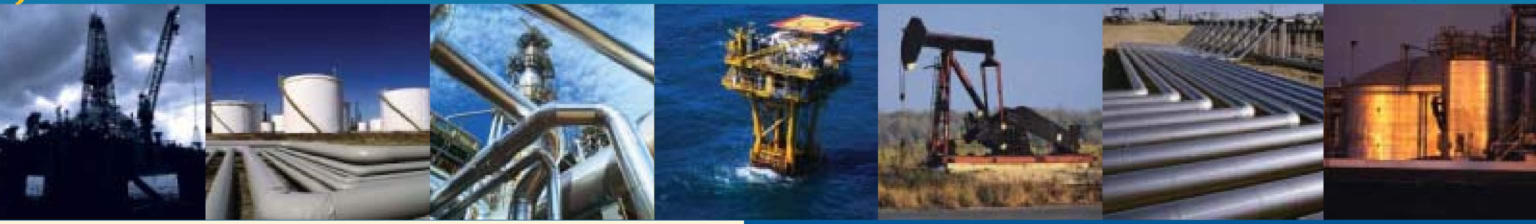

Week of June 22, 2009/US$10.00

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OIL&GAS JOURNAL

International Petroleum News and Technology / www.ogjonline.com

Worldwide Gas Processing

Central Asian, Caucasus energy rivalries intensify
Kansas CBM flow rates correlate to coal gas content
Model determines upstream project design efficiency
Pipeline developments advance operations, integrity

OIL&GAS JOURNAL

June 22, 2009
Volume 107.24

Worldwide Gas Processing

Regular Features

Cover

Williams Cos.' Opal gas plant in southwestern Wyoming has cryogenic processing capacity of 1.45 bcfd and produces more than 67,000 b/d of NGL. Completion in fourth-quarter 2008 of the Overland Pass Pipeline connection at Opal provided the plant with a second NGL take-away pipeline. For more on US and global gas processing in 2008, see this issue's exclusive special report—Worldwide Gas Processing—beginning on p. 50. Photo from Williams, Tulsa, and Jim Blecha Photography Inc., Aurora, Colo.

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General Interest

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Drilling & Production

Processing

Transportation

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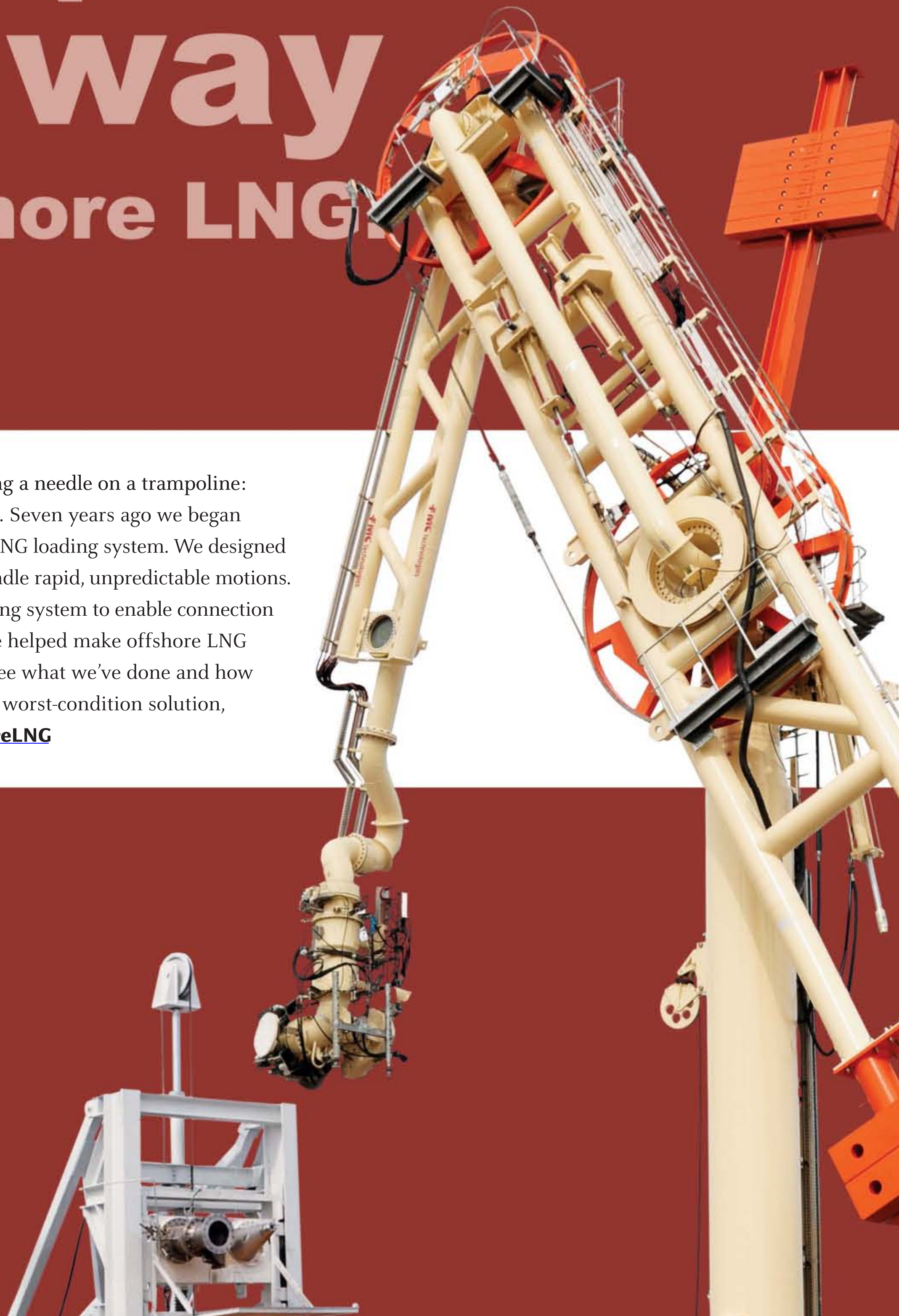

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June 22, 2009

International news for oil and gas professionals
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General Interest — Quick Takes

TransCanada to take ownership of Keystone line

TransCanada Corp. reached agreement with ConocoPhillips to buy its remaining interest in the Keystone pipeline system for roughly $550 million plus the assumption of $200 million of short-term debt. Upon completion of the transaction, TransCanada will be sole owner of the project.

The purchase price reflects ConocoPhillips's capital contributions to date and includes an allowance for funds used during construction. TransCanada will also assume ConocoPhillips's share of the costs associated with completing the project, an incremental commitment of roughly $1.7 billion through the end of 2012.

Pending regulatory approval, the transaction is expected to close in the third quarter.

TransCanada's 2,148-mile Keystone pipeline will transport oil from Canada to the US Midwest. In addition to 1,379 miles of newbuild US line, Keystone includes additions to existing Canadian pipelines and mainline flow reversals. It is expected to start up in December 2009 with the capacity to deliver 435,000 b/d from Hardisty, Alta., to the US at Wood River and Patoka, Ill.

TransCanada plans to extend the line to Cushing, Okla., starting fourth-quarter 2010, expanding it to 590,000 b/d. It has secured firm long-term contracts totaling 495,000 b/d for an average of 18 years.

New pipeline construction of 101 km in Manitoba was about 98% complete as of Apr. 15. TransCanada plans work on a total of six spreads in South Dakota, Nebraska, Kansas, Missouri, and Illinois during 2009.

TransCanada announced plans in July 2008 for the Keystone Gulf Coast Expansion Project (Keystone XL), providing 500,000 b/d additional capacity from western Canada to the US Gulf Coast by 2012. Keystone XL has secured firm contracts for 380,000 b/d for an average of 17 years from shippers.

Keystone XL includes 1,980 miles of 36-in. OD line starting in Hardisty and extending to a delivery point near existing terminals in Port Arthur, Tex. TransCanada anticipates beginning construction in 2010, pending regulatory approvals, and intends to start the line in 2012.

The combined Keystone pipeline system could be expanded to 1.5 million b/d from its as-built capacity of 1.09 million b/d if warranted by market demand.

Gazprom chief forecasts $85/bbl oil at yearend

Oil prices should hit $85/bbl by the end of 2009, and if capital investment is not restored, oil prices could rise to $150/bbl within 2-3 years, warned Alexey Miller, chief executive officer of OAO Gazprom at the European Business Congress in Porto Cervo, Italy.

Miller said it was encouraging that oil prices had crept to $70/bbl recently, adding that this was "a return to a precrisis trend" and not "not a technical correction or accidental fluctuation." At this level, it was double the price at yearend 2008, but still far below the peak reached in July 2008.

It was "financial transactions in the oil markets" and not the physical market that caused low oil prices earlier this year, Miller said. He forecasts that investment in exploration and production will decline by more than 20% in 2009. Operators are reluctant to proceed with projects because of the volatility of the market resulting in a reduction in production capacity and oil supplies within 3-5 years.

A year ago Miller said it was possible that oil prices could leap to more than $250/bbl because of the major imbalance between demand and supply of hydrocarbons by 2012.

Miller recommended that there be a radical overhaul in the operation of the oil market. "The problem is that today the price is determined not on the physical oil market, but on a market for financial instruments. As a consequence, the oil price greatly depends not on fundamental factors, not on the real oil demand and supply, but on the activities of speculating investors."

Miller suggested that long-term oil supply contracts could help exchange trading as it would contain the "impact of speculative capital on the oil price" and help to drive out "economically unjustified intermediaries."

Ecuador appoints Pinto as oil, mining minister

Ecuador President Rafael Correa, vowing to crack down on international oil companies operating in his country, has sworn in Germanico Pinto as the country's oil and mining minister.

"We're going to radicalize our citizens' revolution…and that radicalization implies demanding respect," said Correa after Pinto was sworn in. "Germanico will take a much firmer approach toward all these companies that think they can still keep abusing the country."

Correa said of the companies: "They refuse to pay taxes, and on top of that, they take us to arbitration and press charges against us seeking millions," adding, "We are heading in the right direction. These multinational companies know they can't play around with Ecuador anymore."

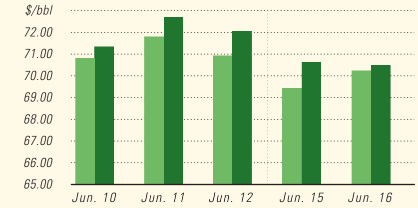
Shortly after assuming his new position, Pinto—essentially playing with words—said there was no need for the government to nationalize the oil industry "because the oil already belongs to the state."

Without providing any details, Pinto said he will promote "a deep change in…how we have been developing productive activities as well as energy and environment activities."

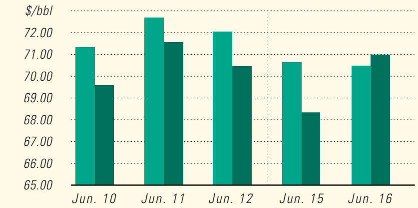
Pinto also said current oil prices are reasonable, adding that he sees no need for a cut in output by the Organization of Petroleum Exporting Countries, which Ecuador rejoined last year.

Industry Scoreboard

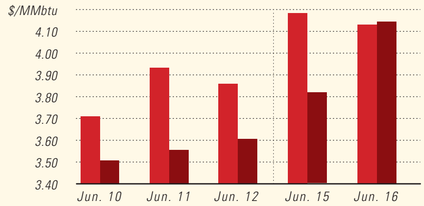
IPE BRENT / NYMEX LIGHT SWEET CRUDE



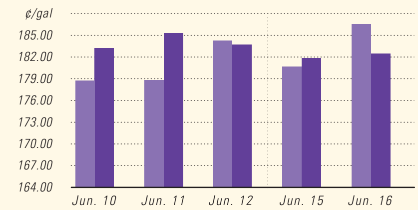
WTI CUSHING / BRENT SPOT



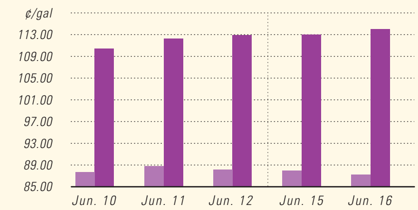
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



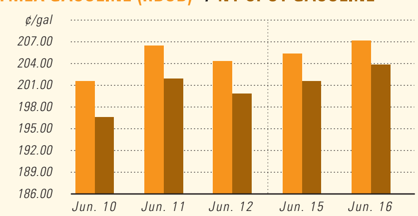
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[1] / NY SPOT GASOLINE[2]



[1]Reformulated gasoline blendstock for oxygen blending.
[2]Nonoxygenated regular unleaded.

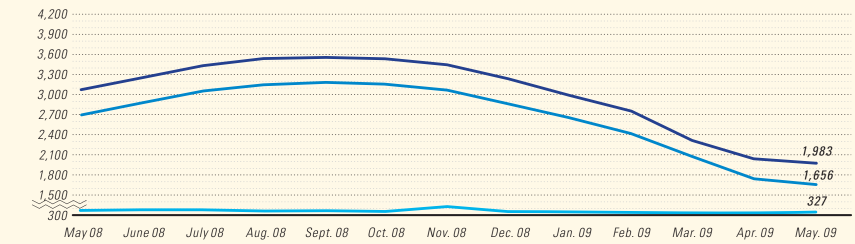
US INDUSTRY SCOREBOARD — 6/22

Latest week 6/5	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,233	9,195	0.4	8,923	9,015	–1.0
Distillate	3,576	3,906	–8.4	3,768	4,117	–8.5
Jet fuel	1,343	1,568	–14.3	1,382	1,555	–11.1
Residual	538	665	–19.1	560	630	–11.1
Other products	3,657	4,370	–16.3	3,974	4,502	–11.7
TOTAL DEMAND	18,347	19,704	–6.9	18,607	19,819	–6.1
Supply, 1,000 b/d						
Crude production	5,358	5,158	3.9	5,288	5,134	3.0
NGL production[2]	1,869	2,423	–22.9	1,851	2,235	–17.2
Crude imports	9,046	9,677	–6.5	9,386	9,751	–3.7
Product imports	2,852	3,228	–11.6	2,970	3,197	–7.1
Other supply[3]	1,674	1,360	23.1	1,661	1,407	18.1
TOTAL SUPPLY	20,799	21,846	–4.8	21,156	21,724	–2.6
Refining, 1,000 b/d						
Crude runs to stills	14,326	15,307	–6.4	14,326	14,877	–3.7
Input to crude stills	14,669	15,654	–6.3	14,669	15,204	–3.5
% utilization	83.1	88.9	—	83.1	86.4	—

Latest week 6/5	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	361,595	365,977	–4,382	302,197	59,398	19.7
Motor gasoline	201,649	203,202	–1,553	210,088	–8,439	–4.0
Distillate	149,718	150,036	–318	113,981	35,737	31.4
Jet fuel–kerosine	41,944	41,373	571	39,863	2,081	5.2
Residual	39,302	40,132	–830	39,505	–203	–0.5
Stock cover (days)[4]			**Change, %**		**Change, %**	
Crude	24.8	25.2	–1.6	19.8	25.3	
Motor gasoline	21.8	22.1	–1.4	22.5	–3.1	
Distillate	41.9	41.8	0.2	27.8	50.7	
Propane	60.1	59.2	1.5	39.4	52.5	
Futures prices[5] **6/12**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	70.83	68.10	2.73	128.14	–57.31	–44.7
Natural gas, $/MMbtu	3.79	3.96	–0.17	12.36	–8.56	–69.3

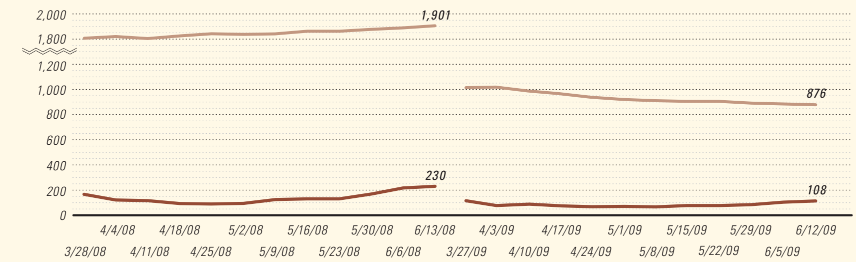
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average of daily closing futures prices.
Sources: Energy Information Administration, Wall Street Journal

BAKER HUGHES INTERNATIONAL RIG COUNT: TOTAL WORLD / TOTAL ONSHORE / TOTAL OFFSHORE



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

Pinto succeeds Derlis Palacios, who offered his resignation last month after failing to resolve several key disputes, including one with Perenco SA, which has declined to pay $338 million that Ecuador claims since raising taxes in 2007 to 99% on windfall oil earnings.

Perenco claims that the windfall tax violates its contract and has taken its case to the International Center for Settlement of Investment Disputes (ICSID), a branch of the World Bank.

In response, the Ecuadoran government seized 70% of Perenco's output in March and tried to auction it in May, despite a ruling by ICSID calling for suspension of the sale until a final judgment had been reached.

Repsol YPF SA also has approached ICSID for resolution of the tax issue, while Occidental Petroleum Corp. has applied to ICSID for $1 billion in compensation for oil fields seized by Correa's predecessor in 2006.

Following Perenco's lawsuit, and faced with those of Repsol YPF and Oxy, Ecuador announced its intention to withdraw from ICSID on May 31, claiming that the court had a bias in favor of Western corporate interests.

According to analyst BMI, Palacios's departure "heralds a further leftward shift of Correa's administration, whose radical agenda has been emboldened by a comprehensive victory following the April 2009 elections."

In view of this, BMI said it expects the government to drive a harder bargain during the ongoing restructuring of the Ecuadorian oil industry, which aims to confine oil operators to a position of service providers to state-run Petroecuador.

"Given the continuously deteriorating operating terms, further exits by foreign players may be expected over the next few years," BMI said. ✦

Exploration & Development — *Quick Takes*

Newfield reports deepwater GOM discoveries

Newfield Exploration Co. reported two natural gas discoveries in the deepwater Gulf of Mexico: Pyrenees on Garden Banks Block 293 and Winter on Garden Banks Block 605.

Pyrenees, drilled in 2,100 ft of water, encountered 125 ft of net pay in three intervals. This could prove to be the company's largest discovery, a Newfield spokesman said.

He described Pyrenees as a gas-condensate discovery. The well was temporarily abandoned pending development plans.

Delineation drilling is planned for the second half of this year. Newfield operates Pyrenees and holds 40% working interest. Partners include Stone Energy Corp. 15%, Ridgewood Energy Corp. 15%, Arena Exploration 15%, and Deep Gulf Energy 15%.

Winter, drilled in 3,400 ft of water, found 44 ft of net pay in two sands. The well was temporarily abandoned. Development options are being considered.

Newfield operates Winter and holds 30% working interest. Partners include Apache Corp. 25%, Deep Gulf Energy 25%, and Royal Offshore 20%.

Tullow Oil has success with Kigogole-3 well

Tullow Oil PLC, London, will suspend its Kigogole-3 exploration well as a future oil-producer following the discovery of more than 20 m of net pay from two separate zones on Uganda's Block 2.

The well reached 575 m TD and encountered "excellent" reservoir sands. The Kasamene-type reservoir sands were in the lower zone with more than 15 m of net oil pay. Thin-bedded oil-bearing sands also were found in another 5 m total net reservoir section above the 15 m main reservoir interval.

Angus McCoss, exploration director at Tullow Oil, said this discovery in the Butiaba region of Block 2 reaffirms the exceptional quality of the prospects within the Victoria Nile Delta play. "We are steadily drilling our prospect inventory in this region and this continued success is enabling us to make significant progress on new leads and prospects. The ongoing campaign will help us define the ultimate limits of this very prolific petroleum system," McCoss said.

Kigogole-3 was drilled southwest of the Kigogole-1 oil discovery. The company said these results lower the risks of some of the adjacent prospects to be drilled later this year on Blocks 1 and 2.

Tullow Oil will now drill the Wahrindi prospect, which is 13 km to the southwest of this well. Drilling is to start later this month, close to the shore of Lake Albert. This well will be drilled to a depth of about 1,300 m.

Murphy reports oil, gas finds off Malaysia

Murphy Oil Corp., El Dorado, Ark., found oil at one exploratory well and gas at another off Malaysia.

A well on the Siakap North prospect in 4,300 ft of water on Block K off Sabah 6 miles from Kikeh field found oil-bearing pay sands of similar age and quality to those at Kikeh. Murphy is evaluating development options including tieback to Kikeh.

A well in 89 ft of water on the East Patricia prospect in Block SK 309 off Sarawak cut 230 ft of net natural gas pay. It is 23 miles off the Bintulu onshore gas receiving facility under construction for the Sarawak gas development.

Murphy operates both discoveries. Petronas Carigali Sdn. Bhd. Holds 20% in Siakap North and 40% of East Patricia. Murphy holds the rest. ✦

Drilling & Production — *Quick Takes*

Connacher reactivates Algar oil sands project

After selling $200 million of first-lien senior secured notes, Connacher Oil & Gas Ltd., Calgary, announced it would reactivate its plan to construct the Algar project, a project similar in size to its first steam-assisted gravity drainage (SAGD) project, Great Divide Pod-1, in northeastern Alberta.

Algar is about 8 km east of Pod 1 and covers eight sections about 80 km south of Fort McMurray.

Alberta's Energy Resources Conservation Board approved the project on Nov. 13, 2008.

As with Pod 1, Connacher has designed Algar to produce 10,000 b/d of bitumen.

The company expects the project to cost a total of $359 million (Can.), including deferral costs of $14 million.

To date, it has completed an 8-km road, site work on the well pads and plant site, and has constructed and stored major component parts for the plant facility offsite. It estimates that completion of the project requires and additional $200 million (Can.).

The company says following completion of a brief prestart-up organizational period, the work at Algar, including drilling of 15 SAGD well pairs, will last about 275 days from commencement of field activities.

Following this, the company expects that it will need 30 days to commission the plant and 90 days to steam the SAGD wells before bitumen production starts.

Jubilee field subsea system ordered

The Jubilee integrated project team placed an order with FMC Technologies Inc. for designing and manufacturing a subsea production system for the Jubilee deepwater development in 4,000-5,100 ft of water off Ghana.

The Jubilee integrated project team consists of Kosmos Energy Inc. (technical operator), Anadarko Petroleum Corp., and Tullow Oil & Gas PLC (unit operator).

The Jubilee discovery well, Mahogany-1, found 312 ft of net pay in Cretaceous sandstone.

Appraisal wells Mahogany-2 and Mahogany-3 on the West Cape Three Points block and wells Hyedua-1 and Hyedua-2 on the adjacent Deepwater Tano block delineated the discover.

Kosmos says drillstem tests of the Mahogany-2 and Hyedua-2 wells indicated individual wells could produce more than 20,000 bo/d.

Kosmos and its partners plan a fast-track development of Jubilee, targeting first production for 2010 with the first phase tapping about 300 million bbl of oil (OGJ Online, June 12, 2009).

FMC will supply 19 enhanced horizontal subsea trees, 5 production manifolds, 3 injection manifolds, a pair of riser bases, and associated control systems, with subsea equipment deliveries scheduled to begin in 3 months.

FMC expects to realize $210 million from the order.

Production will flow to a leased turret-moored floating production, storage, and offloading vessel, owned and operated by Modec Inc. The lease is for 7 years with 13 1-year options.

Facilities on the FPSO are designed to handle 120,000 bo/d oil and 160 MMcfd of gas, as well as to inject 230,000 bw/d. The FPSO, currently being converted from a very large crude carrier, will have 1.6 million bbl of storage capacity.

Operator Kosmos holds a 30.875% in the West Cape Three Points block. Other interest owners include Anadarko 30.875%, Tullow 22.896%, Ghana National Petroleum Corp. 10%, EO Group 3.5%, and Sabre Oil & Gas Ltd. 1.854%.

Tullow is the operator of the Deepwater Tano block and holds a 49.95% interest. Other interest owners are Kosmos 18%, Anadarko 18%, Ghana National Petroleum Corp. 10%, and Sabre Oil & Gas Ltd. 4.05%.

Hibernia southern extension work advances

Development of the southern extension of Hibernia oil and gas field off Newfoundland has advanced with tentative agreement on fiscal terms.

Hibernia partners and the government of Newfoundland and Labrador have signed a nonbinding memorandum of understanding providing for a provincial equity stake of 10% and a top royalty rate of 50%.

Premier Danny Williams announced the agreement at the annual conference of the Newfoundland and Labrador Oil and Gas Industries Association.

Provincially owned Nalcor Energy would pay $30 million for an equity interest in 170 million bbl of oil expected to be produced through subsea wells tied back to the Hibernia gravity-base structure. It also would pay a $2.50/bbl processing fee for its oil. Depending on oil prices, the top royalty for this production would be 42.5%.

For the rest of the 220 million bbl of recoverable oil in the southern-extension area, development would occur from the existing structure. For this oil, the royalty rate would be 42.5% with no price trigger.

The new peak 50% royalty would apply to new licenses in the Hibernia area.

Field operator Hibernia Management & Development Co. (HMDC) recently has been producing 136,000 b/d of oil and 256 MMscfd of natural gas through its platform in 80 m of water 315 km east-southeast of St. John's. The royalty rate has reached 30%.

HMDC applied for development of the Hibernia southern extension in May 2006 but met resistance from the province, which required additional information.

Since then, HMDC has applied for the part of the development that would use the existing platform. It hasn't filed a development plan for the subsea-tieback scheme.

Hibernia field came on stream in November 1997 and has produced 670 million bbl of oil. ✦

Processing — *Quick Takes*

Total-Aramco refinery in Jubail advances

Saudi Aramco Total Refining & Petrochemical Co. has completed an "awarding plan" for engineering, procurement, and construction contracts for the 400,000-b/d refinery it will build in Jubail, Saudi Arabia.

Total SA last year reported a delay in contract awards for the project as it and partner Saudi Aramco assessed global economic conditions (OGJ, Dec. 1, 2008, Newsletter). The review coincided with cancellation by Aramco of a contract with Snamprogetti for development of Manifa oil field off Saudi Arabia.

The Jubail refinery originally was to have processed Arabian Heavy crude and a new grade from Manifa. In a statement about the contract-award plan, the joint venture mentioned only Arabian Heavy.

The venture will let contracts for 13 process packages for the Jubail refinery, which will maximize yields of diesel and jet fuels and also produce 700,000 tonnes/year of paraxylene, 140,000 tonnes/year of benzene, and 200,000 tonnes/year of polymer-grade propylene.

Algeria gas project moves ahead

Algeria's Sonatrach has hired Canada's SNC-Lavalin Group Inc., Montreal, to build natural gas handling facilities in eastern Algeria.

The Algerian state company awarded SNC a $1.1 billion, 39-month contract to build a gas gathering system, gas processing plant, and carbon dioxide reinjection facilities to serve four fields: Rhourde Nouss Central, Rhourde Nouss Southwest, Rhourde Adra, and Rhourde Adra South. The gas processing plant will be at nearby Qartzites de Hamra.

Due for completion in 2012, the project will allow Sonatrach to process and treat about 353 MMscfd, which would generate, according to Algerian Oil Minister Chakib Khelil, about $500 million/year in export revenues. The project will also produce 16,000 b/d of condensate, according to other published reports.

Residue gas from the plant will move more than 1,000 km to Arzew, on Algeria's northwestern Mediterranean coast, where Sonatrach is building a 4.7-million tonne/day train to come on line in 2012. That project will expand the already installed 16.4 million tonnes/year of LNG production capacity at that site.

Clean-fuel specs strain South African refiners

South African refiners will need to invest $4.95 billion by 2014 to comply with clean-fuel specifications, a senior Sasol SA official said earlier this month.

Sasol Executive Director Benny Mokaba said, "Refineries cannot afford to put in the equipment that is required. That's 40 billion rand that doesn't add an additional liter."

Mokaba warned of a clash between the high costs of improving fuel standards and the growing focus on cleaner fuels technology in the country. He said it was important not to jeopardize economic growth.

South Africa's fuel meets Euro 2 emission standards, but European countries have progressed to Euro 5 standards, which lower allowable emissions of nitrogen oxides and particulate matter. Refiners have requested a 5-year delay to have sufficient time to deliver Euro 4 standards.

Speaking at the South African National Energy Association Action for Energy conference in Johannesburg, Mokaba said there could be shortfalls of domestically produced fuels and the need to increase imports.

Nelisiwa Magubane, deputy director-general at South Africa's Department of Energy, said the government would seek greater stakeholder participation to implement its integrated energy plan.

She said integrated energy planning had formerly "fallen flat" for numerous reasons, one of which was enabling legislation. ✦

Transportation — *Quick Takes*

Papua New Guinea LNG partners start work early

ExxonMobil Corp.'s Papua New Guinea LNG project has moved forward another step with the partners agreeing to begin early work activities.

The activities include a range of infrastructure programs like the upgrade and repair of roads, construction of camps, wharf upgrades, early site preparation in the highlands, establishment of training facilities and ordering long lead time items.

Development of this type of infrastructure will contribute towards a swift beginning to the main construction work in early 2010 following final investment decision for the project expected later this year.

The early work will comprise an accelerated investment of about $600 million during the next 12 months prior to the final investment decision and is seen as a major vote of confidence and commitment in the project as a whole.

The early works agreement follows the recent signing of the umbrella benefits sharing agreement as well as progress made on marketing the LNG.

This month a major construction contract for upstream civil infrastructure was awarded to the Clough Curtain engineering joint venture. ExxonMobil also signed an agreement with KBR and WorleyParsons EOS joint venture for services such as training, in-country support and integrated project team services for construction and project management of the development.

PNG LNG comprises a 2-train, 6.3 million tonne/year LNG plant near Port Moresby with gas sourced from several fields in the central highlands region.

Gas storage field planned near Bakersfield

A California company has proposed to construct a natural gas storage facility in depleted Ten Section gas field 10 miles southwest of Bakersfield that would enter service in January 2012.

Tricor Ten Section Hub LLC said the field would have 22.4 bcf of working gas capacity and 10.1 bcf of base gas. It said the field would provide four high-speed cycles per year with a maximum withdrawal rate of 1 bcfd and a maximum injection rate of 0.8 bcfd.

An application filed with the Federal Energy Regulatory Commission said the field will initially connect with the Kern River-Mojave interstate pipeline.

Later potential tie-ins with California's two intrastate systems, Pacific Gas & Electric and Southern California Gas Co., would give the hub a "combined lateral surrounding optionality" of more than 4 bcfd.

Tricor started an open season for Ten Section's capacity on June 1. It asked that the US Federal Energy Regulatory Commission issue a certificate by February 2010.

Ten Section field was discovered in 1936. ✦

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Calendar

✦ Denotes new listing or a change in previously published information.

OIL&GAS JOURNAL online

Additional information on upcoming seminars and conferences is available through OGJ Online, Oil & Gas Journal's Internet-based electronic information source at http://www.ogjonline.com.

2009

JUNE

IAEE International Conference, San Francisco, (216) 464-2785, (216) 464-2768 (fax), website: www.usaee.org. 21-24.

Society of Professional Well Log Analysts Annual Symposium (SPWLA), The Woodlands, Tex., (713) 947-8727, (713) 947-7181 (fax), website: www.spwla.org. 21-24.

SPWLA Annual Symposium, The Woodlands, Tex., (713) 947-8727, (713) 947-7181 (fax), e-mail: webmaster@spwla.org, website: www.spwla.org. 21-24.

International Offshore and Polar Engineering Conference (ISOPE), Osaka, (650) 254-1871, (650) 254-2038 (fax), e-mail: meetings@isope.org, website: www.isope.org. 21-26.

Asia LPG Seminar, Singapore, (713) 331-4000. (713) 236-8490 (fax), website: www.purvingertz.com. 22-25.

API Exploration & Production Standards Oilfield Equipment and Materials Conference, Westminister, Colo., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 22-26.

The Global LNG Congress, Istanbul, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 23-25.

Moscow International Oil & Gas Exhibition (MIOGE) & Russian Petroleum & Gas Congress, Moscow, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 23-26.

Pipeline Integrity Management Seminar, Calgary, Alta., (281) 228-6200, (281) 228-6300 (fax), e-mail: firstservice@nace.org, website: www.nace.org/conferences/pims2009/index.asp. 24-25.

Annual Mid-year Forecast Event, Tulsa, (877) 715-1917, e-mail: info@energy-advocates.org, website: www.energyadvocates.org. 25.

American Society of Safety Engineers Professional Development Conference & Exposition, San Antonio, (847) 699-2929, e-mail: customerservice@asse.org, website: www.safety2009.org. June 28-July 1.

JULY

Rocky Mountain Energy Epicenter Conference, Denver, (303) 228-8000, e-mail: conference@epicenter2008.org, website: www.denverconvention.com. 7-9.

API Offshore Crane Operations and Safety Conference, Houston, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 14-15.

Oil Sands and Heavy Oil Technologies Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilsandstechnologies.com. 14-16.

AUGUST

SPE Asia Pacific Health, Safety, Security and Environment Conference and Exhibition, Jakarta, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

EnerCom's The Oil & Gas Conference, Denver, (303) 296-8834, email: kgrover@enercominc.com, website: www.theoilandgasconference.com. 9-13.

ACS Fall National Meeting & Exposition, Washington, (202) 872-4600, e-mail: service@acs.org, website: www.acs.org. 16-20.

Petroleum Association of Wyoming (PAW) Annual Meeting, Casper, (307) 234-5333, (307) 266-2189 (fax), e-mail: suz@pawyo.org, website: www.pawyo.org. 18-19.

IADC Well Control Conference of the Americas & Exhibition, Denver, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 25-26.

Summer NAPE, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 27-28.

SEPTEMBER

Oil & Gas Maintenance Technology North America Conference, New Orleans, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.ogmtna.com. 1-3.

EAGE Near Surface European Meeting, Dublin, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 7-9.

IAEE European Conference, Vienna, (216) 464-5365, e-mail: iaee@iaee.org, website: www.iaee.org. 7-10.

Offshore Europe Conference, Aberdeen, +44 (0) 20 7299 3300, e-mail: nbradbury@spe.org, website: www.offshore-europe.co.uk. 8-11.

GPA Rocky Mountain Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 9.

GITA's GIS Annual Oil & Gas Conference, Houston, (303) 337-0513, (303) 337-1001 (fax), e-mail: info@gita.org, website: www.gita.org/ogca. 14-16.

Turbomachinery Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), e-mail: inquiry@turbo-lab.tamu.edu, website:http://turbolab.tamu.edu. 14-17.

Annual IPLOCA Convention, San Francisco, +41 22 306 02 30, +41 22 306 02 39 (fax), e-mail: info@iploca.com, website: www.iploca.com. 14-18.

Polar Petroleum Potential 3P Conference, Moscow, (918) 584-2555, (918) 560-2665 (fax), website: www.aapg.org. 16-18.

Annual Energy Policy Conference, Oklahoma City, (202) 580-6532, (202) 580-6559 (fax), e-mail: info@energyadvocates.org, website: www.energyadvocates.org. 20-22.

ADC Drilling HSE Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 23-24.

SPE Eastern Regional Meeting, Charleston, W.Va., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 23-25.

ERTC Sustainable Refining Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 28-30.

DGMK Production and Use of Light Olefins Conference, Dresden, 040 639004 0, 040 639004 50, website: www.dgmk.de. 28-30.

IADC Advanced Rig Technology Conference, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 29.

Unconventional Gas International Conference & Exhibition, Fort Worth, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.unconventionalgas.net. Sept. 29-Oct. 1.

ERTC Biofuels+ Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Sept. 30-Oct. 2.

OCTOBER

Interstate Oil and Gas Compact Commission Annual Meeting (IOGCC), Biloxi, Miss., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 4-6.

SPE Annual Technical Conference and Exhibition, New Orleans, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-7.

World Gas Conference, Buenos Aires, +54 11 5252 9801, e-mail: registration@wgc2009.com, website: www.wgc2009.com. 5-9.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax), e-mail: info@isa.org, website: www.isa.org. 6-8.

Kazakhstan International Oil & Gas Exhibition & Conference (KIOGE), Almaty, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 6-9.

NPRA Q&A and Technology Forum, Ft. Worth, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 11-14.

API Fall Petroleum Measurement Standards Meeting, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 12-15.

GPA Houston Annual Meeting, Houston, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 13.

International Oil & Gas Exploration, Production & Refining Exhibition, Jakarta, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: ogti@oesallworld.com, website: www.allworldexhibitions.com. 14-17.

SPE/EAGE Reservoir Characterization and Simulation Conference and Exhibition, Abu Dhabi, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 18-21.

GSA Annual Meeting, Portland, (303) 357-1000, (303) 357-1070 (fax), e-mail: meetings@geosociety.org, website: www.geosociety.org. 18-21.

The human face of oil and gas

Sam Fletcher
Senior Writer

In early June, the American Petroleum Institute flew 30 working women from the industry to Washington, DC, to tell senators, representatives, and senior staff members what's good about oil and natural gas.

"We wanted to show the human face of the industry, helping policymakers understand that actions that affect the oil and gas industry have consequences for real people all across the country, their families, and their communities," said API spokesperson Karen Matusic.

Well, it's about time! For more than 30 years this reporter has advised every PR person and company executive he could buttonhole to quit sending the "Suits" to testify before Congress and let workers tell the industry's story instead.

Fat-cat heads of major companies with their corporate jets and golden parachutes are just red meat for government panels playing to constituents. A working Joe watching government officials berate industry executives on TV doesn't identify with CEOs trying to explain away "excess profits" or defend the industry's need for tax breaks—especially when those executives take home more in annual bonuses than the average voter could earn in two lifetimes.

It would be more effective if working stiffs from the oil patch and refineries told Washington officials how the oil industry puts food on their tables, roofs over their heads, and pays college tuitions for their kids.

A geologist in West Texas loves and respects the land as much as any Iowa corn farmer. An engineer installing subsea wellheads appreciates the ocean's power and rewards as much as a commercial fisherman. Any roughneck knows better than a government economist the high cost of oil exploration in blood and sweat as well as cash. And a refinery worker has an even greater interest than nearby residents in plant safety because he may be the first casualty if something blows.

A good idea

The fly-in was the good idea of API President and CEO Jack Gerard, who hopes to make it a regular event. "We want our policymakers to meet the hard-working employees of our industry and come away with a better understanding of who we are and what we do to bring Americans the energy they need, now and in the future," he said.

Included were geologists, petrophysicists, land professionals, refinery workers, and others from Louisiana, Illinois, Texas, Arkansas, Alaska, and beyond. "I am a third-generation refinery employee, and I have seen how an industry like ours can create opportunities for people in our area," said Melissa Erker, who works at ConocoPhillips's Wood River refinery in Illinois. "I want to tell policymakers that if they do not make the right decisions now, they could put an industry out of business. It would have a devastating effect on our community where 50% of the budget for the local school district comes from the oil industry."

Louisiana native Aisha Ragas, senior geologist with Anadarko Petroleum Corp., Houston, wants lawmakers to know the industry takes its environmental responsibilities seriously. "All of our jobs are valuable, and we all care about what everyone else cares about: doing our jobs well, taking care of our families, and giving back to the community," she said.

Thuy Rocque, a petroleum engineer with Anadarko, was 11 when her family fled Vietnam in a small fishing boat. Today she's proud to be part of a diverse, high-tech workforce. "People would be surprised at the advanced technology we use to safely produce oil and natural gas," she said.

Geri Storer, a Shell Exploration & Production Co. employee in Anchorage, was a young girl when the Trans Alaska Pipeline was built and oil began to flow from the Prudhoe Bay fields. The impact on her Inupiat community was immediate. "It meant well-paying jobs, better education, and the revenues needed to provide better housing, water, and sewage for people. Those who are setting policy that affects people who live far from Washington need to consider how they are impacting the lives of others," she said.

Lynne Hackedorn, vice-president of land for Cobalt International Energy LP, Houston, an independent producer that pursues niche opportunities in the deepwater Gulf of Mexico, said the proposal to eliminate expensing of intangible drilling costs could have a catastrophic impact on smaller producers like Cobalt that work high-risk areas. "I doubt this company could have been formed without IDC. We have 55 employees, and we depend on this," she said. ✦

Editorial

Beyond fundamentals

More remarkable than hints of oil market recovery this month is growing acceptance that supply and demand don't always paint the whole picture. Current conditions illustrate the void. Oil prices have zoomed despite demand weakness and supply health evident in full inventories and resurgent production-capacity surpluses.

The recovery signals are weak. Inventories relative to demand eased slightly in May. And in June market reports, the International Energy Agency, Organization of Petroleum Exporting Countries, and US Energy Information Administration quit cutting forecasts for annual average consumption by as much as they had done in preceding months. IEA and EIA actually raised their projections marginally. OPEC, although trimming its demand outlook, declared, "The worst appears to be behind us."

Recovery?

But these are indications of a possible end to the market's slide, not necessarily of recovery. Nothing says market projections won't resume their slump next month. Nothing says demand, even if it has quit falling, won't stay depressed.

Yet marker prices of crude oil seem to herald recovery. The futures price for light, sweet crude has traded lately above $70/bbl. EIA expects the second-half average price of West Texas Intermediate oil to exceed the first-half number by $16/bbl. How can this be? Supply and demand—the "fundamentals"—provide no ready answer.

Other influences must be at work. "Prospects for equity markets and the global economy, backed up by exchange-rate fluctuations, expectations about future oil market tightness, and, by inference, a shift of money into or out of futures markets can all influence short-term prices," says IEA in its June Oil Market Report. "Indeed, it is tempting to conclude that the shift in [New York Mercantile Exchange] WTI noncommercial positions from a net 11,000 short in early May to 40,000 net long a month later is sufficient explanation for the surge in prices" of more than 20% during May and into early June.

OPEC's June Monthly Oil Market Report notes the apparent failure of fundamental market weakness to suppress oil prices. "Financial market developments," it says, help explain "this recent divergence between oil market fundamentals and prices." Crude price changes recently have correlated with changes in equity markets, as traders anticipate the oil-demand boost that will accompany economic recovery, and in value of the US dollar.

Similarly, EIA's Short Term Energy Outlook this month attributed May oil price gains partly to "expectations of a global economic recovery and future increases in oil consumption." Also, it said, "a weaker dollar and increasing financial market activity are prompting higher prices for commodities, overshadowing weak oil supply and demand fundamentals."

At this time last year, IEA and EIA remained reluctant to attribute surging oil prices, then approaching $130/bbl, to forces other than supply and demand. "In reality," wrote IEA in June 2008, "these abnormally high prices are largely explained by fundamentals." EIA's June 2008 report cited supply uncertainty and demand growth and predicted, "The overall picture of strong demand and tight supply is expected to continue."

Only OPEC, ever wary of oil-price speculation, in the middle of last year looked unapologetically beyond market fundamentals. "In the absence of any change in fundamentals, this strong [price] volatility reconfirms the view that current price levels do not reflect supply and demand realities but are strongly influenced by future market activities and the prevailing bullish sentiment," it said.

Now all three agencies assert factors other than supply and demand, especially dollar gyrations and financial-market dynamics, as important in the determination of oil prices, at least in the short term. Doing so doesn't disengage them from market theory. Dollars and investment flows are part of the market, after all.

Broadened view

Last year's record indicates the broadened view might, to the benefit of everyone, improve forecasting. After listing the nonfundamental forces elevating oil prices in 2008, OPEC wrote, "A review of prospects for the remainder of the year also shows little support for prices to remain at current levels."

That was in June. Crude prices began a 5-month, $90/bbl plunge in the middle of July. ✦

Central Asian, Caucasus energy rivalries intensify

Gawdat G. Bahgat
Indiana University of Pennsylvania
Indiana, Pa.

Among China, Europe, and Russia, the competition over oil and gas from Central Asia and the Caucasus is intense and growing. In this rivalry China enjoys a cash advantage, while Russia builds on decades-long cultural and political ties. European companies offer more-advanced technology than is available from their Chinese and Russian competitors.

Rivalries aside, the external powers share an interest in promoting political stability in this major energy-producing region. Competition for political influence is likely to complicate the full utilization of the Caspian hydrocarbon wealth (see related story nearby).

More regional and international cooperation is needed. The speedy development of the region's oil and gas resources would benefit all concerned parties.

European security

Europe, with its high standards of living and limited hydrocarbon resources, brings to this competition an historic reliance on external energy supplies. In 2008, Europe imported 54% of its energy. Heavy dependence on foreign supplies has prompted European leaders to articulate a strategy to enhance their energy security. In November 2008, the European Commission issued a new strategy, called the EU Energy Security and Solidarity Action Plan, underscoring the significance of good relations with energy suppliers.

The Caspian region already supplies oil and gas to the EU. Azerbaijan and Kazakhstan export oil to several European countries. Similarly, since 2007 small but growing volumes of Azeri gas has reached several European destinations. In the next few years, oil and gas production from the Caspian region is projected to rise, and Europe's dependence on imported supplies will deepen. The Caspian region therefore is likely to play a bigger role in meeting the EU's energy needs. The question is how to ensure the continuity of these supplies.

The EU has simultaneously pursued several strategies. The Nabucco pipeline is at the heart of European efforts to secure energy supplies outside of Russia. It would bring Central Asian gas to Europe without passing through Russian territory. A consortium of European energy companies, including Turkey's Botas AS, Bulgarian Energy Holding EAD, MOL PLC of Hungary, Austria's OMV Gas & Power GMBH, RWE AG of Germany, and Transgaz SA of Romania, has been planning Nabucco's construction since 2002.

The EU sponsored two conferences in 2009—one in Budapest in January and the other in Prague in May—to rally support for the scheme. In Prague, Azerbaijan, Egypt, Georgia, and Turkey signed an agreement to participate in the huge project, while Kazakhstan, Turkmenistan, and Uzbekistan refused to sign due to pressure from Russia.

The pipeline would connect eastern Turkey, transiting Bulgaria, Romania, and Hungary, with Austria. It would carry 31 billion cu m/year of gas, starting in 2014. Engineering began in April.

Another proposal is the Trans-Caspian pipeline between Turkmenistan and Turkey via Azerbaijan and Georgia. The EU strongly supports the construction of this link; however, the project faces hurdles including the lack of agreement on the legal status of the Caspian and strong opposition from Iran and Russia.

Another project under construction is the Samsun-Ceyhan pipeline, which will carry Russian and Kazakh oil from Turkey's Black Sea port of Samsun to Ceyhan on the Mediterranean coast. The project is being developed by a 50-50 joint venture between Italy's ENI and Turkey's Calik Energy. It will bypass Turkey's narrow and dangerously congested Bosporus Strait and ease traffic in the Dardanelles.

Like Nabucco and the Trans-Caspian pipelines, White Stream is planned to bypass Russia and diversify gas supply routes and sources. It will run from Turkmenistan through Azerbaijan to the Georgian port of Supsa and then through the seabed of the Black Sea and through Crimea in Ukraine to Romania and Poland. The pipeline's capacity will be 30 billion cu m/year.

Russia's advantages

Compared with other foreign powers, Russia enjoys several advantages in the Central Asia and Caucasus region.

Given the Soviet legacy, Russia has strong cultural, economic, and political ties with most of the peoples and governments in the region. Also, the existing energy infrastructure still connects these former Soviet republics to Russia. Almost 2 decades after the demise of the Soviet Union, Russia controls a significant proportion of Kazakh and Turkmen hydrocarbon exports.

And, despite serious efforts to reduce economic and political dependence on Russia and to establish close relations with Europe and the US, Moscow maintains the capability to punish or reward most Central Asian and all the Caucasus nations. An obvious recent example is the 2008 war in Georgia.

Against this background, Russia's relations with Azerbaijan, Kazakhstan, and Turkmenistan have evolved in the last 2 decades. A major drive has been to protect Russia's oil and gas interests and contain competition by other external players, such as China, Europe, and the US.

Gazprom makes most of its profit by selling gas to European buyers. In the last several years Gazprom, for two reasons, has been increasingly concerned about meeting its contractual obligations. Russia's domestic consumption is rising while production is stagnant. One solution is to fill this growing gap by importing gas from the Caspian producers and reselling it to Europe. Another option is to consolidate Moscow's control over transit routes from the region. This strategic framework makes Russia's recent initiatives in Central Asia and the Caucasus easy to understand.

In early 2009 Gazprom and Azerbaijan's national oil company SOCAR signed a memorandum of understanding for supplying Azeri gas to the Russian company beginning in 2010. The companies will conduct joint technical inspections of the Baku-Novo-Filya pipeline, which runs along Azerbaijan's Caspian coast to the Russian border, and do the necessary repairs. Azeri President Ilham Aliyev noted that a deal with Russia would entail little additional investment because there are no transit countries and the pipelines are already in place. This agreement raises doubt about the availability of gas supplies for the Nabucco project.

In 2007 Russia, Kazakhstan, and Turkmenistan signed an agreement to build a gas pipeline along the Caspian Sea coast that would further strengthen Moscow's domination over energy exports from Central Asia. Moscow and Astana also endorsed plans to double capacity of the CPC oil pipeline through additions of pump stations and storage.

In another push toward solidifying its role as Europe's dominant energy supplier, Gazprom, in a joint venture with ENI, plans to lay a 30 billion cu m/year gas pipeline called South Stream under the Black Sea to Bulgaria. The pipeline would branch northward to Austria and southward to Italy. South Stream is largely seen as a setback to Europe's efforts to reduce its dependence on Russia and as a rival to Nabucco pipeline.

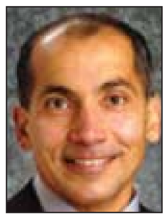
Emerging competitor

China recently has solidified its status as a major competitor for hydrocarbon supplies from Central Asia and the Caucasus. Beijing enjoys several advantages. It has strong historical trade and cultural ties with several nations in the region. It shares a border with three Central Asian states (Kazakhstan, Kyrgyzstan, and Tajikistan). And for the last 3 decades the Chinese economy has been one of the fastest growing in the world. As a result, more than many other economic powers, Beijing has the financial resources and the management efficiency to undertake business opportunities with foreign partners.

A brief review of China's energy outlook can explain the growing role Beijing is likely to play in Central Asia and the Caucasus.

In 2008 China accounted for 1.3% of global oil reserves, 4.8% of oil

The author



Gawdat G. Bahgat (gbahgat@iup.edu) is professor of political science and director of the Center for Middle Eastern Studies at Indiana University of Pennsylvania in Indiana, Pa. He has taught at the university for the past 11 years and has held his current position since 1997. He also has taught political science and Middle East studies at American University in Cairo, the University of North Florida in Jacksonville, and Florida State University in Tallahassee. Bahgat has written and published six books and monographs on politics in the Persian Gulf and Caspian Sea and more than 100 articles and book reviews on security, weapons of mass destruction, terrorism, energy, ethnic and religious conflicts, Islamic revival, and American foreign policy. His professional areas of expertise encompass the Middle East, the Persian Gulf, Russia, China, Central Asia, and the Caucasus. His latest book is Proliferation of Nuclear Weapons in the Middle East (2007). Bahgat earned his PhD in political science at Florida State University in 1991 and holds an MA in Middle Eastern studies from American University in Cairo (1985) and a BA in political science from Cairo University (1977).

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production, and 9.3% of oil consumption. Its gas shares were 1.1% of global reserves, 2.4% of production, and 2.3% of consumption. China's oil consumption will grow by an average rate of 3.4%/year between 2005 to 2030, the highest in the world. Its gas consumption will grow by a world-leading 5.5%/year in that period. China has become the world's biggest contributor to greenhouse gas emissions.

The Chinese government is seeking to diversify the country's energy mix and rely more on renewable sources, nuclear power, and natural gas. The projected large and growing gap between the nation's oil and gas consumption and production has been filled by foreign supplies.

Currently, China depends heavily on the Middle East. Like other major consumers, China is seeking to improve its energy security by diversifying its energy sources. Central Asia thus represents an opportunity. China has built a pipeline to import oil from Kazakhstan, and negotiations to import natural gas from Turkmenistan are in advanced stages.

Chinese oil companies are also involved in developing oil and gas fields in a number of Central Asian states.

The way forward

The increase in global energy demand that accompanies the eventual easing of economic recession will intensify competition for oil and gas from the Central Asia and Caucasus region.

Three dynamics are likely to shape the way forward:

- Since the demise of the Soviet Union, Azerbaijan, Kazakhstan, and Turkmenistan have been among countries introducing economic and political reform. They still have a long way to go in terms of transparency, accountability, and good governance. There is a great deal of uncertainty and ambiguity regarding how much oil and gas reserves these countries hold. Indeed, there is concern that some of them, particularly Turkmenistan, have overcommitted themselves and promised more than they can deliver.
- The rivalry between Brussels, Moscow, and Beijing has strengthened the bargaining power of the Central Asian and Caucasus states. For the first time, Russia has offered to pay "European prices" for their gas. It seems that some of the regional leaders are trying to play off one of these external powers against the others. This political game has been played out in the process of choosing which pipeline to build. The decision about which one to pursue will be better made if it is driven more by an economic cost-benefit analysis and less by strategic considerations.
- It is true that if Central Asian and Caucasus oil and gas go to one consumer, it would be at the expense of other consumers. But it is also true that the

full utilization of the region's hydrocarbon resources would contribute to the overall global energy security. Instead of dividing the region into spheres of influence, Europe, Russia, China, and the US would benefit more by promoting political stability and economic prosperity. Energy should not be seen as a zero-sum game. ✦

Exporter updates: Azerbaijan, Kazakhstan, and Turkmenistan

Gawdat G. Bahgat
Indiana University of Pennsylvania
Indiana, Pa.

The Central Asia-Caucasus region is one of the oldest hydrocarbon producing areas in the world. Since the collapse of the Soviet Union in 1991 the region has attracted special attention from oil and gas consuming nations and international companies.

Azerbaijan, Kazakhstan, and Turkmenistan, in particular, enjoy several advantages. They hold oil and gas proved reserves sufficient to represent the main sources of future production increases outside the Organization of Petroleum Exporting Countries (OPEC). Equally important, they are strategically sandwiched between two major energy-consuming regions—China to the east and Europe to the west, both of which depend heavily on foreign supplies of oil and gas. And, unlike most oil and gas producing nations in the Middle East, Latin America, and Russia, the three Caspian states other than Russia and Iran have welcomed foreign investment to consolidate their political independence and to attract capital with which to build and modernize their energy industries.

These advantages aside, Azerbaijan, Kazakhstan, and Turkmenistan all lack direct access to the high seas and major shipping routes. As a result, the only way for their hydrocarbon exports to reach major global markets is shipping via other countries, largely by pipelines. Oil and gas pipelines are not merely economic schemes; they also reflect and contribute to changing strategic parameters. For most of the last 2 decades, Central Asia and the Caucasus region's three close neighbors—China, Europe, and Russia—have proposed and built several pipelines to serve their energy and political interests.

Together, Azerbaijan, Kazakhstan, and Turkmenistan hold 3.8% of the world's proved oil reserves and 3.3% of its gas reserves. In 2008 their combined share of global oil production was 3.2%, and that of gas was 3.5%. Recent discoveries strongly suggest that the region's oil and gas production will substantially increase.

The scope and timing of oil and gas development in these three Caspian Sea states depend on two dynamics. One is the availability of foreign investment and technology, which in turn depends on the approach authorities in Baku, Astana, and Ashgabat take toward international oil companies. The other is the yet-unclear ability of export capacity to keep pace with expected increases in oil and gas production in the region. The rivalry between regional and global powers will have a great impact on pipeline construction.

Reviews of recent energy developments in these countries follow:

Azerbaijan

Since independence, Azerbaijan has taken a more pro-Western, foreign investment-friendly approach than most other regional powers. This opening to international oil companies has contributed to the vast expansion of the country's hydrocarbon production. Most of the oil comes from the Azeri-Chirag-Guneshli structure, developed by Azerbaijan International Operating Co.

The bulk of Azeri oil is exported via two major pipelines: Baku-Tbilisi-Ceyhan (BTC), with a terminal at the Turkish port on the Mediterranean, and Baku-Novorossiysk, with a terminal at the Russian port on the Black Sea.

Azerbaijan has a similarly successful story with natural gas. The country's production almost doubled in the last decade. Most of the gas comes from three fields—Azeri-Chirag-Guneshli, Bakhar, and Shah Deniz. The latest is considered one of the world's largest gas discoveries in the last few decades. In 2007 Azerbaijan became a net gas exporter. Azeri gas moves mainly to Turkey with small volumes to Georgia and Iran. The major gas pipeline is the South Caucasus, known also as Baku-Tbilisi-Erzurum, which runs parallel to the BTC for most of its route with a connection to the Turkish gas network.

Kazakhstan

Given its size and massive hydrocarbon reserves, Kazakhstan has the potential soon to become a major energy exporter. Astana's oil and gas production has more than tripled over the last decade. Most of the country's oil comes from Tengiz and Karachaganak fields. Kashagan field, discovered in 2000, is the largest oil field outside the Middle East and the fifth largest in the world in terms of reserves. ENI was the major operator of the international consortium developing Kashagan until early 2008, when the Kazakh government doubled its stake in the scheme and stripped ENI of its leading role. Kashagan is scheduled to come on stream in 2013; however, geological and environmental hurdles might delay production.

Kazakhstan exports most of its oil via three major pipelines. Traditionally, Kazakhstan used to export all its oil via the Atyrau-Samara pipeline, a northbound link to the Russian distribution system. In recent years, pumping and heating stations were added to the pipeline. Astana, however, has decided to diversify its oil shipment routes.

The Caspian Pipeline Consortium (CPC) connects Kazakhstan's oil fields in the Caspian Sea with Novorossiysk. It is the only export pipeline on Russian territory with partially private ownership. CPC was officially inaugurated in October 2001. Expansion of the CPC, including additional pump stations and storage facilities, is planned.

The Kazakhstan-China Pipeline represents an important diversification step. The pipeline connects oil fields in Atasu in northwest Kazakhstan with Alashankou in China's northwestern Xinjiang region. China started receiving Kazakh oil in 2006. Kazakhstan also agreed to swap arrangements with Iran. And Astana has endorsed a plan to build a link connecting oil fields to the Baku-Tbilisi-Ceyhan pipeline.

Almost all Kazakh gas is associated with oil production, with Karachaganak and Tengiz the largest sources. Kazakh gas, along with that of Turkmenistan and Uzbekistan, is shipped via the Central Asia Center connecting western Kazakhstan with Russia's gas system.

Turkmenistan

Unlike Azerbaijan and Kazakhstan, Turkmenistan has limited oil reserves but some of the richest gas endowments in Central Asia. Upon independence, Turkmen gas was seen as a competitor to that of Russia. All Turkmenistan gas was exported to Russia via the Central Asia Center pipeline, and the two countries became locked in a price dispute. As a result, Turkmen gas production stagnated for most of the 1990s.

The two nations have signed several agreements since the late 1990s, and Turkmen gas production has since skyrocketed. In addition to gas deals with Moscow, two other developments have boosted production and brightened the outlook: discoveries and a change in political leadership.

Most of Turkmenistan's gas comes from Dauletabad and Shatlyk fields. In the mid-2000s the supergiant South Yolotan-Osman was discovered in the southeastern part of the country. In October 2008 an independent audit confirmed that the field was among the world's biggest. In August 2008 another large field, South Gutlyayak, was discovered.

In addition to the Central Asia Center pipeline, a small proportion of Turkmen gas is exported to Iran via the Korpedzhe-Kurt Kai pipeline. Built in 1997, it was the first in Central Asia to bypass Russia.

Following the death of President Saparmurat Niyazov in December 2006, his successor, Gurbanguly Berdymukhammedov, promised a fresh start in domestic and foreign policies. The new president invited international oil companies to develop the country's hydrocarbon deposits. Though he declared the county "open for business," authorities say Turkmenistan will develop its vast onshore resources itself. International oil companies will be limited to exploration in the Caspian Sea and offered service contracts rather than production-sharing agreements.

Berdymukhammedov has sought to diversify gas exports. In addition to the links to Russia and Iran, his government is negotiating gas deals with Pakistan and India via the so-called Turkmenistan-Afghanistan-Pakistan-India (TAPI) or Trans-Afghanistan pipeline. In July 2007 Ashgabat and Beijing signed an agreement under which the former will supply the latter 30 billion cu m/year of gas for 30 years via the proposed Central Asia Gas pipeline. China will participate in development of Turkmen gas fields.

In April 2008 Berdymukhammedov signed an agreement with Germany's RWE to explore for and develop gas fields in Turkmenistan and agreed to supply the European Union with 10 billion cu m of natural gas. ✦

IHS CERA tracks downturn in upstream, downstream costs

A long surge in the costs of building and operating oil and gas production facilities has reversed course, according to two proprietary indexes. Also, design and construction costs of refineries and petrochemical projects declined during the past 6 months after a long increase.

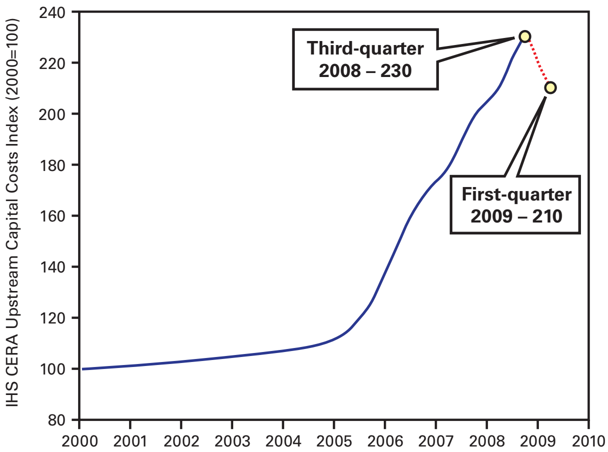
The IHS Cambridge Energy Research Associates (IHS CERA) Upstream Capital Costs Index, which uses 2000 as a baseline with a value of 100, fell 8.5% to 210 during the 6 months between the third quarter of 2008 and first quarter of 2009 (Fig. 1). The index tracks costs of building oil and gas facilities.

Also, the IHS CERA Upstream Operating Costs Index, with the same baseline for operating costs, fell 8% to an index value of 187 (Fig. 2).

Separately, the proprietary IHS CERA Downstream Capital Costs Index, which uses 2000 as a base year, fell 9% to 170 in the 6 months ending in first-quarter 2009 from its level of the prior 6 months (Fig. 3).

HOW UPSTREAM CAPITAL COSTS HAVE FALLEN

Fig. 1



Source: IHS CERA

Upstream costs

"The first signs of a downward shift in [upstream] costs were evident in a moderation that we observed in the last 2 months of the third quarter," said IHS CERA Chairman Daniel Yergin.

The dip in capital costs reflects cuts in upstream activity and a decline in the cost of steel and subsea equipment, IHS CERA said.

Upstream steel costs fell 25.2% in the latest 6 months after rising by 32% in the prior 6-month period.

Operating costs fell because of "a slackening of project activity and lower levels of resource utilization," IHS CERA said.

Some of the largest cost declines were in transportation and consumables, reflecting falling energy prices and the slumping global economy. Costs of well services also dropped.

Costs of offshore operations didn't fall as much as those for onshore work—6% vs. 15%—between third-quarter 2008 and first-quarter 2009.

In that period, operating and capital costs didn't fall as much as crude oil prices did, IHS CERA noted. A reason is the tendency of some costs, such as those for personnel and deepwater vessels, to resist downward pressure.

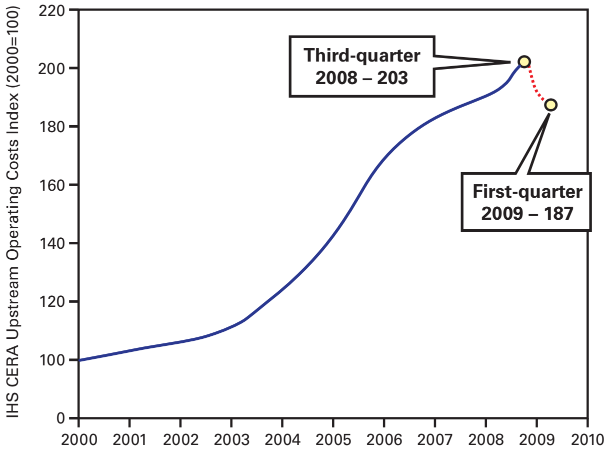
IHS CERA expects upstream capital and operating costs to continue falling because of further declines in materials costs and slackening demand.

The firm's Upstream Capital Costs Index covers equipment, facilities, materials, and skilled and unskilled personnel used in construction of a geographically diverse group of 28 onshore, offshore, pipeline, and LNG projects.

The Upstream Operating Costs Index

HOW UPSTREAM OPERATING COSTS HAVE FALLEN

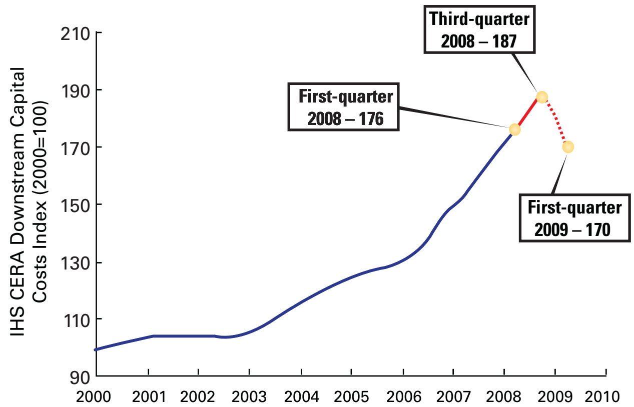
Fig. 2



Source: IHS CERA

HOW DOWNSTREAM CAPITAL COSTS HAVE FALLEN

Fig. 3



Source: IHS CERA

measures cost changes in oil and gas field operations.

Downstream costs

In the 6 months ending in the third quarter of 2008, downstream costs were up 6% from the previous period.

The recent move lowered costs to levels last experienced in late 2007.

"The downward pressures that began to materialize at the end of third-quarter 2008 have now taken hold on the cost of construction materials," said Daniel Yergin, chairman of IHS CERA. "At the same time, slowing demand for both energy-related and general construction projects has slackened demand, causing a further loosening of the construction market costs."

IHS CERA cited a sharp decline in steel costs and the drop in crude oil prices. It said steel costs fell by more than 25% in the past 6 months.

Projects under construction are proceeding, but drops in demand and prices for petrochemicals and refinery products jeopardize future downstream projects.

"We have seen a notable drop in new refinery project starts as companies react to low margins at a time of high costs and declining product demand," said Jackie Forrest, lead researcher for downstream cost index. "Due to the long time horizon associated with downstream projects, the slowdown in new project starts will lead to slower demand in the next few years for downstream construction markets."

Forrest said equipment prices are starting to weaken, but "falling commodity prices have not yet flowed through the entire supply chain to allow for more significant price reductions." All regions tracked by the index showed cost decreases over the past 6 months, IHS CERA said. Among the largest dips were those of Russia, 17%, and South America, 16%.

A strengthening US dollar lowered costs in many regions, Forrest said. For example, the value of the Russian ruble against the dollar reduced costs of labor in Russia by more than 25%.

The index tracks the costs of equipment, facilities, materials, and skilled and unskilled personnel used in the construction of more than 30 refinery and petrochemical projects in many regions. ✦

ERCB lowers Alberta's oil sands production forecast

Guntis Moritis
Production Editor

In its June report on Alberta's 2008 reserves and supply-demand outlook for 2009-18, Alberta's Energy Resources Conservation Board (ERCB) lowered its forecast of bitumen production to 2.7 million b/d in 2018. Last year's report showed production reaching 3.2 million b/d in 2017.

The 2.7 million b/d is still a large increase from the 1.3 million b/d produced from oil sands in 2008.

The 2008 production was 1% less than in 2007. ERCB's report says production from in situ projects increased 9% while production from mining projects because of planned and unplanned maintenance decreased by 8%.

The report notes that in 2008, the upgrading of 264 million bbl of mined bitumen and about 8% of the 213 million bbl from in situ projects yielded 239 million bbl of synthetic crude oil (SCO).

Its oil sands resource estimates at yearend 2008 are:

- Initial in place, 1,731 billion bbl.
- Initial established, 177 billion bbl.
- Cumulative production, 6.4 billion bbl.

- Remaining established, 170 billion bbl.
- 2008 production, 0.477 billion bbl (1.3 million b/d).
- Ultimate potential, 315 billion bbl.

The report reduced the established reserves in Peace River but increased by 14.5 townships the area suitable for mining in the Athabasca region, resulting in a 1.9 billion bbl decrease in initial established reserves.

Of the 170 billion bbl remaining established reserves, ERCB considers 80%, or 135 billion bbl recoverable with in situ methods and the remaining 34 billion bbl recoverable with surface mining methods.

The in situ volumes include production with enhanced recovery methods, such as injection of steam, water, or other solvents into the reservoir to mobilize the bitumen, as well as bitumen and heavy oil produced with primary methods from the Athabasca, Peace River, and Cold Lake regions.

In 2008, average production from the three oil sands areas was:

- Athabasca, 721,500 b/d mined, 232,100 b/d in situ.
- Cold Lake, 310,700 b/d in situ.
- Peace River, 42,000 b/d in situ.

The reports says companies drilled 4,627 wells in the oil sands in 2008. Of these, 1,209 were development wells and 3,428 were exploratory wells.

About 9,700 wells were on production in the oil sands during 2008, with the average well producing 62 bo/d, according to the report. ✦

Groningen field to produce gas for another 50 years

Uchenna Izundu
International Editor

Supergiant Groningen natural gas field in the northern reaches of the Netherlands will continue to produce gas for at least another 50 years, according to Roelf Venhuizen, managing director of Nederlandse Aardolie Maatschappij BV (NAM).

NAM, a joint venture of Royal Dutch Shell PLC and ExxonMobil Corp., operates the field, which has so far produced 1,700 billion cu m of gas since first starting production in 1963. To date, Groningen's reserves are 60% depleted and it holds 1,000-1,100 bcm of gas still to be recovered.

Groningen underpinned the development of a gas market in northwest Europe. Speaking at the 50th anniversary celebrations in Groningen, Venhuizen said the company has drafted a business plan to 2068 that involved the field. "I'm convinced that gas storage will last beyond that," he told an audience comprising Her Majesty Queen Beatrix of the

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Belize's energy independence

One of the more remarkable things about the oil and gas industry is its ability to penetrate every nook and cranny of the known world. Even the tiniest of countries count. Consider Belize.

About 22,960 sq km in size, Belize lies south of Mexico, east of Guatemala, and is just a 2-hr flight from Houston or Miami. With just 320,000 people, Belize has the lowest population density in Central America.

Yet, even those 320,000 people need all the amenities that oil and gas can provide, especially when the local population is augmented by tourists. In the past year, Belize has seen 150,000 tourists arriving by cruise ship alone.

That adds up to a lot of energy demand—even for such a tiny country. Altogether, according to the US Energy Information Administration, Belize consumed 7,400 b/d of oil in 2007—more than twice the 3,210 b/d the country required in 1998.

Production shortfall

As for production, Belize Natural Energy struck oil in the country 3 years ago, with output at 2,260 b/d in 2006. Since then, the figure has climbed. As of February, production from BNE's seven wells averaged 4,300 b/d.

That leaves a consumption-production shortfall of 3,100 b/d—a shortfall that creates space for international political maneuvering.

As might be expected, Venezuela President Hugo Chavez has his hand in Belize's politics. In 2006, under its PetroCaribe scheme, Venezuela began to supply Belize with 4,000 b/d of products.

In 2007, former Belizean Prime Minister Said Musa sought more help from Chavez, saying, "We're examining the possibility of a small refinery or a topping up plant to produce diesel in Belize."

Musa also said Belize needed to find its own oil. "As you know we have a small infantile oil industry—infant industry—producing about 3,000 b/d and we, of course, need to do more exploration."

Empty promises

In 2007, Venezuela mentioned plans to study construction of a small refinery in Belize, but nothing resulted.

Belize took steps to secure the refinery, with a 2,500 b/d facility now operated by the Blue Sky Co., while it also signed a production-sharing agreement with Taiwan's state-owned CPC in January.

There's irony here as CPC had its Venezuelan oil assets nationalized by the Chavez regime and is still negotiating compensation with Venezuela for its $85.2 million investment.

Could CPC's exploration off Belize yield financial results to exceed that $85.2 million loss, even as the Caribbean nation achieves a measure of energy security? Even the Taiwanese are being cautious after getting burned by Chavez.

"We'll send a team there (to Belize) to evaluate the potential for oil," said CPC spokesman Chu Shao-hua. "It's a high-risk area," said Chu, referring to South and Central America. "You've got to be reasonable in your investment there." ✦

Netherlands, politicians, and company representatives.

More than 300 wells have been drilled on the field, which spans 900 sq km. Its pressure from 350 bar is falling meaning that NAM has invested in compressors at most of the production clusters to keep it going. The company has spent €2 billion over 15 years to maintain long-term production with the work program involving modernizing the plant and technology, ensuring the operation is fully unmanned, and improving environmental standards.

"The last site will be modernized with new compressors in September," Venhuizen stated.

Groningen is not empty now because the Dutch government has implemented a policy of focusing on small fields; this has meant that Groningen has adopted the role of a swing supplier. Due to the small fields policy, gas volumes equivalent to half of Groningen field have been discovered in hundreds of others.

But since the field's discovery in 1959, energy markets have become politicized and liberalized. The Netherlands must plan for the next stage in the gas cycle as it will no longer be a net exporter in 15 years, urged Maria van der Hoeven, Dutch minister of economic affairs. So far, Groningen has brought €160 billion in revenues for the country.

"We want to be a gas hub for northwest Europe with gas storage capacity, transport capacity, and trading opportunities. We need to look at new partnerships to realize this," van der Hoeven said.

She added that the government is keen to develop LNG import terminals and pipelines to diversify its supplies in the future and it was keen to see an improvement in the gas markets. "We're in the transition period from fossil fuels to nonfossil fuels and we're trying to develop policy on this. It requires working with companies and the support of the population, particularly for gas storage and carbon capture and storage."

But the meltdown of the financial

markets and volatility of commodity prices have made it more difficult for operators to proceed with investment decisions. Gasunie Chief Executive Officer Marcel Kramer said companies required clear policy frameworks, international dialogues with suppliers, and a sound safety track record to ensure that they could invest in pipelines and facilities to bring gas to the market.

"The Dutch government has laid down the ground rules for gas investment but it needs to do more international cooperation, especially at cross borders," he said. ✦

Brazil considering changes to country's oil law

Eric Watkins
Oil Diplomacy Editor

Brazil's government is considering changes to the country's oil law, despite repeated statements by President Luiz Inacio Lula da Silva and other officials that the new legislation will be finished soon.

"We don't have a definite position yet," said Brazil Presidential Chief-of-Staff Dilma Rousseff. "When we do, we'll make an announcement." Rousseff said a "preparatory" meeting was held recently with the Brazilian president concerning the legislation.

Mines and Energy Minister Edison Lobao earlier told the Estado news agency a government panel formed by Lula would complete its work on the proposed changes by June 15.

Lobao said the Brazilian government would send a new regulatory regime for the country's oil and natural gas industry to Congress by August, with passage of the bill expected in 6 months.

"This year, we will have a new regulatory regime for the subsalt," said Lobao, who repeated his desire to create a separate state-owned company to manage subsalt oil assets.

The working panel is discussing the option, under which the proposed company—to be called Petrosal—would manage development of the reserves and production-sharing agreements.

The idea is based on Norway's Petoro, a state-owned company that manages the country's offshore oil and gas reserves. Like Petoro, Petrosal would offer concessions for exploration and production under production-sharing agreements.

"The president is insisting strongly that we complete the bill quickly so it can be submitted" to the legislature, said Ideli Salvatti of the Partido dos Trabalhadores for Santa Catarina (PT-SC).

"It is obvious that a bill of this magnitude, involving trillions of dollars, is something that needs to be written very carefully, especially so that it will not generate questions," said Salvatti, who is the government leader in Congress. He said adjustments are needed so as not to generate legal doubts concerning the presalt layer.

Lula created the working panel last year to draft the new law, with the aim of giving the government a greater share of the revenues from potentially huge oil discoveries made in the subsalt region offshore Brazil.

A social investment fund is to be created to direct proceeds from oil revenues toward improving Brazil's education system and diminishing poverty, fulfilling long-standing pledges by Lula to utilize the country's oil wealth to aid the broader population. ✦

Associations urge Congress to renew chemical facility security law

Nick Snow
Washington Editor

Thirty-four trade associations, including the American Petroleum Institute and six others from the oil and gas industry, asked Congress on June 11 to reauthorize the chemical facility security law without significant changes.

HR 2477, the Chemical Facility Security Authorization Act, would reauthorize US Department of Homeland Security chemical security standards that Congress enacted in 2006 by extending their sunset date to Oct. 1, 2012. This would provide owners and operators of such installations the necessary certainty to protect citizens and contribute to the economic recovery, the letter said.

"However, we strongly urge you to oppose disrupting this security program by adding provisions that would mandate government-favored substitutions, weaken protection of sensitive information, impose stifling penalties for administrative errors, create conflicts with other security standards, or more away from a performance (or risk-based) approach," it continued.

The bill was introduced on May 19 by US Rep. Charles W. Dent (R-Pa.) and referred to the Energy and Commerce Committee.

In addition to API, the National Petrochemical & Refiners Association, American Exploration & Production Council, International Association of Drilling Contractors, Petroleum Equipment Suppliers Association, National Propane Gas Association, and Petroleum Marketers Association of America signed the letter.

The groups, which also include agricultural, chemical, transportation and manufacturing associations, said that a bill introduced in 2008, the Chemical

Gasoline price unrest

US retail gasoline prices reached an average $2.67/gal on June 15, nearly 60¢ above their average on May 4, the US Energy Information Administration reported. Higher oil prices were the primary culprit, American Petroleum Institute officials told reporters.

"Most analysts have seen an improvement in the worldwide economy, which has helped several commodities including crude oil," API Chief Economist John C. Felmy said. Production cuts by the Organization of Petroleum Exporting Countries, whose members apparently are showing more discipline than usual, also contributed, he said.

Ronald Planting, API's statistics director, added, "We've had some demand growth for gasoline, not terribly strong but much more than for other products. The industry is producing near-record amounts."

Refinery utilization rates have held up better than rates for US manufacturing as a whole, Planting said, adding that at 84%, it's 20 percentage points higher than the domestic manufacturing average, he said.

The average US retail gasoline price should reach its summer seasonal peak in July, with a monthly average near $2.70/gal, EIA said in its latest short-term energy outlook on June 9.

Gasoline demand rises

EIA expects overall oil products demand to drop by an average 550,000 b/d this year because of the weakened US economy, but it anticipates a 30,000 b/d increase in average gasoline demand because of significantly lower prices and stabilized disposal incomes.

API's Felmy said, "Right now, gasoline costs about $1,700-1,800 of the consumer's yearly budget, down about $1,000 from a year ago."

The US Senate Energy and Natural Resources Committee has been preparing an energy bill with several provisions. But other committees on both sides of the Capitol seem more concerned with closing what they consider commodity trading loopholes that contributed to 2008's dramatic oil price spike.

'Transparency and oversight'

Senate Agriculture, Nutrition, and Forestry Committee Chairman Thomas R. Harkin (D-Iowa) noted in a June 4 hearing that he introduced a bill earlier this year which would require all futures contracts to trade on regulated exchanges.

"For many years, derivative contracts have traded very efficiently and openly on regulated exchanges. We have seen the damage done by moves to circumvent properly regulated derivatives trading," Harkin said.

On June 12, the US Commodity Futures Trading Commission used authority it received from Congress in 2008 for the first time to examine whether a contract traded on the Intercontinental Exchange performs a significant price discovery function and should be regulated.

Felmy remained skeptical that speculation was driving the current gasoline price rise. More normal summertime demand certainly is playing a role, he conceded. "But I think the increase in crude prices has played a bigger part," he said. ✦

Facility Anti-Terrorism Act, would have disrupted new federal security standards in the short term and weakened infrastructure protection and economic stability in the long run.

"Our top concern is that legislation could go beyond security protections by creating a mandate to substitute products and processes with a government-selected technology," the letter said. "Congressional testimony found that this could actually increase risk to the businesses that the bill is supposed to protect. Such a standard is not measurable and would likely lead to confusion, loss of viable products, prohibitive legal liability, and business failures."

It also asked that federal lawmakers ensure that any security legislation avoid overlapping or conflicting with existing federal security requirements such as the US Coast Guard's Marine Transportation Security Act. "Any proposal must also protect from release any sensitive security information on site vulnerability," the letter said. ✦

API, labor unions join to lobby for better oil, gas jobs

Nick Snow
Washington Editor

The American Petroleum Institute and 15 labor unions have formed a committee that will lobby for better, higher-paying jobs in the oil and gas industry, the groups announced on June 17.

"The genesis of our committee comes from our mutual interest to develop good, well-paying jobs in the US. Talking over the past few months, it became apparent we have many mutual interests," API Pres. Jack N. Gerard told reporters in a teleconference. "Equally important, it's about energy security in the United States. Experts tell us we'll need to produce more of it domestically, and it's in our mutual interest to come together," he said.

Mark H. Ayers, president of the Building and Construction Trades Department at the AFL-CIO, said, "We intend to work in close cooperation with API to assure that the oil and gas industry remains a good source of income for our members. That will require us to remind lawmakers that competitively priced supplies of oil and gas should remain a part of the US energy portfolio."

Doug J. McCarron, president of the United Brotherhood of Carpenters and Joiners of America, said the committee will provide a great opportunity for craft unions to work with the oil and gas industry to create and maintain well-paying jobs. "I think the biggest opportunity for the building trades industry is in creating training programs to make sure there are qualified people to take these jobs," he said.

API Chairman J. Larry Nichols, who also is Devon Energy Corp.'s chairman and chief executive officer, said he expects the Oil and Natural Gas Labor-Management Committee to be at the forefront of shaping policies to assure oil and gas stay affordable. "If this country doesn't try to continue developing its own oil and gas resources, supplies from outside will cost more and reduce our economic recovery as it begins to occur," Nichols warned.

One impetus for the committee's formation was proposals that have emerged in Congress and the Obama administration, according to API's Gerard. "It's very clear that some of them are not in the best interest of the oil and gas industry and its employees. Our role will be to go up there arm-in-arm and educate people that there are great opportunities here for job creation. Many people don't realize that oil and gas industry jobs pay 2-3 times what other jobs pay, and that creating more of them can help our economy recovery more quickly," Gerard said.

"When you look at the vast US oil and gas resources, we could create another 160,000 jobs by 2030," Gerard continued, adding, "We also shouldn't overlook the $1.7 trillion of revenues that would come from doing this."

AFL-CIO's Ayers said, "We'll take a multifaceted approach. One is public policy, but there are several other areas in which we plan to engage to create good-paying jobs. That will help perpetuate the oil and gas industry and open great opportunities for employment. We have an aging workforce that needs to be replaced. The need's there. The opportunity's there. The jobs are there. We just need to reinvest in America." ✦

TransCanada, ExxonMobil join forces on Alaska natural gas pipeline

Christopher E. Smith
Pipeline Editor

TransCanada Corp. and ExxonMobil Corp. reached agreement June 11 to work together on TransCanada's Alaska Pipeline Project natural gas pipeline.

Tony Palmer, TransCanada vice-president of Alaska development, said the two companies will now jointly advance all aspects of the projects: technical, financial, and regulatory. The companies also will share costs, with TransCanada maintaining a majority interest in the project. Neither Palmer nor Marty Massey, ExxonMobil Production Co. US joint interest manager, would divulge specific percentages of ownership. The two addressed media in a conference call following the announcement.

Palmer noted that the state of Alaska had reviewed the arrangement and determined that no action was required under the terms of the Alaska Gasline Inducement Act (AGIA). Both emphasized that TransCanada's obligations under AGIA remained entirely with the company, with Massey stating that ExxonMobil was in full support of AGIA and that it would help TransCanada meet its obligations under the act.

Massey later said ExxonMobil had not asked the state for any fiscal discussions as part of joining the project and that the company recognized AGIA as the proper forum in which to address fiscal terms.

TransCanada Alaska Co. LLC and Foothills Pipe Lines Ltd. submitted an application in November 2007 under AGIA to build a 1,700-mile, 48-in. OD natural gas pipeline with 4.5 bcfd capacity to Alberta from a new natural gas treatment plant on Alaska's North Slope (ANS). TransCanada was awarded the AGIA license in December 2008 and has since been conducting engineering, environmental reviews, aboriginal engagement, and commercial planning toward a July 2010 initial binding open season. The open season will provide separate terms for ANS producers to wishing to ship their gas intrastate, as LNG, or via the pipeline to Alberta and beyond.

TransCanada and ExxonMobil will increase preopen season spending on the project to $150 million from a previously budgeted $83 million. The companies anticipate a late-2018 startup.

Another line

BP PLC and ConocoPhillips (as Alaska Gas Pipeline LLC) have been pursuing their own 4-bcfd Alaskan gas pipeline project, Denali, which also has an open season slated for 2010 (OGJ, Feb. 9, 2009, p. 54). Following the open season, the companies plan to file for certification from the US Federal Energy Regulatory Commission and Canada's National Energy Board for authorization to move forward with the project.

TransCanada already has NEB authorization for its project.

ConocoPhillips submitted a proposal under AGIA which the state said failed to meet the act's criteria. BP and ExxonMobil did not submit AGIA applications.

Massey remarked repeatedly that ExxonMobil joined the TransCanada project because it provides "the best opportunity to bring all interested parties together," including BP and ConocoPhillips. He also said it has always been ExxonMobil's position that it would take all four companies and the state working together to get a pipeline built.

When asked if the agreement between ExxonMobil and TransCanada left room for other companies to subsequently join the project, Palmer said TransCanada would still give equity status to producers willing to commit a threshold amount of natural gas for shipment. Palmer also emphasized that access to the pipeline would be provided to all potential customers, not just the majors.

DOI reaction

US Secretary of the Interior Ken Salazar described the agreement as "a significant step forward on a project very important to the president and the Department of the Interior as a way to get American energy to the Lower 48. We recognize there are two very strong project proposals, both aiming toward a 2010 open season and both now supported by major gas producers that control vast proven reserves of North Slope gas. We look forward to working with all stakeholders involved with this project."

Alaska Gas Pipeline awarded a front-end engineering and design contract to Fluor WorleyParsons Arctic Solutions in February for a 5-bcfd gas treatment plant to process gas delivered through Denali. The plant would be the world's largest, with process modules weighing up to 9,000 tons (OGJ Online, Feb. 11, 2009).

TransCanada's pipeline would also include a gas treatment plant. Ownership of the pipeline, gas plant, and all other facilities would be fully integrated between the two companies, Palmer said, while conceding that ExxonMobil's expertise in gas treatment would likely see it take the technical lead in that area while TransCanada focused on the pipeline. ✦

AAPG: Unconventional thinking led to great finds

Alan Petzet
Chief Editor-Exploration

Unconventional geologic thinking and risk-taking led to many of the world's recent major oil and gas discoveries, speakers from the companies that made them told a closing session at the American Association of Petroleum Geologists annual convention in Denver.

Hardly anyone was interested in Ghana's offshore when Kosmos Energy Inc., Dallas, decided to explore its deepwater transform margin in 2003, said Phil Lowry, Kosmos senior reservoir geologist.

The Tano basin had three small Albian oil fields and two Late Cretaceous oil fields in shallow water, but earlier explorers felt the deepwater parts of the margin were too risky, Lowry said. Kosmos Energy raised $300 million in 2004 to explore the area.

After imagining an Upper Cretaceous source instead of or in addition to the established Albian source, the company shot 1,000 sq km of 3D seismic in 2005 and perceived potential in stratigraphic pinchout and combination structural traps.

With Anadarko Petroleum Corp. and Tullow Oil PLC as partners, the 2007 Mahogany-1 discovery well in 4,330 ft of water found more than 300 ft of net pay in Cretaceous sandstone and had estimated deliverability of 16,750 b/d.

First production from the discovery, named Jubilee, is expected in 2010. The first development phase is to tap 300 million bbl of oil and reach a production peak of up to 120,000 b/d.

Strong out of the box thinking and aggressive management backing led Chesapeake Energy Corp., Oklahoma City, to investigate and pursue gas in the Jurassic Haynesville shale in Louisiana and Texas, said Chesapeake's John L. Sharp.

Chesapeake drilled the play's first horizontal well in June 2007 in Caddo Parish, La. Now the industry is producing an estimated 400-450 MMcfd from the calcareous mudstone and pursuing it with about 90 rigs, Sharp said. Haynesville production will grow to 2-2.5 bcfd by the end of 2011, he estimated.

Overpressuring at 0.85-0.87 psi/ft of depth is the main reason the Haynesville is destined to become the largest gas field in the US and fifth largest in the world, Sharp said.

"The 20-28 MMcfd wells are real," he said.

North Caspian Operating Co., successor to Agip KCO, is the new operator of supergiant Kashagan oil and gas field in the Caspian Sea off Kazakhstan, said William Zempolich of Eni SPA.

NCO's operating group completed the Kashagan East, West, and Southwest, Kairan, Aktobe, and Kalamkas discovery wells in Paleozoic carbonates below thick and variable Permian salt in the North Caspian basin.

Kashagan field, discovered in 2000, is a Devonian and mid-Carboniferous structure 35 km long at 4,000 m deep with 45° gravity oil and a GOR of 2,800-3,000 scf/bbl in 2-4 m of water. It is overpressured and high in hydrogen sulfide. It was discovered based on 1,475 sq km of ocean-bottom seismic shot in 2001-02.

Production islands will have barriers to protect central islands from ice.

Half of the produced gas will be

reinjected, and the other half will go to gas processing plants at the Boleshak onshore production facility.

Large deepwater subsalt discoveries in the Gulf of Mexico Lower Tertiary Trend have the potential to return gulf oil production to the 4 million b/d peak formerly attained solely from shelf fields, said James Cearley of Chevron Corp.

Among the operating challenges are multistage salt canopies below which explorers can encounter the Wilcox three times and loop currents that can deflect risers so far that rotating drill pipe can burn a hole in them, Cearley noted.

Cumulative production of 500,000 bbl/well equates to a recovery factor of less than 2% in North Dakota's Bakken formation, said Mark Williams, Whiting Petroleum Corp., Denver.

Many wells average 10,000 ft of true vertical depth and a 10,000-ft lateral with 10 sliding sleeves for frac stages, and Whiting has drilled two laterals that extend across 2 sq miles each. These 1,280-acre units have room for a second and possibly a third 2-mile lateral, Williams said.

He said the Bakken play has more than 700 horizontal wells, most of them drilled since 2004 and heavily weighted to 2007-09, and that wells for which operators have reported initial production of 1,000 boe/d or more have almost exclusively been in the Parshall/Sanish field area. ✦

Aussie energy minister proposes retention lease system reforms

Australian Resources and Energy Minister Martin Ferguson released a discussion paper on his proposals to reform the country's retention lease system.

One of the proposals includes strengthening the "use-it-or-lose-it" provisions, where the government will no longer tolerate companies "stranding" Australian discoveries by branding them subcommercial while they turn their resources and attention to developing fields overseas.

Ferguson says he and his department are determined to rigorously apply the commerciality test to ensure gas fields in particular are developed at the earliest possible time.

"Australia's political stability can mean our resources are put to the back of the queue in terms of development planning," Ferguson said. "Companies chose to get in and out of nations with greater sovereign risk, knowing that their Australian titles can be warehoused and kept for a rainy day. However, our economic strength and political stability should not be allowed to continue to work to Australia's detriment," he said.

The retention lease program was first introduced in 1985. There are now 40% of Australian titles held as retention leases. This amounts to 46 5-year retention leases, 32 of them off the coast of Western Australia. ✦

Kansas CBM well flow rates correlate to coal gas content

Michael L. Ebers
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From 2001 to 2005, Quest Resource Corp. developed a set of procedures to collect, desorb, and calculate the gas contents for coal and carbonaceous shales using air rotary drill cuttings in eastern Kansas.

These procedures are fast, inexpensive, and reliable; and they can be easily completed by staff geologists in the field and in the lab. The resulting gas content data were used to make exploratory and well completion decisions in eastern Kansas.

The coal gas content data obtained from the desorption of air rotary drill cuttings were compared to the well production data. A direct correlation exists between the coal gas content and the average daily well production. In most cases, the higher the gas content of the coals, the more productive the well. Low coal gas content resulted in poorly producing wells with marginal economics.

Sample collection

From 2001 to 2008, the author collected and desorbed 1,127 air rotary drill cuttings samples from 217 wells in eastern Kansas.

Three quarters of these samples were from Quest Resource wells. The other samples were from wells drilled by SEK Energy LLC, Hopewell Operating Inc., N&B Enterprises, and Carroll Energy LLC. Another 239 samples from 55 wells are included in this study that were collected and desorbed by other Quest Resource and SEK Energy geologists in eastern Kansas.

Collection procedures

Sample collection procedures were developed by Quest geologists with the assistance of Well Refined Drilling and L&S Well Services personnel.[1]

With air rotary drilling rates varying from 100 to 250 ft/hr and high pressure cuttings returns, various different collection techniques were attempted.

The cuttings from a coal will normally return to the surface in less than 2 min after being drilled, and the cuttings from a 2-ft thick coal will exit the blooie line in less than 30 sec. Thus, it is absolutely necessary for the wellsite geologist to: 1) know the stratigraphy during drilling, 2)

CARBONACEOUS SHALE GAS CONTENT DATA*

Table 1

Geological unit	Eastern Kansas county	No. of desorption samples	Average thickness, ft	Range of gas contents (scf/ton)	Average gas content (scf/ton)
Stark shale	Allen	3	2.7	14.4-19.1	16.1
	Wilson	21	2.6	6.7-55.0	33.7
	Woodson	10	2.2	7.0-46.6	30.8
Hushpuckney shale	Allen	5	2.4	6.1-27.8	19.4
	Chautauqua	2	4.0	24.1-29.0	26.6
	Wilson	16	2.4	8.2-54.8	36.2
	Woodson	10	2.2	7.4-61.2	40.9
South Mound shale	Wilson	15	3.0	7.8-42.0	27.5
Lexington shale	Allen	9	1.9	11.2-30.9	19.7
	Chautauqua	6	2.5	8.0-27.0	12.3
	Labette	5	2.0	2.6-16.1	11.6
	Montgomery	9	2.3	6.0-20.0	10.9
	Neosho	18	2.6	6.4-47.1	19.2
	Wilson	17	1.6	4.3-50.9	28.2
	Woodson	9	1.8	13.4-31.0	21.1
Summit shale	Allen	11	3.8	12.7-35.0	23.3
	Chautauqua	5	3.1	13.5-22.0	18.0
	Labette	34	2.7	7.4-28.1	16.8
	Montgomery	14	2.9	5.0-22.5	15.0
	Neosho	28	2.8	11.1-38.4	24.7
	Wilson	70	2.1	10.4-54.5	27.1
	Woodson	16	2.2	7.4-45.0	23.1
Mulky shale	Chautauqua	7	4.8	27.6-36.8	31.9
	Labette	35	3.7	10.9-41.1	22.8
	Montgomery	20	4.1	13.7-38.5	29.6
	Neosho	35	3.1	12.0-40.0	30.2
	Wilson	74	2.9	7.9-64.0	35.9
	Woodson	13	2.9	16.1-68.8	39.8
Croweburg shale	Allen	6	1.4	9.7-20.0	15.3
	Chautauqua	5	2.0	8.0-27.6	18.5
	Labette	18	1.4	7.1-35.0	15.0
	Montgomery	8	1.7	8.0-21.0	14.8
	Neosho	18	1.9	8.0-32.6	20.3
	Wilson	34	1.5	8.0-59.8	27.1
	Woodson	6	1.6	10.0-26.9	18.6
Weir shale	Labette	3	5.2	7.0-16.3	12.6
	Neosho	4	3.2	11.0-27.9	17.2
	Wilson	12	3.1	12.6-39.0	24.7

*Upper and Middle Pennsylvanian Series.

know when to expect to intersect each coal or carbonaceous shale, 3) continuously monitor the cuttings stream, 4) be prepared to collect a sample at a moment's notice, and 5) collect a high percentage of the exiting cuttings in order to obtain sufficient sample for a desorption canister.

The following sampling procedures were found to be the most effective. The wellsite geologist continuously monitors the cuttings stream at the end of the blooie line by using sieves that are either hand-held or attached to a piece of PVC pipe. A large bucket of fresh water to wash the cuttings is placed next to the end of the blooie line.

By continuously monitoring the cuttings stream and with stratigraphic data from nearby wells, the geologist is able to anticipate the next zone to be sampled. The driller assists with this process by conveying to the geologist when the drilling rate changhes.

When coal or carbonaceous shale cuttings are first observed, or are anticipated, the geologist (or a drill helper at the geologist's direction) takes an expanded metal trash can and places it over the end of the blooie line at an angle. This takes a fair degree of strength, and safety clothing (including a heavy long-sleeve shirt, boots, leather gloves, safety glasses with side shields, and hard hat) is required.

Three or more trash cans need to be available, in cases where the zone to be collected is over 2 ft in thickness. It is often necessary to rotate the trash can during collection, since the cuttings stream will quickly abrade holes in the side of the expanded metal trash can.

Sample preparation

After the sample is collected in the expanded metal trash can, it is immersed in a large bucket of drill water and agitated to remove fine cuttings and clay. Then the sample is placed in the desorption canister, packing the sample as the canister is filled to within ½-in. of the top.

If there is not sufficient sample to fill a 12-in. canister, smaller canisters (2 in., 4 in., or 6 in. in height) are used. If there is still 1½ in. or more of headspace at the top of the canister after filling, it is recommended that the canister be filled to ½ in. of the top with drill water. After filling the canister, it should be placed in a cool place in the summer or in a heated vehicle in the winter, until it is transported to the laboratory for desorption. Canisters need to be stored and transported upright.

It is difficult to calculate the gas content of a mixed coal and carbonaceous shale sample. This is due to the fact that the recovered gas desorbs from both the carbonaceous shale and the coal. The Mulky coal, Croweburg coal, and Tebo coal all have overlying carbonaceous shales. Cuttings samples of these coals will always contain carbonaceous shale.

Every effort should be made to separate the coal cuttings from the carbonaceous shale before placing the sample in a canister. The coal can be separated from the carbonaceous shale by panning. The different panning methods include: 1) rotating the sample in the expanded metal trash can in the large tub of water, 2) swirling the cuttings with water in a large rubber tub, or 3) agitating the sample in a large sieve in water.

The coal, being less dense, will work its way to the top of the slurried sample, where it can be skimmed off. It is much more desirable to have a small canister (2-in. or 4-in.) filled with a high percentage of coal than a 12-in. canister filled with a mixed sample containing a small percentage of coal.

All canisters need to be pressure tested for 24+ hr prior to use. An air pump is used to pressure the canister to 15 psi, the canister is sealed, and the

Pennsylvanian coal gas content data*

Table 2

Geological unit	Eastern Kansas county	No. of desorption samples	Average coal thickness, ft	Range of bulk coal gas contents (scf/ton)	Average gas content bulk coal (scf/ton)
Mulberry coal	Allen	7	0.9	124-153	138
	Neosho	6	0.8	160-240	187
	Wilson	29	1.1	79-314	179
	Woodson	4	1.2	161-203	178
Mulky coal	Labette	18	1.1	132-265	194
	Montgomery	6	1.1	210-300	237
	Neosho	30	0.7	86-320	205
	Wilson	68	1.1	75-324	231
	Woodson	13	1.3	48-355	265
Ironpost coal	Labette	2	2.0	194-200	197
	Montgomery	3	1.4	121-189	156
Bevier coal	Allen	10	1.1	57-146	110
	Labette	27	1.3	72-300	167
	Montgomery	4	1.2	135-243	205
	Neosho	13	1.5	72-173	111
	Wilson	14	1.4	127-292	196
	Woodson	2	0.9	88-102	95
Croweburg coal	Allen	8	0.9	73-194	139
	Chautauqua	4	0.6	116-200	169
	Labette	28	1.1	112-245	174
	Montgomery	8	0.9	100-185	141
	Neosho	25	0.9	100-293	184
	Wilson	34	0.8	144-325	206
	Woodson	11	0.9	77-305	180
Fleming coal	Allen	3	1.5	107-141	123
	Labette	12	1.2	83-235	159
	Neosho	5	1.6	94-149	122
	Wilson	15	1.3	72-205	164
	Woodson	3	1.6	176-218	190
Mineral coal	Allen	9	1.4	63-153	113
	Labette	13	1.2	77-155	113
	Neosho	4	1.2	100-144	127
	Wilson	4	0.6	101-198	148
	Woodson	2	1.0	68-76	72

*Marmaton and Upper Cherokee Group coals.

PENNSYLVANIAN COAL GAS CONTENT DATA* Table 3

Geological unit	Eastern Kansas county	No. of desorption samples	Average coal thickness, ft	Range of bulk coal gas contents (scf/ton)	Average gas content bulk coal (scf/ton)
Tebo coal	Labette	1	1.0	159	159
	Neosho	2	0.8	139-158	148
	Wilson	2	0.6	96-180	138
	Woodson	2	0.8	75-214	144
Weir coal	Allen	3	1.0	88-140	121
	Labette	16	2.7	88-218	157
	Montgomery	6	1.6	88-275	178
	Neosho	9	0.9	102-261	158
	Wilson	26	1.6	83-282	205
	Woodson	5	1.9	154-234	185
Bluejacket coal	Labette	3	0.9	88-166	135
	Montgomery	1	1.2	131	131
	Neosho	3	1.0	119-273	195
	Wilson	7	1.9	76-270	163
Dry Wood coal	Labette	4	0.9	94-198	136
	Neosho	2	1.0	26-91	58
Rowe coal	Allen	4	1.1	141-229	181
	Crawford	3	1.7	71-103	86
	Labette	19	1.1	33-235	168
	Montgomery	7	2.1	194-331	249
	Neosho	28	1.4	141-274	208
	Wilson	24	1.5	123-304	219
Neutral coal	Labette	9	1.0	73-235	166
	Montgomery	2	1.2	230-288	259
	Neosho	27	1.2	141-269	209
	Wilson	18	1.0	123-288	198
Riverton coal	Allen	11	2.6	62-269	170
	Crawford	4	2.2	82-129	98
	Labette	33	1.9	59-294	205
	Montgomery	10	2.0	189-317	259
	Neosho	40	2.7	131-307	236
	Wilson	47	1.7	91-347	231
	Woodson	10	1.8	58-223	188

*Lower Cherokee Group coals.

pressure is monitored. If there is any loss of pressure, the canister is not to be used. Leaks can be detected by immersing the pressurized canister in water.

Desorption of samples

The desorption canisters are transported to the laboratory at the end of drilling each day. Air rotary drill rigs in eastern Kansas normally drill only one shift per day.

The laboratory is kept at a constant 70° F.

The canisters are allowed to heat up-cool down to laboratory temperature before initial desorption. An inverted graduated cylinder on a ring stand is used to measure the desorbed gas. Flexible tubing is attached to each canister's valve. The graduated cylinder is moved from one group of canisters to the next to facilitate measurement of the desorbed gas.[2]

Initial measurements of desorbed gas are conducted 2-3 times/day, decreasing to 2-3 times/week as the desorption rate decreases. The canisters are allowed to desorb until the sample no longer is desorbing any measurable gas. This can take from 3 weeks or less to over 3 months.

No corrections were made for variations in barometric pressure, slight variations in room temperature, fluid pressure in the graduated cylinder, etc. The overall objective of this desorption is to obtain gas content data that are sufficiently accurate to be used as a screening tool to make exploratory and well completion decisions.

Calculating gas content

The desorption of cuttings will not yield gas content data as accurate as the desorption of cores.

The same collection and desorption procedures were followed in all samples collected in eastern Kansas. This resulted in gas content data that were then able to be used for comparative purposes throughout eastern Kansas.

After desorption is complete, the samples are air dried, split using a riffle splitter, and weighed. One of the main disadvantages of desorbing cuttings versus cores is that, in most cases, when collected, the cuttings samples are mixed lithologies. With samples of carbonaceous shale mixed with limestone and-or noncarbonaceous shale, a representative sample can be visually separated, each fraction weighed, and the weight of the carbonaceous shale in the total sample calculated.

All coal samples are sent to a coal laboratory where the coal is separated by flotation using a heavy liquid (specific gravity of 1.75 grams/cc) and the percentage of coal, by weight, determined.

If the coal sample contains carbonaceous shale, the percentage of the shale can be visually separated and weighed in a representative sample, in order to determine the percentage, by weight, of carbonaceous shale in the sample. A determination is then made as to what percentage of the measured gas desorbed from the coal and what percentage desorbed from the carbonaceous shale.[3]

Air rotary cuttings circulate to the surface very quickly, and the interval from the time that the sample is drilled to the time the cuttings are sealed in a canister is only 5 to 10 min. This negates the need to calculate the lost gas.

It is not known how much gas is released from the sample during the actual drilling process when the sample comes in contact with the high pressure percussion air hammer bit. The air rotary drill cuttings are ¼ in. or less in diameter; and once desorption is complete, probably little, if any, residual gas remains.

This study

The gas content data from the desorption of 1,366 canisters from 272 wells drilled in eastern Kansas were used in this study.

Of these canisters, 492 were carbonaceous shale samples and 874 were coal samples. From 1 to 16 canisters were collected on an individual well. Either all potentially productive coals and carbonaceous shales were collected in a well (normally 6 to 10 canisters) or, due to the proximity of desorption data from nearby wells, only 1 to 3 zones were selected to be canistered.

It is not uncommon to miss collecting canister samples from individual zones for the following reasons: 1) the wellsite geologist was busy canistering a sample and missed the next sample, 2) unanticipated zones were encountered, 3) collection of insufficient sample due to various factors, including badly mixed cuttings, the drill bit pulverizing the coal, etc., and 4) unsafe collecting conditions, including excessively high air pressure, excessive water discharging from the blooie, etc.

Zones sampled

In eastern Kansas, eight carbonaceous shales and 14 coals were canistered and the gas contents calculated (Tables 1-3).

On a typical well, of these 22 zones, only 6-10 zones would be present and in sufficient thickness to sample. The sampled carbonaceous shales varied in average thickness from 1.4 to 5.2 ft and averaged 2.6 ft thick (Table 1). The coals varied in thickness from 0.6 to 2.7 ft and averaged 1.3 ft (Tables 2-3). The thickest coal sampled in an individual well was the Weir coal with a thickness of 6½ ft.

EASTERN KANSAS COALS AND CARBONACEOUS SHALES THAT CONTAIN GAS — Table 4

Unit	Comments
Stark shale mbr	Shown on Fig. 1.
Hushpuckney shale mbr	Shown on Fig. 1.
South Mound shale mbr	Shown on Fig. 1.
Mulberry coal bed	Shown on Fig. 1.
Lexington shale	Shown on Fig. 1 as the Anna shale mbr
Summit shale	Shown as the Little Osage shale mbr on Fig. 1 (the Summit coal bed is only present in a small area in NE Neosho County, very thin, never canistered).
Mulky shale	Not shown on Fig. 1 but directly above the Mulky coal bed.
Mulky coal bed	Shown on Fig. 1.
Ironpost coal bed	Not shown on Fig. 1 but is between the Breezy Hill ls mbr and Bevier coal bed (the Ironpost coal is present only in southern Labette and Montgomery counties).
Bevier coal bed	Shown on Fig. 1
Croweburg shale	Not shown on Fig. 1. Directly above the Croweburg coal bed.
Croweburg coal bed	Shown on Fig. 1.
Fleming coal bed	Shown on Fig. 1.
Mineral coal bed	Shown on Fig. 1.
Tebo coal bed	Shown on Fig. 1.
Weir shale	Not shown on Fig. 1. Directly above the Weir-Pittsburg coal bed.
Weir coal bed	Shown on Fig. 1 as the Weir-Pittsburg coal bed (In this article and in common usage in eastern Kansas it is referred to as just the "Weir coal").
Bluejacket coal bed	Shown on Fig. 1 as an unmarked coal (black line) between the Sevell ls mbr and Bluejacket ss mbr.
Dry Wood coal bed	Shown on Fig. 1.
Rowe coal bed	Shown on Fig. 1.
Neutral coal bed	Shown on Fig. 1.
Riverton	Shown on Fig. 1.

The uppermost stratigraphic zone collected in eastern Kansas was the Stark shale member of the Dennis limestone in the Kansas City Group (Fig. 1 and Table 4).[4] The lowest Pennsylvanian stratigraphic zone collected is the Riverton coal near the base of the Cherokee Group, just above the top of the Mississippian limestone. Desorption canisters of the Chattanooga shale have also been collected in a number of locations in eastern Kansas.

In Allen, Labette, Montgomery, Neosho, and southern Wilson counties, the zones collected ranged from the Lexington shale to the Riverton coal (Fig. 1). These zones occur over an average stratigraphic thickness of 494 ft. In northern Wilson, Woodson, and Chautauqua counties, the zones collected ranged from the Stark shale to the Riverton coal.

These zones occur over an average stratigraphic thickness of 767 ft. The shallowest zone canistered was the Summit shale at 227 ft in a well in Labette County, and the deepest zone canistered was the Riverton coal at 1,654 ft in a well in Chautauqua County.

Gas content

Table 1 summarizes the gas content data for the eight carbonaceous shales

GAS CONTENT OF EASTERN KANSAS SHALES AND COALS* — Table 5

Eastern Kansas county	No. of wells sampled	Avg. no. of canisters collected	Range of gas content, Mcf/acre	Average gas content, Mcf/acre
Allen	9	7.8	1,504-3,005	2,066
Chautauqua	3	7.0	1,339-2,229	1,823
Labette	26	7.6	1,221-4,359	2,890
Montgomery	4	7.8	2,081-4,273	2,829
Neosho	23	7.6	2,202-5,326	3,836
Wilson	34	7.7	1,786-5,549	3,478
Woodson	11	8.3	2,089-5,577	3,245
Average				**3,104**

*Pennsylvanian age Carbonaceous shales and coals.

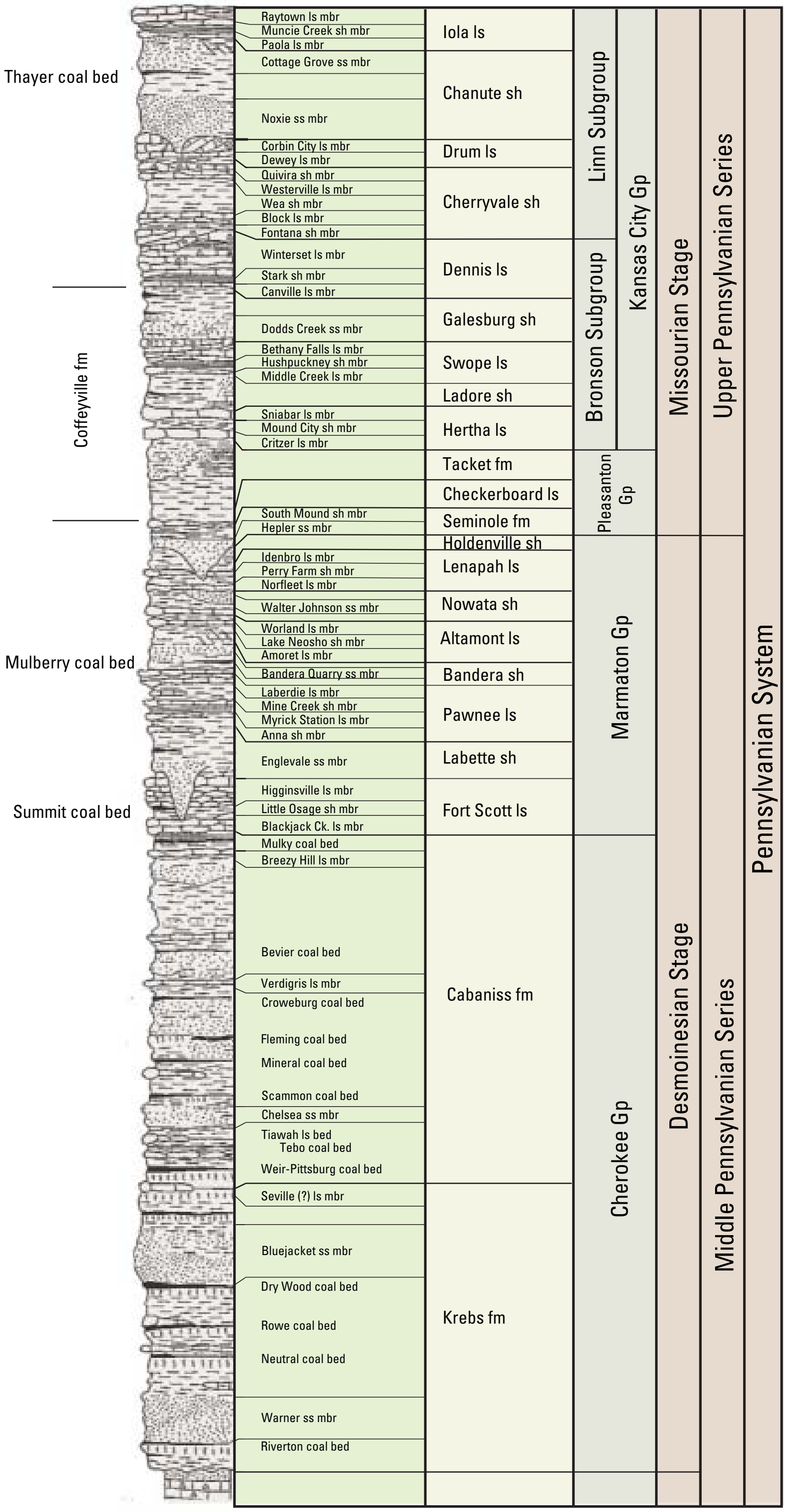
HOW GAS CONTENT AND PRODUCTION RATES CORRELATE — Table 6

Bulk coal gas content category,[1] scf/ton	Number of wells averaged in category	Range of production per well, Mcfd[2]	Avg. well production, Mcfd[2]
139 to 160	7	4.8-53.1	17.4
161 to 180	6	2.7-43.1	14.0
181 to 200	8	7.4-60.9	29.7
201 to 220	23	7.1-137.0	45.0
221 to 240	22	12.5-84.5	45.6
241 to 260	18	19.5-131.6	67.8
261+	12	24.8-163.9	59.0

[1]Weighted average of the 2 or 3 highest gas content coals in a well. [2]Average rate for a 12 month period starting with the peak production month.

EASTERN KANSAS COALS AND CARBONACEOUS SHALES

Fig. 1



Source: After Jewett, 1968.

in eastern Kansas.

This table groups the gas content data by county. All of these zones are productive in various areas in eastern Kansas. The most commonly completed carbonaceous shales are the Summit, Mulky, and the Croweburg.

Tables 2 and 3 summarize the gas content data from the 14 coals sampled in eastern Kansas. Most of these coals are productive in various areas in eastern Kansas. The most commonly completed coals are the Mulky, Croweburg, Weir, Rowe, and Riverton.

Canister samples were collected from 272 wells in eastern Kansas. A complete set of all carbonaceous shales and coals (that were present in sufficient thickness) were sampled in 110 of these wells.

In these wells, 6 to 10 carbonaceous shales and coals were sampled. Table 5 summarizes the gas content data in these 110 wells. This table, listed by Kansas county, shows the range in total gas content per well and the average gas content per well. The gas content varies from a low of 1,221 to a high of 5,577 Mcf/acre with an average of 3,104 Mcf/acre.

Production correlation

A comparison was made between the coal gas content and well production. Of the 272 canistered wells in eastern Kansas, two or more coals were collected in 223 of these wells (for various reasons, not all coals that were present were canistered in every well; or in certain outlier areas, most coals were very thin or absent).

Production data

Production data for these 223 wells (with gas content data from two or more coals) was researched at the Kansas Geological Survey web site. The website lists the monthly production data on each producing gas well in eastern Kansas (most wells in eastern Kansas are multizone completions, and the gas from all zones in a well are commingled).

Of the 223 wells with gas content data on 2 or more coals, only 96 wells had sufficient production data to be included in this comparison. Most of the remaining wells had no production data or had been producing for only a short time. The wells with no production data were mostly shut-in gas wells awaiting a pipeline, and in a few cases the wells had been plugged and abandoned.

The average daily production rate was determined from each of the 96 wells. This was calculated for a 12-month period starting with the month of peak production, which occurs after a period of dewatering.

Nearly all coalbed methane wells in eastern Kansas require dewatering to be productive. This is especially true in new areas with little or no production.

In areas that have been developed and there are only infill drilling locations, this dewatering period is significantly shorter. On two thirds of the wells, peak production occurred within 7 months after the start of pumping, and peak production on the remaining one third of the wells took 8 months or longer.

Coal gas content

A weighted average gas content was calculated for the two (when only two were available) or three coals with the highest gas content for the above 96 wells.

Sixty-two wells had gas content data for three or more coals. The remaining 34 wells had gas content data for two coals. The average coal gas contents were divided into one of seven categories (Table 6). Wells, based on their average coal gas content, were sorted into their appropriate category.

Production vs. content

The daily production for all of the wells in each gas content category was averaged (Table 6). Two important conclusions can be made from Table 6. They are:

- There is, in most wells, a general correlation between coal gas content and well production. On average, gas production increases as coal gas content increases.
- There is a correlation between the coal gas content and the average daily production rate for the poorest producing well in each category. Generally, the average daily production rate for the poorest producing well in each category increases with higher gas contents.

From 2001 to 2005, Quest Resource as part of its exploration program, would lease small outlier tracts. These tracts would be 10-30 miles from established coalbed methane production in eastern Kansas.

Quest would drill one or two air rotary wells, canistering cuttings from all of the carbonaceous shale and coal zones encountered. When the results of these desorption samples indicated that the gas contents were generally poor, Quest, with minimal effort and expense, was able to redirect its exploration efforts to more productive areas.

Acknowledgments

The author thanks Quest Resource Corp., SEK Energy LLC, Carroll Energy LLC, Hopewell Operating Inc., and N&B Enterprises for permission to include company gas content data in this report. Thanks to Joe Bruns, Tom Ebers, Julie Shaffer, and Carol Shiels for reviewing drafts of this article. ✦

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The author

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Colombia

Pacific Rubiales Energy Corp., Toronto, has a zone discovery at the Abanico-20 exploratory well in the northeastern part of Abanico oil field in Colombia's Upper Magdalena basin.

The well cut 113 ft of net oil pay in three Cretaceous Lower Guadalupe sandstones. It flowed 901 b/d of 22.5° gravity oil with 4.7% bs&w from 46 ft of perforations. TD is 2,986 ft MD, 1,809 ft TVD ss. Porosity averages 22.6%.

Texas

Gulf Coast

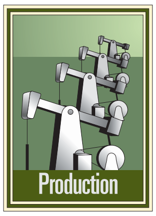
The Griffin Oil Unit-2 well in Gonzales County, Tex., has produced more than 33,000 bbl of oil from Cretaceous Austin chalk since being restored to production in July 2006, said Lucas Energy Inc., Houston.

Lucas Energy purchased the well for $15,000 and spent $120,000 on a pumping unit, tubing and rods, and a workover. The well had yielded 280,000 bbl before being shut-in in 2000.

Production tax is abated due to a shut-in tax exemption the company received from the state. Lucas Energy holds 100% of the working interest.

Life-cycle energy efficiency model influences upstream project design

Theo Mallinson
Siemens Energy Inc.
Houston



Through analysis of life-cycle costs, upstream facilities engineers can evaluate design alternatives such as turbine vs. motor driver selection and establish best practices for various types of facilities.

The upstream oil and gas industry historically has focused primarily on equipment availability as a primary design input, which differs significantly from typical designs or operating strategies found in sectors operated on smaller margins, such as refining and chemicals.

The analysis method discussed can benefit preappraise, appraise, and select project stages of a typical offshore development. The primary technique covered involves profiling various options with life-cycle analysis to determine potential energy efficiency and carbon footprint improvement.

This article discusses how these input factors affect decision making early in project planning and execution. A hypothetical analysis of a West Africa floating production, storage, offloading (FPSO) project illustrates the model.

Based on a presentation to Deep Offshore Technology, New Orleans, Feb. 4, 2009.

Availability to efficiency

As defined in this analysis, availability is a measure of the time a piece of equipment or system works compared to the required time.[1] The requirement for a high overall availability often results in installation of spare equipment, even though the peak rate period may be short compared with the life of the facility.

In this article, efficiency, termed intensity when expressed as a percentage, is the amount of energy expended compared with the energy produced by the facility. Projects have not included efficiency as a primary design metric for several reasons, despite the potential for savings and environmental benefits. Reasons include for not including efficiency include:

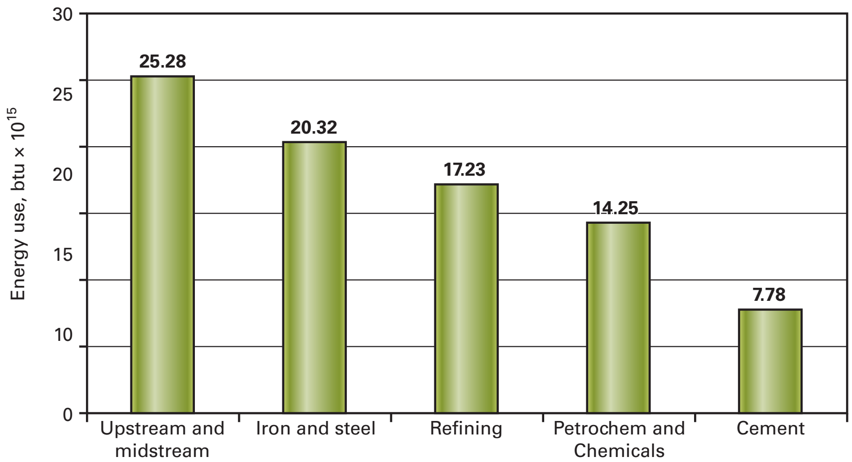
• Lack of a valuation method for fuel gas in developments without access to gas markets.

• Difficulty in prediction modeling for the life of the field to quantify benefits.

• Variability in emissions tax regimes and incentives for energy efficiency.

INDUSTRY ENERGY CONSUMPTION

Fig. 1



Note: Top energy intensive industries, worldwide 2005.

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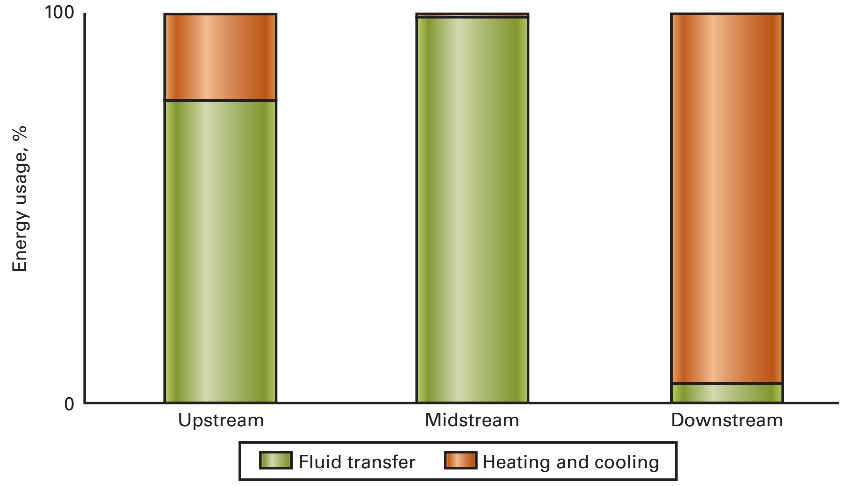
ENERGY USAGE DISTRIBUTION Fig. 2



This is not to assert that efficiency is more important than uptime. At current oil prices, uptime return can be about double any savings due directly to lower energy use.[2]

Some methods discussed for improving efficiency, however, also may increase or at least maintain benchmark availability values.

While it may appear difficult to justify design or operating strategy changes in an environment of relatively high oil prices, one should balance the status quo against the realization that the easiest and cheapest incremental barrel of oil to produce is typically a theoretical one from an existing facility. This production often results from a noncapital expense project.

It should then be possible to quantify and realize some of these operational lessons during the design phase.

This approach differs from others published in that energy efficiency is a primary design metric rather than as an operating facility assessment exercise.

To better understand the issue, we first describe energy use in a broader context across these focus industries, identify a particular area of improvement opportunity and determine the changes needed to effect that improvement.

Energy usage

Upstream and midstream oil and gas are the most energy intensive industries in the world in terms of annual heat input (Fig. 1).[3,4] Based on 2005 production of 254 × 10^{15} btu from oil and gas combined,[5] the oil and gas industries collectively consume nearly 20% of the fuel value of produced fluids in compression and pumping, heating, and other processes.

Sectors in the industry use this energy differently (Fig. 2).[2,3] Upstream on average expends the majority of energy in fluid transportation.

This varies depending on the type of operation in question. A heavy oil extraction facility in northern climes will have a greater proportion of energy

Energy Efficiency Profile

Profile Year	Field Energy Produced (MMBtu/yr)	Field Energy Consumed (MMBtu/yr)	Field Energy Flared (MMBtu/yr)	Field Energy Vented (MMBtu/yr)	Average Intensity (%)
1	244,843,796.5	4,493,828.2	0.0	0.0	1.84
2	358,992,157.0	5,260,813.2	0.0	0.0	1.47
3	358,801,729.7	5,282,425.0	0.0	0.0	1.47
4	326,596,582.0	5,098,255.2	0.0	0.0	1.56
5	294,391,434.4	4,914,085.3	0.0	0.0	1.67
6	236,171,875.5	4,500,131.2	0.0	0.0	1.91
7	189,462,597.4	4,178,789.3	0.0	0.0	2.21
8	151,988,001.8	3,901,552.0	0.0	0.0	2.57
9	121,923,673.2	3,659,251.3	0.0	0.0	3.00
10	97,804,399.1	3,434,752.4	0.0	0.0	3.51
11	78,454,175.0	3,199,339.2	0.0	0.0	4.08
12	62,931,716.0	2,945,147.4	0.0	0.0	4.68
13	50,482,079.2	2,766,358.4	0.0	0.0	5.48
14	40,491,906.6	2,455,701.8	0.0	0.0	6.06
15	32,483,902.1	2,336,287.3	0.0	0.0	7.19
16	26,061,725.0	2,235,902.1	0.0	0.0	8.58
17	20,911,422.5	2,143,486.8	0.0	0.0	10.25
18	16,778,303.2	1,981,168.0	0.0	0.0	11.81
19	13,466,715.3	1,930,849.2	0.0	0.0	14.34
20	10,811,066.5	1,889,093.6	0.0	0.0	17.47
Total Field	2,733,849,258.2	68,607,216.7	0.0	0.0	2.51

The software includes a screen for selecting various system capacities to match the composite requirement (Fig. 3).

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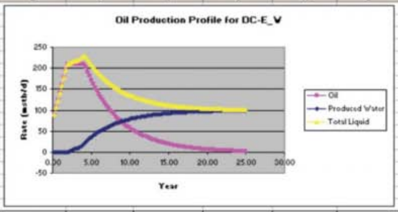
Oil Profile	Input			Calculated	
Reservoir Area	100.0	km2	STOIIP	3000	mmstb
STOIIP Density	30.0	mmstb/Km^2	Reserves	1500	mmstb
Recovery Factor	50.0	%	Reserves Accessed	600	
Plateau Rate	220.0	mstb/d	Reserves/annum	5.3	%
Initial well rate	15.0	mstb/d	R/P	18.9	years
Well prod before decline	20.0	% well reserves	Res/Well Prod	5	mmstb
Well Drain Area (max)	2.0	Km^2	Reserves Prod	101	mmstb
Volume Formation Factor	0.4		Rec Fac Prod	3.4	%
Efficiency Factor	1.0		Reserves/well (max)	30	mmstb
Decline Exponent	0.0		Area/well	5.00	Km^2



Year	Number of Wells	Reserves Acc'd mmstb	Efficiency Factor	Oil Rate mstb/d	Water Rate mbd	Liquid Rate mbd	Cum Oil mmstb	Cum Water mmb	Frac Accessed Res Prod	Total Liquid mbd	Water Cut %	GOR scf/b	FWHP psig	FWHT Deg F	WI Rate mstb/d	WI Press psig
0.25	6.25	188	1.0	89.1	0.0	89.1	8	0	0.04	8	0.00	1600	2000	160	145.0	5500
0.50	7.5	225	1.0	106.9	0.0	106.9	18	0	0.08	18	0.00	1604	2000	160	145.0	5500
0.75	8.75	263	1.0	124.7	0.0	124.7	29	0	0.11	29	0.00	1608	2000	160	145.0	5500
1.00	10	300	1.0	142.5	0.0	142.5	42	0	0.14	42	0.00	1612	2000	160	145.0	5500
1.25	11.25	338	1.0	160.3	0.0	160.3	56	0	0.17	56	0.00	1616	2000	160	145.0	5500
1.50	12.5	375	1.0	178.1	0.0	178.1	72	0	0.19	72	0.00	1620	2000	160	145.0	5500
1.75	13.75	413	1.0	195.9	0.0	195.9	90	0	0.22	90	0.00	1624	2000	160	145.0	5500
2.00	15	450	1.0	209.0	0.0	209.0	109	0	0.24	109	0.02	1628	2000	160	145.0	5500
2.25	16.25	488	1.0	209.0	1.6	210.6	127	0	0.26	128	0.05	1632	2000	160	145.0	5500
2.50	17.5	525	1.0	209.0	4.0	213.0	146	1	0.28	147	0.08	1636	2000	160	145.0	5500
2.75	18.75	563	1.0	209.0	6.1	215.1	165	1	0.29	166	0.10	1640	2000	160	145.0	5500
3.00	20	600	1.0	209.0	8.0	217.0	184	2	0.31	186	0.12	1644	2000	160	145.0	5500
3.25	20	600	1.0	209.0	9.7	218.7	203	3	0.34	205	0.13	1648	2000	160	145.0	5500
3.50	20	600	1.0	209.0	11.2	220.2	221	4	0.37	225	0.17	1652	2000	160	145.0	5500
3.75	20	600	1.0	209.0	15.2	224.2	240	5	0.40	245	0.21	1656	2000	160	145.0	5500
4.00	20	600	1.0	209.0	19.6	228.6	259	7	0.43	266	0.25	1660	2000	160	145.0	5500
4.25	20	600	1.0	202.4	24.5	226.9	277	9	0.46	286	0.29	1664	2000	160	145.0	5500
4.50	20	600	1.0	191.6	28.9	220.5	295	12	0.49	306	0.33	1668	2000	160	145.0	5500
4.75	20	600	1.0	181.4	32.7	214.1	311	15	0.52	325	0.36	1672	2000	160	145.0	5500
5.00	20	600	1.0	171.7	36.3	208.0	326	18	0.54	344	0.40	1676	2000	160	145.0	5500
5.25	20	600	1.0	162.5	39.7	202.2	341	21	0.57	362	0.43	1680	2000	160	145.0	5500
5.50	20	600	1.0	153.8	42.9	196.7	355	25	0.59	380	0.46	1684	2000	160	145.0	5500
5.75	20	600	1.0	145.6	45.9	191.5	368	29	0.61	397	0.49	1688	2000	160	145.0	5500
6.00	20	600	1.0	137.8	48.8	186.6	380	34	0.63	414	0.52	1692	2000	160	145.0	5500
6.25	20	600	1.0	130.5	51.5	182.0	392	38	0.65	430	0.54	1696	2000	160	145.0	5500
6.50	20	600	1.0	123.5	54.1	177.6	403	43	0.67	446	0.57	1700	2000	160	145.0	5500
6.75	20	600	1.0	116.9	56.5	173.4	414	48	0.69	462	0.59	1704	2000	160	145.0	5500
7.00	20	600	1.0	110.6	58.8	169.5	424	54	0.71	477	0.61	1708	2000	160	145.0	5500
7.25	20	600	1.0	104.7	61.0	165.8	433	59	0.72	492	0.63	1712	2000	160	145.0	5500
7.50	20	600	1.0	99.1	63.1	162.2	442	65	0.74	507	0.65	1716	2000	160	145.0	5500
7.75	20	600	1.0	93.8	65.1	158.9	450	71	0.75	521	0.67	1720	2000	160	145.0	5500
8.00	20	600	1.0	88.8	66.9	155.7	458	77	0.76	535	0.69	1724	2000	160	145.0	5500
8.25	20	600	1.0	84.1	68.7	152.7	466	83	0.78	549	0.71	1728	2000	160	145.0	5500
8.50	20	600	1.0	79.6	70.3	149.9	473	89	0.79	562	0.72	1732	2000	160	145.0	5500
8.75	20	600	1.0	75.3	71.9	147.2	480	96	0.80	576	0.74	1736	2000	160	145.0	5500
9.00	20	600	1.0	71.3	73.4	144.7	486	102	0.81	589	0.75	1740	2000	160	145.0	5500
9.25	20	600	1.0	67.5	74.8	142.3	492	109	0.82	601	0.76	1744	2000	160	145.0	5500
9.50	20	600	1.0	63.9	76.1	140.0	498	116	0.83	614	0.78	1748	2000	160	145.0	5500
9.75	20	600	1.0	60.5	77.4	137.9	504	123	0.84	626	0.79	1752	2000	160	145.0	5500
10.00	20	600	1.0	57.2	78.6	135.8	509	130	0.85	639	0.80	1756	2000	160	145.0	5500
10.25	20	600	1.0	54.2	79.7	133.9	514	137	0.86	651	0.81	1760	2000	160	145.0	5500
10.50	20	600	1.0	51.3	80.8	132.1	518	144	0.86	663	0.82	1764	2000	160	145.0	5500
10.75	20	600	1.0	48.5	81.8	130.3	523	152	0.87	674	0.83	1768	2000	160	145.0	5500

The model requires a production depletion curve complete with major power users (Fig. 4).

dedicated to heating than an equatorial sweet-oil production facility. In midstream, transportation comprises nearly the entire energy budget. For downstream, more than 90% of energy used is for heating through a direct furnace or boiler application, for steam or other heat medium generation, and for process cooling requirements.

Reduction of required work or losses in the transport segment provides the largest target for energy efficiency improvements in upstream, although heat integration may also have significant opportunities.

The analysis refers to heat integration in the downstream sense, where a design plans and matches process heating and cooling loads to reduce outside requirements and recovers excess process and utility heat for power generation (cogeneration cycle).

Design guidelines

Projects can apply several categories of potential efficiency improvements during the design phase. Generally, one can group these into strategies that reduce the amount of work required, reduce the concomitant losses in performing the work, and reduce fluid losses outside of energy requirements.

Note that some approaches will require multidiscipline support such as optimization between reservoir requirements and facility design. Methods for reducing the energy required for the three strategies include:

1. Reducing work through:

- Variation in arrival pressure to analyze horsepower requirements.
- Smoothing of peak flow to reduce design case requirements (plateau extension).
- Waste heat recovery (whether for additional power generation or for process needs).
- Heat integration, such as use of cross exchangers.
- Use of drag reduction agents to reduce pressure losses in supply or export lines.
- Offshore deep suction indirect cooling (suction from seawater in the thermocline).

2. Reducing lost work through:

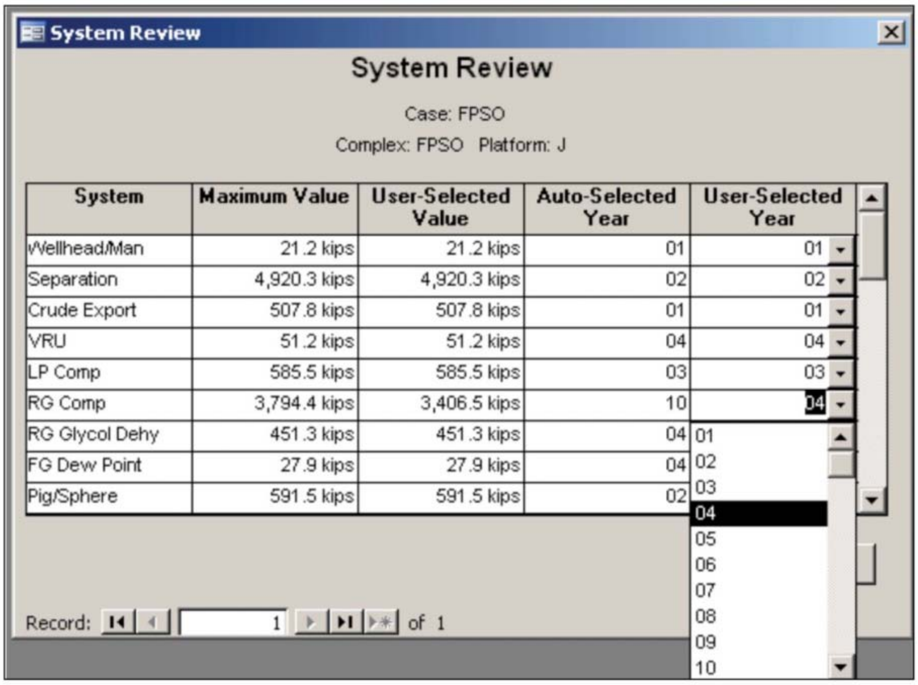
- Increased number of pumping-compression units required for peak rates (more flexibility as rates decline).
- Variable speed electric motors.
- Variable inlet guide vanes for compressors and turbines.
- Variable speed mechanical couplings, such as Voith Vorecon.
- Modern electric motors.
- Centralized electric generation from larger, higher efficiency colocated turbine generators.
- Provision of power from outside high efficiency source, such as local grid driven by a combined-cycle gas turbine (CCGT) plant.

3. Reducing nonenergy-related fluid loss through:

- Elimination of continuous vent or flare sources.
- Fugitive emission surveys.
- Recovery and reuse of spilled hydrocarbons.

Some of the proposed alternatives will have a higher capital expenditure (capex) than the traditional facility. Therefore, a comparison needs a method to quantify the operating expenditure (opex) effect and relate it to current project dollars.

The method will need software that allows quick analysis of alternatives

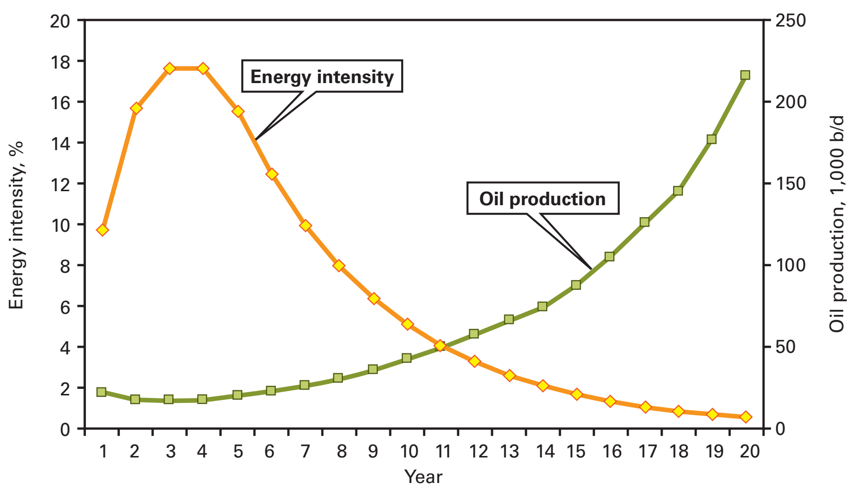


System	Maximum Value	User-Selected Value	Auto-Selected Year	User-Selected Year
Wellhead/Man	21.2 kips	21.2 kips	01	01
Separation	4,920.3 kips	4,920.3 kips	02	02
Crude Export	507.8 kips	507.8 kips	01	01
VRU	51.2 kips	51.2 kips	04	04
LP Comp	585.5 kips	585.5 kips	03	03
RG Comp	3,794.4 kips	3,406.5 kips	10	04
RG Glycol Dehy	451.3 kips	451.3 kips	04	01
FG Dew Point	27.9 kips	27.9 kips	04	02
Pig/Sphere	591.5 kips	591.5 kips	02	03

This screen shows the profile for the generated annual energy production and use (Fig. 5).

ENERGY INTENSITY, OIL PRODUCTION

Fig. 6



during the initial decision-making phases of the project. Late changes to the project involve rework and therefore may not achieve the expected savings, and late project work typically focuses on capex savings rather than efficiency and uptime.

Additionally, the method requires a framework to ensure commonality of reporting basis to support comparisons.

Full field life cycle

The process design engineer's primary concern is the sizing of equipment and systems in accordance with a composite base case.

The most conservative and simplest approach combines the peak rate of each fluid, though this rarely results in a practical design. More commonly, the engineers will prepare several representative cases from reservoir model production data that include parameters such as high arrival temperature, low arrival temperature, maximum oil flow, maximum gas flow, maximum total liquids, and maximum compressor horsepower at end of life arrival pressure.

While not necessarily a discrete model, the combination of these sizing cases results in a composite overall design base case.

Prediction of what these design cases should be, given time and personnel constraints during this early phase of the project, is difficult. The engineer, therefore, will often select the same definitions as used previously.

Alternatively, a base case for all expected contingencies developed through a year-on-year modeling approach can determine utility use, emissions load, and energy efficiency at the particular combination of production rates provided by the reservoir model.

Fig. 3 shows an example of selecting various system capacities to match this composite requirement. Note that values have a common weight value for comparison purposes only.

In any case, one can evaluate a system requirement on such factors as horsepower, allocated area, direct capex cost, and volumetric throughput from which one can select an appropriate model year or base model updated to change inputs.

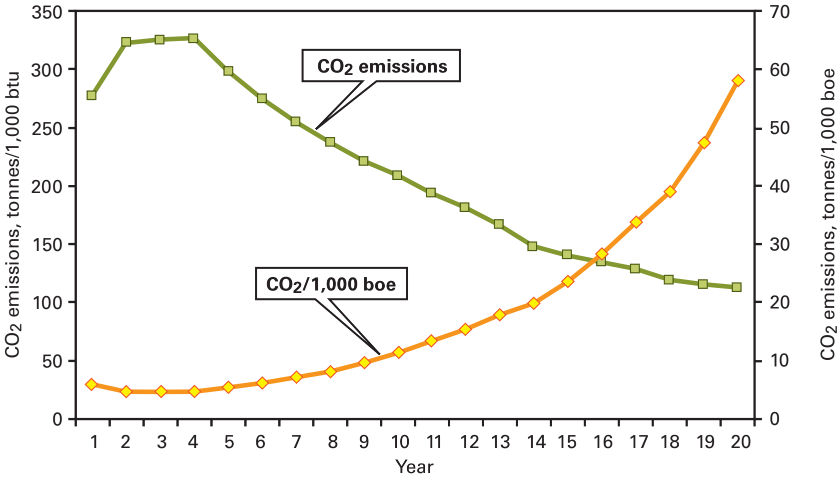
For a turbine-driven reinjection gas compressor, one may consider an approach for finding the point at which a 3 × 50% design (two units in operation, one unit spare, 50% of the time) becomes more attractive than a 2 × 100% design.

The 2 × 100% design usually costs less from a capex perspective, due to fewer units, less overall weight, smaller allocated area and simplified piping.

The 3 × 50% design, however, is more efficient in the sense that installed capacity is closer to the requirement for a longer cummulative period. As the facility moves away from the requirement for compression, the 3 × 50% design provides better flexibility with less recycling required.

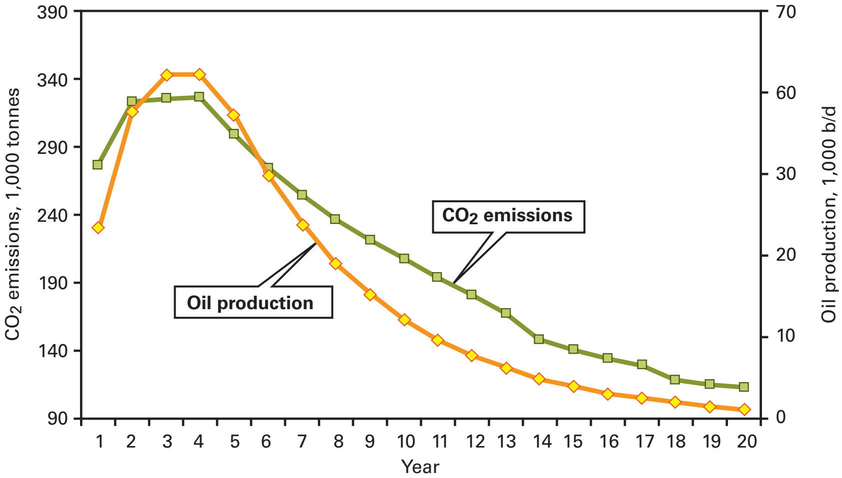
CO_2 EMISSIONS

Fig. 7



CO_2 EMISSIONS, OIL PRODUCTION

Fig. 8



One needs to quantify the benefits to determine whether this advantage outweighs the capex increase.

In addition to providing additional data during the design phase, another important application of this approach is for providing an ongoing operational target, for energy use or emission, similar to a nameplate processing capacity. Those involved on a day-to-day basis can make significant nondesign-related improvements, such as taking trains offline when not required, driving antisurge or capacity control valves towards minimum position, performing fugitive emission surveys, etc. Real-time data in an indicator or scorecard format could support this effort.[6]

Establishing current costs

In the early days of the oil industry, associated gas was considered a nuisance and therefore it was vented or flared. As markets developed for using this gas as a fuel or feedstock, the industry started to understand the reservoir drive mechanisms better. It then began using the gas for reinjection as well as for gas sales.

In areas without access to gas markets and below the recoverable threshold for capital-intensive LNG developments, the industry still considers the associated gas as free.

Most producing countries prohibit continuous flaring or will prohibit it in the near future. One valuation, therefore, could be cost avoidance of associated fines.

Assuming that a gas market becomes available due to population center shift, nearby development leading to improved infrastructure, or invention of more efficient small field technologies for transporting the gas to market, an analysis could determine a discounted net present value of the gas based on future sale.

Another method involves looking at the associated cost of using the gas due to emissions taxes. Norway is an example of a country with significant reserves and a mature CO_2 tax, currently at about \$60/ton CO_2. The EU rate for 2008-12 is \$33/ton CO_2.

Different fuel gases will provide varying amounts of carbon per standard volume, but assuming 133.759 lb CO_2/Mscf[7] at the EU tax rate, this equates to about \$2.21/Mscf. This compares to the 2007 average price for US industrial gas of \$7.59/Mscf.[8]

For valuing the price of carbon emissions separately from the actual cost of the fuel gas itself, the EU rate seems reasonable. Note that Norway's Ministry of Finance is pushing to join the current EU trading system.[9]

Discounting for present value in countries without any expected requirements in the near future could also be developed.

Alternately, one can use methods provided by several consultancies with a focus towards carbon pricing strategies, such as www.pointcarbon.com.

Model evaluation

A West African FPSO project illustrates the model. This is a common offshore development type and provides some advantages when preparing an illustrative case, as typically storage requirements determine deck area and the deck area is relatively constant regardless of the process configuration.

The base requirement for the facility modeled is 210,000 b/d light sweet crude processing, 360 MMscfd gas processing (used for fuel but primarily sent to reinjection), 90,000 b/d produced-water handling, and 150,000 b/d treated-seawater injection.

Fluid data

The model builds the composite base case and all alternative variants directly from the fluid data. Proper determination of the composite case requirements includes preparing a production depletion curve complete with major power users, such as water injection and gas injection requirements.

Notwithstanding potential sensitivity studies based on variation in production rates, Fig. 4 depicts a representative depletion curve tool.

Note that this layout has a quarterly input, which provides sufficient granularity to phase in additional development wells during the early life of the field and for infill wells later on.

Base case preparation

After preparing the model with the fluid data, the engineer must review the peak requirements of the various systems. This involves quantitatively looking at the loads predicted by the software during the field life (Fig. 3).

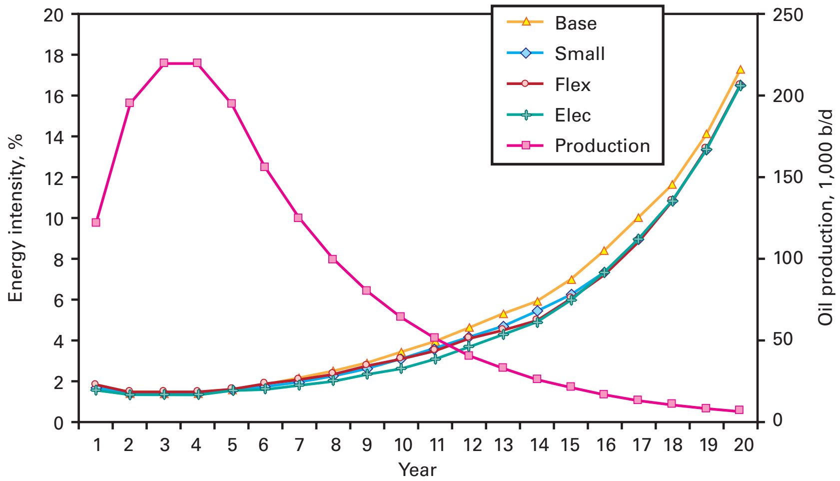
The base case model sets the benchmark for comparing other alternatives. This requires that the model generate a set of values for each case.

Once the model updates the base case against the asynchronous peaks determined by the software (Fig. 3), it can produce curves of annual energy production and use against the depletion curve (Fig. 5).

Evaluation metrics of potential interest are the minimum energy intensity (Fig. 6) and CO_2/boe (Fig. 7). These provide a measure of the maximum efficiency of the particular design arrangement for a given depletion profile with respect to energy used and CO_2 emissions. One can use these results to compare against the capex difference for the various arrangements.

MODEL ENERGY INTENSITY

Fig. 9



From the emissions perspective, plotting against production provides another way to visualize the drop in efficiency as the facility moves away from the peak throughput point (Fig. 8). The gap between the plots after year 6 provides a measure of the marginal drop in efficiency.

Alternatives studied

The following alternative cases all consider the same depletion profile for illustrative purposes. The peak requirements for the power generation and reinjection gas compression systems are selected based on maximum horsepower. The software model automatically selected the other system peaks on maximum weight basis.

- Base—FPSO base case.
- Small—Change 2 × 50% LM2500+ driven reinjection gas compressors to 2 × 50% LM2500 driven reinjection gas compressors (available horsepower reduction, requirement is now 94.5% of site rated available horsepower).
- Spared—Change 2 × 50% LM2500+ driven reinjection gas compressors to 3 × 50% LM2500+ driven reinjection gas compressors (improve availability).
- Flexi—Change 2 × 50% LM2500+ driven reinjection gas compressors to 3 × 33% Titan 130 driven reinjection gas compressors (improve availability and late life flexibility).
- Elec—Change 2 × 50% LM2500+ driven reinjection gas compressors to 2 × 50% variable speed drive (VSD) electric motor driven reinjection gas compressors (power generation forced from 3 × 50% with total load of 18.9 Mw attached to 4 × 33% with total load of 60.8 Mw attached).
- Import—Change 2 × 50% LM2500+ driven reinjection gas compressors to 2 × 50% VSD electric motor driven reinjection gas compressors and have power generation requirement of 61.5 Mw replaced with import power from shore. Remaining fuel gas users are inert gas generation and low-pressure compression.

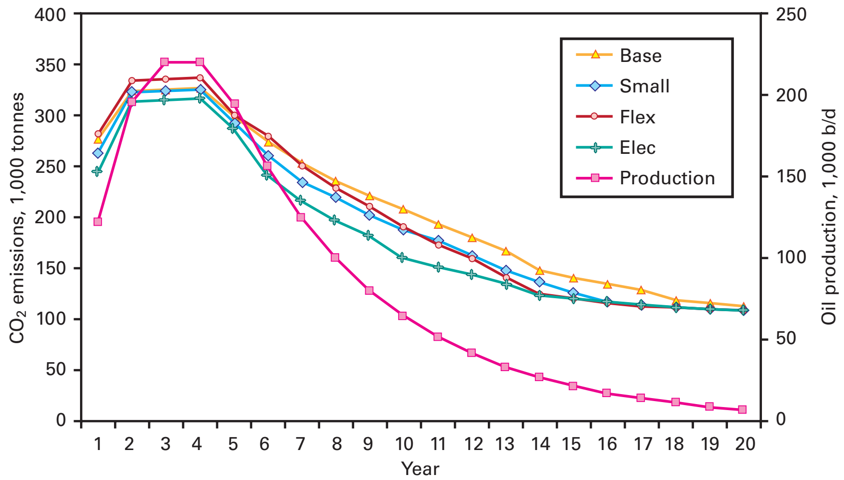
Model comparisons

The Elec model shows the best efficiency and emissions performance of the cases studied. A simple net present value calculation for the difference between the Base and Elec cases includes a combination of the fuel used and emissions as modeled, and uses a value of \$3.795/MMbtu for fuel (based on 50% of pricing above and 1,000 btu/scf) and \$33/ton CO_2 for emissions, and annual inflation of 2.5% for all pricing.

This comparison indicates an NPV of \$47 million (\$31.4 million for fuel gas savings and \$15.6 million for emis-

MODEL CO_2 EMISSIONS

Fig. 10



sions avoidance), which can be evaluated against the expected capex increase from the Base model. When combined with expected improvements in uptime, for the modeled case an all-electric drive approach may have significant benefits vs. the traditional design with dedicated gas turbines at each major power user.

Note that the graphs do not include the Spared and Import cases. Spared produces the same efficiency curves as Base. The improvement in availability requires generation of a reliability and maintainability (RAM) study to support the increased capex.

Import provides a much lower local emissions and fuel usage, shifting the burden to shore-based power plant with higher expected efficiency (even with transmission and conversion losses). One needs to balance this against the capex impact of powerline installation, changes in the production facility design and other factors outside the scope of this article.

Further development

Further development work includes:

• Integrate more sophisticated financial analysis within the model.

• Combine financials with risks and probabilities of various events such as changing product prices and excessive inflation.

• Ensure depletion model includes effect of gas cycling in gas lift or gas reinjection situations and water influx for water injection cases.

• Complete opex model with overhead, uptime, maintenance, other consumables, logistics, modifications and turnarounds, well workovers and decommissioning costs.

Observations

As with any comparison process, one important constraint is to ensure that the model uses a common basis. Additionally, the available data may mask other phenomena. For this reason, below are several potential misunderstandings:

• Companies can report gas used for fuel on a platform on a boe or heating value basis.[10] Depending on the heating value of the fuel gases in use, a boe comparison across fields or used as a benchmark may introduce some confusion. A common conversion of 5.8 Mscf gas to 1 boe depends on the gas calorific value. It uses 1,000 btu/scf. The standard definition of a boe is 5,798,615.481 btu.

• Btu basis should be standardized because several definitions exist. The article uses the International Steam Unit definition of 1,055.05585262 btu = 1 Joule.

• Drivers vary by region, so that the engineer should expect alternatives to present different values depending on the development criteria. As an example,[11] an onshore Canadian heavy oil development combines high direct energy intensity requirements, a near Arctic environment, and a relatively high market price for gas. These factors would combine to make energy efficiency improvements much more valuable than a similarly sized facility in places such as Venezuela.

• Companies can report carbon tax in \$/ton of carbon or \$/ton of CO_2. There are 27.3 tons of carbon/100 tons of CO_2.

• If the model can include an agreed basis on a current dollar value to improve percent uptime, one could select a more efficient process despite increased capex and otherwise insufficient opex savings. A RAM study could highlight the uptime differences between the two designs. ✦

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The author

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Global processing capacity trails advances in production

Warren R. True
Chief Technology Editor-LNG/ Gas Processing

Global gas processing activity in 2008 remained flat, despite gains in global natural gas production.

Natural gas production last year advanced in every region, as climbing natural gas prices spurred global production growth of nearly 7% (OGJ, Mar. 9, 2009, p. 64).

Each major region of the world witnessed growth in gas production, with the Middle East leading the way with more than 18% (1.8 tcf) growth. Countries of the Western Hemisphere produced more than 1.6 tcf (4.8%) over 2007.

Gas processing capacity, however, lagged this growth. In the US, capacity moved ahead by nearly 2% but Canada's growth was flat (Table 1).

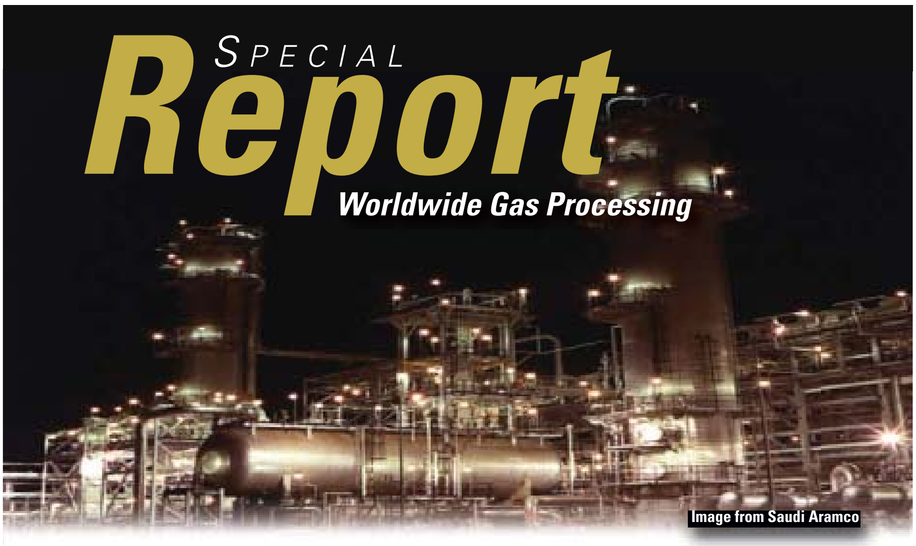


Image from Saudi Aramco

For the entire world, OGJ's data show that capacity growth in virtually every region stagnated.

Natural gas processing capacity outside the US and Canada continued to outgrow combined capacities in the world's two largest processing countries, a trend that emerged in 2005. For 2008, processing capacities of the two North American nations held at slightly less than 50% of world capacity. That trend was pushed by plants' capacities in the US advancing by only 1.8%, while Canadian plants' capacities remained flat.

Highlights

The marginal advantage in gas processing capacity for regions outside the US and Canada continued in 2008, the fourth year in a row to show this imbalance.

Production of Canadian NGL barely ticked upward. Combined with US production, NGL output from the two countries' gas plants resumed a decline evident in recent years but reversed somewhat in 2007. Total NGL production for the two North American countries reached 108.3 million gpd, or 37% of global NGL production. For 2007, the countries' combined production was 130.4 million gpd, or more than 44% of global NGL production. For 2006, the figure was 38.7% of world totals; for 2005, slightly more than 33%; for 2004, more than 34%; and in 2003, more than 40%.

On Jan. 1, 2008, OGJ data show that US gas processing capacity stood at more than 72 bcfd, up from 71 bcfd for 2007; throughput in 2008 only 395 MMcfd ahead of 2007, averaging slightly less than 46 bcfd (less than 64% utilization); and NGL production, more than 75.7 million gpd, compared with 76 million gpd for 2006 (Table 1; Fig. 1).

Fig. 2 shows pricing differentials in the US between LPG—the most widely traded NGL on the world market—and crude oil for the first trading day of each month in 2008. With crude oil prices escalating sharply during the first half of the year then dropping over the last half, the chart nonetheless reflects the historically normal relationship between LPG and crude oil continued throughout 2008. (An accompanying article, beginning on p. 58, discusses international trade in LPG and ethane.)

In March 2009, Enterprise Products Partners LP announced start-up of the expansion at its Meeker II gas processing plant in Colorado's Piceance basin. The expansion doubled capacity to 1.5 bcfd with the capability to extract as much as 70,000 b/d of NGL. Enterprise expects gas volumes at the expanded plant to reach 1.1 bcfd by yearend, when NGL production will reach 60,000 b/d. Photo from Enterprise.

Sources

Oil & Gas Journal's exclusive, plant-by-plant, worldwide gas processing survey and its international survey of petroleum-derived sulfur recovery provide industry activity figures.

Canadian data are based on information from Alberta's Energy and Utilities Board that reflect actual figures for gas that moved through the province's plants and are reported monthly to the EUB. For 2000 for the first time, OGJ took these data for all of Alberta and compiled annual figures and thereby created a new baseline for data comparisons thenceforth.

(Effective Jan. 1, 2008, the province realigned the EUB into two separate regulatory bodies: the Energy Resources Conservation Board to regulate the oil and gas industry and the Alberta Utilities Commission to regulate the utilities industry.)

In addition to EUB figures for Alberta and to operator responses to its annual survey, OGJ has supplemented its Canadian data with information from the British Columbia Ministry of Employment & Investment's Engineering and Operations Branch and the Saskatchewan Ministry of Energy & Mines.

As 2008 began, gas processing capacity outside Canada and the US stood at more than 127 bcfd; throughput outside Canada and the US for 2008 averaged 80.5 bcfd, up from 77.8 bcfd in 2007 and 80 bcfd in 2006. NGL production in 2008 outside the US and Canada averaged 182.4 million gpd compared with 163 million gpd in 2007 and 170 million gpd in 2006 but still off of 2005 production of more than 201 million gpd.

The current state of gas plant construction in the world appears in Table 2, based on OGJ's worldwide construction surveys. Table 3 ranks the world's major natural gas reserves by country at the start of 2008; Table 4, the world's top natural gas producing countries for 2008; and Table 5, the world's leading NGL producers.

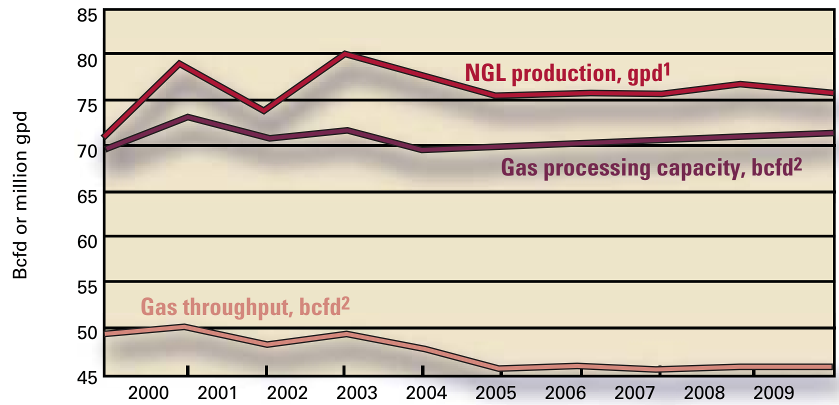
Activity

Global gas plant construction, especially in the Middle East, is responding to the increases in natural gas production that occurred last year. Following is a review of project plans and progress announced in the last 15-18 months.

OGJ subscribers can download, free of charge, the 2009 Worldwide Gas Processing Survey tables at www.ogjonline.com: Click on Resource Center, Surveys, OGJ Subscriber Surveys, then Worldwide Gas Processing, and choose from the list below June 22, 2009. To purchase spreadsheets of the survey data, please go to http://www.ogj.com/resourcecenter/orc_survey.cfm or email orcinfo@pennwell.com.

US GAS PROCESSING TRENDS

Fig. 1



[1]Based on a 12-month average for previous year. [2]As of Jan. 1 of each year.

Asia, Australia

China National Petroleum Corp. announced last month it will begin construction later this year on a gas processing plant in the South Sulige block currently operated by Total SA. The plant will be on line by yearend 2010.

CNPC and Total are developing the South Sulige block in what will be one of the largest investments by a foreign company in China's onshore oil and gas sector.

The report in a Chinese newspaper did not provide planned plant capacity.

Preliminary work on the 2,400-sq km South Sulige block has begun. Total plans to drill about 2,000 wells at South Sulige over the field's life of 20-25 years. Peak gas production is estimated to be about 3 billion cu m/year, a level that may be achieved 3 years after first production.

In Australia, the Chevron Australia-led Gorgon joint venture said last year it plans to build a 284-MMcfd gas plant beside its LNG plant on Barrow Island. Plans call for gas to be brought on stream for domestic use about the time the JV commissions the LNG project's last of three 5 million tonne/year LNG train (OGJ Online, May 19, 2009).

In March 2009, Houston-based Apache Corp. awarded Clough Ltd. a $45 million (Aus.) contract for engineering of the 200-MMcfd Devil Creek gas processing plant, southwest of Dampier. Apache will operate a $585 million (US) natural gas venture in Western Australia.

The plant will process gas from offshore Reindeer field, owned by Apache (55%) and Santos Ltd. (45%), to supply Citic Pacific Ltd.'s Sino Iron project at Cape Preston.

Production is slated to begin in second-half 2011.

Africa, Middle East

In Africa in May, state-owned Ghana National Petroleum Corp. announced it was looking for investors to fund a $1 billion gas processing plant. The site had yet to be selected but is likely to be about 130 km west of the western port city of Takoradi.

The plant will initially have an inlet capacity 150 MMcfd with likely expansion in 3 years to 600 MMcfd. Gas from Tullow Oil PLC's Jubilee field, off the country's west coast, will feed the plant.

Oil production is to start in 2010, with gas following in 2012.

In Egypt, Dana Gas, Sharjah, announced earlier this year it had started production from its recent Al Basant gas-condensate discovery in the West Manzala concession in the Nile Delta.

The company also began producing from its El Wastani East-2 sidetrack, Dana Gas Egypt's first highly deviated, horizontal well in Egypt.

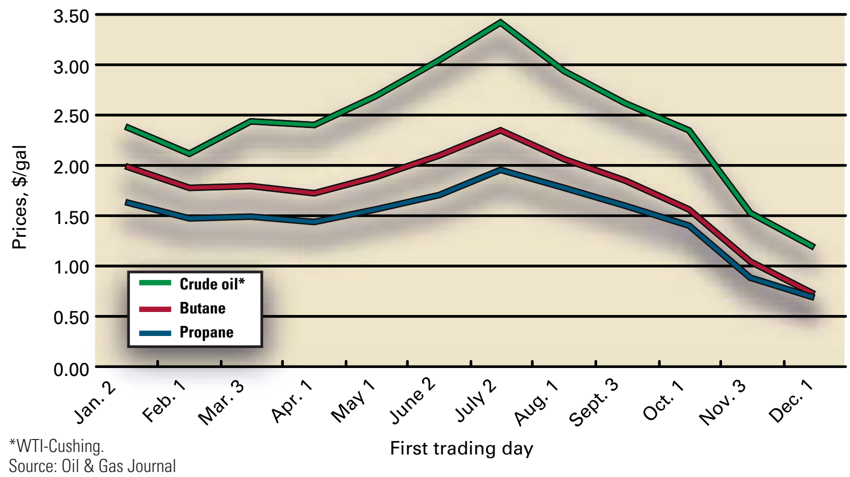
The Al Basant discovery was developed on fast track, said the company, with two 17-km pipelines, one 6 in. OD and 12 in., to transport Al Basant production to the El Wastani integrated gas plant. The plant has design capacity of 160 MMscfd and 7,500 b/d of condensate and LPG but is currently operating at 153 MMscfd gas and 5,400 b/d.

Dana said the new gas production from Al Basant will "allow testing the plant beyond its full design capacity and identifying components that require modification, or upgrading." It will also maximize throughput, while targeting production levels of 170 MMscfd.

In Saudi Arabia, Saudi Aramco has several major multibillion dollar projects under way to boost natural gas processing capacity. The company's latest annual review, for 2008 and published in April 2009, says that, when completed, these projects will increase processing capacity for associated and

US LPG DIFFERENTIAL, PRICE TRENDS: 2008

Fig. 2



*WTI-Cushing.
Source: Oil & Gas Journal

nonassociated gas to 12.5 bcfd from 9.3 bcfd.

The Hawiyah NGL recovery plant started up in second-half 2008. The associated pipelines were completed in November 2007 to deliver C_2+. The plant can process nearly 4 bcfd of sales gas to yield 310,000 b/d of NGL as feedstock for the country's expanding petrochemical industry.

Transport capacity on the existing East-West NGL pipeline, says the annual review, is being increased to 555,000 b/d from 425,000 b/d to meet demand on the west coast for ethane and NGL.

The Khursaniyah gas plant, with processing capacity of 1 bcfd of associated gas, was to have begun operating the middle of 2009, but published reports have put the start-up closer to October. The plant will be able to produce 560 MMscfd of sales gas and 280,000 b/d of C_2+.

A company spokesman declined to provide OGJ with an update on the schedule of this or any other project summarized here.

The Hawiyah gas plant expansion to process an additional 800 MMcfd of non-associated gas is to be completed mid 2009 and will raise the plant's capacity to 2.4 bcfd.

Expansion of the Ju'aymah gas plant to fractionate additional NGL was to have come into service in first-half 2009. The project adds 260,000 b/d of C_2+ capacity and 260,000 b/d of C_3+ capacity for a total of 815,000 b/d and 715,000 b/d, respectively, of fractionating capacity, according to the report.

Expansion of the Yanbu' gas plant is increasing existing NGL fractionation capacity to 555,000 b/d from 370,000 b/d to meet increasing demand for ethane as a petrochemical feedstock, specifically at the Yanbu' and Rabigh petrochemical complexes. This project was to have been on line in mid-2009.

Karan gas field, discovered in 2006 east of Jubail, is Saudi Aramco's first nonassociated offshore gas field. Drilling is under way; the company ultimately plans 23 wells on five producing platforms. The program to develop the field will provide offshore platforms, pipelines, new gas treating and upgraded facilities at the Khursaniyah gas plant. Saudi Aramco projects output from Karan field at about 1.6 bcfd.

Combined with associated gas from the Manifa project, the net production increase of gas processing at the Khursaniyah plant will reach 1.8 bcfd, says the annual review. Offshore gas production is slated for early 2012.

Saudi Aramco's Master Gas System can process more than 9 bcfd and deliver more than 7 bcfd of net sales gas to industrial customers around the country. A project to expand the transmission system in the eastern region, funded in 2007, is set for completion in 2010. This project will expand the MGS with 215 km of 56-in. pipe paralleling existing lines in order to serve future demand in Jubail and Ras az-Zawr. A total of seven stations will be installed to protect critical equipment for black powder corrosion, says the 2008 review.

In January 2009, Saudi Aramco awarded a contract to the Bonatti Group to build a plant to recover and treat residual gasses produced in the Uthmaniyah and Shedgum gas plants and currently being flared. Work was to have begun immediately with a target completion of October 2010.

As part of developing its $9 billion Manifa offshore oil field project, Saudi Aramco will also build a 1-bcfd gas plant. The processing plant will receive gas from offshore fields Arabiyah and Hasbah, both near Manifa field.

The Manifa project will be Saudi Aramco's largest offshore field when fully operating and add 900,000 b/d of capacity to the country's oil production. As well as heavy crude, Manifa field will produce 120 MMcfd of sour gas, 50,000 b/d of condensate, and 950,000 b/d of produced water. Production from the field targets mid-2011.

In addition, the nearby Khursaniyah gas plant is being upgraded to handle additional gas from the project.

In April in Iran, the managing director of Oil Industries Engineering and Construction Company said the Siri NGL project will come on stream by the end of March 2010.

The Siri NGL project includes Siri-to-Qeshm pipeline, Siri-to-Kish pipeline, Siri NGL plant, and Kish booster station, all estimated to cost $450 million.

The NGL plant is to produce 841 tonnes/day of propane, 328 tonnes/day of butane, 361 b/d of pentane, and 1,250 b/d of gas condensates. Siri Island sits in the southern waters of Iran off Hormozgan Province.

In Abu Dhabi, as part of plans to develop Shah sour-gas field, Abu Dhabi

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Worldwide gas processing roundup

Table 1

Region	[1]2007	[2]2008	Change	Change, %
US				
Gas capacity, MMcfd	71,062.7	72,342.7	1,280.0	1.8
Gas throughput, MMcfd	45,501.7	45,897.2	395.5	0.9
NGL production, 1,000 gpd	76,227.6	75,757.6	–470.0	–0.6
Proved reserves, bcf	211,085.0	237,726.0	26,641.0	12.6
CANADA				
Gas capacity, MMcfd	53,010.0	53,010.0	—	—
Gas throughput, MMcfd	29,946.6	29,230.2	–716.4	–2.4
NGL production, 1,000 gpd	32,521.8	32,524.8	3.0	—
Proved reserves, bcf	58,200.0	57,906.0	–294.0	–0.5
WESTERN EUROPE				
Gas capacity, MMcfd	24,495.0	24,495.0	—	—
Gas throughput, MMcfd	9,501.2	9,501.2	—	—
NGL production, 1,000 gpd	9,689.6	9,689.6	—	—
Proved reserves, bcf	160,132.0	157,105.0	–3,027.0	–1.9
EASTERN EUROPE				
Gas capacity, MMcfd	2,796.0	2,796.0	—	—
Gas throughput, MMcfd	1,426.5	1,426.5	—	—
NGL production, 1,000 gpd	10,142.4	10,142.4	—	—
Proved reserves, bcf	2,026,709.0	2,005,781.0	–20,928.0	–1.0
LATIN AMERICA				
Gas capacity, MMcfd	18,448.2	18,448.2	—	—
Gas throughput, MMcfd	12,427.3	12,343.3	–84.0	–0.7
NGL production, 1,000 gpd	35,929.9	33,991.9	–1,938.0	–5.4
Proved reserves, bcf	273,140.0	277,198.0	4,058.0	1.5
MIDDLE EAST				
Gas capacity, MMcfd	39,264.2	39,264.2	—	—
Gas throughput, MMcfd	27,318.0	27,318.0	—	—
NGL production, 1,000 gpd	86,323.1	86,323.1	—	—
Proved reserves, bcf	2,548,900.0	2,591,653.0	42,753.0	1.7
AFRICA				
Gas capacity, MMcfd	17,254.2	17,407.2	153.0	0.9
Gas throughput, MMcfd	9,642.4	9,642.4	—	—
NGL production, 1,000 gpd	16,777.3	16,684.0	–93.3	–0.6
Proved reserves, bcf	489,630.0	494,078.0	4,448.0	0.9
ASIA-PACIFIC				
Gas capacity, MMcfd	24,960.2	24,960.2	—	—
Gas throughput, MMcfd	20,290.8	20,227.8	–63.0	–0.3
NGL production, 1,000 gpd	25,799.1	25,593.1	–206.0	–0.8
Proved reserves, bcf	415,393.0	430,412.0	15,019.0	3.6
TOTAL-excl. US				
Gas capacity, MMcfd	180,227.8	180,380.8	153.0	0.1
Gas throughput, MMcfd	110,552.8	109,689.4	–863.4	–0.8
NGL production, 1,000 gpd	217,183.2	214,949.0	–2,234.3	–1.0
Proved reserves, bcf	5,972,104.0	6,014,133.0	42,029.0	0.7
TOTAL-incl. US				
Gas capacity, MMcfd	251,290.5	252,723.5	1,433.0	0.6
Gas throughput, MMcfd	156,054.5	155,586.5	–468.0	–0.3
NGL production, 1,000 gpd	293,410.8	290,706.5	–2,704.3	–0.9
Proved reserves, bcf	6,183,189.0	6,251,859.0	68,670.0	1.1

[1]Proved gas reserve totals for 2006 are as of Jan.1, 2008 (OGJ, Dec. 24, 2008, p. 24). [2]Proved gas reserve totals for 2008 are as of Jan.1, 2009 (OGJ, Dec. 22, 2008, p. 22).

Worldwide gas plant construction*

Table 2

Country	2009	2008
Africa	1	2
Asia-Pacific	—	3
Canada	—	1
Eastern Europe	1	2
Middle East	2	4
Latin America	—	5
US	7	7
Western Europe	—	—
Total	**11**	**24**

*Includes new plants, expansions, and modifications scheduled for completion in the year listed. 2009 data are from OGJ, Apr. 6, 2009. 2008 data are from OGJ, Apr. 7, 2008.

World's major gas reserves

Table 3

Country	Estimated proved reserves, tcf	Share, %
Russia	1,680.0	26.9
Iran	991.6	15.9
Qatar	891.9	14.3
Saudi Arabia	258.0	4.1
US	237.7	3.8
Abu Dhabi	198.5	3.2
Nigeria	184.2	2.9
Venezuela	170.9	2.7
Algeria	159.0	2.5
Iraq	112.0	1.8
Kazakhstan	85.0	1.4
Turkmenistan	94.0	1.5
Indonesia	106.0	1.7
Malaysia	83.0	1.3
China	80.0	1.3
Norway	81.7	1.3
Uzbekistan	65.0	1.0
Egypt	58.5	0.9
Canada	57.9	0.9
Kuwait	62.9	1.0
Libya	54.4	0.9
Netherlands	50.0	0.8
Ukraine	39.0	0.6
Australia	30.0	0.5
Oman	30.0	0.5
Argentina	15.6	0.2
UK	12.1	0.2
Subtotal	**5,888.9**	**94.2**
Others	365.5	5.8
Total	**6,254.4**	**100.0**

Source: OGJ, Dec. 22, 2008, p. 22

National Oil Co. and ConocoPhillips will build a 1-bcfd gas plant for the field, located about 180 km southwest of Abu Dhabi city, said Adnoc. The plant will process about 570 MMcfd.

The project also involves construction of new gas and liquid pipelines, and sulfur-exporting facilities at Ruwais. Upon completion, the partners will form a new company to operate the Shah facilities with Adnoc holding a 60% interest and ConocoPhilips 40%.

Russia

Late in 2008, Sibur Group, one of Russia's leading petrochemical companies, announced plans for a gas processing expansion project in Noyabrsk, in the middle of west Siberian oil fields, about 300 km north of Surgut.

US-based Fluor Corp.'s scope of work includes the EPCM services for expansion and upgrade of the Vyngayakhinskaya compressor station, the compressor Station 3 of the Nizhnevartovsk gas processing complex, and construction of the Vyngapurovsky gas plant and associated pipelines, as well as LPG storage and loading Noyabrsk.

Americas

In April, EnCana Corp., Calgary, announced plans to build the Cabin gas processing plant 60 km northeast of Fort Nelson, BC.

Phase 1, 400-MMcfd, is due on stream in third-quarter 2011. The plant will be expanded as the Horn River basin gas-shale production grows.

In Mexico, Pemex plans a 250-MMcfd gas processing plant at the Poza Rica gas complex in Veracruz state in northern Mexico to handle new supplies from the Chicontepec basin that is currently under development, the company said earlier this year.

Chicontepec, mainly an oil field, also produces associated natural gas. Only in the early stages of developing Chicontepec, Pemex plans to produce about 1 bcfd in the area by 2016 and propane, butane, and natural gasoline at the new plant.

Contract awards and construction were due to start by mid-2009 with 2 years anticipated for construction.

In the US in April, Range Resources Corp., Fort Worth, updated its Marcellus shale activity in the Pennsylvania Appalachia, announcing completion and commissioning on a 30-MMcfd cryogenic gas processing plant in Washington County, south of Pittsburgh.

The plant is part of the second phase of infrastructure work based on a 2008 agreement with MarkWest Energy Partners LP that set plans for development of gas processing and pipelines in the area. The companies completed the first phase of those plans in October 2008.

That initial phase included a 30-MMcfd refrigeration gas plant, three compressor stations, and about 25 miles of pipelines. The second phase adds three compressor stations and 20 miles of gathering and pipelines. The new cryogenic plant will bring Range's total processing capacity in southwestern Pennsylvania to 60 MMcfd.

When the second plant starts up later this summer, Range plans to divert natural gas flowing to the first-phase plant to the second cryogenic plant. The company said it wants to fill the cryogenic plant "as soon as practical" because it can extract a larger portion of natural gas liquids from the high-btu Marcellus gas.

Once the cryogenic plant is fully loaded, Range said, it will begin flowing gas from previously drilled Marcellus wells into the expanded pipeline system. As Range adds more production, it will be processed through the first-phase refrigeration plant. Range said it will be tying in new wells and expects the refrigeration and cryogenic plants to reach full capacity in third-quarter 2009.

The company said earlier this year it had 15 Marcellus wells in various stages of completion, waiting to be turned to production.

WORLD'S 20 TOP GAS PRODUCING COUNTRIES: 2008

Table 4

Country	Production, bcf	Share, %
Russia/FSU	28,490.0	26.4
US	21,453.0	19.9
Canada	5,602.2	5.2
Iran	3,515.0	3.3
Norway	3,503.9	3.3
Algeria	3,300.0	3.1
Netherlands	3,030.0	2.8
China	2,828.7	2.6
Indonesia	2,730.0	2.5
UK	2,594.1	2.4
Saudi Arabia	2,570.0	2.4
Mexico	2,532.4	2.3
Qatar	2,170.0	2.0
Malaysia	1,725.0	1.6
Egypt	1,610.0	1.5
UAE	1,565.0	1.5
Argentina	1,491.0	1.4
Pakistan	1,463.0	1.4
Trinidad	1,379.7	1.3
Australia	1,350.8	1.3
Top 20 total	**94,903.8**	**88.1**
Other	12,873.6	11.9
Total	**107,777.4**	**100.0**

Source: OGJ, Mar. 9, 2009, p. 64

WORLD'S TOP 10 NGL PRODUCING COUNTRIES: 2008

Table 5

Country	Production, bcf	Share, %
US	75,757.6	26.0
Saudi Arabia	37,044.0	12.7
Canada	32,524.8	11.2
Mexico	19,711.0	6.8
Kuwait	18,684.8	6.4
Iran	12,917.5	4.4
Australia	10,733.3	3.7
Russia/FSU	9,127.9	3.1
UAE	8,978.6	3.1
Venezuela	7,312.9	2.5
Top 10 subtotal	**232,792.4**	**80.0**
Rest of world	58,234.1	20.0
Total worldwide	**291,026.5**	**100.0**

A third phase of the project will add 20 MMcfd of refrigeration capacity by the end of September, increasing total processing capacity to 80 MMcfd.

Also in progress is construction of a 120-MMcfd cryogenic plant expected to come on line in January 2010. At the same time, Range said, it is adding more compression and pipelines as it continues to drill new Marcellus shale wells throughout the rest of the year.

The drilling program, said the company, keeps it on track to end 2009 at its Marcellus production target of 80-100 MMcfd net.

In Utah, units of Ute Energy LLC and Anadarko Petroleum Corp. formed Chipeta Processing LLC to operate a gas processing and delivery hub for the Greater Natural Buttes area of the Uinta basin of Utah.

Ute Energy is an investment of Quantum Energy Partners, Quantum Resources Management, and the Ute Indian Tribe of the Uintah and Ouray Indian Reservation, Utah.

Chipeta owns an existing 250 MMcfd refrigeration processing facility and earlier this year started up a second 250-MMcfd cryogenic processing facility.

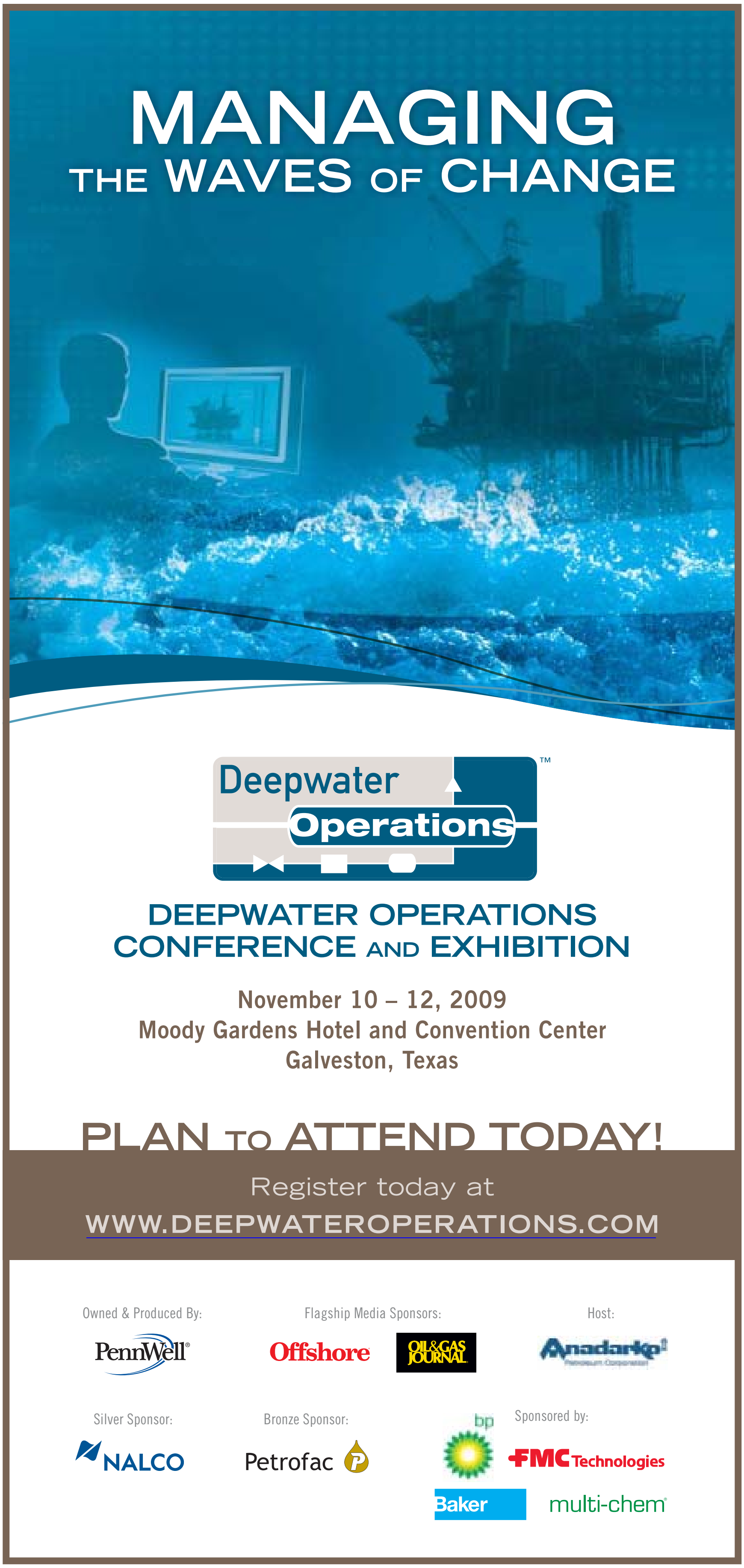
In Colorado in March, Enterprise Products began operations at its Meeker II gas processing plant in the Piceance basin. The Meeker II expansion doubles processing capacity at the Meeker complex to 1.5 bcfd with the capability to extract up to 70,000 b/d of NGL.

Enterprise also began operating its expanded Shilling and Thompsonville plants in South Texas and started up its relocated Chaparral plant in the Permian Basin. Meeker is supported by long-term commitments from 10 of the largest producers in the Piceance, according to the company. Current inlet volume at Meeker is about 750 MMcfd with about 38,000 b/d of NGL being extracted. Natural gas volumes will eventually reach about 1.1 bcfd by yearend and produce about 60,000 b/d of NGL.

Chaparral was an idle plant acquired in the 2004 merger with GulfTerra Energy Partners LP and was relocated from southeast Texas. It can handle up to 40 MMcfd and extract more than 2,000 b/d of NGL.

Expansions were also completed at two processing plants that are part of Enterprise's South Texas system. At the Shilling plant in Webb County, capacity was increased to 110 MMcfd from 60 MMcfd

The partnership also modified existing equipment rather than build new systems to expand its Thompsonville plant in Jim Hogg County. Re-piping and other efforts designed to enhance efficiency increased capacity at the facility by 10%, to 330 MMcfd from 300



MMcfd, while maintaining ethane and propane recovery percentages.

Enterprise also completed expansion of its Gulf Coast NGL pipeline system earlier in 2009. This expansion follows the company's service at Meeker II and expansion of three natural gas processing facilities in the Piceance basin of Colorado.

Enterprise said it completed installing two 8-in. pipelines to increase NGL throughput capacity from the partnership's Norco fractionation plant west of New Orleans to refineries and petrochemical plants in southern Louisiana.

The Norco fractionation plant can separate up to 75,000 b/d of NGL and is owned 100% by an affiliate of Enterprise. The plant receives mixed NGL via pipeline from refineries and gas processing and fractionation plants in Texas, southern Louisiana, and along the Gulf Coast of Mississippi and Alabama.

The company said one of the pipelines is dedicated to a Garyville, La., refinery and will transport natural gasoline under long-term agreement. The second pipeline will allow Enterprise to increase delivery of NGL to refineries and petrochemical plants in the St Charles Parish area.

In Alaska earlier this year, Denali—The Alaska Gas Pipeline LLC announced it would build what it called the world's largest gas-treatment plant.

The plant, to be located on the North Slope, is part of Denali's overall project. It will remove carbon dioxide, water, hydrogen sulfide, and other impurities from the gas before it is shipped in the pipeline.

It will also provide initial gas chilling and compression. The GTP will be the largest plant of its type in the world, according to the announcement, and will have process modules weighing up to 9,000 tons. Denali is also planning for the construction of a pipeline to deliver 4 bcfd of gas from the North Slope of Alaska to markets in the Lower 48, Alaska, and Canada. ✦

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WORLDWIDE GAS PROCESSING

Leena Koottungal, Survey Editor/News Writer

Country	No. plants	MMcfd Gas capacity	MMcfd Gas throughput	Production, 1,000 gpd (average based on the past 12 months) Ethane	Propane	Iso-butane	Normal or unsplit butane	LPG mix	Raw NGL mix	Debut. natural gasoline	Other	Total products
Algeria	4	5,335.2	4,268.2	—	—	—	—	632.8	—	—	5,449.2	6,082.0
Angola	2	200.0	137.0	—	—	—	—	—	199.0	—	—	199.0
Argentina	14	4,885.3	3,076.0	712.0	654.7	—	414.0	—	7.0	493.2	—	2,280.9
Australia	5	4,340.5	3,244.5	2,500.0	710.0	—	1,034.9	—	1,725.0	345.0	4,418.4	10,733.3
Austria	2	86.0	80.5	—	—	—	—	—	—	58.6	76.0	134.6
Azerbaijan	1	—	—	—	—	—	—	—	—	—	—	—
Bahrain	1	280.0	260.0	—	118.4	112.5	—	—	—	204.9	—	435.8
Bangladesh	4	140.0	83.4	—	—	—	—	—	—	0.0	41.9	41.9
Bolivia	12	882.8	622.4	—	—	—	—	171.0	238.0	132.4	383.0	924.4
Brazil	15	1,083.4	370.3	—	—	—	—	669.8	101.6	108.0	1.6	881.0
Brunei	2	1,182.0	967.4	52.2	9.1	—	—	—	—	290.0	—	351.3
Canada	967	53,010.0	29,230.2	7,540.3	1,149.1	—	899.5	805.3	11,721.7	3,184.3	7,224.7	32,524.8
Chile	2	477.0	381.6	—	39.6	12.9	14.3	—	185.0	19.3	—	271.1
China	2	774.4	—	—	—	—	—	—	—	—	—	—
Colombia	7	333.0	247.3	76.5	58.0	—	63.0	88.8	27.0	63.0	—	376.3
Denmark	1	933.0	680.0	—	—	—	—	—	—	—	—	—
Ecuador	2	41.0	20.5	—	—	—	—	97.1	—	37.3	—	134.4
Egypt	20	4,663.0	2,133.0	—	—	—	—	1,606.4	—	—	1,671.3	3,277.7
Equatorial Guinea	1	870.0	170.0	—	—	—	—	102.8	—	—	36.7	139.5
France	1	570.0	563.0	—	139.0	—	132.0	—	—	270.0	—	541.0
Hungary	8	1,137.4	461.0	—	71.0	38.8	40.7	139.8	—	71.3	228.3	589.9
India	11	3,691.9	2,945.1	—	227.8	—	—	3,939.7	768.2	714.3	884.5	6,534.5
Indonesia	13	7,972.3	7,089.7	—	625.1	—	304.4	305.3	1,521.9	—	1,965.1	4,721.8
Iran	22	17,142.0	10,509.0	—	—	—	—	—	3,726.9	—	9,190.6	12,917.5
Iraq	4	2,081.0	1,550.0	—	—	—	—	7.3	—	2.2	—	9.5
Italy	20	5,175.0	1,495.0	—	—	—	—	—	—	25.8	—	25.8
Kazakhstan	4	155.0	10.0	—	—	—	—	296.0	35.9	—	0.6	332.5
Kuwait	4	1,752.2	1,033.0	2,355.6	3,684.1	—	2,627.3	8,595.8	—	1,422.0	—	18,684.8
Libya	9	4,897.0	2,567.0	—	273.0	294.0	126.0	37.8	1,749.0	567.0	551.0	3,597.8
Malaysia	5	4,250.0	3,400.0	—	23.2	—	28.2	—	—	57.0	—	108.4
Mexico	8	4,879.0	2,671.0	2,179.1	—	—	—	3,424.7	12,346.7	—	1,760.5	19,711.0
Mozambique	1	—	—	—	—	—	—	—	—	—	—	—
Myanmar	1	24.0	—	—	17.0	26.2	—	—	—	4.7	—	47.9
Netherlands	2	725.0	315.0	—	—	—	—	—	—	—	230.5	230.5
New Zealand	3	944.5	489.0	—	4.7	—	5.2	270.9	—	16.0	805.8	1,102.6
Nigeria	4	1,268.0	228.0	—	—	—	—	—	3,415.1	—	84.0	3,499.1
Norway	4	3,150.0	530.8	—	2,596.7	586.7	1,452.7	—	175.4	1,389.7	—	6,201.2
Oman	8	826.0	309.4	—	—	—	—	—	202.0	43.0	—	245.0
Pakistan	12	1,195.0	858.7	—	—	—	—	53.8	64.9	—	9.1	127.8
Peru	4	545.7	298.2	—	—	—	—	14.9	1,399.0	—	12.8	1,426.7
Poland	1	55.0	—	—	—	—	—	33.6	—	—	16.8	50.4
Qatar	2	1,010.0	220.0	1,397.0	1,681.0	—	1,103.0	0.0	1,618.7	122.0	—	5,921.7
Russia	24	1,405.6	925.5	563.7	—	—	709.7	6,559.9	—	1,056.8	237.8	9,127.9
Saudi Arabia	10	10,040.0	8,496.0	—	—	—	—	—	24,234.0	—	12,810.0	37,044.0
Serbia and Montenegro	1	43.0	30.0	—	11.3	6.0	8.4	—	—	16.0	—	41.7
Syria	1	450.0	—	—	—	—	—	507.0	—	—	—	507.0
Thailand	5	1,070.0	1,030.0	1.6	—	—	—	557.0	49.1	84.0	—	691.7
Trinidad & Tobago	3	1,394.0	1,101.0	—	290.3	88.6	99.3	—	—	195.0	—	673.2
Tunisia	1	174.0	139.2	—	—	—	—	—	—	—	209.0	209.0
Ukraine	1	—	—	—	—	—	—	—	—	—	—	—
United Arab Emirates	9	3,923.0	3,295.6	—	792.5	—	612.0	—	374.9	—	7,199.2	8,978.6
United Kingdom	11	13,856.0	5,836.9	—	—	—	—	—	948.0	1,572.5	36.0	2,556.5
United States	577	72,342.7	45,897.2	10,504.1	9,309.2	1,656.0	3,603.4	138.6	43,970.1	4,038.4	2,537.9	75,757.6
Uzbekistan	2	—	—	—	—	—	—	—	—	—	—	—
Venezuela	14	3,927.0	3,555.0	—	—	—	—	—	7,312.9	—	—	7,312.9
Vietnam	1	150.0	120.0	—	281.0	—	188.0	495.0	—	—	167.9	1,131.9
Yemen	4	1,760.0	1,645.0	—	—	—	—	903.0	676.2	—	—	1,579.2
Total, excl. US	**1,302**	**181,155.2**	**109,689.4**	**17,377.9**	**13,456.6**	**1,165.7**	**9,862.6**	**30,315.5**	**74,823.1**	**12,565.2**	**55,702.3**	**215,268.9**
World total	**1,879**	**253,497.9**	**155,586.5**	**27,882.0**	**22,765.7**	**2,821.7**	**13,466.1**	**30,454.1**	**118,793.1**	**16,603.6**	**58,240.2**	**291,026.5**
Canada												
Alberta	903	46,333.7	24,685.0	7,153.6	978.3	—	584.6	126.4	10,866.4	2,616.1	7,222.0	29,547.3
British Columbia	34	5,681.4	3,935.8	295.0	112.7	—	302.6	565.0	66.0	537.8	—	1,879.1
Northwest Territories	2	219.9	28.3	—	—	—	—	—	—	—	—	—
Nova Scotia	2	600.0	441.0	—	—	—	—	—	752.0	—	—	752.0
Ontario	1	—	—	—	—	—	—	—	—	—	—	—
Saskatchewan	25	175.0	140.1	91.7	58.1	—	12.3	113.9	37.3	30.4	2.7	346.4
Total Canada	**967**	**53,010.0**	**29,230.2**	**7,540.3**	**1,149.1**	**0.0**	**899.5**	**805.3**	**11,721.7**	**3,184.3**	**7,224.7**	**32,524.8**
US												
Alabama	14	1,358.0	475.3	—	124.2	—	76.1	—	247.5	54.5	132.7	635.0
Alaska	5	9,525.0	9,298.0	—	1.2	—	—	—	168.4	—	0.6	170.2
Arkansas	5	873.8	507.4	—	—	—	—	—	27.1	—	—	27.1
California	31	1,112.2	825.3	29.2	864.4	94.9	412.6	6.2	71.3	395.2	98.5	1,972.3
Colorado	43	3,132.7	1,651.7	417.2	431.3	57.3	177.1	8.7	903.5	166.7	170.2	2,332.0
Florida	1	32.0	4.0	—	—	—	—	—	41.0	—	—	41.0
Illinois	1	2,200.0	1,426.0	1,440.0	655.0	127.0	159.0	—	2,940.0	75.0	—	5,396.0
Kansas	12	2,828.5	904.5	—	—	—	—	—	1,789.0	—	260.3	2,049.3
Kentucky	4	120.0	106.1	—	—	—	—	—	153.5	—	—	153.5
Louisiana	70	18,180.3	9,026.3	1,149.8	856.7	276.1	298.7	—	6,563.4	552.4	333.8	10,030.9
Michigan	22	1,549.4	625.7	—	5.6	—	3.0	2.6	476.5	1.5	9.8	499.0
Mississippi	4	1,603.4	900.1	—	—	—	—	—	1,000.2	—	—	1,000.2
Montana	4	15.4	8.9	—	36.6	—	27.7	—	4.5	15.7	—	84.5
New Mexico	26	3,194.0	2,392.9	2,020.1	1,139.1	171.7	406.1	—	2,122.5	454.9	118.0	6,432.4
North Dakota	7	242.5	167.5	—	287.3	20.0	148.9	—	60.0	132.2	0.0	648.4
Ohio	4	25.0	10.0	0.1	2.8	0.8	1.9	—	8.2	—	2.3	16.1
Oklahoma	58	3,624.0	2,353.2	388.8	371.4	51.3	163.6	56.9	6,060.2	167.0	304.9	7,564.1
Pennsylvania	9	73.0	32.5	—	26.0	—	14.8	—	4.1	7.8	6.5	59.2
Tennessee	2	8.0	1.5	—	—	—	—	—	—	—	—	—
Texas	193	15,724.3	11,197.3	4,243.9	3,415.4	712.3	1,178.3	64.2	18,986.9	1,529.6	627.7	30,758.2
Utah	14	531.0	243.2	—	21.6	—	24.0	—	253.0	12.1	9.8	320.5
West Virginia	8	585.0	304.0	250.9	176.0	30.3	86.2	—	378.0	65.5	—	986.9
Wisconsin	1	—	—	—	—	—	—	—	—	—	—	—
Wyoming	38	5,795.2	3,427.8	564.1	894.6	114.3	425.4	—	1,709.3	408.2	462.8	4,578.7
Total US	**577**	**72,342.7**	**45,897.2**	**10,504.1**	**9,309.2**	**1,656.0**	**3,603.4**	**138.6**	**43,970.1**	**4,038.4**	**2,537.9**	**75,757.6**

Source of Alberta data: Alberta Energy and Utilities Board, data series ST50, ST13A. Source of British Columbia data: Government of British Columbia, Ministry of Energy and Mines, www.em.gov.ba.ca. Source for Saskatchewan data: Saskatchewan Industry and Resources, tel. 306/787-2596.

Global turmoil reaches international LPG markets

Walt Hart
Ron Gist
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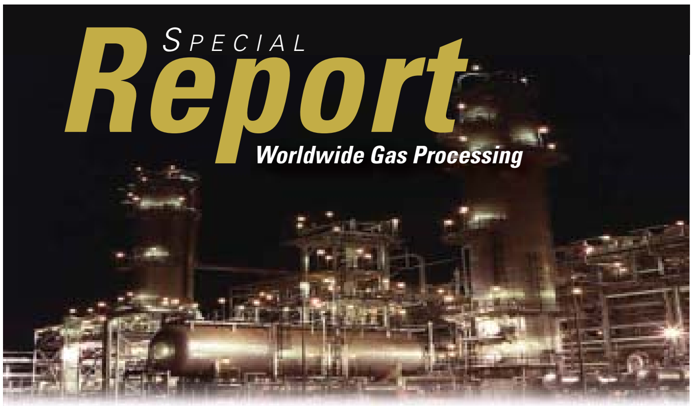
Less than a year ago global LPG prices approached all-time highs. Since then, the global economy has moved into a recession, the world's largest LPG producer (the US) has undergone a major change in political leadership, and crude oil prices have collapsed. These and other changes have affected global LPG markets and trade.

Despite the turmoil, LPG production in 2008 rose in nearly every region of the world. In 2008, global supply was about 239 million tonnes (about 7.7 million b/d), up by 3.7% from 2007. This increase compares with a compound supply growth of about 2.2%/year 2000-07. Because LPG is a by-product of oil and gas production and refining, LPG production continued to increase in 2008 relative to 2007, due mostly to higher crude oil and LNG production rates.

About half of global LPG demand comes from residential and commercial markets for heating and cooking in homes and businesses. Within limits, base demand that consists of residential-commercial demand and a significant fraction of other LPG demand is relatively insensitive to price. The balance of the LPG market is relatively small but highly sensitive to changes in LPG pricing.

On a long-term basis, global storage of LPG for later consumption is quite limited. Few locations around the world have a large amount of excess primary LPG storage capacity. Because LPG is a by-product, it is not feasible to reduce global LPG production in response to oversupply. Consequently, when regional markets' supplies exceed their base demand, LPG prices usually begin to drop relative to petroleum products.

The LPG market is typically cleared by price-sensitive olefins producers that can substitute LPG for other feedstocks. These petrochemical companies do so opportunistically as prices come under downward pressure during periods of oversupply for the premium LPG markets.



LPG demand increased around the globe in 2008 to keep pace with supply. Base demand increased by 2.8%, and price-sensitive petrochemical demand increased by nearly 30% to absorb the additional supply that was available.

Purvin & Gertz has been calling for a surge of LPG supply as a result of strong demand for crude oil and a rush of LNG liquefaction projects, which is only partially offset by solid but limited growth in premium LPG markets. Indeed, the global LPG supply in excess of base demand has built every year since 2002, resulting in a compound growth in the "base surplus" of nearly 20%/year 2002-08.

As might be expected, by-product, surplus LPG requires an incentive to be consumed, so that LPG prices have been growing weaker compared with crude oil during the past few years, even as absolute prices for LPG and crude oil have fluctuated.

LPG trade has also been affected by the increase in LPG production and the global recession. Recent shifts in petrochemical demand patterns have prompted shippers, hoping to benefit from an expected increase in LPG trade, to commission new LPG ships. This has caused freight rates to plunge.

Global supply

Global supplies of LPG rose to nearly 239 million tonnes in 2008 from 198 million tonnes in 2000. Thus, supplies increased by about 2.4%/year. Purvin & Gertz expects supplies will reach about 270 million tonnes by 2012 (Fig. 1).

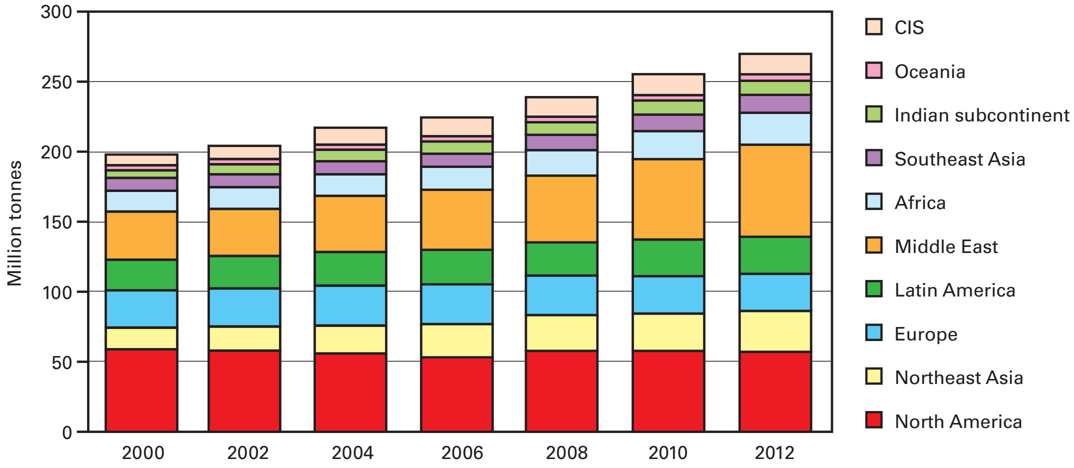
Natural gas processing continues to be the largest source of LPG supply, accounting for nearly 60% of total worldwide production. Refineries accounted for nearly all the remaining production. Other sources account for less than 0.5% of worldwide LPG production.

Regional comparisons

Regional LPG production has shown some notable shifts in this decade. In 2000, LPG produced east of the Suez Canal ("East of Suez") totaled about 35% of world supply. By 2008, East of Suez's share of total production had risen to about 40%, and Purvin & Gertz estimates that about 45% of the world's LPG supplies will come from East of Suez by 2012.

WORLD LPG SUPPLY

Fig. 1



On a percentage basis, production increases have been particularly high in CIS countries (Commonwealth of Independent States), where supply nearly doubled to about 13.8 million tonnes in 2008 from 6.9 million tonnes in 2000. Other regions where production grew quickly in the same period include the Middle East, the Indian subcontinent, and northeast Asia, each of which saw average growth exceed 4%/year so far this decade.

Since 2000, total global LPG production has increased by more than 41 million tonnes. On an absolute production basis, the largest supply increase came from the Middle East, which increased to about 47.4 million tonnes in 2008 from a relatively large base of 34.3 million tonnes in 2000, an increase of 13.1 million tonnes.

Thus, the Middle East accounted for nearly a third of the global increase in LPG production so far this decade. Other regions with large absolute increases included the CIS with an increase of about 6.9 million tonnes, and northeast Asia at 10.1 million tonnes. These three regions accounted for almost three-quarters of the world's net increase in LPG supply 2000-08.

Middle East

The Middle East was responsible for one-fifth of world LPG supply in 2008 and has averaged 4.1%/year growth in LPG supply since 2000 despite consecutive production decreases in the region in 2001 and 2002. In 2008, about 66% of Middle East LPG production resulted from the processing of associated gas, with 24% from nonassociated gas (including LNG) and the other 10% as refinery by-product.

Increased crude oil production in the Middle East in this decade has increased production of associated gas and consequently in LPG production related to associated gas. Countries of the Organization of Petroleum Exporting Countries, however, have cut crude oil production, which should reduce LPG produced from associated gas in 2009. We do not expect LPG from associated gas to recover to 2008 levels for several years.

Nonassociated gas is pushing increased LPG production in the Middle East; LPG production from nonassociated gas has more than doubled since 2000. In 2000, nonassociated gas was responsible for about 15% of Middle East LPG supply, but that share increased to 24% by 2008 and should ramp up to more than 40% by 2012. The increase in LPG from nonassociated gas is driven by LNG and other dedicated regional gas projects but also includes contributions from gas-to-liquids projects.

Saudi Arabia remains the largest LPG producer in the region with about 43% of the Middle East's 2008 production of more than 47 million tonnes. The Saudi share of Middle East LPG production is decreasing, as the great majority of the country's LPG production is currently from associated gas and refineries. The UAE was the second largest Middle East LPG producer in 2008, with output of 7.2 million tonnes and a share of more than 15%.

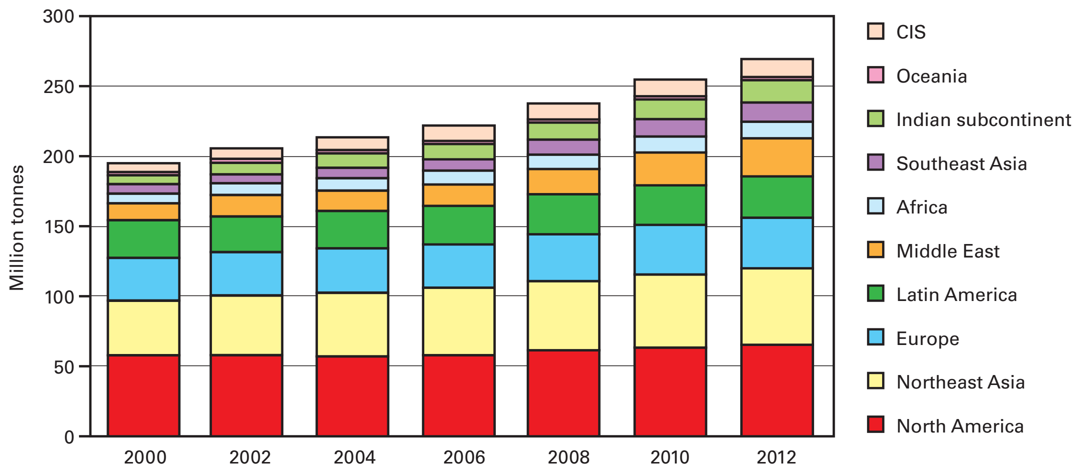
Iran is a close third with 2008 production of 7.0 million tonnes of LPG—more than double its production in 2000. LPG production has been surging in Qatar due to numerous gas projects, and we expect the country will become the second largest LPG producer in the Middle East by 2012.

By 2012, LPG production in the Middle East will likely reach more than 65 million tonnes, and nonassociated gas should account for about 85% of the increase. More than 95% of the Middle East increase will be from Saudi Arabia, Qatar, the UAE, and Iran.

Iraq had a dramatic LPG production decrease in 2003 due to the war, but the overall impact on the region was relatively small since Iraq's production was less than 5% of the total Middle East region. Iraqi LPG output has steadi-

WORLD LPG DEMAND

Fig. 2



ly risen since 2003, and 2008 production reached more than 80% of what was produced in the years immediately before the war.

US, Canada

The region consisting of the US and Canada remained the world's largest producer of LPG in 2008, accounting for about 24% of world supply. The US produced about 82% of the region's LPG in 2008. Natural gas processing is responsible for about 61% of the total regional LPG production.

Production in this region peaked in 2000 at more than 59 million tonnes but then declined to less than 55 million tonnes by 2003. Since 2003, production has increased each year except for 2005 but not enough to prevent an overall decline of 1.3 million tonnes 2000-08.

The decrease in LPG production 2000-03 largely reflects a structural decline in conventional natural gas production in the US and Canada that continues today. The decline has been stemmed in recent years by greater production of unconventional gas, including tight sands gas from the Rockies and the Barnett shale play. A large amount of LPG production in the prolific Gulf of Mexico region was knocked off line for several months during 2005 by two major hurricanes.

The US recession reportedly began in December of 2007, but the impact on 2008 LPG supply was limited. In 2008, US refinery production of propane was down by about 5% compared with 2007, while butane output was up by more than 40%. Net refinery LPG was up by 2% in the US. In Canada, 2008 refinery production of propane was likewise reduced, while butane production increased, for a net LPG production decrease of less than 1%.

US refinery crude oil throughput decreased by less than 4% in 2008, but refinery yields to gasoline decreased during the same timeframe. Also, 2008 had two significant hurricanes on the US Gulf Coast that reduced refinery operating rates while 2007 had none. Thus, while refinery production of propane decreased in the US and Canada in 2008, it is unclear that the decline was driven by recession.

LPG from US gas plants increased in 2008. A sharp decline in natural gas prices and a recession-related increase in the difficulty of obtaining financing resulted in a collapse in the gas-directed rig count starting in September 2008 after the rig count had reached record levels.

The reduction in natural gas production, however, has lagged the drop in the rig count, so that any decline in US LPG production related to the reduction in gas-directed drilling rigs won't be evident until this year. LPG from Canadian gas plants decreased in 2008, which reflects the decline in conventional natural gas production.

Purvin & Gertz expects LPG production in the US and Canada to remain at around 58-59 million tonnes through 2012. Refinery production is likely to increase modestly. We expect that the LPG associated with unconventional gas such as shale gas will continue to boost LPG supplies but that the decline in conventional gas will eventually cause LPG in the US and Canada to resume a steady decline.

Northeast Asia

Northeast Asia had the second largest increase in LPG production in the world 2000-08, behind the Middle East. LPG production increased to about 25.8 million tonnes in 2008 from 15.8 million tonnes in 2000. More than 90% of the rise in LPG output was contributed by refineries in China. Essentially all of the LPG production in the region comes from refineries, as there is no appreciable gas processing, and the first coal-to-liquids (CTL) plants in China have only recently started up.

The remainder of the increase in LPG production in the region came from refineries in Korea and Taiwan. Japan's LPG production slightly decreased during the period.

Despite the global recession, China was able to increase LPG production by 6% in 2008 relative to 2007. China felt the impact of its economic slowdown later than the US and managed to increase crude throughput at its refineries by nearly 6%. Purvin & Gertz expects that refinery production of LPG

will continue to increase significantly in China in the forecast period.

Africa

In Africa, LPG production rose to 18.3 million tonnes in 2008 from 14.7 million tonnes in 2000, resulting in growth of 2.8%/year. The net increase in production 2000-08 was driven by increases in West Africa, namely Nigeria, Angola, and Equatorial Guinea, which had a combined increase of 2.8 million tonnes of LPG/year compared with 2000. These three West African countries were responsible for more than three quarters of the growth in African LPG supplies since 2000.

Algeria is still the largest LPG producer in Africa, however, with 2008 output at 9.1 million tonnes. Algeria is also the second largest exporter in the world after Saudi Arabia, but production in Algeria has decreased slightly since 2000. Egypt and Libya had increases of 0.5 and 0.4 million tonnes of LPG/year, respectively, compared with 2000. About 85% of African LPG production is from natural gas processing.

Purvin & Gertz expects LPG production to continue to expand rapidly in Africa. LPG production from the continent is likely to increase to about 22.6 million tonnes/year by 2012 from 18.3 million tonnes/year in 2008. We expect the largest absolute production increases from Algeria and Nigeria, although civil unrest in Nigeria continues to threaten production.

Latin America

LPG production in Latin America (including Mexico and the Caribbean) was about 24.3 million tonnes in 2008, flat compared with 2007. Within Latin America, Mexico is the largest producer of LPG, with 6.5 million tonnes of LPG in 2008. Brazil, Venezuela, and Argentina are also large producers, with combined 2008 LPG production of 13.7 million tonnes.

Together, these four countries contributed about 83% of the 2008 LPG production in the region. Brazil has had the largest supply growth since 2000, up about 1.6 million tonnes/year. Gas processing in Latin America accounts for more than 60% of LPG production.

Purvin & Gertz expects that total LPG production in the region will rise to about 27.1 million tonnes by 2012. At 1.1 million tonnes/year, Peru should have the largest supply growth through 2012 as several new projects are brought on line. Venezuela, Brazil, and Mexico should also show significant LPG production growth through 2012. LPG production in Argentina should be relatively flat over the forecast period.

Indian subcontinent

On the Indian subcontinent, LPG production rose to 8.8 million tonnes in 2008 from 6.3 million tonnes in 2000, resulting in growth of more than 4%/year. India dominates the region's LPG supply, with around 94% of production; nearly all of the balance of production is from Pakistan. More than 70% of LPG production is from refineries. Although some significant gas discoveries have been made this decade, more than 85% of the regional LPG production growth since 2000 has been from refineries.

Several significant crude capacity expansions are expected in India 2010-12. Consequently, Purvin & Gertz expects that regional LPG production will increase to about 10.2 million tonnes by 2012.

Southeast Asia, Oceania

Southeast Asian countries produced about 10.5 million tonnes of LPG in 2008, up from 8.8 million tonnes in 2000. About 60% of regional LPG is produced from gas processing. The largest producing countries in the region are Thailand, Malaysia, and Indonesia, with Thailand being the largest at more than 40% of regional production.

LPG production in Oceania is much smaller at 3.9 million tonnes in 2008. LPG supply in Oceania is dominated by Australia, which has consistently generated more than 95% of the Oceania region's LPG. About 87% of 2008 Australian LPG production was from natural gas processing.

Thailand has had the largest increase in LPG production so far this decade in either region. LPG production in Thailand increased to 4.3 million tonnes in 2008 from 3.0 million tonnes in 2000, with a boost from a large gas processing plant added in 2004. Another such plant is to be added in the forecast period. Almost two thirds of Thailand's LPG is from gas processing.

Australian LPG production increased to 3.8 million tonnes in 2008 from 3.2 million tonnes in 2000. The largest jump in output occurred 2003-06 and was due largely to LPG from the Bayu Undan project in the Timor Sea and a fourth LNG train on the Karratha gas plant on the North West Shelf. A fifth LNG train was added in 2008, which should help boost LPG production in Oceania to about 4.5 million tonnes/year by 2012.

Europe; CIS

About 18.3 million tonnes of LPG was produced in northern Europe in 2008. Nearly half of that LPG output was in the North Sea, and most of the rest came from refineries. Germany was the largest North Europe refinery source of LPG, with about 3.0 million tonnes of LPG generated in 2008. North Sea LPG production appears to have peaked around 2006 at 9.3 million tonnes and should decline to about 7.7 million tonnes by 2012. Purvin & Gertz expects that LPG from northern Europe refineries should decline by an average of 0.6%/year through 2012.

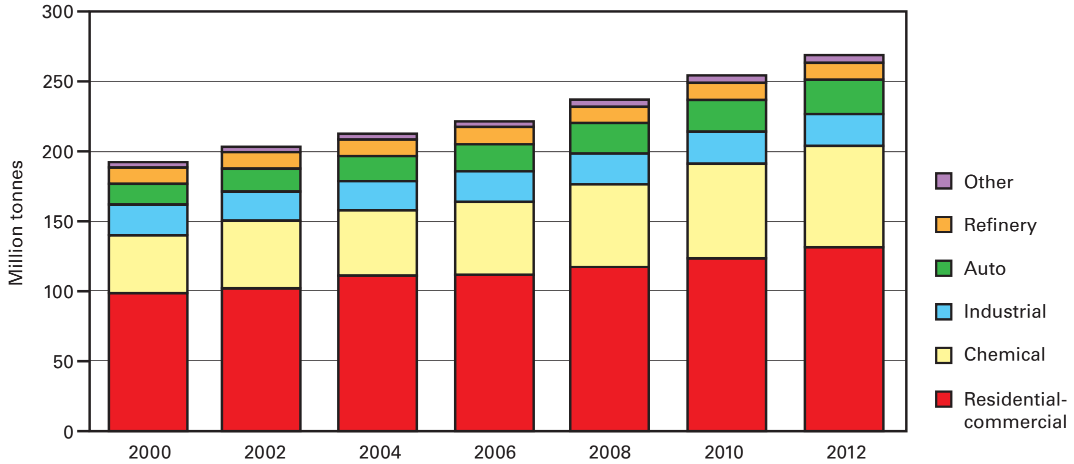
Southern Europe generated about 9.6 million tonnes of LPG in 2008, almost all from refineries. The largest producing countries in 2008 were France at 2.7 million tonnes and Italy at 2.3 million tonnes. LPG output from southern Europe is likely to be flat through 2012.

The CIS has experienced a strong increase in LPG supply so far in this decade. In 2008, the CIS produced 13.8 million tonnes of LPG, a 9%/year increase since 2000. Purvin & Gertz expects growth to slow in the CIS in the forecast period.

LPG demand growth

LPG DEMAND, SECTORS

Fig. 3



As noted earlier, total LPG demand consists mostly of base demand, but total LPG demand also includes a tranche of petrochemical demand that is highly sensitive to price fluctuations.

Total global demand for LPG was about 239 million tonnes in 2008. Purvin & Gertz estimates that the market will grow to about 270 million tonnes by 2012. Thus, total demand will likely grow by about 3.1%/year in the forecast period (Fig. 2). Although total global demand growth for LPG since 2000 averaged 2.5%/year, growth rates in individual geographic regions have varied widely.

In contrast to total demand, base demand was about 223 million tonnes in 2008 and will grow to about 251 million tonnes by 2012. Base demand should increase by 3.0%/year in the forecast period, which is slightly lower than the growth for total demand. Price-sensitive demand growth should average nearly 6%/year in the forecast period.

The highest growth in base demand has occurred in developing regions of the world, driven by residential-commercial consumption (Fig. 3). Overall, base demand grew at 2.1% since 2000. In the more mature economies of Western Europe, Japan, and North America, however, LPG base demand has been relatively flat or slightly down since 2000.

Northeast Asia

In 2008, Northeast Asia had the world's second largest base demand (after North America), but its growth of 8.5 million tonnes so far this decade has been the largest in the world by volume. Most of the growth in northeast Asia has occurred in China, which increased demand to about 19.4 million tonnes in 2008 from 12.3 million tonnes in 2000.

China's LPG demand is about 80% residential-commercial, with the balance consisting of industrial and engine fuel demand. High LPG prices followed by a slowing economy have made China's LPG consumption stagnate over the past few years despite the overall rise since 2000.

Japan is the second largest LPG consumer in northeast Asia and the world's largest LPG importer. Japan's economy is mature, and base demand has decreased by 1.2 million tonnes since 2000. Japan has a large petrochemical industry, however, with flexibility to use LPG in place of naphtha, and price-sensitive demand has increased by 0.9 million tonnes since 2000. Consequently, total demand in Japan has decreased by less than 0.3 million tonnes compared with 2000.

South Korea is the world's largest consumer of LPG for automobile fuel (autogas). Autogas has recently amounted to about half of Korean LPG demand. In 2008, autogas consumption was on track to exceed 2007 demand until fourth quarter 2008, when demand fell well below that of fourth-quarter 2007. Similarly, industrial demand for LPG had risen to unprecedented levels by third-quarter 2008 but fell sharply in the fourth quarter due to the global recession.

We expect economic growth in Asia to resume in the forecast period and result in rising consumption of LPG, although more slowly than earlier in the decade. In the forecast period, Purvin & Gertz expects Chinese demand to be the main driver of LPG growth in northeast Asia. Purvin & Gertz expects total demand growth in northeast Asia to average about 2.2%/year through 2012.

Middle East

The Middle East had the second largest regional volume increase in LPG demand 2000-08, after northeast Asia. More than 70% of the increase of 6.5 million tonnes came from chemical demand, while the balance of the total increase was nearly all from the residential-commercial sector. In 2008 chemicals comprised close to half of total LPG demand in the Middle East, and by 2012 that figure will rise to about 63% of total LPG demand as new projects come on stream.

Saudi Arabia has been the largest Middle East user of LPG for chemicals production and currently accounts for about 73% of the region's LPG consumption for chemicals. Because other

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Middle East countries are rapidly adding LPG-based chemical capacity (notably Iran and Qatar), Saudi Arabia is likely to increase its share of Middle East chemical LPG demand only slightly through 2012.

Total LPG demand growth in the Middle East should average nearly 11%/year in the forecast period, mostly from the rapid growth in LPG consumption as chemical feedstock.

Indian subcontinent

LPG demand in the Indian subcontinent grew to about 12.6 million tonnes in 2008 from 7.2 million tonnes in 2000, resulting in growth of more than 7%/year. India accounts for about 92% of the total LPG consumption on the subcontinent. About 96% of the region's total LPG consumption is residential-commercial demand.

With a large, rapidly developing population and the lowest regional per-capita residential-commercial consumption of LPG in the world, the Indian subcontinent has great potential to expand LPG demand. Purvin & Gertz expects demand growth of nearly 6%/year in the forecast period.

Southeast Asia

With the region's demand being only about 4% of global LPG demand, the LPG market in Southeast Asia is relatively small. The region has experienced total LPG demand growth of about 6.7%/year since 2000, however, and we expect demand growth to average more than 7%/year through 2012.

About 40% of 2008 demand in Southeast Asia was concentrated in Thailand, which has an established LPG market with a relatively high residential-commercial market penetration of about 28 kg/person. Thailand's LPG demand received a boost from autogas in 2008, as a strong LPG subsidy intended for cooking fuel created a significant advantage for LPG relative to gasoline. The price advantage at the pump and the demand fell with petroleum prices in second-half 2008.

Indonesia had a surge of LPG demand growth in 2008 as the Indonesian government attempted to convert residential consumers of kerosine over to LPG in order to reduce the cost of subsidies. As a result, Indonesia jumped from the fourth largest consumer of LPG in Southeast Asia to the second largest. Purvin & Gertz expects that very high growth will continue in Indonesia during the forecast period.

Vietnam had the highest compound demand growth (more than 20%/year) and the second largest LPG volume growth in Southeast Asia. Vietnam's LPG market is nearly 90% residential-commercial consumption. Vietnam is likely to continue strong LPG demand growth through 2012 but at lower rates than seen so far this decade.

Oceania

Oceania is by far the smallest region for LPG demand, with 2008 consumption at around 2.1 million tonnes. Australia's LPG consumption dominates the region, with about 89% of total LPG demand.

More than 60% of Australia's LPG consumption is attributed to autogas demand. Like nearly all markets with a large autogas segment, Australia's autogas market has received substantial government support. The Australian government, however, has recently announced plans to reduce autogas subsidies, so that LPG demand growth will likely diminish significantly.

US, Canada

The region including the US and Canada is the largest LPG market in the world and is quite mature. The region's base demand for LPG had low growth 2000-08 relative to the world average. Price-sensitive demand depends on the competitiveness of LPG as a chemical feedstock and the health of the petrochemical industry.

LPG has been gaining share as a petrochemical feedstock at the expense of light naphtha. Petrochemical demand for LPG generally trended up in this decade until petrochemical operating rates collapsed in September 2008. With the relatively low base-demand growth and the recent plunge in petrochemical output, total LPG demand in 2008 in the US and Canada was fairly flat compared with 2000.

Because the US and Canada are mature markets, Purvin & Gertz expects that LPG demand growth other than chemicals should average only about 1.5%/year through 2012. Petrochemical demand for LPG will depend largely on the recovery of the chemical industry, which is struggling not only from the recession, but also from a global overbuild in olefins capacity.

As global LPG supply exceeds global LPG base demand during the next several years, it is likely that relatively inexpensive LPG will be available to the flexible US petrochemical producers, which should help them compete against the naphtha crackers in Europe and Asia.

Latin America

The Latin American market, which includes Mexico and the Caribbean down through South America, is the world's third largest regional consumer of LPG. Within the region, about 75% of the LPG is used in the residential-commercial sector. Combined demand in Mexico, Brazil, and Venezuela accounts for about two-thirds of the region's LPG consumption.

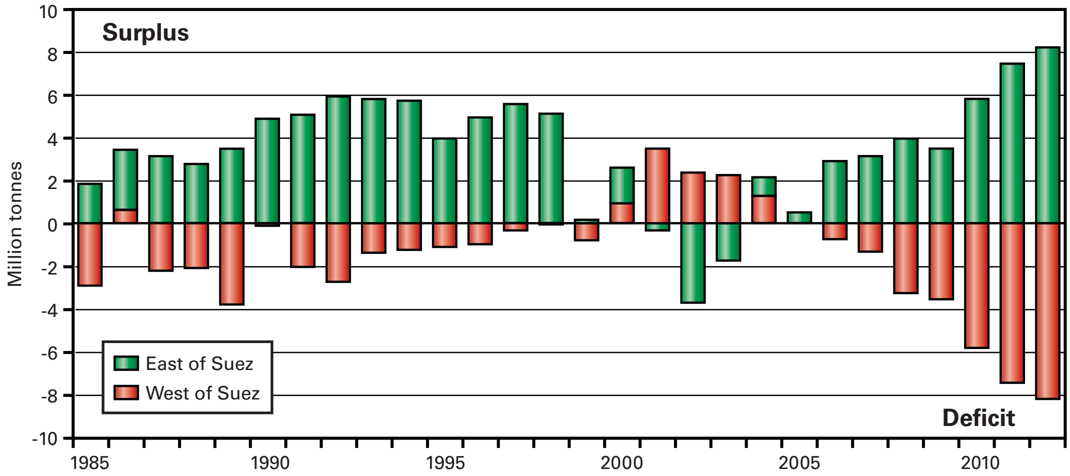
Latin American LPG demand has rebounded to about 28.1 million tonnes in 2008 from a low of 25.4 million tones in 2003. Purvin & Gertz expects that demand will grow to nearly 30 million tonnes by 2012.

For many years, Mexico had the highest per-capita residential-commercial use of LPG of any country in the world. Its residential-commercial consumption of LPG has dropped, however, by more than 1 million tonnes/year since 2000, while the country's population continues to increase. Consequently, at about 63 kg/person, it is likely that Mexico now has a slightly lower per-capita, residential-commercial LPG consumption than Russia or Japan. At 8.9 million tonnes of total LPG demand, Mexico is still the largest consumer of LPG in Latin America.

At 1.1 million tonnes, Venezuela had the largest increase in total LPG demand in Latin America since 2000. Purvin & Gertz expects Brazil to have the highest volume of LPG demand growth in the region through 2012.

REGIONAL LPG TRADE

Fig. 4



Europe

Base demand in northern Europe has grown slowly to 13.2 million tonnes in 2008 from 12.0 million tonnes in 2000. In contrast, base demand in southern Europe decreased from 17.2 million tonnes in 2000 to about 14.8 million tonnes in 2008.

In northern Europe, LPG residential-commercial demand is about three-quarters propane, while in southern Europe propane supplies only about half of the demand for heating and cooking. The residential-commercial market in southern Europe is also about three times the size of the residential-commercial market in northern Europe.

Both northern and southern Europe have countries with large autogas markets. Poland, Turkey, and Italy all rank in the Top 10 consumers of LPG for engine fuel in the world. Overall, autogas consumption in northern Europe is similar to that of southern Europe. The two regions also have similar-sized industrial LPG markets.

Europe's olefins production is largely naphtha-based. In the late fall and winter, LPG typically does not compete economically against naphtha because heating and cooking demand makes it too expensive for cracking. A major drop in petrochemical operating rates began in September of 2008, and naphtha became favored as a feed in the same month, consistent with the seasonal pattern. Consequently, consumption of LPG in 2008 was affected less by the petrochemical slump in Europe than it was in North America.

Both northern and southern Europe have significant centers of petrochemical production—Amsterdam-Rotterdam-Antwerp (ARA) area in the north and the Fos-Lavera area near Marseille in the south. Northern Europe petrochemical plants receive a large portion of their feedstocks from the North Sea, while much of the Lavera-area LPG is from the local refineries and Algeria.

LPG consumption for petrochemicals is roughly four times greater in northern Europe than in southern Europe. Price-sensitive LPG demand for ethylene production has increased dramatically in both regions since 2000. Purvin & Gertz expects that base demand in Western Europe will grow at only about 0.6%/year through 2012. Price-sensitive demand growth, however, should remain relatively strong, with growth of about 9%/year during the forecast period.

CIS

Between 1990 and 1998, demand in the CIS region steadily declined due to weak economic conditions. In recent years, however, positive growth has returned to these markets. LPG demand in the CIS has grown at near 8%/year since 2000.

In 2008, demand in the CIS totaled about 11.1 million tonnes. Russia accounts for the largest portion of the regional demand, consuming more than 80% of the LPG. Within Russia, the residential-commercial sector uses slightly less than one-half of the total, and petrochemical consumption of LPG accounts for almost 40%. We expect LPG demand in the CIS to rise to about 12.5 million tonnes by 2012.

Africa

In Africa, about 85% of LPG demand is concentrated on the northern coast, and 95% of LPG is consumed by the residential-commercial market segment. The balance of demand consists mainly of autogas consumption in Algeria and some industrial demand in North Africa. Total LPG demand was about 10.6 million tonnes in 2008, which reflects a compound growth of about 5.0%/year since 2000.

At about 4.1 million tonnes, Egypt had the largest LPG demand in Africa—more than double the demand from Algeria or Morocco (1.9 and 1.8 million tonnes in 2008, respectively). Although Nigeria is the second largest producer of LPG in Africa, its annual consumption would amount to less than the supply provided by two very large gas carriers. Purvin & Gertz expects LPG demand growth in Africa to average about 3.6%/year through 2012.

Waterborne LPG trade

Global waterborne LPG trade increased in 2008 to about 55.2 million tonnes, compared with 51.5 million tonnes in 2007 and 40.8 million tonnes in 2000. In this decade, growth in global supplies has generally exceeded base demand growth, and the "excess" supplies have not been produced in markets where the LPG can be consumed by flexible petrochemical demand. Consequently, the supply in excess of base demand has needed to be shipped to balance the markets (Fig. 4).

Waterborne LPG trade has increased every year since 2000 except 2001 and 2007. The export dip in 2007 was caused by some unusual or temporary events including terminal maintenance issues in the North Sea, OPEC crude production cuts that reduced associated gas production, and an unusually cold winter in South America that compelled Southern Cone countries to keep their LPG to help compensate for a shortage of natural gas.

In 2008, the 3.6 million tonne increase in waterborne LPG exports was driven by a 2 million tonne increase from the Middle East and a 1.2 million tonne increase from the North Sea, as maintenance work was completed. In the Middle East, the largest increase in LPG exports was 1.5 million tonnes from Qatar, due to new LNG capacity coming on line. Another 0.4 million tonnes of exports were added by Iran.

The world's largest LPG exporter, Saudi Arabia, actually decreased LPG exports in 2008 by nearly 0.5 million tonnes in order to supply new petrochemical facilities. There were enough smaller increases in LPG exports by countries such as Kuwait and Bahrain to offset the Saudi reduction.

Latin America was able to increase exports by about 0.3 million tonnes compared with 2007, but exports were far below 2006 as the gas shortage persisted in 2008. A bright spot was Trinidad, which increased exports by about 0.4 million tonnes. Decreased exports from Venezuela of about 0.2 million tonnes, however, partially offset the gain from the Caribbean. African exports had a net increase of 0.2 million tonnes, as increased shipments from West Africa were able to offset a 0.3 million tonne decline from Algeria.

On the destination side of LPG trade, import demand for propane continued to be soft in China as domestic refineries were able nearly to meet internal demand and consumers balked at the relatively high international prices for much of the year.

Chinese LPG imports of 4.3 million tonnes were down by about 0.3 million tonnes from 2007 and by 1.4 million tonnes from their peak in 2004. Lagging import demand, it's been reported, prompted Chevron to shut down an LPG terminal in Guangdong and also compelled BP to seek buyers for its two large Chinese terminals. Some terminals are now being used to import and then reexport in smaller quantities within Asia, rather than only to support the domestic LPG market.

While LPG import demand was down in China, it was significantly increased in Japan and Taiwan, which combined for a 1.5 million tonne increase in imports over 2007. Much of this increase in imports was due to opportunistic petrochemical demand for LPG. Other large increases in LPG imports were recorded for India and Brazil. India increased waterborne imports by about 0.3 million tonnes, while Brazil received about 0.4 million tonnes more LPG than in 2007. These increases were largely to satisfy residential-commercial demand.

The US Gulf Coast has been the traditional "market of last resort" when there is significantly more global supply of LPG than base demand. Despite an increase of global waterborne LPG exports, waterborne imports to the US Gulf Coast dropped by 0.2 million tonnes in 2008.

Because LPG cracking costs were generally much lower than for naphtha in 2008, LPG flowed to crackers in Asia and Europe. LPG also continued to fill the heating fuel gap left by natural gas in Latin America. Consequently, the US found itself without an increase in imports of off-season LPG.

Purvin & Gertz expects that the US Gulf Coast will see significant increases in LPG imports over the forecast period. ✦

The authors

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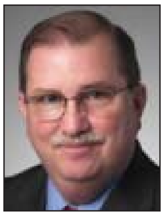
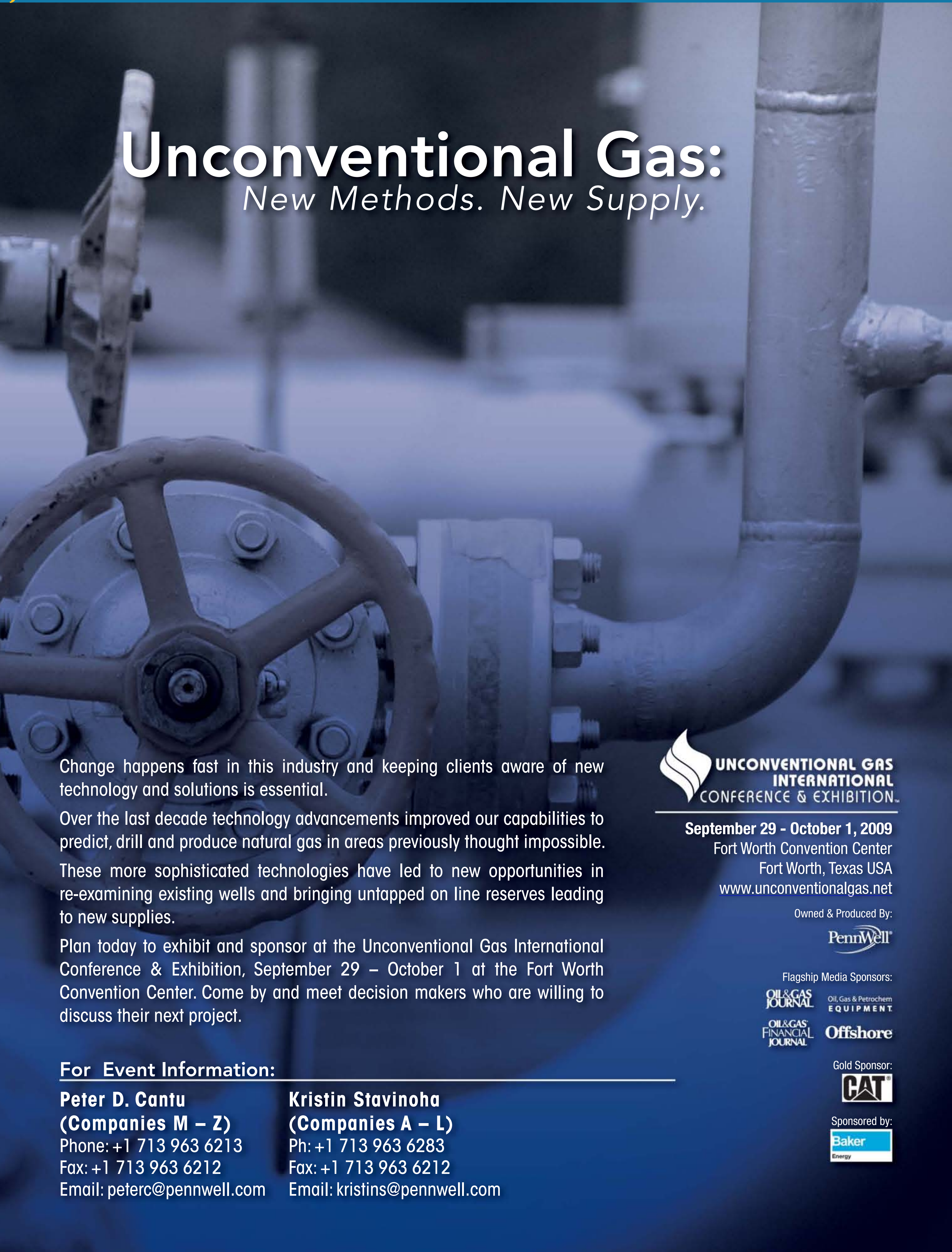
Ronald L. Gist (rlgist@purvingertz.com) is a managing consultant in the Houston office of Purvin & Gertz Inc., having joined the company in 1996. He began his career with EI DuPont de Nemours & Co. in 1971 after receiving both BS and MS degrees in chemical engineering from Colorado School of Mines. Gist chaired GPA's market information committee and is currently chairman of the Houston chapter of GPA.



Ken W. Otto (kwotto@purvingertz.com) is a senior vice-president and director in the Houston office of Purvin & Gertz Inc. He joined EI DuPont de Nemours & Co. in 1977, then moved to Champlin Petroleum Co. in 1979 and served 4 years at Corpus Christi Petroleum Co. Otto joined Purvin & Gertz in 1986, was elected principal of the company in 1987, senior principal in 1990, and vice-president in 1997. He holds a BS (1977) in chemical engineering from the University of Texas at Austin.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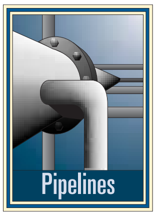
Subsea pipeline developments advance operations, integrity

Christopher E. Smith
Pipeline Editor



The proliferation of offshore pipelines has increased the premium on being able to effectively monitor their operations and intervene when necessary. At the same time, the competitiveness and potential volatility of oil and gas commodity markets make it important that any intervention have the minimum possible effect. Recent developments in subsea pipeline materials, monitoring, and maintenance technology are helping meet these requirements.

T.D. Williamson SA last month announced a successful hot-tap operation for tie-in of Ettrick field's natural gas export line, allowing gas to move from UK Central North Sea blocks 20/2a and 20/3a 120 km to the ExxonMobil-operated Scottish Area Gas Evacuation (SAGE) gas plant north of Aberdeen. The hot tap occurred under 311 ft of water while maintaining the pipeline's operating pressure of 117 barg.

Acergy was primary contractor on the project, providing engineering, procurement, installation, and precommissioning of the hot-tap assembly and the subsea structures. T.D. Williamson supplied all hot-tap equipment.

T.D. Williamson worked with Acergy on endurance testing as part of factory-based trials. System integration tests followed endurance testing (Fig. 1). Finally, T.D. Williamson supervised the dive team executing the hot tap from a dedicated dive-support vessel, ensuring the operation was conducted according to written procedures.

Nexen Petroleum UK Ltd. operates Ettrick field. Gas is exported from FPSO Aoka Mizu via a steep wave flexible riser connected to a 6-in. ID nonpressure seal flexible flowline. The flowline runs to a gas export pipeline end manifold that in turn is connected by a hot-tapped 6-in. ID jumper to the 350-km, 30 in. OD, ExxonMobil-operated SAGE export trunkline.

NKT Flexibles supplied the 6-in. ID. piping for export jumpers, riser, and

Preparation for the offshore hot tap included system integration tests at the BiFab yard, Methil, UK. The hot-tap machine—with the hot-tap valve attached—was lowered from the hot-tap installation frame (in white) into the subsea protection frame. Once situated in the protection frame, engineers supervised connection of the hot-tap machine and valve to the hot-tap nipple for pressure testing before performing the hot tap (Photo by T.D. Williamson; Fig. 1).

flowline, all with a design pressure of 172.4 bar and a design temperature of 60° C.

Nexen's original development plans called for a fixed platform complex featuring a wellhead platform, process platform, utilities and quarters platform, and three jackets and piles. FPSO production calls for 20,000-30,000 b/d oil and 35 MMcfd gas.

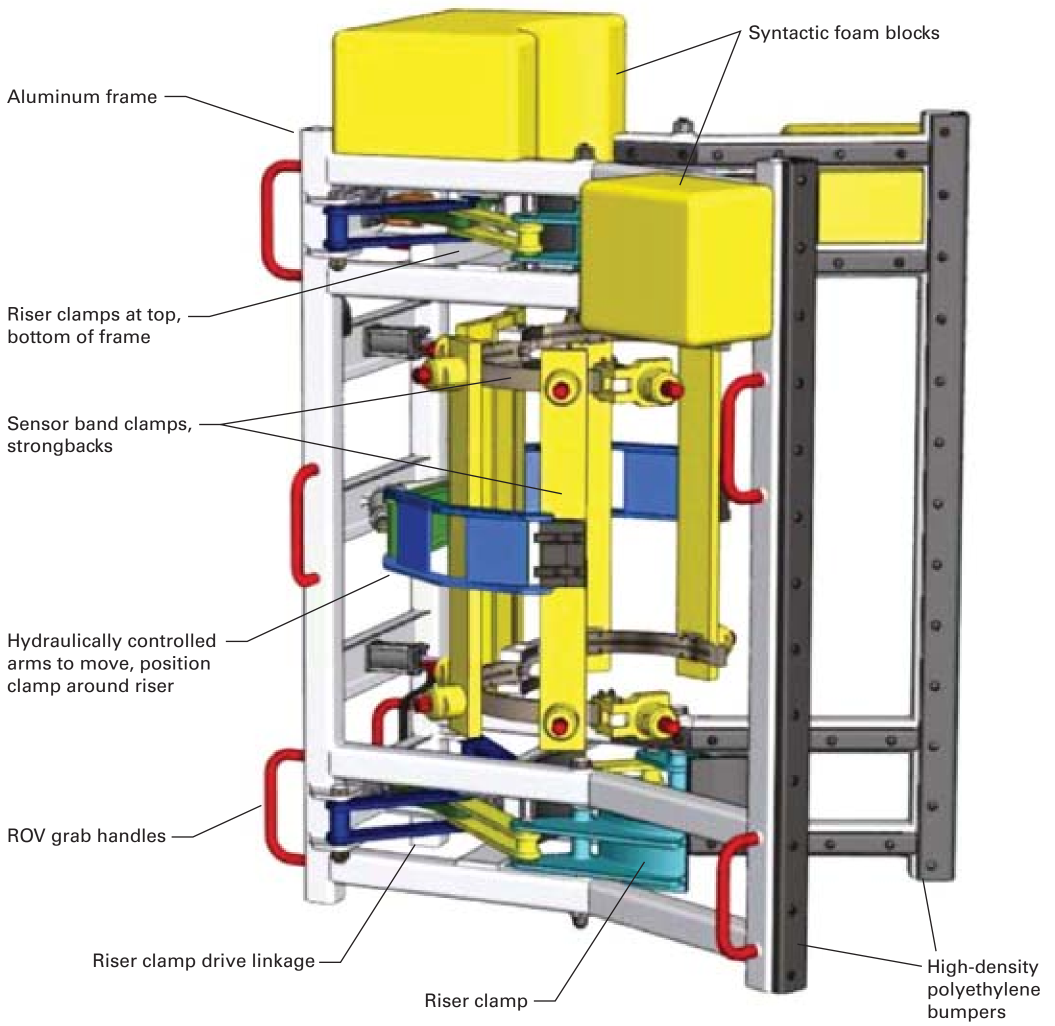
Technology acquisition

Subsea 7 Ltd. was also active on the hot-tap front, announcing in May 2009 the acquisition of exclusive global license rights for subsea grouted tee (SSGT) hot-tap technology. According to Subsea 7, SSGT enables under-pressure intervention—including repairs, bypass or replacement, blockage removal, and branch connections—on high- and low pressure subsea pipelines without major hyperbaric welding or production shutdowns.

Mechanical divers can deploy SSGT, originally developed by Advantica in the 1990s for use on high-pressure onshore pipelines, without human diver assistance. Subsea 7 and GL Industrial Services UK Ltd led a joint industry project sponsored by BP, Total, and ConocoPhillips on adapting SSGT for subsea use. DNV has since verified this application.

ROV-DEPLOYABLE SSSA

Fig. 2



Development

BMT Scientific Marine Services Inc. announced development of a sensor assembly and installation tool permitting strain sensor installation by remotely operated vehicle on underwater pipelines (Fig. 2). The subsea strain sensor assembly (SSSA) attaches to a pipeline or riser at depths up to 10,000 ft, measuring tensile and bending strain and alerting operators to excessive strain or potential fatigue damage (Fig. 3).

The ROV-installed SSSA is an adaptation of BMT SSSAs (Fig. 4) installed as part of project development at BP's Greater Plutonio block 18 hybrid riser tower off the coast of Angola, Petrobras' P-52 free standing riser tower off Brazil, and Chevron's Tahiti spar pull tubes and steel catenary riser in the Gulf of Mexico.

BP installed its Greater Plutonio block 18 hybrid riser tower in 1,310 m of water during September 2007. It embedded a comprehensive, permanent hybrid riser tower monitoring system (HRTMS) in the tower's architecture. The core of the HRTMS consists of two axial strain sensing assemblies at two elevations along the tower.

The HTRMS has tracked changes in tower strain and attitude since Sept. 10,

This subsea strain sensor assembly (SSSA) alerts operators to excessive tensile and bending strain along a pipeline at water depths up to 10,000 ft (Fig. 3).

Subsea strain sensor specifications

Table 1

Specifications	Description
Type	Subsea static, dynamic strain sensor
Accuracy	±4 microstrain over a ±100 microstrain range
Resolution	±0.25 microstrain
Gage length	750 mm
Diameter	50 mm
Measurement range	±5,000 microstrain
Physical	
Temperature range	0-70° C.
Temperature effect on zero	±0.005% of full-scale/°F.
Temperature effect on slope	±0.015% of full-scale slope/°F.
Housing	Inconel 625 bellows with flanged ends
Maximum depth	3,500 psi (2,400 m)
Electrical	
Power/individual sensor	24v DC, maximum current = 25 ma/sensor
Signals	4-20 ma, 2 wires
End connector sensors	Tronic 4-way Penetrator with Aquatron 75 connecting hoses
Design characteristics	
Design life	25 years
Qualification testing	
Individual temperature; hydrostatic pressure sensitivity tests	Extent of full-load calibration on actual pipe joint decided in conference with client on case-by-case basis

2007.[1] The new sensor assembly and installation tool will allow retrofitting of similar devices to existing subsea pipelines.

Tool properties

The accompanying table summarizes the properties of BMT's standard subsea strain sensor. The sensing element consists of a customized submersible linear variable differential transformer. The sensor body is not exposed to seawater unless the pressure-balanced oil filled flexible housing fails. Subjecting the strain sensors to hydrostatic pressure with the sensors enclosed in a fixture with a known strain response to pressure established SSSA sensitivity.

A central processor with pressure-sensitivity test data for each sensor and the estimated depth change from atmospheric to installation corrects for pressure effects on the SSSA. The system only requires correction at depths greater than 200 m.[1]

BMT's ROV-deployable SSSA has a support frame for the sensor package clamped to the pipeline or riser before installation starts. This frame provides an anchor for the ROV, ensuring fitting and adjustment of the sensors without damage.

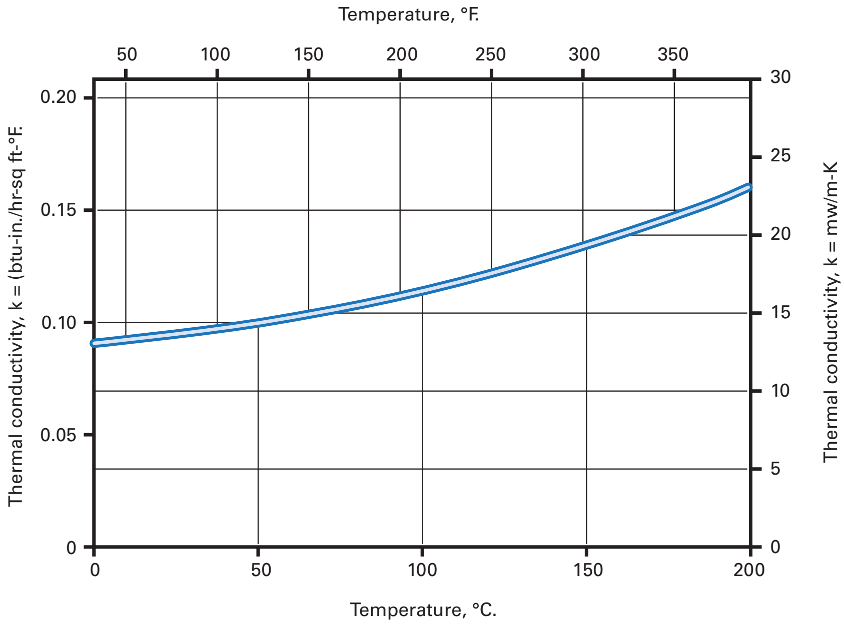
Adaptation of this standard SSSA allows these devices to be installed postconstruction by ROV rather than exclusively as an integrated part of the initial project (Fig. 4).

Aerogel progress

Aspen Aerogels completed delivery in March 2009 of its Spaceloft advanced thermal insulation to Technip for a 21-km subsea natural gas pipeline connect-

ASTM C177 results

Fig. 5



ing Petrobras's Canapu field (1,700 m deep) to its Cidade de Vitoria floating production platform in 1,400 m water depths. Technip installed the insulation on the piping at its spoolbase in Mobile, Ala., before transport to Brazil.

The Canapu-CdV pipeline is the first in Brazil to use pipe-in-pipe design (production pipe surrounded by carrier pipe with insulation in between). Spaceloft's flexible blanket form simplified installation into the annulus between the two pipes.

Spaceloft is a hydrophobic, flexible nanoporous aerogel blanket insulation with nominal thicknesses of 5 mm and 10 mm, allowing use of a smaller and less costly outer pipe. Spaceloft's combination of silica aerogel and reinforcing fibers has a maximum use temperature of 390° F. and a nominal density of 9.4 lb/cu ft. Its R-value = 10.3/in. Fig. 5 shows its ASTM C 177 thermal conductivity.

Technip Offshore UK previously prequalified Aspen aerogel products for pipe-in-pipe reeling and offshore operations, deploying subsea pipe-in-pipe systems in both the Gulf of Mexico and offshore West Africa (OGJ, July 10, 2006, p. 57). ✦

Reference

1. Zimmerman, C., Edwards, R., de la Cruz, D., Talmont, P., Duley, D., and Maroju, S., "Recent Experience With A Comprehensive Riser Tower Monitoring System," DOT International conference, New Orleans, Feb. 3-5, 2009.

Equipment/Software/Literature

Deepwater pipeline coatings can be mixed on site

The new ETNAFLOW portable mixing plant blends glass syntactic polyurethane (GSPU) coating and insulation systems for deepwater pipelines on site in remote locations.

The plant allows for safe and efficient mixing of materials, while an advanced process control helps ensure formulation accuracy and the quality and consistency of the finished product. ETNAFLOW requires fewer human and capital resources to operate, eliminates storage and disposal requirements of conventional GSPU mixing systems and, due to its closed-loop design, helps to minimize potential for chemical exposure or injury to workers from moving machinery, the company says.

Designed for local operations, the portable mixing plant consists of raw materials holding and dosing units, plus a blending operation where the polyurethane and the glass microspheres are mixed. The company ships the unit to the customer's site, provides initial setup, training, remote monitoring, and continuing technical support. Installation and training can be completed in as little as 2 weeks, the company notes.

Source: **Dow Hyperlast,** Station Rd., Birch Vale, High Peak, Derbyshire SK22 1BR, UK.

New underwater tree for marginal field development

The new AZ-10 subsea tree is suited for marginal field developments and fast-tracked projects.

The company says its unit has the ability to reduce the drilling and completion cost for a subsea completion by more than 40%, while reducing the first oil schedule by 15 months.

The AZ-10 is ready to be deployed off the shelf. It features a totally concentric tree and hanger system, and it requires only five tools to install.

The monobore vertical tree weighs less than 50,000 lb, can be handled by all cranes without disassembly, and installed with Gen II or newer semisubmersibles. These features provide for smaller crews and fewer third-party services, the firm points out.

The AZ-10 features a patented universal tubing hanger and running tool system that is factory assembled, easily transported, and ready for quick and easy wellhead and tree interface. The system is flexible and compatible with wellhead equipment from any of the major service providers regardless of profile and any BOP stack.

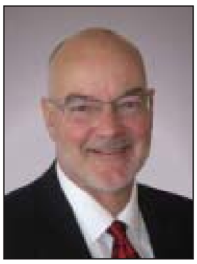
All of components and assemblies have been designed and validated using API specifications 6A and 17D under the API Q-1/ISO 29001 Quality System Standard requirements.

Source: **Argus Subsea,** 5510 Clara Rd., Houston, TX 77041.

Services/Suppliers

Fugro Gravity & Magnetic Services,

Houston, has named Terry Crabb business development manager for the Australia/Asia region. He will be based in Perth and will be responsible for sales, marketing, and business development. Crabb has more than 30 years of geoscience experience, including serving as the chief geophysicist at Scintrex in Canada and as the CEO of Australian Geophysical Surveys in Perth. He is a member of the Petroleum Exploration Society of Australia, Australian Institute of Mining and Metallurgy, and Australian Society of Exploration Geophysicists, where he previously served as president. Crabb has a BS in geology/geophysics and an MBA from the University of Adelaide.



Crabb

Fugro GMS is a part of Fugro, which interprets and processes data about the earth collected at sea, on land, and from the air.

AKITA Drilling Ltd.,

Calgary, has appointed Karl Ruud president and CEO, replacing John Hlavka, who is retiring. Ruud, previously president and COO, has extensive drilling experience in Canada and abroad and has been with AKITA since the company was formed.

AKITA is an Alberta drilling contractor.

Mako DeepWater,

Houston, has changed its name to Seanic Ocean Systems to reflect growth of its new product lines in deck equipment and handling systems, in addition to the continued growth of its subsea tooling business.

The company was formed to address the growing demand for simple, rugged, and reliable subsea tooling for remote intervention. Seanic now also offers design, manufacture, and repair of deck equipment such as A-frames, launch and recovery systems, heave compensation, and specialty winches, along with standard product line ROV tooling such as torque tools, flying lead orientation tools, standard and zero leak hot stabs, manifolds, buckets, and ROV interface panels.

Hampson-Russell Software & Services,

Houston, a CGGVeritas company, has opened a new technical support office in Villahermosa, Mexico. A resident team of geophysicists will provide onsite support for its advanced geophysical interpretation software to main client Pemex and other clients in Mexico. This team will join the CGGVeritas reservoir characterization services center already in place in Villahermosa. Hampson-Russell will also open a support office in Beijing later in the year.

CGGVeritas is a leading international pure-play geophysical company delivering a wide range of technologies, services, and equipment (through Sercel) to the global oil and gas industry.


Early Bird Registration
$840 through July 17th.

Imports of crude and products

	Districts 1–4		District 5		Total US		
	6/5 2009	5-29 2009	6-5 2009	5-29 2009	6-5 2009	5-29 2009	*6-6 2008
	1,000 b/d						
Total motor gasoline	925	960	24	45	949	1,005	1,310
Mo. gas. blending comp.	643	695	24	45	667	740	916
Distillate	159	203	49	0	208	203	211
Residual	383	454	44	34	427	488	216
Jet fuel-kerosine	75	60	27	13	102	73	162
Propane-propylene	86	128	2	4	88	132	111
Other	515	515	(25)	11	490	526	349
Total products	**2,786**	**3,015**	**145**	**152**	**2,931**	**3,167**	**3,275**
Total crude	**8,448**	**7,873**	**1,198**	**905**	**9,646**	**8,778**	**9,786**
Total imports	**11,234**	**10,888**	**1,343**	**1,057**	**12,577**	**11,945**	**13,061**

*Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Purvin & Gertz LNG netbacks—June 12, 2009

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant — $/MMbtu					
Barcelona	7.31	4.72	5.94	4.62	5.28	5.87
Everett	3.09	1.16	2.76	1.26	1.66	3.36
Isle of Grain	2.85	1.05	2.28	0.98	1.43	2.30
Lake Charles	1.24	–0.33	1.04	–0.20	–0.05	1.80
Sodegaura	3.42	5.49	3.67	5.21	4.55	2.83
Zeebrugge	4.67	2.57	4.06	2.46	3.16	4.12

Definitions, see OGJ Apr. 9, 2007, p. 57.
Source: Purvin & Gertz Inc.
Data available in OGJ Online Research Center.

Crude and product stocks

District	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 bbl						
PADD 1	14,394	52,575	35,465	11,057	59,846	16,699	4,120
PADD 2	84,676	47,182	21,590	8,099	32,313	1,233	19,643
PADD 3	190,743	70,246	39,714	12,336	42,265	17,519	26,357
PADD 4	17,218	5,592	1,931	673	2,916	382	[1]1,117
PADD 5	58,946	27,607	21,836	9,208	12,696	4,299	—
June 5, 2009	**365,977**	**203,202**	**120,536**	**41,373**	**150,036**	**40,132**	**51,237**
May 29, 2009	**363,111**	**203,417**	**120,128**	**40,449**	**148,375**	**38,468**	**49,352**
June 6, 2008[2]	**306,757**	**209,090**	**103,474**	**39,751**	**111,704**	**38,166**	**38,002**

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Refinery report—June 5, 2009

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,279	1,283	2,306	62	367	139	50
PADD 2	3,251	3,230	2,033	185	875	42	263
PADD 3	7,417	7,118	2,820	645	2,153	279	662
PADD 4	561	558	285	27	153	12	[1]63
PADD 5	2,735	2,536	1,353	415	504	129	—
June 5, 2009	**15,243**	**14,725**	**8,797**	**1,334**	**4,052**	**601**	**1,038**
May 29, 2009	**15,040**	**14,733**	**9,378**	**1,439**	**4,036**	**552**	**1,072**
June 6, 2008[2]	**15,785**	**15,480**	**9,113**	**1,566**	**4,506**	**710**	**1,126**
	17,672 Operable capacity		**86.3% utilization rate**				

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Additional analysis of market trends is available through **OGJ Online**, *Oil & Gas Journal's* electronic information source, at http://www.ogjonline.com.

OIL&GAS JOURNAL online research center.

OGJ crack spread

	*6-12-09	*6-13-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	79.85	148.94	–69.09	–46.4
Brent crude	70.10	135.09	–64.99	–48.1
Crack spread	9.75	13.85	–4.10	–29.6
FUTURES MARKET PRICES				
One month				
Product value	81.10	151.86	–70.75	–46.6
Light sweet crude	70.83	134.73	–63.90	–47.4
Crack spread	10.27	17.13	–6.85	–40.0
Six month				
Product value	80.30	149.06	–68.76	–46.1
Light sweet crude	74.60	135.58	–60.98	–45.0
Crack spread	5.71	13.48	–7.78	–57.7

*Average for week ending.
Source: Oil & Gas Journal
Data available in OGJ Online Research Center.

OGJ GASOLINE PRICES

	Price ex tax 6-10-09	Pump price* 6-10-09	Pump price 6-11-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	203.6	250.1	412.8
Baltimore	206.1	248.0	400.6
Boston	209.9	251.8	403.0
Buffalo	201.8	262.7	418.6
Miami	215.8	267.4	421.2
Newark	206.7	239.3	394.4
New York	196.4	257.3	410.3
Norfolk	200.7	239.1	393.5
Philadelphia	208.2	258.9	412.0
Pittsburgh	206.3	257.0	401.2
Wash., DC	220.8	259.2	412.8
PAD I avg	206.9	253.7	407.3
Chicago	241.1	305.5	440.3
Cleveland	227.7	274.1	394.7
Des Moines	224.9	265.3	395.1
Detroit	230.2	289.6	406.4
Indianapolis	217.4	276.8	396.4
Kansas City	213.7	249.7	392.1
Louisville	231.1	272.0	401.2
Memphis	208.1	247.9	385.5
Milwaukee	231.5	282.8	409.7
Minn.-St. Paul	224.3	268.3	397.6
Oklahoma City	216.9	252.3	382.5
Omaha	216.8	262.1	392.3
St. Louis	212.6	248.6	390.9
Tulsa	210.2	245.6	380.2
Wichita	210.2	253.6	374.3
PAD II avg	221.1	266.3	395.9
Albuquerque	213.8	250.2	385.6
Birmingham	206.0	245.3	393.1
Dallas-Fort Worth	210.6	249.0	397.8
Houston	206.8	245.2	390.1
Little Rock	203.1	243.3	391.2
New Orleans	207.1	245.5	394.8
San Antonio	201.4	239.8	388.2
PAD III avg	207.0	245.5	391.5
Cheyenne	210.1	242.5	382.9
Denver	210.9	251.3	390.6
Salt Lake City	204.4	247.3	392.9
PAD IV avg	208.5	247.0	388.8
Los Angeles	218.9	286.0	443.5
Phoenix	209.7	247.1	408.9
Portland	225.9	269.3	420.3
San Diego	221.5	288.6	452.4
San Francisco	229.4	296.5	448.6
Seattle	226.3	282.2	429.2
PAD V avg	222.0	278.3	433.8
Week's avg.	**214.3**	**259.9**	**403.1**
May avg.	**179.0**	**224.6**	**372.9**
Apr. avg.	**156.7**	**202.3**	**339.3**
2009 to date	**157.1**	**202.7**	--
2008 to date	**290.0**	**333.6**	--

*Includes state and federal motor fuel taxes and state sales tax. Local governments may impose additional taxes.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

REFINED PRODUCT PRICES

Spot market product prices

	6-5-09 ¢/gal
Motor gasoline (Conventional-regular)	
New York Harbor	192.91
Gulf Coast	191.41
Los Angeles	203.45
Amsterdam-Rotterdam-Antwerp (ARA)	195.46
Singapore	188.81
Motor gasoline (Reformulated-regular)	
New York Harbor	198.66
Gulf Coast	193.20
Los Angeles	215.45

	6-5-09 ¢/gal
Heating oil No. 2	
New York Harbor	174.70
Gulf Coast	171.45
Gas oil	
ARA	174.89
Singapore	180.00
Residual fuel oil	
New York Harbor	145.17
Gulf Coast	153.50
Los Angeles	160.19
ARA	143.61
Singapore	147.42

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

BAKER HUGHES RIG COUNT

	6-12-09	6-13-08
Alabama	5	3
Alaska	4	7
Arkansas	44	49
California	21	42
Land	20	42
Offshore	1	0
Colorado	41	100
Florida	1	0
Illinois	0	0
Indiana	2	2
Kansas	17	8
Kentucky	10	11
Louisiana	133	162
N. Land	74	57
S. Inland waters	6	23
S. Land	11	25
Offshore	42	57
Maryland	0	1
Michigan	0	1
Mississippi	8	12
Montana	0	13
Nebraska	0	0
New Mexico	36	79
New York	2	7
North Dakota	36	71
Ohio	8	13
Oklahoma	76	213
Pennsylvania	37	20
South Dakota	0	2
Texas	320	929
Offshore	1	11
Inland waters	0	2
Dist. 1	12	24
Dist. 2	14	31
Dist. 3	25	69
Dist. 4	29	96
Dist. 5	78	182
Dist. 6	49	122
Dist. 7B	10	29
Dist. 7C	10	72
Dist. 8	40	138
Dist. 8A	10	28
Dist. 9	17	43
Dist. 10	25	82
Utah	14	41
West Virginia	22	26
Wyoming	31	74
Others—HI-1;NV-2;VA-5;	8	15
Total US	**876**	**1,901**
Total Canada	**108**	**230**
Grand total	**984**	**2,131**
US Oil rigs	183	389
US Gas rigs	685	1,504
Total US offshore	47	68
Total US cum. avg. YTD	**1,158**	**1,809**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	6-12-09 Rig count	6-12-09 Percent footage*	6-13-08 Rig count	6-13-08 Percent footage*
0-2,500	41	9.7	78	5.1
2,501-5,000	66	62.1	134	53.7
5,001-7,500	117	15.3	257	14.3
7,501-10,000	192	5.2	445	3.8
10,001-12,500	167	4.1	472	2.5
12,501-15,000	150	1.3	318	0.3
15,001-17,500	113	—	125	—
17,501-20,000	43	—	70	—
20,001-over	32	—	37	—
Total	**921**	**8.9**	**1,936**	**7.3**
INLAND	12		28	
LAND	869		1,852	
OFFSHORE	40		56	

*Rigs employed under footage contracts.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]6-12-09	[2]6-13-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	21
Alaska	710	670
California	654	650
Colorado	62	66
Florida	6	4
Illinois	27	26
Kansas	101	106
Louisiana	1,447	1,293
Michigan	16	16
Mississippi	61	60
Montana	94	85
New Mexico	165	162
North Dakota	194	157
Oklahoma	176	170
Texas	1,350	1,351
Utah	57	57
Wyoming	150	143
All others	66	79
Total	**5,356**	**5,116**

[1]OGJ estimate. [2]Revised.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US CRUDE PRICES

	6-12-09 $/bbl*
Alaska-North Slope 27°	40.78
South Louisiana Sweet	71.75
California-Kern River 13°	63.70
Lost Hills 30°	72.10
Wyoming Sweet	61.54
East Texas Sweet	68.00
West Texas Sour 34°	62.50
West Texas Intermediate	68.50
Oklahoma Sweet	68.50
Texas Upper Gulf Coast	61.50
Michigan Sour	60.50
Kansas Common	67.50
North Dakota Sweet	57.50

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	6-5-09
United Kingdom-Brent 38°	66.55
Russia-Urals 32°	66.30
Saudi Light 34°	64.17
Dubai Fateh 32°	66.35
Algeria Saharan 44°	67.42
Nigeria-Bonny Light 37°	68.58
Indonesia-Minas 34°	70.18
Venezuela-Tia Juana Light 31°	66.81
Mexico-Isthmus 33°	66.70
OPEC basket	66.67
Total OPEC[2]	65.88
Total non-OPEC[2]	65.29
Total world[2]	65.62
US imports[3]	63.70

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

US NATURAL GAS STORAGE[1]

	6-5-09	5-29-09	6-6-08	Change, %
	bcf			
Producing region	957	934	659	**45.2**
Consuming region east	1,091	1,024	951	**14.7**
Consuming region west	395	379	265	**49.1**
Total US	**2,443**	**2,337**	**1,875**	**30.3**

	Mar. 09	Mar. 08	Change, %
Total US[2]	**1,656**	**1,247**	**32.8**

[1]Working gas. [2]At end of period.
Source: Energy Information Administration
Data available in OGJ Online Research Center.

World oil balance

	2008 4th qtr.	2008 3rd qtr.	2008 2nd qtr.	2008 1st qtr.	2007 4th qtr.	2007 3rd qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	19.51	19.13	19.96	20.15	20.90	21.06
Canada	2.31	2.34	2.25	2.37	2.38	2.40
Mexico	2.04	2.11	2.16	2.10	2.16	2.06
Japan	4.67	4.30	4.59	5.41	5.25	4.70
South Korea	2.12	2.07	2.09	2.33	2.31	2.06
France	2.01	1.92	1.92	1.98	2.02	1.94
Italy	1.64	1.65	1.61	1.62	1.75	1.65
United Kingdom	1.71	1.64	1.72	1.72	1.73	1.73
Germany	2.64	2.69	2.41	2.48	2.54	2.55
Other OECD Europe	7.29	7.46	7.24	7.42	7.62	7.55
Australia & New Zealand	1.14	1.12	1.14	1.13	1.15	1.12
Total OECD	**47.08**	**46.43**	**47.09**	**48.71**	**49.81**	**48.82**
NON-OECD						
China	7.46	8.10	8.19	8.07	7.61	7.91
FSU	4.38	4.35	4.31	4.31	4.35	4.25
Non-OECD Europe	0.80	0.80	0.79	0.79	0.81	0.82
Other Asia	8.75	8.95	9.60	9.51	9.29	8.92
Other non-OECD	15.60	16.45	16.08	15.15	14.96	15.54
Total non-OECD	**36.99**	**38.65**	**38.97**	**37.83**	**37.02**	**37.44**
TOTAL DEMAND	**84.07**	**85.08**	**86.06**	**86.54**	**86.83**	**86.26**
SUPPLY						
OECD						
US	8.43	8.18	8.75	8.64	8.58	8.36
Canada	3.40	3.40	3.22	3.38	3.40	3.48
Mexico	3.12	3.15	3.19	3.29	3.33	3.46
North Sea	4.38	4.07	4.33	4.46	4.57	4.28
Other OECD	1.61	1.59	1.58	1.54	1.57	1.57
Total OECD	**20.94**	**20.39**	**21.07**	**21.31**	**21.45**	**21.15**
NON–OECD						
FSU	12.46	12.42	12.60	12.59	12.65	12.55
China	3.99	3.97	4.00	3.94	3.87	3.88
Other non–OECD	12.51	12.41	12.20	12.24	12.12	12.04
Total non-OECD, non-OPEC	**28.96**	**28.80**	**28.80**	**28.77**	**28.64**	**28.47**
OPEC*	**35.16**	**36.18**	**35.84**	**35.72**	**35.15**	**34.42**
TOTAL SUPPLY	**85.06**	**85.37**	**85.71**	**85.80**	**85.24**	**84.04**
Stock change	**0.99**	**0.29**	**–0.35**	**–0.74**	**–1.59**	**–2.22**

*Includes Angola.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

US petroleum imports from source country

	Feb. 2009	Jan. 2009	Average YTD 2009	Average YTD 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	372	720	555	514	41	8.0
Angola	671	543	604	468	136	29.1
Kuwait	251	242	246	252	–6	–2.4
Nigeria	498	509	504	1,110	–606	–54.6
Saudi Arabia	1,115	1,362	1,245	1,563	–318	–20.3
Venezuela	1,139	1,353	1,252	1,214	38	3.1
Other OPEC	910	947	928	1,020	–92	–9.0
Total OPEC	**4,956**	**5,676**	**5,334**	**6,141**	**–807**	**–13.1**
Canada	2,515	2,544	2,530	2,527	3	0.1
Mexico	1,364	1,430	1,399	1,317	82	6.2
Norway	74	90	82	93	–11	–11.8
United Kingdom	285	147	212	185	27	14.6
Virgin Islands	333	367	350	366	–16	–4.4
Other non-OPEC	2,664	2,918	2,799	2,434	365	15.0
Total non-OPEC	**7,235**	**7,496**	**7,372**	**6,922**	**450**	**6.5**
TOTAL IMPORTS	**12,191**	**13,172**	**12,706**	**13,063**	**-357**	**-2.7**

Source: DOE Monthly Energy Review
Data available in OGJ Online Research Center.

OECD total net oil imports

	Feb. 2009	Jan. 2009	Dec. 2008	Feb. 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,528	–1,240	–1,421	–1,330	–198	14.9
US	10,369	11,246	10,736	10,531	–162	–1.5
Mexico	–1,254	–1,213	–1,228	–1,160	–94	8.1
France	1,806	1,739	1,876	1,681	125	7.4
Germany	2,325	2,275	2,273	2,079	246	11.8
Italy	1,261	1,485	1,531	1,328	–67	–5.0
Netherlands	1,233	974	1,116	912	321	35.2
Spain	1,668	1,360	1,618	1,558	110	7.1
Other importers	3,889	3,859	4,142	3,903	–14	–0.4
Norway	–2,437	–2,052	–2,247	–2,206	–231	10.5
United Kingdom	–3	226	193	29	–32	–110.3
Total OECD Europe	**9,742**	**9,866**	**10,502**	**9,284**	**458**	**4.9**
Japan	4,768	4,580	4,839	5,426	–658	–12.1
South Korea	2,519	2,454	1,954	2,111	408	19.3
Other OECD	780	903	925	1,085	–305	–28.1
Total OECD	**25,396**	**26,596**	**26,307**	**25,947**	**–551**	**–2.1**

Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD* total gross imports from OPEC

	Feb. 2009	Jan. 2009	Dec. 2008	Feb. 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	451	442	484	542	–91	–16.8
US	4,956	5,676	5,652	5,839	–883	–15.1
Mexico	11	18	22	30	–19	–63.3
France	722	792	906	616	106	17.2
Germany	355	530	539	409	–54	–13.2
Italy	966	1,101	1,172	1,100	–134	–12.2
Netherlands	571	779	572	391	180	46.0
Spain	1,036	759	908	671	365	54.4
Other importers	863	999	1,095	1,176	–313	–26.6
United Kingdom	285	257	392	316	–31	–9.8
Total OECD Europe	**4,798**	**5,217**	**5,584**	**4,679**	**119**	**2.5**
Japan	4,273	3,712	4,116	4,360	–87	–2.0
South Korea	2,572	2,628	2,348	2,170	402	18.5
Other OECD	376	612	440	720	–344	–47.8
Total OECD	**17,437**	**18,305**	**18,646**	**18,340**	**–903**	**–4.9**

*Organization for Economic Cooperation and Development.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

Oil stocks in OECD countries*

	Feb. 2009	Jan. 2009	Dec. 2008	Feb. 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	178	179	179	176	2	1.1
Germany	279	277	273	276	3	1.1
Italy	128	128	127	129	–1	–0.8
United Kingdom	99	100	96	95	4	4.2
Other OECD Europe	727	727	732	680	47	6.9
Total OECD Europe	**1,411**	**1,411**	**1,407**	**1,356**	**55**	**4.1**
Canada	192	196	196	192	—	—
US	1,770	1,762	1,735	1,662	108	6.5
Japan	619	618	630	605	14	2.3
South Korea	157	149	135	149	8	5.4
Other OECD	107	114	113	113	–6	–5.3
Total OECD	**4,256**	**4,250**	**4,216**	**4,077**	**179**	**4.4**

*End of period.
Source: DOE International Petroleum Monthly Report
Data available in OGJ Online Research Center.

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From the Subscribers Only area of OIL&GAS JOURNAL online www.ogjonline.com

Ethanol's green goodness clouded by water strains

For a supposedly clean-burning gasoline additive, ethanol always has carried a full load of environmental compromises.

The problem of volatility is a longstanding example. It's why ethanol promoters focus on tailpipe emissions of ozone precursors and ignore evaporative emissions. Generally, ethanol improves the former but aggravates the latter.

The Editor's Perspective

by Bob Tippee, Editor

And it turns out that ethanol from corn—most of the ethanol burned as fuel in the US—doesn't live up to its press notices as a way to combat global warming. To sweep this one under the rug, ethanol promoters want everyone to ignore the forests displaced by fuel-crop agriculture.

New to the list of questions about ethanol's environmental goodness is water use.

Growing mandates for the fuel additive through 2022 require energy conservation and careful planning for land use and crop choices, warns a new study published by the Shell Center for Sustainability at Rice University in Houston.

The water needed to grow feedstock for a liter of ethanol in the US ranges from 500 l. to 5,000 l., the study says, depending on crop and location.

For ethanol from irrigated corn grown in Nebraska, travel in a car that achieves 16 mpg of ethanol represents the use of about 50 gal of water/mile driven (gwpm), the study calculates.

"This value could decrease to 23 gwpm for corn grown in Iowa or increase to 90 gwpm if sorghum ethanol is used or to 115 gwpm if the sorghum is grown in Texas," it says.

The peak mandate for corn ethanol in 2015 could require 6 billion cu m/year of water for ethanol, about 3% of the total used for US irrigation in 2000, the study estimates.

The ethanol mandate also will hurt water quality by raising the use of nitrogen fertilizer and pesticides, it adds.

"Such threats to water availability and water quality at local to national scales represent a major obstacle for sustainable biofuel production and require careful assessment of crop selection and management options," the study says.

That kind of planning has been ostentatiously absent in the agricultural gold rush incited by US subsidies and mandates for ethanol.

(Online June 12, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Crude tests $73/bbl

The July contract for benchmark US light sweet crude hit an intraday high of $73.23/bbl June 11 on the New York Mercantile Exchange before closing at $72.68/bbl, up $1.35 for the day after the International Energy Agency in Paris increased its prediction of global oil demand for the first time in 10 months.

However, oil closed at $72.04/bbl June 12 after the Organization of Petroleum Exporting Countries reported its production increased for the second consecutive month, up 135,000 b/d to 28.27 million b/d in May.

IEA increased its oil demand forecast by 120,000 b/d to 83.3 million b/d. The latest total is down 2.9% from 2008 demand, compared with IEA's previous prediction of a 3% decline (OGJ Online, June 11, 2009).

OPEC expects world oil demand growth to be down 1.6 million b/d in 2009, broadly unchanged from its previous report. It revised its 2009 projected growth for the world economy up by a mere 0.1%, still down 1.3% from 2008 levels. It expects non-OPEC production to increase by 200,000 b/d above 2008 production.

The 11 OPEC members excluding Iraq increased their production by 118,800 b/d to 25.903 million b/d in May. Analysts expect compliance with official production quotas will continue to erode as crude prices rise.

The average price for OPEC's basket of 12 reference crudes surged almost 14% in May to $56.98/bbl, its highest monthly average in 7 months, driven by the widespread hope for a recovery in petroleum demand. OPEC's basket price was up 68¢ to $70.87/bbl on June 11. Officials at OPEC reported the tanker market rebounded in May. "The [very large crude carrier] sector continued to suffer the most from the global economic crisis and OPEC output adjustments. Clean spot freight rates rose by 37% on average. After reaching a high level, storage at sea lost momentum towards the end of the month due to the narrowing of the contango structure in the crude futures market," officials said.

May market increased

Analysts in the Houston office of Raymond James & Associates Inc. said, "Commodity prices rallied in May and the energy indices took note, outperforming the broader market by over 10%. While we believe both oil and natural gas may be in for short-term corrections in the coming weeks, the bifurcation between the two continues to grow. Oil is simply waiting for demand to recover before climbing even higher. Natural gas is headed towards full storage, and prices will plummet."

They said, "Oil has ripped for 4 months in a row now, jumping 30% in May (and already up 6% in June). Oil has more than doubled off its bottom from back in February. While the global economy has started to show 'green shoots' of recovery, we still believe that a dramatic rebound in oil demand isn't in the cards for 2009, and a short-term pullback is likely given worldwide storage levels, which are still full."

Raymond James observed, "The global economic crisis continues to obscure oil demand, with virtually no near-term visibility. Despite recent stimulus packages around the world, we assume depression-era year-over-year demand destruction of 3.5%. In spite of brimming worldwide inventories, oil has spiked to over $70/bbl over the last few months (over 100% above its February low). However, we believe global demand will need to stabilize (and possibly recover) before oil prices can be maintained at this level. We don't expect to see this until 2010, hence our $52.50/bbl second-half forecast. Even if oil prices saw a short-term pullback, we believe the long-term story is intact and accordingly model $65/bbl in 2010. Indeed, if anything, given the number of marginal supply projects that have been shelved, the long-term outlook for crude is actually stronger."

As for natural gas, Raymond James analysts said, "While the fundamentals continue to deteriorate (year-over-year storage surplus quickly approaching 600 bcf), natural gas rode a technical rally higher in May, finishing the month up 14%. We believe this is solely the result of a lot of new money entering the market and still believe full storage will drive prices below $3/Mcf toward the end of summer."

They said, "Despite our assumption of a 70% peak-to-trough decline in the gas rig count, we believe shut-ins may still total 500-750 bcf. To force such large shut-ins, natural gas prices would need to fall well below $3/Mcf. Moreover, LNG imports could be substantially above our estimates, causing an even higher amount of shut-ins. For 2010, the outlook is still uncertain."

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