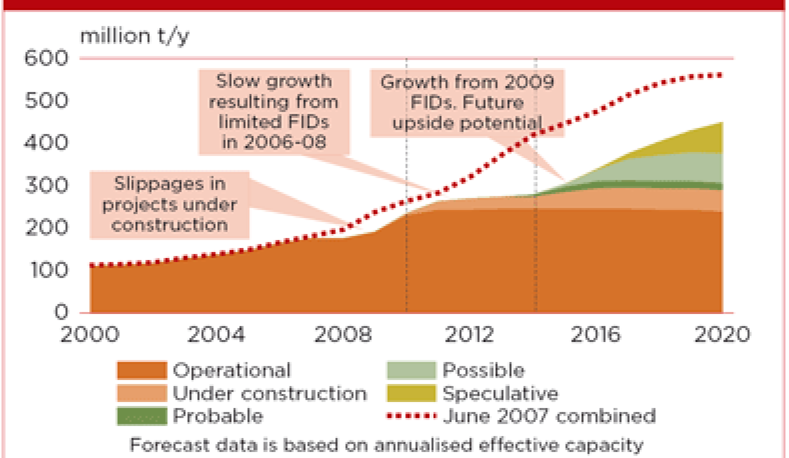
Source: Wood Mackenzie

But Argentina and Kuwait, two countries not identified in the 2007 forecast, have also begun importing, using moored floating storage and regasification units to overcome short- to medium-term gas-supply shortages. While Argentina has ample gas reserves, low regulated prices have stifled upstream investment and created a need to import LNG to meet peak demand. Kuwait, despite being a large oil producer, started to import LNG to meet peak gas requirements, after plans to import piped volumes from neighbouring countries failed to materialise. Dubai, scheduled to start importing LNG within the next two years, is another new, unexpected importer to emerge since 2007. The addition of several new South American and Middle Eastern importers – principally to meet peak demand in the southern hemisphere winter months and air-conditioning loads for the Middle East summer months – potentially adds a new seasonal dynamic and outlet for suppliers during the typically quieter months between May and September. But overall demand for the two regions is expected to be only 7m t/y by 2015, so their effect on the market will be limited. With seven new countries expected to import LNG by 2013 and over 20 potential longer-term prospects, the LNG market will continue to become more diverse. Other more speculative markets may emerge in the same way as Argentina and Kuwait. The new markets will increase incremental demand, but because most of the proposals are for smaller markets, the volumes will be fairly small compared with the growth in larger markets such as China and the UK.

Global supply

Supply has continued to grow but the pace of development has fallen short of expectations. Slippages in the start dates of projects under construction in the past three years have reduced the supply capacity outlook for 2010 of 235m t/y by 11% (29m t/y) against the forecast in 2007 (see Figure 2). Further ahead, the limited number of new projects that achieved FID between 2006 and 2008 will stall new capacity growth in the 2012-14 period. Challenges to developing new supply, particularly in the Atlantic basin, have also hindered longer-term growth prospects. By 2020, over a quarter of the projects included in the 2007 forecast have seen the timing of first LNG pushed back. Wood Mackenzie's forecasts are conservative compared with developers' predictions. Each project is assessed by taking a variety of factors into consideration, including inter alia: gas exploration; technical issues; government policy; fiscal regimes; project costs; LNG marketing; corporate positions; geopolitics; and the externalities of the global market. Potential start dates are then assigned to the strongest candidates. Where competing projects are aiming, but unlikely, to be developed in parallel, it is difficult to pick one project over another. All are included within Wood Mackenzie's LNG Tool to provide flexibility and allow different outcomes to be considered, but the aggregated global view of supply including the possible and speculative categories is overstated.

Figure 2: Global LNG supply outlook



Source: Wood Mackenzie LNG Tool, Jun 2007 and Nov 2009

In reality, new supply will be developed at a slower rate. With the potential for future slippages and disruptions at established facilities, the total supply capacity on stream by 2020 might well be closer to 300m t/y than 400m t/y.

In line with the broader interest being shown in unconventional oil and gas, a large number of unconventional LNG supply projects have been proposed since 2007. Some are unconventional in terms of their feedstock, such as gas produced from coal seams – commonly referred to as coal-seam gas (CSG) or coal-bed methane (CBM). Others are unconventional in that the proposed LNG liquefaction plant will be offshore, on floating facilities. Interest in these new emerging technologies is being driven by the challenges associated with accessing conventional gas resources for LNG supply.

Most of the proposed CSG/CBM to LNG projects are in eastern Australia, with several projects in Queensland planning to pipe CSG to liquefaction plants in the Gladstone Harbour area, although there are also plans to use CBM to support LNG production at Indonesia's Bontang plant. Eastern Australia is attractive to LNG project developers because of the enormous CSG resource and the limited size of the local market creates the potential to monetise the gas though LNG exports. In addition, the physical remoteness of the resources means securing land access for drilling rigs and pipelines is unlikely to be a significant problem. Indeed, the very low population density and land-use intensity are much more compatible with the relatively intrusive nature of CSG developments.

Two projects to convert Canadian shale gas into LNG have been proposed for Kitimat, British Columbia. There are no significant barriers to physically accessing the gas resources proposed to support LNG projects, but doubts around the economics of production and commercial pricing must be addressed.

A significant number of small-scale floating LNG (FLNG) projects – targeting stranded reserves in the 1-2 trillion cf range – have been proposed by a range of players, while a far smaller number of large-scale FLNG developments have been proposed, mainly because of the significant technical and financial development problems. The two most noteworthy, large-scale developments are: in Australia, where Shell has entered the front-end engineering design (Feed) phase for the Prelude project; and Brazil, where Petrobras, BG, Repsol and Galp have entered Feed on a project to monetise pre-salt gas reserves.

The growing difficulties associated with accessing conventional gas reserves to supply LNG projects has encouraged players to pursue unconventional resources. CSG-LNG and FLNG have shown the largest potential, but both face significant challenges before reaching commercialisation. If these barriers are overcome, unconventional projects will offer some upside to international oil companies struggling to bring new LNG supply to market. However, while niche opportunities are likely to emerge, unconventional gas is expected to make up only a small proportion of overall LNG supply.

The global recession and meteoric rise of shale gas in the US have changed the dynamics of the LNG industry in the last three years. The more pessimistic outlook for demand at a time when a wave of new supply is coming on stream has alleviated the tightness in the market and exerted downward pressure on prices over the short to medium term. Demand continues to rise, but the longer-term outlook is significantly lower than forecast in 2007. China is the notable exception and has surpassed expectations, primarily because of the large tranche of long-term supply it has secured over recent years. Developing new LNG supply remains a big task, however, and unconventional LNG supply projects offer only limited upside, which suggests the market may tighten sooner rather than later.

The relationship between LNG and unconventional gas is one the industry is cautiously watching. On the one hand, unconventional gas may allow new sources of LNG supply to be developed. On the other, the development of unconventional resources in LNG importing countries has the potential to lead to significant LNG demand destruction.

Unconventional gas: friend or foe?

Unconventional production in importing countries is already having a material effect on the industry – a point emphasised by the development of 5bn cf/d of shale-gas output in the US over the past three years and the resulting fall in forecast LNG demand. In comparison, the volumes associated with unconventional LNG supply projects are far smaller and unlikely to come to fruition until mid-decade.
The rapid development of unconventional gas in North America has dramatically reduced the outlook for gas prices and LNG imports in the US. With interest in unconventional gas growing will we see a similar trend emerge in other parts of the world? Could unconventional gas development have a similar impact in China and/or Europe? There are a myriad of issues that make the outlook for unconventional gas production highly uncertain. But one thing is certain, unconventional gas' influence on the LNG industry is growing.

Natural Resources Canada

Much has changed in the North American LNG market in the past few years. Throughout the early to mid 2000's, concerns over decreasing conventional supplies of domestic natural gas led to bullish predictions about future LNG demand in North America, resulting in an investment boom to build new LNG import facilities. Around 2008, dramatic changes in the market on account of surging U.S. unconventional natural gas production(mostly from shale gas) started to change the outlook for LNG imports. Natural gas production increased, North American prices fell significantly, and the expected need for LNG was dampened. The future of LNG imports in North America went from bright to uncertain. In Canada, most of the proposed projects were either cancelled or suspended on account of:

1. Difficulties securing long-term supply commitments,
2. Concerns over existing excess re-gasification capacity in North America, and
3. The prospects for domestic shale gas as a new long term source of natural gas.

Currently, the United States has a considerable surplus of re-gasification capacity. For example, between January and March 2009, the total unutilized capacity was 91%. This figure is only slightly lower for the same time period in 2010. Most of this excess re-gasification capacity is located in the U.S. Gulf of Mexico region.

Canadian LNG Projects The map below displays the locations of all the LNG import and export facilities in Canada (e.g. operational, approved, suspended and cancelled facilities).

Canadian LNG Projects				
Project	**Location**	**Status**	**Start Date**	**Initial Capacity**
1. Canaport LNG	New Brunswick	Operational	June 2009	1.0 Bcf/d
2. Kitimat LNG(proposed export terminal)	British Columbia	Pending Construction (approval obtained)	2014 (expected start-up)	0.7 Bcf/d
3. Rabaska LNG	Québec	Suspended (approval obtained)	N/A	N/A
4. Cacouna LNG	Québec	Suspended (approval obtained)	N/A	N/A
5. Grassy Point	Newfoundland	Suspended	N/A	N/A
6. Keltic/Maple LNG	Nova Scotia	Suspended	N/A	N/A
7. Énergie Grand-Anse	Québec	Suspended	N/A	N/A
8. Westpac LNG	British Columbia	Cancelled	N/A	N/A
9. Teekay/Merrill Lynch Export	British Columbia	Cancelled	N/A	N/A
TOTAL CANADIAN IMPORT CAPACITY				**1.0 Bcf/d**

At present, Canaport LNG's receiving and re-gasification terminal at Saint John, New Brunswick is Canada's only operational LNG terminal.

One of the proposed LNG terminals that is gaining traction in Canada is Kitimat LNG Inc.'s export terminal near the Port of Kitimat, British Columbia. Originally slated to be an LNG import facility, in 2008 Kitimat reversed its proposal to an LNG export facility. This move reflected the increased optimism over new shale gas developments in north eastern B.C. and North America more broadly, as well as the expectation that natural gas prices in Asia would continue to exceed those in B.C. If realized, the project could further connect the North American gas market with the Asia Pacific market.

Khelil says shale causing LNG glut

New natural gas production from the US, along with liquefied-natural-gas projects globally, is leading to an excess of capacity in liquefied natural gas, Algeria's energy minister said today.

News wires 19 April 2010 23:32 GMT

Chakib Khelil, speaking before a meeting in Oran of the Gas Exporting Countries Forum, of which he is president, said the glut had led to a drop in prices to which the group was trying to find solutions. Amid a recent drop in demand, "the spectacular development of non-conventional gas production...[in North America] seems to be sustainable" due to technology, Khelil said. This will "generate idle capacity in re-gasification." He added that new LNG capacity "will clearly contribute to exacerbate the excess of LNG already in the market," and singled out Australia as adding to this new capacity.

Qatar has also expanded its LNG market share in Europe thanks to new production. Khelil said the ramp up in LNG and US non-conventional gas came as "demand in major consuming countries has for the first time in recent history dropped significantly in 2008 and 2009." "Forecasts for the next five years are rather worrying as they display only very weak growth," he said.

Nov 11, 2010 - The West Australian - ABIX via COMTEX

A large number of major new LNG developments are planned for Australia, with a forecast increase in output of 4.2% annually until 2035. The estimate by the International Energy Agency means that companies who have not yet managed to win clients for their LNG may be finding it tough to match supply with finite demand. Major player Woodside Petroleum has been forced to reassure investors on the future of its projects, especially after a divestment by stakeholder Shell.

The Global LNG Glut: Factors That May Assuage the Agonies of the Suppliers

November 6, 2010 Published at: www.thepeninsulaqatar.com

The world is currently experiencing an LNG glut. There are schools of thought as to when the glut would end. However, factors like the ongoing global economic recovery and the fact that CO_2 emission is relatively less during the combustion of natural gas may assuage the woes of the LNG suppliers.

The current global LNG glut is very interesting. While this bodes well for energy security, it sends shivers in the spine of suppliers. Whereas Qatar’s Deputy Prime Minister and Minister of Energy and Industry is predicting the glut to end by 2013, the energy watchdogs to consumers think that it will last for a decade. Unlike oil, there is no strong parallel body in the gas industry like OPEC, whose members could agree to stifle supply. However, there are some factors that may bring some smiles to the face of the suppliers. Some countries are not completely out of the woods of the economic downturn. Even for those who have turned the corner, the economic growth rate is relatively low. However, as more and more factors come out of the recession and their economic growth rate increases, it is expected that demand for LNG may increase. NLG demand may also pick up if a more binding deal is agreed at the imminent climate change talks in Cancun, considering the fact that natural gas is more benign than the other fossil fuels with respect to carbon emissions. It will be interesting to see how the factors enumerated play out in the global LNG arena.

GULF NEWS

Qatar joins Russia in shutting LNG plants amid global glut

Bloomberg
Published: 00:00 June 11, 2010

Construction of the world's largest gas-to-liquids plant in Qatar. Suppliers are trying to support the market on one hand, but on the other hand, holding the gas back for when the price is more attractive. Image Credit: Bloomberg

Moscow/London: Qatar, the world's largest producer of liquefied natural gas, will idle 66 per cent of its export plants this year, reversing earlier plans and joining Russia in curtailing supply amid a global glut.
Qatar's two LNG producers, Ras Laffan Liquefied Natural Gas and Qatar Liquefied Gas, had an "unusually heavy" maintenance programme during the past two months that shut six of 12 production units for several weeks, New York-based consultant Poten & Partners said in a report. Another two units will undergo repairs this summer.

Russian gas-export monopoly Gazprom, which supplies about a quarter of Europe's gas, cut its 2010 production goal on Wednesday because of reduced demand. Qatar has changed tack from a January comment by Faisal Al Suwaidi, then chief executive officer of QatarGas, that his company probably wouldn't idle any LNG units for maintenance in 2010. Qatar and Russia rejected a proposal by Algeria in April that exporting nations trim shipments to support prices. "There have been more shutdowns globally than we have seen in the past, and LNG units are being shut," said Andrew Pearson, an analyst at Edinburgh-based consultant Wood Mackenzie. "Suppliers are trying to support the market on one hand, but on the other hand, holding the gas back for future months and years when the price is more attractive."
Prices are less than a third of the record $15.78 (Dh57.94) reached in Dec-ember 2005, when cold weather drained inventories already depleted by earlier hurricane damage in the Gulf of Mexico. US gas futures slumped 31 per cent during the first three months of the year, fluctuated near $4 per million British thermal units during April, then rose 19 per cent since May 24, to close at $4.677 Wednesday on the New York Mercantile Exchange.

Gas for delivery in July 2011 was $5.384 per million Btu, a premium of 15 per cent over the front-month contract. At the start of the year, the premium for July 2011 over gas for July this year stood at 6.6 per cent. Gazprom said it aims to produce 519.3 billion cubic metres of gas this year, scaling back an earlier forecast of 529 billion. "Gazprom is now revising down figures because of a lack of demand," Vsevolod Cherepanov, head of the gas, condensate and oil production department, told reporters in Moscow.

Qatar's decision to shut units even as it increases overall capacity underscores the challenge LNG producers face in balancing abundant supplies with long-term expectations of demand growth. LNG is gas that is cooled and transformed into a liquid for transportation by ship.

Worldwide consumption of gas fell 2.1 per cent last year, BP said in its annual Statistical Review of World Energy on Wednesday, the first decline on record and the most among the major fuel types. RasGas reported its first LNG shutdown in April and QatarGas followed in May. The combined output of the units being shuttered is 41 million tonnes a year, out of the country's export capacity of 61.5 million.

Gas prices have fallen during the past year as more nations boost exports and the US, the world's biggest consumer, increases domestic production from shale-rock deposits. A global oversupply of gas is expected to continue for another five years, Bernhard Reutersberg, chief executive officer of German utility E.ON Ruhrgas AG, said last month.

Qatar aims to boost LNG capacity 43 per cent this year to an annual 77 million tonnes by adding three new trains to the dozen already operating. It accounted for 20 per cent of global exports in 2009, selling mostly to Japan, South Korea, India and Spain, according to BP. Additional supplies entered the market even as US stockpiles jumped to the highest in a decade in May, according to the Energy Department. European gas purchasers, including Essen-based E.ON Ruhrgas, have cut the amount bought under long-term contracts, which are linked to oil prices, and are instead seeking more from the spot market, which is typically cheaper.

Crude oil for July delivery rose 3.3 per cent to $74.38 a barrel on Wednesday on Nymex. Oil prices are down 6.2 per cent this year after rallying 78 per cent in 2009. Members of the Gas Exporting Countries Forum, which includes Russia, Iran and Qatar, failed to agree in April on an Algerian proposal to buttress prices by reducing spot sales. Qatari Minister of State for Energy Mohammad Al Sada said in March that his country didn't plan to reduce output to support prices.

THE global monitoring and control agency for energy affairs, the Paris based International Energy Agency (IEA) is predicting that massive increases in supplies of natural gas will lead to the world "swimming in gas" for another decade "as US domestic production surges and other nations ramp up their abilities to export gas as Liquefied Natural Gas (LNG)".

The global glut of natural gas is expected to keep prices of the fuel depressed for at least a decade and threatens to railroad efforts to boost investment in renewable energy sources, the JEA said in its World Energy Outlook for 2010 -- an annual forecast of energy supply, demand and consumption authored by the world's developed nations including Canada and the United States published last week. The revelation by the IEA should have significant implications for Jamaica, as the country seeks to shift a significant portion of its energy consumption to that source in a bid to lower increasing costs and increase the viability of local businesses to expand and generate new employment. Of added interest is the projection that the United States, Jamaica's largest trading partner, might become a net exporter of gas soon. Energy and Mining Minister, James Robertson has pinned his hopes on a turnaround in Jamaica's high energy costs, particularly for electricity generation on LNG, which is to be introduced into the energy mix under a private sector-led project. "The LNG option offers significant benefits to the country. It is important, for example, to point out that at the current differential between crude oil and natural gas prices, Jamaica would save at least US$300 million per annum on energy import costs, even after taking into account the cost of the infrastructure necessary to handle LNG," Robertson noted in a recent interview.

"In this regard, the US$300 million per annum that we could now be saving if we had LNG, excludes the loss of earnings by the plants in the bauxite and alumina sector that had to cease or reduce operations owing to their inability to compete with plants elsewhere, due primarily to their use of oil as the main source of energy," he added.

The IEA, whose mandate includes a focus on the "3Es" of sound energy policy: energy security, economic development, and environmental protection, is projecting that the demand for natural gas will rise, but it will take until 2020 to absorb the surplus. "The gas glut will be with us 10 more years," said IEA chief economist, Faith Birol in a Reuters report. It anticipates a "global oversupply of gas on the order of 200 billion cubic meters beginning next year," according to a Reuters story. That quantum is more than three times the excess supply that was available as recently as 2007.

The story notes that "even rising global gas use, which will increase faster than any other fossil fuel, won't overcome a production surge that is emerging from shale gas resource development in the United States, and in Canada." Recent technological developments have facilitated the extraction of gas from shale reserves that hitherto were uneconomic to mine, greatly increasing the availability of gas. "Already, there are some signs of that change in the works. In the past month, more than 19 billion cubic feet of liquefied natural gas were shipped out of the Gulf of Mexico, about half the amount that will be imported to the region for the month of November," according to Waterborne Energy, a Houston research firm. Given that just a year ago LNG terminals in the region didn't have the ability to re-export the LNG they took in, this is a major turnaround. As of late last week three tankers were waiting in the Gulf of Mexico outside Sabine Pass to load up with LNG that had previously been offloaded at Sabine Pass, Waterborne noted. Meanwhile, the IEA also revealed that peak demand for crude oil globally "already came and went unnoticed in 2006 and the world should be prepared for a future of rising prices of the commodity". According to the IEA's World Energy Outlook, released on November 9, oil demand will increase to 99 million barrels per day (mbd) by 2035, up from 84 mbd in 2009, driving oil prices over US$200 a barrel by 2035, which is equivalent to $113 in 2009 real dollars.