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Deepwater Challenges and Opportunities

Global oil, gas outlook bright; US gas production nears plateau
Asia-Pacific products demand to rebound in 2006 and later
Pipeline grouping method improves aggregate data

OIL&GAS JOURNAL®

Nov. 27, 2006
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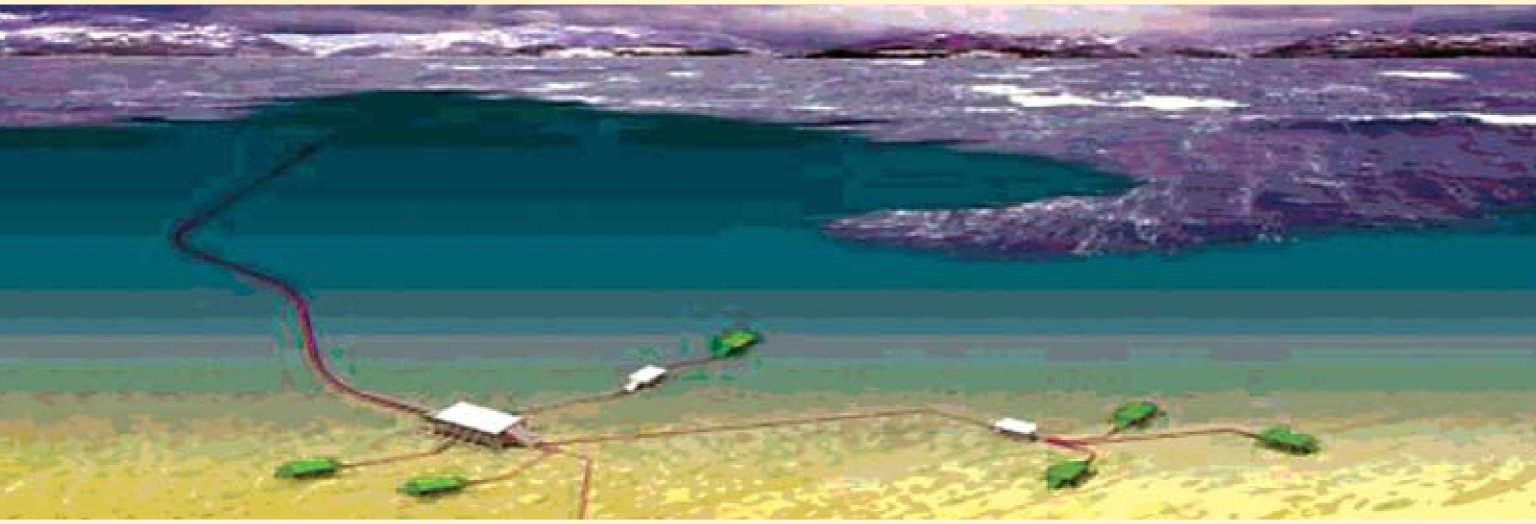
Deepwater Challenges and Opportunities



Regular Features

Cover

A stationary lifting device placed the topsides onto the deep-draft semisubmersible hull of the Independence Hub docked at Kiewit Offshore Services Ltd.'s facilities near Corpus Christi, Tex. Once moored in 8,000 ft of water in the eastern Gulf of Mexico, Independence Hub initially will process gas from 10 deepwater gas fields lying in 8,000-9,000 ft of water that otherwise would be uneconomical to develop on a stand-alone basis. The article in the special section on p. 43 describes the project in more detail. Photo from Enterprise Products Partners LP.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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Nov. 27, 2006

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General Interest — *Quick Takes*

Nigerian militants leave oil-pumping station

Militants in Nigeria have abandoned an oil-pumping station operated by Nigeria Agip Oil Co. (NAOC) after a 2-week siege, freeing nine contract workers and some 20 government soldiers.

A government spokesman said the armed men left the facility in the early hours of Nov. 19 after a truce was brokered by the Bayesla state government.

A senior police officer confirmed that the hostages had been released and the flow station vacated, but he could not say if any ransom was paid to the militants.

Agip's Tebidaba oil-pumping station in Nigeria's southern Bayelsa state was overrun and shut down following an attack on Nov. 6 by armed militants, according to company and government officials (OGJ Online, Nov. 6, 2006).

Murkowski releases new pipeline contract report

Alaska Gov. Frank Murkowski on Nov. 16 submitted a 350-page Interim Fiscal Interest Finding (IFIF) report to the Alaskan legislature that provides an economic analysis supporting construction of a natural gas pipeline from the North Slope.

Murkowski, who is leaving office Dec. 4, said he was ready to assist Gov.-elect Sarah Palin and the legislature.

Alaska Department of Revenue Commissioner Bill Corbus prepared the IFIF report, including proposed changes to a draft contract that Murkowski negotiated with North Slope producers. The first draft was released in May (OGJ, June 5, 2006, Newsletter).

The oil companies have not agreed to any of the proposed changes, Murkowski said. The IFIF includes a draft limited liability corporation contract under which the project would be built and operated by a partnership of the state of Alaska and North Slope producers.

"This document represents the future of Alaska," Murkowski said. "We must transition our oil-based economy to one based on gas production."

Murkowski declined to say whether he might ask for additional legislative consideration on the pipeline. The Alaska Supreme Court is reviewing an Alaska state district court ruling that Murkowski cannot unilaterally approve the pipeline contract. Murkowski appealed the lower court ruling.

EPA issues subsoil tank containment grant rules

The US Environmental Protection Agency issued the final secondary containment grant guidelines for states on Nov. 16, implementing a key provision of the underground storage tank amendments in the 2005 Energy Policy Act.

Secondary containment provides a barrier between an underground storage tank and the environment by holding leaking petroleum between the barrier and tank so the leak can be detected. EPA, which provides funding to states through grants to regulate underground storage tanks, said it worked with states and regional tank offices to develop the guidelines.

The guidelines provide compliance requirements, detailed definitions and examples for states choosing to implement the secondary containment provision. Owners and operators would not be required to retrofit equipment, but would have to follow the guidelines with replacements or installation of new equipment, the agency said.

EPA said states receiving funds under Subtitle 1 of the Waste Disposal Act must by Feb. 7, 2007, implement either these guidelines or financial responsibility and certification grant guidelines that the agency will issue in the next few months.

The agency is giving states maximum flexibility to establish their own secondary containment requirements by that date because it is only a few months away. For states demonstrating good faith efforts to meet the requirements, EPA said it has the flexibility to continue providing them assistance as they implement their programs. ✦

Exploration & Development — *Quick Takes*

Husky completes White Rose delineation

Husky Energy Inc., Calgary, has completed the White Rose 2006 delineation program, resulting in an increase of the assessment of White Rose oil field's recoverable resources by 190 million bbl of oil. The field is in the Jeanne d'Arc basin 350 km east of St. John's, Newf.

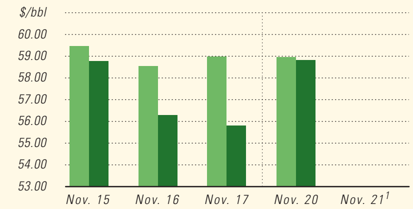
"The results of this delineation program, along with the strong performance of the current development, should allow White Rose to significantly extend its production plateau," said Chief Executive and Pres. John C.S. Lau.

Contributing to the increase in the assessment of the field's resources is Husky's hydrocarbon discovery at the North Amethyst K-15 delineation well in the southwestern section of White Rose. This discovery could contain recoverable resources of 40-100 million bbl of oil, with a likely estimate of 70 million bbl. The K-15 well, drilled to 2,566 m on White Rose Significant Discovery License 1044, revealed a 50-55-m oil column with high reservoir quality in the Aptian-age Ben Nevis Avalon formation. The company is continuing to assess core and fluid samples and wireline log data.

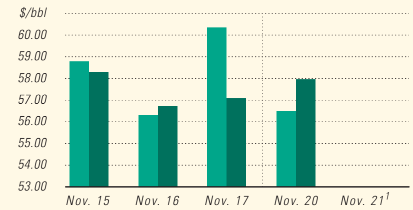
Earlier this year Husky announced results of the O-28 delineation well, which was drilled in the western section of the field.

Industry Scoreboard

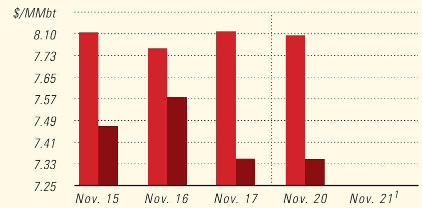
IPE BRENT / NYMEX LIGHT SWEET CRUDE



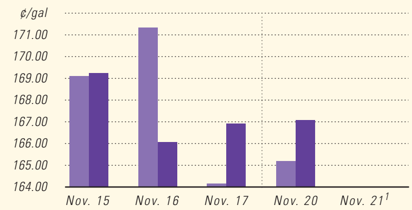
WTI CUSHING / BRENT SPOT



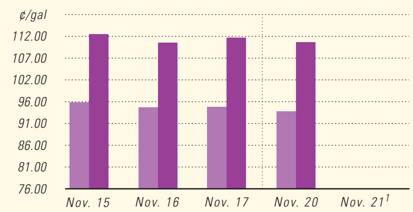
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



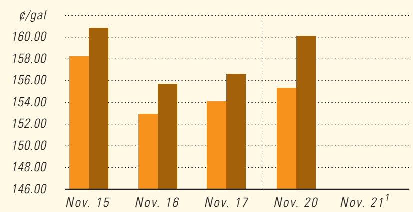
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE / NY SPOT GASOLINE[2]



[1]Not available.
[2]Nonoxygenated regular unleaded.

Scoreboard

Due to the holiday in the US, data for this week's industry Scoreboard are not available.

Further review of the well data and geological modeling has resulted in Husky's upgrading its estimate of recoverable resources in this area to 50-200 million bbl of oil, with a current likely estimate of 120 million bbl. A further delineation well is planned in 2007 to confirm the resource estimates and to assist in future development planning.

The total estimate of about 190 million bbl of recoverable resources from the K-15 and O-28 wells is incremental to the White Rose proven and probable reserves. The two wells are near the SeaRose floating production, storage, and offloading vessel.

Husky is conducting front-end engineering on the White Rose field's southern extension, which the company expects to develop as a subsea tieback to the SeaRose FPSO. Production from this pool is scheduled for late 2009, pending regulatory approvals. The southern extension reserves are included in the current estimate of White Rose proven and probable reserves. It is anticipated that the K-15 discovery also will be developed through the southern extension development.

The SeaRose FPSO is producing 110,000 b/d of oil from five production wells. A sixth production well is being completed and is expected to come on stream later this month, increasing reservoir production capacity to 125,000 b/d of oil.

Field operator Husky Energy holds a 72.5% interest in the project. Petro-Canada holds the remaining 27.5%.

Vinccler boosting Falcon basin production

PetroFalcon Corp., Carpinteria, Calif., said its PetroCumarebo joint venture with Petroleos de Venezuela SA (PDVSA) looks forward to accelerating activity on the East and West Falcon blocks in northern Venezuela.

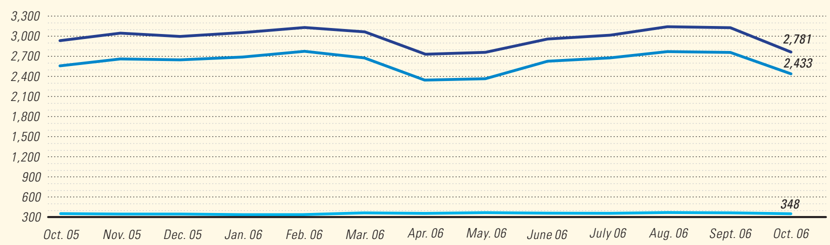
PetroFalcon's Vinccler Venezuela and PDVSA-Corporación Venezolana del Petróleo signed the joint venture conversion agreement on Sept. 29, giving PetroCumarebo rights to the two blocks covering 838,000 acres for 20 years.

Gross production from the two blocks totals 1,200 b/d of oil and 12 MMcfd of gas.

Vinccler Venezuela, with 40% interest, was expanding facilities to handle 20 MMcfd and 1,700 b/d at La Vela field and 30 MMcfd and 5,000 b/d at Cumarebo field.

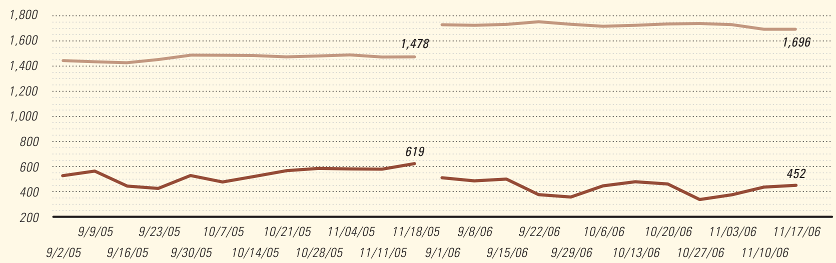
Cumarebo field began producing 10

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

MMcfd and 285 b/d of oil in early August, when the field was tied into PDVSA's Interconnection Centro Occidente gas pipeline to the Paraguana Peninsula.

PetroCumarebo plans to develop Los Moroches oil and gas field, discovered in 1995 on West Falcon by the previous operator. Vinccler Venezuela also delineated several structural prospects around Cumarebo field on 85 km of 2D seismic data gathered in 2005.

Due to the delay in incorporating the JV, PetroCumarebo will not be able to spend its 2006 capital budget of $40.7 million.

Gentry makes Alberta oil discovery

Gentry Resources Ltd., Calgary, said a well drilled in the Mississippian Pekisko formation within the Princess exploration area of southern Alberta encountered a net pay interval of 12 m within a gross pay column of 40 m.

The discovery well is 8 miles south of Gentry's existing Tilley-to-West Tide Lake Pekisko oil fairway.

On test, the well flowed for 8 hr at the equivalent of 925 b/d at a flowing pressure of 200 psig. Gentry Resources expects to install a temporary battery by early December, and the well is expected to produce at a restricted initial well allowable rate of 125 b/d.

Two more exploratory wells are to be drilled in December, 15 miles south of the discovery well, to test another possible oil fairway. Five additional exploratory wells on the block are planned for first-quarter 2007.

Lundin signs PSC for two Ethiopian blocks

Swedish independent Lundin Petroleum AB signed a production-sharing contract for Blocks 2 and 6 in southeastern Ethiopia's Ogaden basin.

The two-block area spans more than 24,000 sq km.

Lundin holds a 100% interest in the PSC area through the exploration period, with the Ethiopian government having an option for a 10% interest following a commercial discovery.

No wells have been drilled on Blocks 2 or 6, but indications of light oil, gas, and condensate have been documented in well tests and surface seeps south and east of the blocks, Lundin said.

Silverstone UK North Sea well finds gas

Silverstone Energy Ltd., a North Sea exploration and production company, struck natural gas with the 49/21–10A Vulcan East exploration well, drilled to 8,125 ft TD in the southern UK North Sea.

The Vulcan East well discovered an accumulation separate from adjacent Vulcan field, said Silverstone, the operator. The discovery is estimated to contain 150-200 bcf of gas in place in a 345-ft column.

Silverstone and partners, ConocoPhillips and BP PLC, are reviewing the well results to determine the viability of bringing the field onto production. Following evaluation of the Permian Rotliegendes sand reservoir, the well was suspended for possible future use as a development well.

Silverstone of Aberdeen was formed 18 months ago as a 50-50 joint venture between private equity fund Lime Rock Partners and Calgary independent Storm Ventures International Inc.

Chile's Magallanes area gets new gas flow

GeoPark Holdings Ltd., Hamilton, Bermuda, said it has become the first private company to produce oil and gas in southern Chile.

As operator of the 440,000-acre Fell Block, GeoPark is the only oil and gas company operating in Chile other than state Empresa Nacional de Petroleo (ENAP).

GeoPark is producing 5.4 MMcfd of gas and 50 b/d of condensate from single wells in Molino, Ovejero, and Nika fields on the Fell Block in the Austral basin northwest of the Straits of Magellan. It is selling gas to the Methanex methanol plant at Tierra del Fuego, Argentina, and condensate to ENAP.

GeoPark plans to tie in Santiago Norte field in late 2006 and other fields in second quarter 2007.

A workover rig has been cleaning out more wells since September, and a drilling rig is due to arrive in first quarter 2007. A 650 sq km 3D seismic survey is under way on the Fell Block.

GeoPark holds 100% interest in the Fell Block, having acquired the last 10% interest from ENAP earlier this year.

The Fell Block in Chile and GeoPark-operated Cerro Dona Juana, Del Mosquito, Loma Cortaderal blocks in Argentina total more than 700,000 acres.

KMV plans three more gas wells in Oklahoma

Mammoth Energy Group Inc. subsidiary KMV Consulting, Denver, currently drilling five wells in its shallow gas project in Rogers County, Okla., has made arrangements to drill three more wells there.

The wells will be drilled in the next few months on acreage KMV leased in May when it took over and began expanding the gas project. KMV recently secured an additional 1,476 acres, doubling the acreage under lease to 2,551 net acres.

The three wells planned would put KMV's total well count at 18 producing wells, with five more scheduled by yearend. The area has a 100% success rate reported on over 300 wells, due largely to a blanket Excello shale-coalbed methane seam that covers the area.

On the recently acquired acreage, Mammoth's Chief Executive Christopher Miller said eight oil wells can be recompleted to produce gas and brought on line for about half the cost to drill and complete a well.

"Of the next 15 wells we plan to drill, about half of them fall into this category. Therefore, we hope to have about 30 wells producing by the end of the first quarter 2007," Miller said.

KMV retains a 49.5% net revenue interest in the 18 gas wells, having sold 33% of its working interest to Allied Energy Group Inc., Bowling Green, Ky., for $1.5 million.

MOL to explore two blocks in Pakistan

MOL Pakistan Oil and Gas BV, a subsidiary of Hungary's MOL Group, will explore the Margalla and Margalla North blocks under concession agreements with the Pakistani government.

The blocks are in Punjab, North West Frontier Province (NWFP), and Islamabad. The Margalla Block covers 1,387 sq km and the Margalla North Block, 1,562 sq km.

MOL will conduct environmental and geological and geophysical studies; acquire, process, and interpret 2D seismic data; reprocess existing seismic data; and drill exploratory wells based on the results of the data.

It has made several gas and condensate discoveries on the Tal Block in NWFP (OGJ Online, Sept. 8, 2006). ✦

Drilling & Production — *Quick Takes*

Shell lets EPC contract for Perdido project

Shell Offshore Inc. has let an engineering, procurement, and construction (EPC) contract to Technip for a production spar hull and mooring system for the Perdido hub project 200 miles south of Freeport, Tex., in the Gulf of Mexico.

The contract covers spar hull and mooring system design and fabrication, load out onto a transportation vessel, transportation and quayside delivery at a Gulf of Mexico yard, and design of the steel catenary risers, top tension risers, and umbilicals. The contract value was not disclosed.

Technip's operations and engineering center in Houston will provide the overall project management, and the global engineering for the hull and mooring system, as well as engineering and procurement support for the riser tensioner system. The detailed hull design and fabrication will be carried out by Technip's yard in Pori, Finland.

Shell will operate the hub, called Perdido Regional Host, with a 35% interest. Other interests are Chevron Corp., 37.5%, and BP PLC, 27.5%. The facility will be capable of handling 130,000 boe/d, and it is expected to come on line "around the turn of the decade," Shell said. It will handle production from Great White, Tobago, and Silvertip fields.

Shell plans to moor the regional direct-vertical-access spar in a record water depth of 8,000 ft of water. The common processing hub, on Alaminos Canyon Block 857 near the Great White discovery, will have a drilling and completion rig and will gather, process, and transport production from wet trees as far away as 30 miles. Pipelines from the facility will connect to undisclosed locations in Texas (OGJ, Nov. 6, 2006, Newsletter).

Denser fracs improve Woodford gas flows

Gas flow rates are much improved at the more recent horizontal wells with higher frac densities in the Woodford shale play in the Arkoma basin of southeastern Oklahoma, said Newfield Exploration Co., Houston.

Newfield, which has production data from 29 horizontal Woodford wells, said initial gross production averages nearly 6 MMcfd from the eight horizontal wells it has tested that were treated with the higher frac densities.

Two of the eight wells, which have laterals of 1,600-3,500 ft, had initial production of 10 MMcfd, and two others flowed 7 MMcfd of gas. Fracs at the eight wells involved three to seven stages.

The company's gross production from the play has grown to nearly 80 MMcfd from 25 MMcfd at this time in 2005.

MarkWest Energy Partners LP, Denver, and Newfield plan to place in service more than 50 miles of large-diameter pipe in early December to complete the low and high-pressure backbone of the planned 400-mile, four-county gathering system (see map, OGJ, Oct. 9, 2006, p. 31). This is more than 3 months ahead of schedule.

Once the backbone is completed, Newfield will have the ability to produce from any part of its 125,000 net acre position.

The 2007 plan calls for the drilling of 150 horizontal wells. Permitted spacing of 640 acres would allow nearly all of the company's current acreage to be held by production by the end of 2007 based on the anticipated drilling rate as activity ramps up to 20 rigs from 11 operated rigs at present.

Antrim secures drilling rig for UK North Sea

Antrim Energy Inc., Calgary, has secured a semisubmersible rig to drill three Causeway appraisal-development wells next year on UK North Sea Block 211/22a.

Antrim, the operator and owner of 65.5% interest in the block, hired AGR Peak Well Management (Peak) to conduct the drilling program. Peak earlier had managed the drilling on East Causeway.

Antrim will spud the first appraisal-development well in May 2007, about 2 miles southwest of the East Causeway discovery. The company expects to drill to 11,500 ft and to appraise the Middle Jurassic Brent Group of sandstones, specifically the Tarbert, Ness, and Etive formations.

The drilling program follows Antrim's East Causeway discovery 211/23d-17z, which flowed on final test at multiple stabilized rates of up to 7,500 b/d of light, sweet oil (OGJ, Aug. 18, 2006, Newsletter).

The test rate did not include the 8,100 b/d of oil flow rate previously recorded from the Ness formation in the suspended 211/23b-11 well in an eastern fault compartment.

Kuwait planning gas production by 2008

Kuwait, which in March announced the discovery of 35 tcf of free natural gas and a large quantity of light oil in what it called its "northern oil fields," plans to start commercial production of gas late next year or early January 2008, according to Farouk al-Zanki, head of state-owned Kuwait Oil Co. (KOC).

At an oil and gas conference in Kuwait City, al-Zanki said the firm expects an initial output of 180 MMcfd, which it would increase to 600 MMcfd by 2011 and to 1 bcfd by 2014-15.

Al-Zanki said KOC would have a provisional plan for natural gas development by the end of November or in early December.

He said the company is searching for more gas in five exploration sites in the same region, which he did not name. It needs gas for its desalination plants and for a planned large refinery.

Al-Zanki also repeated an earlier commitment to increase Kuwait's oil production capacity to 3 million b/d by 2010, to 3.5 million b/d by 2015, and 4 million b/d by 2020 from the current 2.6 million b/d.

In January, Kuwait said it also planned to start exploration for natural gas in what it called undisputed parts of offshore Dorra field, which Iran also claims. At the time, Kuwait's energy ministry undersecretary Issa al-Oun told the Al-Siyassah newspaper: "Talks with Iran are continuing over the continental shelf. But, we have decided to...start exploration in the undisputed part."

Oun said Kuwait would soon invite bids for seismic surveys of part of Dorra field and other Kuwaiti offshore fields. He said he did not expect Iran to object to the measure. ✦

Processing — *Quick Takes*

BP lets $3 billion Whiting refinery work

BP Products North America Inc. has awarded Fluor Corp. several major packages, valued at a combined $3 billion, for upgrades to increase Canadian heavy oil processing capacity at its 399,000 b/cd Whiting refinery in northwest Indiana.

The work scope includes the overall integrated program management and construction management; plus the independent engineering, procurement, and fabrication of three major work packages, including a revamped crude distillation unit, a gas oil hydrotreater, and support infrastructure facilities.

The front-end engineering design, the initial award valued at $300 million, is under way.

The project will increase capacity for coking, hydrogen production, hydrotreating, and sulfur recovery. Construction is expected to start in 2007 and be completed by 2011 (OGJ Online, Sept. 25, 2006, Newsletter).

North West picks CLG for proposed upgrader

North West Upgrading Inc., Calgary, has selected the technology of Chevron Lummus Global LLC (CLG) for a 77,000 b/d hydrocraking unit at North West's proposed heavy oil upgrader facility in Sturgeon County, Alta.

The upgrader, which will use CLG's LC-FINING technology, will have a total capacity of 231,000 b/d of blended feedstock, including 150,000 b/d of crude bitumen. It will produce light, low-sulfur products and diluent.

The project, for which regulatory approval is expected by mid-2007, is to be built in three phases. The first phase is scheduled to come on stream in early 2010, with a capacity of 50,000 b/d of bitumen at a cost of more than $2.4 billion (Can.). All three phases are to be concluded by 2015.

CLG will provide an engineering package that includes a reactor design package, follow-up technical support during detailed engineering design, training prior to start-up, ICR catalysts and start-up support during the commissioning of the upgrader.

CLG is a 50-50 joint venture of Chevron USA Inc. and ABB Lummus Global.

GAIL JV to build petrochemical plant in Assam

India's state-owned GAIL India Ltd. is the lead promoter of a $1.2 billion integrated petrochemical complex in India to be built in Lepetkata district in Dibrugarh, Assam.

The complex will contain a gas separation plant, hydrocracker unit, and downstream polymer and integrated offsite utilities and plants. It will have a capacity of 220,000 tonnes/year of ethylene and 60,000 tonnes/year of propylene.

GAIL will hold 70% equity in the project, and the remaining 30% will be shared among three other partners: Oil India Ltd. (OIL), Numaligarh Refinery Ltd. (NRL), and the Assam state government.

The project will be completed in 60 months from the date of financial closure. The Assam state government has selected the site, and participants have obtained necessary environmental clearance.

OIL will provide 6 million standard cu m/day of gas as feedstock for the complex, and Oil & Natural Gas Corp. will provide 1.35 million standard cu m/day until Mar. 31, 2012, and reduce it to 1 million standard cu m/day thereafter. The complex also will utilize 160,000 tonnes/year of petrochemical-grade naphtha from NRL. ✦

Transportation — *Quick Takes*

Gas-purchase agreements advance Galsi line

New gas-purchase agreements by five Italian energy companies have given a push to plans for a third gas pipeline between North Africa and Europe.

The companies, Enel, Edison, Hera, Ascopiave, and Worldenergy, have agreed to import a total of 6 billion cu m/year of gas from Algeria via the proposed pipeline connecting Algeria with Italy by way of Sardinia.

Sonatrach of Algeria, Enel, and Wintershall of Germany formed a venture to study feasibility of the pipeline in December 2001 (OGJ, Jan. 7, 2002, Newsletter). Other companies have joined the venture, now called Galsi.

The project envisions four pipeline segments: 640 km onshore between Hassi R'mel gas field in Algeria and El Kala on the Algerian coast; 310 km between El Kala and Cagliari on Sardinia in water as deep as 1,950 m; 300 km between Cagliari and Olbia on the northern Sardinian coast; and 220 km between Olbia and Pescaia, southeast of Florence, in water as deep as 900 m.

Sonatrach says the Galsi pipeline will have a capacity of 8 billion cu m/year, and it projects start-up at the end of 2009.

Gaz de France launches large LNG vessel

Gaz de France has launched the 154,500-cu-m Provalys LNG carrier, one of the world's largest, at Montoir-de-Bretagne.

The 190 m by 43.5 m vessel is equipped to load LNG in arctic conditions.

Gaz de France is both owner and charterer. It now operates 11 LNG vessels and has two under construction at Chantiers de l'Atlantique: one with 74,000 cu m of capacity due for delivery by yearend and another with 154,000 cu m of capacity due in early 2007.

MISC orders four Aframax tankers from Tsuneishi

Malaysian International Shipping Corp. (MISC) subsidiary AET Inc. Ltd. has placed a $260 million order with Japan's Tsuneishi Corp. for four 107,500 dwt Aframax tankers.

The first of the tankers will be delivered in 2009, and the three remaining units will be delivered in 2010, said MISC.

MISC also said it took delivery of its eighth very large crude carrier (300,397 dwt) from Japan's Universal Shipbuilding Corp. on Oct. 31 at a cost of $65 million. ✦

Calendar

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

OIL&GAS JOURNAL online research center.

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.

NOVEMBER

Process Industry Maintenance Summit, Antwerp, 44 207 368 9579, 44 207 368 9401 (fax), e-mail: kate.warren@wbr.co.uk, website: www.wbr.co.uk/mainte-nanceeurope/index.html. 27-30.

IADC Drilling Gulf of Mexico Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 28-29.

Power-Gen International Conference, Orlando, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pgen.events.pennnet.com. 28-30.

Ethanol Summit, Houston, (207) 781-9617, (207) 781-2150 (fax), e-mail: cgroff@intertechusa.com, website: www.intertechusa.com. Nov. 30-Dec. 1.

DECEMBER

Annual Energy Caribbean Conference, Port of Spain, +44 (0)20 7017 4037, +44 (0)20 7017 4981 (fax), e-mail: monique.quant@informa.com. website: www.ibcenergy.com/carib-bean. 4-5.

Independent Operators Forum, London, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.operators-forum.com. 4-6.

Seatrade Middle East Maritime Conference & Exhibition, Dubai, +44 1206 545121, +44 1206 545190 (fax), e-mail: events@seatrade-global.com, website: www.seatrade-middleeast.com. 4-6.

GASTECH International Conference & Exhibition, Abu Dhabi, +44 (0)1895 454 592, +44 (0)1895 454 584 (fax), e-mail: info@gastech.co.uk, website: www.gastech.co.uk. 4-7.

Renewable Energy in the New Low Carbon Britain Conference, London, +44 (0) 20 7467 7100, +44 (0) 20 7255 1472, e-mail: info@energyinst.org.uk, website: www.energyinst.org.uk. 5.

IADC Drilling Gulf of Mexico Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 5-6.

OSEA International Exhibition & Conference, Singapore, +44 20 7840 2139, +44 20 7840 2119 (fax), e-mail: osea@oesallworld.com, website: www.allworldexhibitions.com. 5-8.

Annual CO2 Flooding Conference, Midland, Tex., (432) 552-2430, (432) 552-2433 (fax), website: www.spe-pb.org. 6-8.

Annual China Gas Conference, Beijing, 65 6536 8676, 65 6536 4356 (fax), e-mail: marcy.chong@abf.com.sg, website: www.abf-asia.com. 11-12.

Ethanol Summit, Houston, (207) 781-9603, (207) 781-2150 (fax), website: www.intertechusa.com/ethanol. 11-12.

2007

JANUARY

Petrotech India Conference and Exhibition, New Delhi, +44 (0) 20 8439 8890, +44 (0) 20 8439 8897 (fax), e-mail: adam.evan-cook@reedexpo.co.uk, website: www.petrotech2007.com. 15-19.

Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: oaconference@pennwell.com, website: www.offshoreas-iaevent.com. 16-18.

✦Power-Gen Middle East Conference, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 22-24.

API Exploration and Production Winter Standards Meeting, Scottsdale, Ariz., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 22-26.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwater-operations.com. 23-25.

SPE Hydraulic Fracturing Technology Conference, College Station, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 29-31.

✦Underwater Intervention Conference, New Orleans, (281) 893-8539, (281) 893-5118 (fax), website: www.underwaterintervention.com. Jan. 30-Feb. 1.

FEBRUARY

NAPE Expo, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: nape@landman.org, website: www.napeonline.com. 1-2.

IPAA Small Cap Conference, Boca Raton, Fla., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 5-8.

IADC Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 6-7.

Russia Offshore Oil & Gas Conference, Moscow, +44 (0) 1242 529 090, +44 (0) 1242 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyex-change.co.uk. 7-8.

Multiphase Pumping & Technologies Conference & Exhibition, Abu Dhabi, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.multi-phasepumping.com. 11-13.

SPE Middle East Oil & Gas Show & Conference (MEOS), Bahrain, +44 20 7840 2139, +44 20 7840 2119 (fax), e-mail: meos@oesallworld.com, website: www.allworldexhibitions.com. 11-14.

International Petrochemicals & Gas Technology Conference & Exhibition, London, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 12-13.

IP Week, London, +44(0)20 7467 7100, +44(0)20 7580 2230 (fax); e-mail: events@energyinst.org.uk, website: www.ipweek.co.uk. 12-15.

Pipeline Pigging & Integrity Management Conference, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: info@clarion.org, website: www.clarion.org. 12-15.

CERA Week, Houston, (800) 597-4793, (617) 866-5901, (fax), e-mail: register@cera.com, website: www.cera.com/ceraweek. 12-16.

International Downstream Technology & Catalyst Conference & Exhibition, London, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 14-15.

SPE/IADC Drilling Conference and Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-22.

AustralAsian Oil Gas Conference and Exhibition, Perth, (704) 365-0041, (704) 365-8426 (fax), e-mail: sarahv@imexmgt.com, website: www.imexmgt.com. 21-23.

Pipe Line Contractors Association Annual Meeting, Aventura, Fla., (214) 969-2700, e-

Calendar

mail: plca@plca.org, website: www.plca.org. 21-25.

International Conference and Exhibition on Geo-Resources in the Middle East and North Africa, Cairo, 00202 3446411, 00202 3448573 (fax), e-mail: alisadek@mailer.eun.eg, website: www.grmena.com.eg. 24-28.

Laurance Reid Gas Conditioning Conference, Norman, Okla., (405) 325-3136, (405) 325-7329 (fax), e-mail: bettyk@ou.edu, website: www.lrgcc.org. 25-28.

CERA East Meets West Executive Conference, Istanbul, (800) 597-4793, (617) 866-5992 (fax), e-mail: register@cera.com, website: www.cera.com. 26-28.

SPE Reservoir Simulation Symposium, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-28.

Subsea Tieback Forum & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. Feb. 27-Mar. 1.

International Symposium on Oilfield Chemistry, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Feb. 28-Mar. 2.

MARCH

Gas Arabia International Conference, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 5-7.

SPE E&P Environmental and Safety Conference, Galveston, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 5-7.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), website: http://turbolab.tamu.edu. 5-8.

Purvin & Gertz International LPG Seminar, Houston, (713) 236-0318 x229, (713) 331 4000 (fax), website: www.purvingertz.com. 5-8.

Natural Gas Conference, Calgary, Alta., (403) 220-2380, (403) 284-4181 (fax), e-mail: jstaple@ceri.ca, website: www.ceri.ca. 5-8.

✦Power-Gen Renewable Energy & Fuel Conference, Las Vegas, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 6-8.

Annual Fuels & Lubes Asia Conference, Bangkok, +632 772 4731, +632 772 4735 (fax), e-mail: conference@flasia.info, website: www.flasia.info. 7-9.

GPA Annual Convention, San Antonio, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 11-14.

SPE Middle East Oil & Gas Show & Conference (MEOS), Bahrain, +44 20 7840 2139, +44 20 7840 2119 (fax), e-mail: meos@oesallworld.com, website: www.allworldexhibitions.com. 11-14.

NACE Annual Conference & Exposition, Nashville, (281) 228-6200, (281) 228-6300, website: www.nace.org. 11-15.

NPRA Security Conference, The Woodlands, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 12-14.

China Offshore Expo, Tianjin, 84 8 9634388, 84 8 9635112 (fax), e-mail: cp-info@hcm.vnn.vn, website: www.cpexhibition.com. 15-17.

NPRA Annual Meeting, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 18-20.

SPE/ICoTA Coiled Tubing and Well Intervention Conference and Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-21.

ARTC Refining & Petrochemical Annual Meeting, Bangkok, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 20-22.

Offshore West Africa Conference & Exhibition, Abuja, (918) 831-9160, (918) 831-9161 (fax), e-mail: owaconference@pennwell.com, website: www.offshorewestafrica.com. 20-22.

Georgian International Oil, Gas, Energy and Infrastructure Conference & Showcase, Tbilisi, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 22-23.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 25-27.

American Chemical Society National Meeting & Exposition, Chicago, (202) 872-4600, (202) 872-4615 (fax), e-mail: natlmtgs@acs.org, website: www.acs.org. 25-29.

Turkish Oil & Gas Exhibition and Conference, Ankara, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 27-29.

IADC/SPE Managed Pressure Drilling & Underbalanced Operations Conference, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 28-29.

Offshore Mediterranean Conference, Ravenna, +39 0544 219418, +39 0544 39347 (fax), e-mail: conference@omc.it, website: www.omc.it. 28-30.

SPE Production and Operations Symposium, Oklahoma City, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Mar. 31-Apr. 3.

APRIL

SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 1-3.

AAPG Annual Convention and Exhibition, Long Beach (918) 584-2555, (918) 560-2694 (fax), e-mail: postmaster@aapg.org, website: www.aapg.org. 1-4.

✦PIRA Natural Gas and LNG Markets Conference, Houston, 212-686-6808, 212-686-6628 (Fax), e-mail: sales@pira.com, website: www.pira.com. 2-3.

China International Oil & Gas Conference, Beijing, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 3-4.

IADC Environmental Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 3-4.

Instrumentation Systems Automation Show & Conference, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 11-12.

Journally Speaking

One small step?

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

No less an authority than the International Energy Agency has renewed its warning about a future of limited fossil energy and more environmental damage from burning too much of it.

At the UN Framework Convention on Climate Change 12th annual conference in Nairobi earlier this month, IEA Executive Director Claude Mandil addressed twin concerns: energy security and environmental threat.

He based his remarks on IEA's recent World Energy Outlook 2006, which envisions a world lacking "adequate and secure supplies of energy at affordable prices" and facing "environmental harm caused by consuming too much of it."

The WEO06 "confirms that fossil-fuel demand and trade flows, and greenhouse-gas emissions would follow their current unsustainable paths through to 2030 in the absence of new government action."

Government action should, Mandil said, encourage private-sector investment in practices and technologies that move the world away from dependence on fossil fuels.

Nearly simultaneously with his remarks came news that seems to confirm private industry is indeed making small steps in that direction.

Grim vision

The WEO06 reference scenario takes into account, among other conditions, how global energy markets will evolve under policies enacted by mid-2006 and assumes no new actions are taken (OGJ, Nov. 20, 2006, p. 28).

It is a sobering scenario: Primary energy demand worldwide increases by slightly more than 50% through 2030, growing by an average 1.6%/year, and by more than 25% through 2015 alone.

More than 70% of the increase in demand comes from developing countries, "with China alone accounting for 30%." Growth of these countries' economies and populations will shift the center of gravity of global energy demand, says the study.

In the reference scenario, fossil fuels' dominance of world energy demand through 2030 actually goes up, to 81% from 80%. But among fossil fuels, "coal sees the biggest increase in demand in absolute terms, driven mainly by power generation." Coal remains second in its share of demand, behind crude oil.

That's bad news for any progress on reducing greenhouse-gas (GHG) emissions.

Under the reference scenario, global energy-related CO_2 emissions in 2004-30 increase by 55%. Coal, which in 2003 became the No. 1 contributor to CO_2 emissions, "consolidates this position through to 2030," says WEO06.

And just as developing countries, under the reference scenario, lead the way in energy demand growth, they also lead in CO_2 emissions growth. Their share in world emissions rises to more than 50% by 2030 from 39% in 2004.

Again, China leads among developing countries, "responsible for about 39% of the rise in global emissions." The country's emissions in 2004-30 more than double.

Under the reference scenario, China overtakes the US before 2010 as the "world's biggest emitter."

Burning biogas

On the same day Mandil was speaking, the US Energy Information Administration was reporting that total GHG emissions in the US grew more slowly in 2005—by 0.6%—than for any year since 1990 (OGJ, Nov. 20, 2006, p. 34). For the previous 14 years, GHG emissions in the US have grown at an average 1%/year.

The report admits that last year some unusual factors held down energy consumption, and therefore GHG emissions, among them severe weather and higher energy prices.

But there was other, admittedly small but no less encouraging news from California involving a unit of a major oil company.

Chevron Energy Solutions and the city of Millbrae, Calif., have completed facilities at Millbrae's water-pollution control plant that use inedible kitchen grease from restaurants to produce biogas. This biogas is then burned to generate renewable power and heat to treat the city's wastewater.

Microorganisms in the plant's digester tanks, said the company, eat the grease and other organic matter, naturally producing methane gas, which fuels the plant's new 250-kw microturbine cogenerator to produce electricity for wastewater treatment.

"Meanwhile, excess heat produced by the cogenerator warms the digester tanks to their optimum temperature for methane production," it said.

The process will generate about 1.7 million kw-hr/year, said the company, meeting 80% of the plant's power needs. The net effect will reduce CO_2 emissions by 1.2 million lb/year.

The $5.5-million total cost of the project was reduced by about $200,000, thanks to a rebate through California's Self-Generation Incentive Program and administered by Pacific Gas and Electric Co.

Maybe this is the kind of government action Mandil was talking about. ✦

Editorial

Democrats and energy

Democrats newly in control of the US Congress have a unique opportunity to act constructively on energy. The political party they defeated in elections this month abandoned the high ground of energy realism. Seldom does an incoming party get such a chance to steer a foundering policy quickly onto reasonable course.

To do that, however, Democrats will have to turn away from past rhetoric. Speaker-to-be of the House Nancy Pelosi of California has blustered about ending tens of billions of dollars of tax "give-aways" to "Big Oil." She won't make good on the promise. The tax code isn't as generous as populist mythology claims it to be, least of all to big oil and gas companies. Does the Democratic leadership want only to slap around oil companies for sins no graver than being large, unpopular, and for the past several quarters anomalously profitable? Or does it want to get serious about energy?

Energy independence

If the Democrats decide to make history and get serious about energy, a solid first step would be to forget about energy independence. Here, they begin with an advantage. The Republicans have been babbling about energy independence for several years. Democrats thus can reject a policy illusion and discredit Republicans at the same time, confident that everyone soon will forget that they've touted the same impossible dream.

Energy independence is a slogan, not a reasonable ambition for the US or any other industrial country. Participants in a commercially interdependent world are dependent on globally traded energy by definition. They can't be otherwise. They can't be energy-independent, even if they're lucky enough to produce all the energy they use. Prices of energy in international trade affect prices of other goods and services, even prices and supplies of energy in supposedly energy-independent countries.

Slogans upholding ideals can be inspiring, of course. Energy independence would be just such a useful ideal if it inspired politicians to pursue maximum domestic production of economically sensible energy and judicious rates of consumption. With energy, however, ambition stirred up by the allure of independence never ends there. It inevitably breeds wishes disconnected from economics and physics. And it tricks politicians otherwise committed to market freedom into believing that energy is some special case to which markets are irrelevant.

For so important a factor in national economic health, disregard for the discipline of economics, for the practicalities of physics, and for the efficiencies of markets is dangerous. But it's the foul stew that bubbles up when oil prices rise enough to make politicians notice how much of the oil the US uses is imported. Then everyone panics, energy independence becomes the battle cry, and expensive and mostly futile policy proposals receive serious attention from adults who should know better.

Imported oil is indeed less preferable than domestically produced oil and in that context merits concern. But imported oil is better for energy consumers and for the national economy than substitutes that cost many times more, even homegrown substitutes. This is why the US imports oil.

It's also a reason, beyond futility, for energy independence not to become a policy priority. By "energy independence," advocates mean not importing any oil, which means somehow replacing the equivalent of 13 million b/d of crude oil and products. The US might lower the import rate, or at least slow its rate of increase, at acceptable cost by removing limits on oil and gas leasing and by dismantling whatever barriers stay in the way of nuclear plant construction.

Other options

Only two other policy options remain: 1) lowering consumption by mandate or imposed cost, such as via new energy taxes, and 2) forcing the replacement of one energy form by something much more expensive. Both of those options are costly. They would become politically unacceptable long before they displaced anywhere near 13 million b/d of oil imports.

The Democrats can start the US on a fresh and constructive track with energy by acknowledging realities underlying the country's challenges in this vital area. Arguments about energy independence obsess about barrels. Energy reality never ignores dollars. ✦

Global oil, gas outlook bright; US gas production nears plateau

Henry R. Linden
Illinois Institute of Technology
Chicago

Data for liquids presented in this article suggest that global crude oil, natural gas liquids (NGL), and Alberta oil sands production will plateau at above 118 million b/d and productive capacity at 123 million b/d in 2031—far later than current alarmist predictions—even without the likely development of tar sands and other bitumens and extra-heavy crude.

Unfortunately there are no reliable data on total recoverable global natural gas resources and of cumulative production, which are required to estimate the time and quantity of peak gas production.

Nevertheless, the global natural gas outlook is also quite bright, with Jan. 1, 2006, proved reserves of 6,112 tcf, and total 2003 global consumption of 95.5 tcf rising to 182 tcf in 2030, according to the Energy Information Administration (EIA) Reference Case in its International Energy Outlook 2006. This is equivalent to a roughly 40-year gas reserve life. This outlook is especially positive, as global gas exploration and resources development have not been nearly as intensive as for crude oil.

In the US, however, current gas production of 19 tcf/year is already near its projected plateau, and a decline in domestic production seems inevitable unless there is a much more aggressive leasing policy, both off and onshore, especially for unconventional natural gas resources such as coalbed methane (CBM), tight sands gas, Devonian shale gas, and gas from ultradeep formations.

This article addresses both these two critical issues:

• The time and magnitude of peak global production of conventional petroleum liquids, such as crude oil and lease condensates, and oil from Alberta oil sands and NGL.

• The magnitude and time of peak US natural gas production.

World liquids resources

In addition to crude oil, lease condensate, and NGL, conventional petroleum liquids now include crude recovered from Alberta oil sands, which have been included in proved reserves since Jan. 1, 2003.[1]

According to the International Energy Outlook 2006, as shown in Table 1, estimated proved and undiscovered world oil resources are 2,961.6 billion bbl, which includes 1,292.5 billion bbl of proved crude oil, lease condensate, and NGL reserves.[2] The US Geological Survey's estimates of reserve growth and undiscovered resources also include lease condensates and NGL. Worldwide, NGL production during the first 3 months of this year was 7.613 million b/d, or 10.3% of the total liquids production, in addition to 73.761 million b/d of crude oil production.[3 4]

In order to estimate the time of peak global oil or hydrocarbon liquids production, there must be a good estimate of cumulative production through 2005. This estimate would include unconventional sources such as the prolific Alberta oil sands that have made Canada the world's No. 2 reserve holder after Saudi Arabia, with 178.8 billion bbl as of Jan. 1, 2006, out of the total 1,292.5 billion bbl proved reserves.[5]

The most reliable value is 986.496 billion bbl through Jan. 1, 2005, from the 61st edition of the DeGolyer and MacNaughton Twentieth Century Petroleum Statistics 2005.[6] These data, for crude oil only, exclude NGL. Updating this value with an estimated global crude oil production of 71.794 million b/d in 2005 would add 26.205 billion bbl to the Jan. 1, 2005, value of 986.496 billion bbl for a total of 1,012.701 billion bbl.[5]

To estimate cumulative global petroleum liquids production through January 1, 2006, including NGL, the value of 1,012.701 billion bbl would have to be raised by 10.3% to 1,117.009 billion bbl on the basis of the admittedly sketchy data cited for 2006.

Using the widely questioned but very useful technique of M. King Hubbert in assuming that oil and gas production follows a sigmodial (logistic) curve with the area under the curve representing the total resource base, the estimated ultimate global recovery of petroleum liquids would be 4,078.6 billion bbl.[7] These volumes consist of 2,961.6 billion bbl of estimated world oil resources as of Jan 1, 2006, and 1,117.0 billion bbl of cumulative production through 2005.

The author, in an earlier two-part OGJ article: "Rising expectations of ultimate oil, gas recovery to have critical impact on energy, environmental policy" published in the Jan. 19 and 26, 2004, issues, estimated that the total remaining recoverable resources of all petroleum liquids could be as high as 7,900 billion bbl.[7] This amount excludes 3,500 billion bbl of shale oil but includes NGL and oil from oil and tar sands, other bitumens, and extra-heavy crude. This is in agreement with a recent article in OGJ, "End of oil? No it's a new day dawning," by Mike Bohorich.[8] The midpoint would then be 2,039.3 billion bbl. Deducting cumulative production of 1,117 billion bbl, leaves 922.3 billion bbl of remaining recoverable petroleum liquids, based on current technology and geological data.

EIA, in its International Energy Outlook 2006 for the Reference Case, projects that world oil productive capacity will exceed production through 2030 (Table 2).[9]

This corresponds to an average production of about 100 million b/d, or 36.5 billion bbl/year. On this basis, peak production would not be reached for 25 years (922.3/36.5) i.e., Jan.1, 2031, at over 118 million b/d globally and well below productive capacity of 123 million b/d in 2030, far later than current alarmist predictions.

Furthermore, over this time span, nonconventional oil production from oil sands, bitumens, and extra-heavy crude will displace a great deal of existing global oil consumption. Alberta oil sands production alone is projected to reach 3 million b/d in 2015.[10]

Then, as widely reported in the media, on Sept. 5, 2006, Chevron Corp. announced a major crude oil discovery in the deep Gulf of Mexico in the Lower Tertiary trend with reserves that could be as high as 15 billion bbl.[11]

Cambridge Energy Research Associates forecasts that the deepwater area of the Gulf of Mexico will produce 800,000 b/d within 7 years. In addition, there are good prospects for biofuels, synthetic fuels from coal and oil shale, and conversion of surface transport to hydrogen proton exchange membrane (PEM) fuel cell propulsion using carbon-emission-free sources of hydrogen. The latter could be generated by the modified Integrated Coal Gasification Combined Cycle process in which raw synthesis gas produced by steam-oxygen pressure gasification of coal or lignite is processed with additional steam by catalytic water gas shift ($CO + H_2O \rightarrow CO_2 + H_2$) into more hydrogen and carbon dioxide, and the CO_2 is removed and sequestered in suitable underground formations.[12]

Pollutants, primarily hydrogen sulfide, also are removed and used as a source of byproducts such as elemental sulfur. The logistics of distributing this hydrogen are still in question, but an intermediate step would be fully commercial catalytic natural gas reforming filling stations—admittedly with still a relatively small amount of CO_2 emissions, but a substantial improvement over conventional internal combustion engines.

Estimated world oil resources,[1] 1995-2025

Table 1

Region	Proved reserves	Reserve growth	Undis-covered	Total
	Billion bbl			
OECD[2]				
US	21.4	76.0	83.0	180.4
Canada	178.8	12.5	32.6	223.9
Mexico	12.9	25.6	45.8	84.3
OECD Europe	15.1	20.0	35.9	71.0
Japan	0.1	0.1	0.3	0.5
Australia-New Zealand	1.5	2.7	5.9	10.1
Non-OECD				
Russia	60.0	106.2	115.3	281.5
Other Europe-Eurasia	19.1	32.3	55.6	107.0
China	18.3	19.6	14.6	52.5
India	5.8	3.8	6.8	16.4
Other Asia	10.3	14.6	23.9	48.8
Middle East	743.4	252.5	269.2	1,265.1
Africa	102.6	73.5	124.7	300.8
Central and South America	103.4	90.8	125.3	19.5
Total world	**1,292.5**	**730.2**	**938.9**	**2,961.6**
OPEC[3]	901.7	395.6	400.5	1,697.8
Non-OPEC	390.9	334.6	538.4	1,263.9

[1]Reserves include crude oil (including lease condensate) and natural gas plant liquids. [2]Organization for European Cooperation & Development countries. [3]Organization of Petroleum Exporting Countries.
Sources: International Energy Outlook 2006, Energy Information Administration (2006), US Geological Survey, World Petroleum Assessment 2000 (http://pubs.usgs.gov/dds/dds-060/), Proved reserves as of Jan. 1, 2006 (OGJ, Dec. 19, 2005, p. 24)

Global liquids productive capacity vs. production

Table 2

Date	Production	Productive capacity
	Million b/d	
2003	79.6	82.3
2010	91.6	94.3
2015	98.3	101.6
2020	104.1	107.6
2025	110.7	114.9
2030	118.0	123.3

Source: Energy Information Administration, International Energy Outlook 2006

Biomass role questioned

Biomass or energy crops in general are most dubious as replacements for fossil fuels because of prohibitive land requirements, large labor and energy requirements in planting, cultivation, and harvesting such crops, and unacceptable environmental impacts.[13]

Reliance on biomass to replace a significant portion of fossil fuels would disturb the global carbon cycle of the 200 gigatonnes (1 Gt =1 billion tonnes) of carbon that circulate in the form of CO_2 annually between terrestrial sources and sinks, the surface and deep ocean, and the atmosphere.[14] All numerical values used here cite only the carbon content as a surrogate for the CO_2, which, in turn, is used as a surrogate for all anthropogenic greenhouse gases.

The ocean absorbs 92 Gt/year of


Global Oil Flows
Source: Energy Information Administration
The fact is, the vast majority of countries rely on the few energy-producing nations that won the geological lottery, blessing them with abundant hydrocarbons. And yet, even regions with plenty of raw resources import some form of energy. Saudi Arabia, for example, the world's largest oil exporter, imports refined petroleum products like gasoline.
So if energy independence is an unrealistic goal, how does everyone get the fuel they need, especially in a world of rising demand, supply disruptions, natural disasters, and unstable regimes?
True global energy security will be a result of cooperation and engagement, not isolationism. When investment and expertise are allowed to flow freely across borders, the engine of innovation is ignited, prosperity is fueled and the energy available to everyone increases. At the same time, balancing the needs of producers and consumers is as crucial as increasing supply and curbing demand. Only then will the world enjoy energy peace-of-mind.
Succeeding in securing energy for everyone doesn't have to come at the expense of anyone. Once we all start to think differently about energy, then we can truly make this promise a reality.
willyoujoinus.com
OBJECTIVES
EFFICIENCIES
ENERGY IMPORTS BY OIL EXPORTING COUNTRIES
GASOLINE
ELECTRICITY
NATURAL GAS
COAL
Saudi Arabia
Russia
Norway
UAE
Nigeria
Source: Energy Information Administration
WHAT NEEDS TO BE DONE
— DIVERSIFY ENERGY SUPPLIES
• FIND MORE TRADITIONAL FUELS
• DEVELOP ALTERNATIVES AND RENEWABLES
— FOSTER OPEN MARKETS & TRANSPARENCY
— ENCOURAGE CONSERVATION/ ENERGY EFFICIENCY
Chevron Steps Taken:
• Investing over $15 billion a year to bring energy to market.
• Developing energy through partnerships in 26 countries.
• Committing hundreds of millions annually to alternative and renewable energies to diversify supply.
• Since 1992, have made our own energy go further by increasing our efficiency by 24%.
Chevron
Human energy™
Projected Global Oil Demand
2004 DEMAND 82 mbpd*
2030 DEMAND 115 mbpd
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CO_2. Of this amount, 90 Gt/year move from the surface of the ocean to the atmosphere, so the ocean naturally sequesters 2 Gt/year.

Another 100 Gt/year of carbon are fixed by photosynthesis, of which 50 Gt are lost from the 550 Gt inventory of land biota to the soil and detritus that emits 50 Gt/year from decomposition. Because 50 Gt are returned by plant respiration, 50 Gt are left to naturally revegetate the land biomass, at a revegetation rate of 11 years (550/50 = 11).

There also is 2 Gt/year of natural carbon sequestration largely due to Northern Hemisphere afforestation of the 8 Gt/year of anthropogenic emissions from fossil fuel combustion and cement production and continuing tropical deforestation. Thus, total natural carbon sequestration currently is about 4 Gt/year. Any large use of biomass as a substitute for fossil fuels could disrupt this natural carbon cycle. It would also take more than twice the land area of the Earth to produce enough biomass to replace the energy content of current fossil fuel use by natural revegatation (Table 3).

Of course, substantial additional amounts of biomass would be required to convert the large portion of the total to liquid and gaseous fuels. Proposals to use corn stalks or sugar cane stalks as a source of cellulosic ethanol would destroy the fertility of the soils, which requires that the organic matter and nutrients in these materials be returned and plowed under. The basic problem is the inefficiency of photosynthesis, which is 100 times lower than the efficiency of photovoltaic power.

Thus, the solution to our energy problems is not regression to the use of fuel wood, etc., but technology. This is why the "hydrogen economy" based on photovoltaic power and PEM electrolysis and hydrogen storage, as well as nuclear, wind, and hydroelectric power, where available, are the much-preferred alternatives.

The basic problem with intermittent photovoltaic and wind power is, of course, their intermittency, although there are means to store excess energy.

Unfortunately, because of limited uranium resources at acceptable costs, even nuclear power is not sustainable, but it can be a source of emission-free power supply during the transition period. However, development of breeder reactors would triple to more than quintuple the energy content of fossil fuel reserves and recoverable resources (Tables 4 and 5).

LAND AREA INSUFFICIENT FOR BIOMASS TO REPLACE FOSSIL FUELS — Table 3

Terrestrial biomass	550 GtC*
Annual land biomass production	50 GtC
Land area of earth	14.6×10^9 hectares (ha)
Carbon sequestration	3.42 tonnes/ha/year
2003 global fossil fuel use	361.6×10^{15} btu
Dry biomass carbon equivalent @8,000 btu/lb and 50 wt % C	10.25 GtC
Annual land harvest requirement	3.00×10^9 ha
Natural revegetation rate	11 years
Total land requirements for natural biomass replacement – More than double global land area	33.0×10^9 ha

*1 gigatonne (Gt) of carbon (C) = 1 billion tonnes (10^9).
Source: Henry R. Linden, updated Reference 13.

CONVENTIONAL FOSSIL FUEL RESERVES, RESOURCES — Table 4

Fuel	Proved reserves	Technically recoverable resources estimate, current upper bound
Natural gas	$6,112 \times 10^{12}$ cu ft $6,265 \times 10^{15}$ btu	$20,000 \times 10^{12}$ cu ft $20,500 \times 10^{15}$ btu
Conventional crude oil and condensate, Canadian oil sands, natural gas liquids (NGL)*	$1,544 \times 10^9$ bbl $8,492 \times 10^{15}$ btu	$3,600 \times 10^9$ bbl $19,800 \times 10^{15}$ btu
Coal and lignite	1.001×10^{12} short tons $21,021 \times 10^{15}$ btu	7×10^{12} short tons $147,000 \times 10^{15}$ btu
Total	**$35,778 \times 10^{15}$ btu**	**$187,300 \times 10^{15}$ btu**

*Proved global crude oil reserves, including Canadian oil sands, as of Jan. 1, 2006, are 1,292.5 billion bbl. There are no global data on proved reserves of natural gas liquids. The estimate of 251.7 billion bbl reflects the US ratio of 7.928 billion bbl of proved NGL reserves to 192.5 tcf of proved reserves of dry natural gas as of Dec. 31, 2004. See Reference 21.
Sources: OGJ, Dec. 19, 2005, p. 20; Energy Information Administration's International Energy Outlook 2006, EIA's Annual Report 2004

Unconventional resources

There are no global data on natural gas resources equivalent to oil resources. However, there are comprehensive data on the US natural gas resource base, thanks to the Potential Gas Committee.[15] As shown in Table 6, the Dec. 31, 2004, estimate of probable, possible and speculative resources, including CBM, is 1,199.255 tcf for the Lower 48 and Alaska. Proved reserves as of Dec. 31, 2004 were 192.5 tcf. However, the US supply outlook is not encouraging at a US production of 19 tcf/year, leaving only about 7 years before US gas production as currently practiced would peak.

In recent months there has been a shift in sentiment about the outlook for US natural gas supplies. This shift has been reflected in a decline in the level of NYMEX Natural Gas Futures from over \$8/million btu in March to \$6-6.50/million btu in late May and early June and to below \$6/million btu in early September.

There was, however, a temporary run-up to about \$7/million btu in late June and to over \$8/million btu in early August. This was the result of worries about the beginning of the tropical storm season and the unusual heat wave in much of the US that reduced the working gas storage reinjection rate somewhat to below the 5-year average. Storage was still well above the 51.4 bcf/week required to completely fill working gas storage to 3.4 tcf by the end of October.[16]

However, this positive outlook then suffered a setback, with rapidly declining reinjection rates and, apparently, small premature drawdowns in July and August 2006.[17 18 19] Surprisingly, NYMEX futures held at \$6.50-7.00/million btu in much of August but started rising again in late August before dropping to as low as \$4.50/million btu in late September and early October as the working gas storage outlook greatly improved to a possible record of 3.5 tcf at the start of the withdrawal season Nov. 1. This gas price volatility is expected to continue as indicated by a rise of NYMEX futures to about \$7.50/

million btu at the end of October.

One of the major positive impacts on gas prices is that there is growing optimism about the potential of unconventional gas, such as gas from tight formations, Devonian shales, geopressured reservoirs, coal beds, and extremely deep horizons. Of highest probability is that technology advances can increase the production of three sources of unconventional gas above the levels projected by EIA through 2025 (Table 7).[20]

The Rocky Mountain region is by far the largest source of CBM and tight sands gas but much of the underdeveloped resources of unconventional gas are inaccessible (Table 8).[21]

Total US CBM proved reserves as of Dec. 31, 2004, were 18.390 tcf, according to EIA, and 2004 production was 1.720 tcf.[21] In view of the huge US coal resource base, the research, development, and demonstration (RD&D) programs to enhance the technology for CBM discovery, development, and production seems especially promising, including the use of CO_2 destined for sequestration to stimulate production. For example, as shown in Table 6, the Potential Gas Committee in its estimated potential US gas resources, December 2004, projects the probable US resource of CBM at roughly 18 tcf, the possible resource at 57 tcf, the speculative resource at 95 tcf, and the total potential resource at 169 tcf, now a relatively conservative estimate.

One of the first priorities should be to obtain a more reliable estimate of technically recoverable Lower 48 unconventional natural gas resources. The Potential Gas Committee of the Colorado School of Mines' Potential Gas Agency, the Department of Energy's Office of Oil and Gas, and DOE's EIA in its Annual Energy Outlook series, all produced widely differing values. For example, in the EIA Annual Energy Outlook 2004 (January 2004), the technically recoverable Lower 48 unconventional natural gas resources as of Jan. 1, 2002, are given as 475 tcf, including 343 tcf tight gas, 58 tcf shale gas, and

Conventional fossil fuel vs. U_3O_8 resource bases[1]

Table 5

	Proved, currently recoverable	Estimated total remaining recoverable
Conventional fossil fuels (see Table 3)	35,778	187,300
U_3O_8@<\$30/lb[2]		
In burner reactors	950	3,300
In breeder reactors	72,000	250,000
U_3O_8@<\$300/lb[3] in breeder reactors	97,000	1,000,000

[1]Excludes some Soviet or former Soviet Union countries. Values are in quadrillion (10^{15}) btu (Quads). [2]About \$80/Kg U. [3]About \$800/Kg U.
Sources: Table 3, Henry R. Linden, updated Reference 13

74 tcf CBM (Table 9)[22] compared with 184.1 tcf of Lower 48 proved conventional gas reserves on Dec. 31, 2004, reported by EIA in its "2004 Annual Report of US Crude Oil, Natural Gas and Natural Gas Liquids Reserves."[23]

An article by Sam Fletcher, "Major US supply role seen for unconventional gas," extensively quotes Scott R. Reeves, a well-known authority on this subject, from an earlier conference in Houston and gives a good history of the development of unconventional gas.[24] In particular, it covers CBM from the early 1980s to the early 1990s as a major supply source thanks to Section 29 federal tax credits and research by DOE and the Gas Research Institute (GRI). Yet, according to Reeves, the US will still see tremendous production growth. He is especially optimistic about CBM, whose development was nearly entirely the result of GRI's RD&D investments and which should offer additional opportunities to the new Gas Technology Institute (GTI) formed by the merger of GRI and the Institute of Gas Technology in 2000. Reeves makes many useful suggestions on enhanced CBM production technologies and promising areas for exploration and notes that the Green River basin alone contains a resource base of 314 tcf of CBM.

Methane hydrates

Methane hydrates have tremendous potential.[25] In fact, more than half of all the organic carbon on Earth (recoverable and nonrecoverable fossil fuels, soil, dissolved organic matter, land biota and peat) is in the form of marine and permafrost methane hydrate deposits. This is equivalent to 706,000 tcf of methane, of which 112,000-113,000 tcf is in US coastal deposits and a small permafrost deposit at 95% probability. About 100,000 tcf of methane would meet total current US energy consumption of about 100 quadrillion (10^{15}) btu for 1,000 years. However, the current development initiatives seem to remain focused on the more "conventional" forms of unconventional natural gas, especially CBM.

US gas peak production

As shown in Table 6, the Potential Gas Committee of Colorado School

Traditional US gas resources excluding proved reserves

Table 6

Resource category-depth Area, Dec. 31, 2004	Probable resource +	Possible resource +	Speculative resource =	Total potential resource
	Mean values, bcf			
Lower 48				
Onshore	154,755	244,893	182,959	582,958
Offshore	15,177	59,954	97,285	172,418
Total Lower 48	**169,930**	**304,848**	**280,285**	**756,494**
Alaska				
Onshore	31,717	22,300	40,417	94,432
Offshore	5,142	19,499	74,788	99,366
Total Alaska	**36,856**	**41,816**	**115,129**	**193,831**
Total traditional	**206,765**	**346,208**	**396,628**	**949,957**
Coalbed gas*	**17,570**	**56,780**	**94,948**	**169,298**
Grand total US	**224,335**	**402,988**	**491,576**	**1,119,255**

*Aggregated coalbed gas estimates are arithmetically added to subtotal of means to derive grand total. Note: Totals are subject to rounding and slight differences due to statistical aggregation of distributions.
Source: Potential Gas Committee report December 2004, Potential Gas Agency, Colorado School of Mines September 2005

of Mines, Potential Gas Agency, in its biannual estimates of total US potential gas resources arrived at a Dec. 31, 2004, mean value of 1,119.255 tcf, including CBM, but excluding proved reserves.[15] They also updated cumulative production to 1,053 tcf.[26] Adding Dec.31, 2004, proved reserves of 192.5 tcf for the US, including Alaska, results in a total original resource of 2,365 tcf (Table 10).[15]

Assuming a symmetrical bell-shaped (logistic) curve of annual production as Hubbert proposed,[7] with the area under the curve representing ultimately recoverable resources, the peak production would be reached at the midpoint of cumulative production, or 2,365/2 = 1,183 tcf. Less 1,053 tcf cumulative production as of Dec. 31, 2004, leaves only 130 tcf of cumulative production before annual production declines.

At the current annual US natural gas production of 19 tcf/year,[27] there would remain only 7 years before US natural gas production would plateau. This technique of projecting peak production in a given producing area is highly questionable because it does not take into account technology advances, such as increased CBM and new methane hydrate production, nor does it reflect the new, more-liberal state and federal leasing policies for offshore conventional gas production.

New technology impact

Convincing proof that technological development can dramatically increase proved hydrocarbon fuel reserves can be found in the catapulting of Canada from having 5 billion bbl of crude oil reserves—putting it at the low end of the world's crude oil and condensate reserve holders—to 180 billion bbl on Jan. 1, 2003. This advanced Canada to No. 2, after Saudi Arabia, with 259 billion bbl Jan. 1, 2003, and to 264 billion bbl in January of this year. This was due to recoverable bitumen in Alberta's oil sands' being accepted for inclusion as a refinable source of petroleum liquids in 2003, thanks to technology advances.[1]

This ranking has held roughly steady through Jan. 1 of this year, with Iran and Iraq vying for No. 3 and 4 at 132 billion bbl and 115 billion bbl, respectively. In addition, OPEC's share of global crude oil and condensate reserves dropped by this single development from 79.4% on Jan. 1, 2002, to 67.5% on Jan. 1, 2003, and 69.8% in Jan. 1 of this year. For comparison, US proved crude oil reserves on that date were 21.4 billion bbl. With all the large global resources of oil and tar sands and other bitumens, such as the Athabasca tar sands in Alberta and Orimulsion in Venezuela's Orinoco tar belt, further extensions of the competitive liquid petroleum fuels resource base can be expected. The heavy oil product Orimulsion is used as substitute for residual fuel oil.

There is no reason why similar revolutionary technology advances cannot dramatically increase the global proved gas reserves of 6,112.1 tcf on Jan. 1 of this year, especially if the industry successfully pursues partial development of US and Japanese methane hydrate resources.[5]

PROJECTED US UNCONVENTIONAL GAS PRODUCTION — Table 7

Lower 48	2002	2025
	– Production, tcf/year –	
Total tight sands gas	3.877	6.041
Rocky Mountain region	(1.502)	(3.998)
Total coalbed methane	1.502	1.992
Rocky Mountain region	(1.320)	(1.611)
Devonian shale gas	0.600	1.132
Total	**5.979**	**9.165**

Source: Energy Information Administration

US UNCONVENTIONAL RESOURCES ACCESSIBILITY — Table 8

	Unconventional resources, tcf
Officially inaccessible	23.44
Inaccessible due to development constraints	83.72
Accessible with lease stipulations	47.51
Accessible under standard lease terms	172.92
Total	**327.58**

Source: Energy Information Administration

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US UNCONVENTIONAL GAS UNDEVELOPED RESOURCES Table 9

Region As of Jan. 1, 2002	Tight sands	Coalbed methane	Gas shales
		tcf	
Rocky Mountain	241	61	2
Northeast	18	9	37
Midcontinent	13	—	4
West Coast	7	—	—
Southwest	5	—	15
Gulf Coast	59	4	—
Total	343	74	58

Grand total 475 tcf

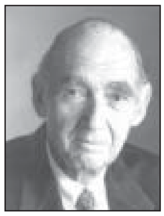
Source: Energy Information Administration, Annual Energy Outlook 2004 With Projections to 2025, January 2004

US ULTIMATELY RECOVERABLE GAS VOLUMES Table 10

	Tcf*
Proved reserves	193
Potential resources	950
Coalbed methane	169
Cumulative production	1,053
Ultimately recoverable resource	**2,365**

*192.5 tcf is the correct reserves values for the Lower 48 plus Alaska on Dec. 31, 2004, as reported by the US Energy Information Administration, not the189 tcf total US proved reserves used by the Potential Gas Committee Dec. 31, 2003.
Source: Energy Information Administration Office of Oil and Gas Dec. 31, 2004, Potential Gas Committee Report

The author



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Prompt passage of federal pipeline safety bill urged

Nick Snow
Washington Correspondent

New federal pipeline safety legislation is overdue and should be passed before the end of the year, witnesses and lawmakers agreed at a Nov. 16 hearing before the Senate Commerce, Science, and Transportation Committee.

"We need to enact pipeline safety reauthorization legislation before the end of this Congress," urged Tim Felt, president and chief executive of Explorer Pipeline in Tulsa. "A lot of work has gone into the current bills, and there are no major disagreements about what a compromise should look like," he said, "Let's get a good bill passed now."

Committee chairman Ted Stevens (R-Alaska) responded: "We're going to do our best to get this bill passed this year, but obviously will be in negotiations with the House on it. We don't expect surprises and are gratified with the increased confidence in the safety system we have heard from all of you today," he said as the hearing ended about 90 minutes later.

Prospects for sending a completed bill to the White House during 2006 aren't good because Stevens's committee has yet to mark up its bill, S. 3961, and send it to the Senate floor for final passage. It would then move to a conference involving House bill, H.R. 5782, and the administration's original proposals contained in H.R. 5678, unless a more expeditious procedure emerged.

"We understand that some efforts are being made to reconcile differences among the bills at the committee level, with the hope that a single proposal could be voted on in both houses before the end of the session," said Thomas J. Barrett, who heads the US Department of Transportation's Pipeline and Hazardous Materials Safety Administration. "We ask Congress to pass a reauthorization bill this year, focusing on the key similarities among the bills," he continued.

Significant improvement

The 109th Congress recessed for the Thanksgiving holiday and will return in early December. But it will need to complete work on a final pipeline safety authorization bill before Dec. 16, when Hanukkah begins. If it doesn't, the matter would be pushed into 2007 and the 110th Congress.

That would be ironic as it's generally agreed that the current federal law has been working. "The Pipeline Safety Improvement Act of 2002 is a success. Industry and DOT have cooperated to achieve significant improvement in pipeline safety, and this improvement is demonstrated by our industry's record," said Felt, who testified on behalf of the American Petroleum Institute and the Association of Oil Pipe Lines.

Terry Boss, the Interstate Natural Gas Association of America's senior vice-president for environment, safety, and operations, said that, while the 2002 law addressed operator qualification programs, public education, population encroachment on rights of way, and other issues, its integrity management program has been the most significant provision for interstate gas pipelines.

"The program is doing what Congress intended—verifying the safety of gas transmission pipelines in populated areas and identifying and removing potential problems before they occur. Based on 2 years of data, the trend is that natural gas transmission pipelines are safe and becoming safer," he said.

Local distribution companies also believe the 2002 law, which expired Sept. 30, has been working well and only needs minor adjustments, according to E. Frank Bender, vice-president of Baltimore Gas & Electric Co.'s gas distribution and new business division. He testified on behalf of the American Gas Association and American Public Gas Association.

"Our companies have identified one major area we believe requires considerable improvement—excavation damage prevention. Congressional attention to more-effective state excavation damage programs can and will result in real, measurable decreases in the number of incidents occurring on natural gas distribution lines each year," he told the committee.

Barrett also said progress in the last 5 years has been made in all pipeline safety areas except construction damage to distribution systems. Such incidents increased by 50% from 1996 to 2005 "and will continue to get worse if we don't do something about it," he warned.

'Crowded underground'

Construction damage to distribution pipelines can almost always be prevented, and PHMSA has sought practices to eliminate the problem, Barrett continued. "The challenge is managing this activity without damaging a very crowded underground infrastructure—one that gets more crowded every day, not just with pipelines, but with new telecommunications, electric, water, sewer, and other infrastructure," he said.

He said the Bush administration wants authority to establish a grant program to encourage more states to develop effective pipeline damage prevention programs. State agencies and PHMSA also need civil enforcement authority against anyone who fails to notify authorities before excavating, he said.

"Ensuring the safety of 2.3 million miles of pipelines is an enormous task," Barrett said. "Our state partners oversee 90% of operator compliance with pipeline safety regulations. We seek to raise the cap on grants provided to state pipeline agencies over 6 years from 50% to 80% to offset the increasing cost of the programs they execute, consistent with the programs of the [DOT]," Barrett said.

Boss said interstate gas pipelines also want improved state excavation damage-prevention programs. INGAA members think the 2002 law's 7-year reassessment interval and its jurisdictional status for direct lateral lines should be changed, he said in his written testimony.

Carl Weimer, executive director of the Pipeline Safety Trust in Bellingham, Wash., said improvements are needed, but there has been significant progress since 1999 due to efforts by federal lawmakers and regulators, pipelines, and citizens.

"Pipeline operators now have clear requirements for communicating to the public and local government, and [the US Office of Pipeline Safety] has unveiled new additions to its own website and communications programs," Weimer said. "Perhaps just as significant, many progressive thinking pipeline companies have taken pipeline safety serious enough that they are now leading by example by operating and maintaining their pipelines in ways that go beyond the minimum federal standards," he added.

Weimer said there are elements in the other 2 bills as well as the one before Stevens's committee that should

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be included in a final law reauthorizing the 2002 Pipeline Safety Act. But he also noted that the bills do not have provisions to make more information available publicly, provide access to inspection findings, more effectively report overpressurization events, or make pipeline holding companies more financially accountable. ✦

FERC grants first market-based gas storage rates request

Nick Snow
Washington Correspondent

The Federal Energy Regulatory Commission on Nov. 16 granted an interstate natural gas storage operator market-based rates for the first time.

Under a new approach adopted in Order No. 678, issued on June 16, FERC said that Northern Natural Gas Co. may charge market-based rates to initial shippers submitting winning bids and signing precedent agreements for firm delivery service from a planned expansion of the company's underground storage aquifer field in Redfield, Iowa.

The agency also clarified the order and denied requests for a rehearing on it. Order No. 678 established more-flexible criteria for evaluating proposals for market-based pricing of gas storage services. It implemented Section 312 of the 2005 energy policy act, which FERC adopted to make gas prices less volatile and to encourage development of more domestic storage capacity, Chairman Joseph T. Kelliher said.

"There is a need to expand gas storage capacity," Kelliher said. "There is no question that we have reached the physical limits of our gas storage capacity. We have significant untapped potential; yet gas storage capacity has expanded by only 1.4% since 1988," he maintained. "Pricing reforms can help develop untapped storage capacity to the benefits of consumers and the markets themselves."

Northern Natural Gas plans to expand the Redfield storage facility, which it developed in 1954, by about 10 bcf, with a peak withdrawal rate of 175 MMcfd, according to FERC.

Based in Omaha, the company began in 1930 as a small gas utility serving 44 Nebraska, Iowa, and Kansas communities. It added pipelines, exploration and production, and other assets until 1985 when its parent, InterNorth, merged with Houston Natural Gas Co.

The combined company became Enron Corp. After Enron's collapse in late 2001, Northern Natural Gas became part of Dynegy Corp. in February 2002 before being acquired by MidAmerican Energy Holdings Co., part of Berkshire Hathaway Inc., the following August. It currently focuses on gas transmission, storage, and distribution.

FERC said Northern Natural was the first operator to request market-based rates under Order No. 678's criteria. The order states that a provider may receive market-based rates for storage and related service at a specific facility placed in service after Aug. 8, 2005, if FERC determines that such rates are necessary and in the public interest to encourage capacity construction, and customers are adequately protected.

The commission said Northern Natural met those qualifications based on facts presented in the case. Existing storage customers will not be affected by the market-based proposal, it added.

Northern Natural will be required to separately account for all costs associated with facilities to provide the market-based services. This will ensure that existing customers do not subsidize the expansion project's cost, FERC said. ✦

Venture seeks better seismic imaging of deep prospects

Alan Petzet
Chief Editor-Exploration

A partnership led by Repsol YPF SA has launched a project to apply unprecedented computing power to geophysics to reduce the risk in exploration of deep subsalt prospects under ultradeep water of the Gulf of Mexico.

Repsol YPF said the partnership gives it exclusive or privileged access to the know-how it needs to combine for the first time the hardware and software necessary to commercially image structures that, at more than 40,000 ft, are impossible to resolve on today's best 3D seismic data.

The company said it is pursuing the "full realization of the next generation of seismic imaging technology, including a specialized technique called reverse time migration (RTM), that will accelerate and streamline oil and gas exploration by several orders of magnitude compared to current industry standards."

Joining Repsol YPF in the Kaleidoscope Project are 3DGeo Development Inc., a private Houston imaging company formed by Stanford University associate professor and seismic imaging pioneer Biondo Biondi, and the Barcelona Supercomputing Center (BSC), owned by the government of Spain. 3DGeo will open a Barcelona office.

Repsol YPF also has joined the university's Stanford Exploration Project, an industry-funded academic consortium aimed at improving the theory and practice of constructing 3D and 4D images of the earth from echo soundings.

Applying RTM

Industry has known of the RTM technique since the 1970s, but the computer power necessary to perform it profitably and apply it widely has not been available, said Francisco Ortigosa of Houston, Repsol YPF's chief geophysicist and Kaleidoscope project leader.

The technique involves the fast Fourier transform of 3D data sets, which requires computing power many times greater than what is in use in exploration today, Ortigosa said.

"We can realistically say that we will reach speeds fast enough to make RTM a routine processing [step] in exploration and not something for special processing. If we achieve RTM with the productivities of salt profile migration, we will be satisfied," he said.

The cost of supercomputers based on IBM Corp.'s Cell Broadband Engine (BE) processor may also decline because the gaming industry plans to produce millions of similar processors, Ortigosa added.

The partnership gives Repsol YPF exclusive access to the three key components of advanced seismic imaging.

These are: the RTM codes or algorithms through the company's relationship with the pioneers of the technology; privileged access through the Barcelona center to Cell BE-based systems; and exclusive access to the center's research experience and the MareNostrum supercomputer.

MareNostrum, developed by IBM, is the world's fifth most powerful supercomputer. Public benchmarks show that the Cell BE processors perform the computation of fast Fourier transforms 40 times faster than the leading brand processors, Repsol YPF said.

Biondi said, "3DGeo will develop a suite of production-ready high-end imaging applications that implement the most advanced algorithms developed at 3DGeo, at Stanford, and in the industry, culminating with heretofore unimplemented cutting-edge, full-wavefield imaging techniques.

"Testing of these new compute-intensive imaging algorithms will benefit from the exceptional computational capabilities available at the MareNostrum supercomputer center in Barcelona, and with BSC's vast experience in computer architecture and parallelization."

The imaging development effort will require extensive testing and trial runs of challenging 3D data sets. The development and testing will be conducted at the MareNostrum supercomputer center by 3DGeo personnel working in conjunction with Repsol YPF and BSC personnel.

The project

Kaleidoscope "brings together the necessary components of modeling, algorithms, and the uniquely powerful computing power of the MareNostrum supercomputer to realize the promise of RTM and incorporate it into daily processing flows," Repsol YPF said.

The process integrates steps traditionally taken sequentially, Ortigosa said.

3DGeo is one of the pioneers in wave-equation migration and velocity-model building. The Barcelona center has vast experience in computer architecture and in parallelization for the Cell BE processor.

Biondi said, "We estimate that this solution will accelerate seismic imaging by several orders of magnitude compared to conventional solutions running on standard Linux clusters."

First deployment of RTM in the gulf could come as early as the end of the first quarter of 2007. The partnership is initially chartered for 5 years but is meant to develop into a long-term relationship as other technology challenges emerge, Ortigosa said. Eventually RTM could have application off West Africa and Brazil, he added.

Repsol YPF operates 45 of the 85 exploration blocks in which it holds interests in the gulf, where it has been a player since 2002. The blocks are in Green Canyon, Atwater Valley, Alaminos Canyon, and Mississippi Canyon. The company's first important gulf production is to start in 2007 at a net 7,500 b/d of oil and 7.5 MMscfd of gas from Neptune field. ✦

CERA study: Oil production to track 'undulating plateau'

The "peak oil" theory, stipulating that world oil production will soon peak and sharply decline, is flawed, according to an analysis by Cambridge Energy Research Associates (CERA).

Instead of a peak, CERA says, production is more likely to trace an "undulating plateau" that will last for a decade or more beyond 2030. The report added that during later decades of the plateau period, unconventional production of heavy oil, gas-related liquids (condensate and natural gas liquids), gas-to-liquids, and coal-to-liquids will supplement traditional liquids supply.

"It is likely that the situation will unfold in slow motion and that there are a number of decades to prepare for the start of the undulating plateau. This means that there is time to consider the best way to develop viable energy alternatives that would eventually provide the bulk of our transport energy needs and ensure that there is a useable production stream of conventional crude for some time to come," CERA said.

Peter M. Jackson, CERA director of oil industry activity, said, "The 'peak oil' theory causes confusion and can lead to inappropriate actions and turn attention away from the real issues."

He added, "Oil is too critical to the global economy to allow fear to replace careful analysis about the very real challenges with delivering liquid fuels to meet the needs of growing economies. This is a very important debate, and as such it deserves a rational and measured discourse."

Hubbert analysis

The CERA report contends that the often-cited Hubbert model, which patterns production as a bell curve, fails to recognize that recoverable reserve estimates evolve with time and are subject to significant change. The model also underplays the impact of technological advances.

Although M. King Hubbert accurately predicted timing of the peak in US Lower 48 oil production in 1970, the CERA study says, he underestimated the peak rate by 20% and total cumulative Lower 48 production during 1970-2005 by 15 billion bbl.

Hubbert's symmetrical post-peak reservoir decline-curve assumptions also fail to match observations of typical oil-field production profiles, which are often asymmetrical, even without new technology or enhanced recovery.

The CERA report also challenges the peak-oil theory's reliance on assertions that new discoveries aren't replacing production. It calls the argument "incomplete," saying it ignores the role of development and economic considerations that can encourage companies and governments to favor development over exploration.

CERA's report contends that it is not reservoir constraints but aboveground factors such as geopolitics, conflict, economics, and technology that will dictate future oil supply.✦

Republican group opposes broad OCS reform bill

Nick Snow
Washington Correspondent

If an Outer Continental Shelf leasing reform bill comes before the full House during the lame-duck session, it should be S. 3711 and not the broader HR 4761, 18 House Republicans told Majority Leader John Boehner (R-Ohio).

"We opposed the House OCS bill when it came before us in June, and we continue to do so. If the House needs to consider an OCS bill, we ought to take up the Senate-passed bill," they said in a Nov. 15 letter to Boehner.

The letter was not intended to suggest that all the signers would vote for the Senate bill, they added in a footnote. Several House members who voted against HR 4761 would not sign the letter because they did not want to even recommend bringing the Senate's bill to the floor when the House returns on Dec. 5, the signers said.

Backers of S. 3711, which focuses on the eastern Gulf of Mexico, have dropped the idea of sending the two bills to conference and are pressing for the House to pass the Senate version instead, congressional sources have told OGJ (OGJ, Oct. 9, 2006, p. 27).

Two of HR 4761's main sponsors defended their measure, which would provide a way for coastal states beyond the Gulf of Mexico to share in future OCS revenues because it would open more areas for natural gas development.

Noting that US industries cannot compete in global markets when they pay the most for gas, Rep. John E. Peterson (R-Pa.) said on CNBC's "Squawkbox" on Nov. 15, "We have to make natural gas affordable in this country; we have lots of it. There's never been a beach eroded by natural gas drilling. We've given good distances offshore for protection. We're the only country in the world that doesn't use its outer continental shelf for the production of energy."

During the same program, Neil Abercrombie (D-Ha.), said: "You have to look to the future. All over the world, everybody is pumping natural gas. Norway, New Zealand, China is doing it for Cuba—right off the coast of Florida! We're the ones who are falling behind. If we intend to be competitive in any way, shape, or form in the future of this 21st century, we have to tap our natural gas resources."

But Reps. Charles H. Bass (R-NH), Roscoe G. Bartlett (R-Md.), Sherwood L. Boehlert (R-NY), Michael N. Castle (R-Del.), Vernon J. Ehlers (R-Mich.), Michael G. Fitzpatrick (R-Pa.), Rodney P. Frelinghuysen (R-NJ), Jim Gerlach (R-Pa.), Wayne T. Gilchrist (R-Md.), Nancy L. Johnson (R-Conn.), Timothy V. Johnson (R-Ill.), Sue W. Kelly (R-NY), Mark Kirk (R-Ill.), Ray H. LaHood (R-Ill.), Jim Leach (R-Iowa), Jim Ramstad (R-Minn.), Jim Saxton (R-NJ), and Christopher Shays (R-Conn.) said HR 4761 would go too far.

"The American people made clear on election day that [they want] Congress to take pragmatic, targeted approaches to solving problems rather than engage in ideological sparring. Continued efforts to promote the House bill—which would open the entire US coastline to oil drilling and which would sweep away environmental protections, undermine local control, and increase the deficit—would signal that we have not gotten the message of election day," they said in their letter to Boehner. ✦

Senate Democrats signal climate-change push

Nick Snow
Washington Correspondent

Three incoming Senate committee chairmen have asked President George W. Bush to commit to working with the new Congress in passing aggressive climate change legislation in 2007.

The recent elections signaled a need to change direction in many areas, including global warming, said Sens. Jeff Bingaman (D-NM), Barbara Boxer (D-Calif.), and Joseph I. Lieberman (D-Conn.).

"If we are to leave our children a world that resembles the earth we inherited, we must act now to address [greenhouse gas] emissions. When the 100th Congress begins in January, we pledge to work to pass an effective system of mandatory limits on greenhouse gases," they wrote in a letter to Bush.

Bingaman will chair the Energy and Natural Resources Committee, Boxer the Environment and Public Works Committee, and Lieberman the Homeland Security and Government Affairs Committee when Democrats take control of the Senate.

They noted that the US is among 189 countries with representatives meeting in Nairobi, Kenya, to discuss global warming.

"Unfortunately, we are not satisfied with the level of US participation in the international negotiations and in reducing our own domestic [GHG] emissions. Therefore, as incoming chairs of three important Senate committees on global warming, we seek your commitment to work with the new Congress to pass meaningful climate change legislation in 2007," the senators wrote Bush.

They and other Senate Democrats have repeatedly said the Bush administration and the Republican congressional leadership have not taken climate change seriously.

The three senators said they have written or cosponsored legislation to combat global warming.

"Although our approaches differ slightly, we—along with the overwhelming majority of the scientific community—agree that human-caused global warming is real and that we must pass legislation to address this threat. We are committed to achieving this result," they said. ✦

COMPANY NEWS

Gazprom gets 51% of new JV with Lukoil

OAO Lukoil Holdings ceded control of a joint venture for new projects to state-controlled OAO Gazprom's oil subsidiary, Gazprom Neft.

"Gazprom is our big brother; the big brother must have 51%," Lukoil Chief Executive Vagit Alekperov told reporters during a Nov. 17 news conference in Moscow.

In other recent company news:

- JED Oil Inc., Calgary, said JMG Exploration Inc., an affiliate incorporated in Nevada, has decided to abandon plans in which JED would have acquired JMG.
- Isramco Inc., Houston, agreed to buy certain oil and gas properties in Texas and New Mexico from Five States Energy Co. LLC, Dallas, for $100 million. Closing is scheduled for Jan. 20, 2007.
- Serica Energy PLC and BG Group PLC subsidiary BG International Ltd. have agreed to exchange interests in adjacent exploration licenses in the UK Central North Sea.
- Petro-Canada plans to divest its interests in five in situ oil sands properties in Alberta so it can focus on other oil sands properties, some of which are scheduled to start in situ bitumen production in 2011.

Gazprom's new JV

Gazprom's new JV involves participation in projects in Russia and abroad, Alekperov said. He emphasized that Lukoil would not lose control of its existing upstream assets.

The Lukoil-Gazprom Neft JV is expected to focus on Siberia and northern Russia, including the arctic region of Timan-Pechora.

JED-JMG deal folds

JMG was formed in late 2004 and taken public last year. JED said the acquisition was called off because of changes in both companies and in general market conditions since a letter of intent was signed (OGJ, Apr. 3, 2006, p. 33).

JED has concentrated on development drilling, and JMG on exploration in western Canada and the US, both working closely with Enterra Energy Trust, an oil and gas income trust set up in 2003.

Isramco acquires assets

Isramco's newly acquired assets include 660 producing oil and gas wells. Net income from the properties during the first 7 months of 2006 was $11 million. Isramco said its share of estimated proved developed reserves include 2 million bbl of oil and 28 bcf of gas.

Isramco explores off Israel through Isramco Negev 2 LP. In the US, Isramco's wholly owned subsidiary, Jay Petroleum LLC, owns various interests in oil and gas wells in Louisiana, Texas, Oklahoma, and Wyoming.

Serica-BG exchange assets

Serica is operator and 50% interest owner of Block 23/16f, on which it is currently drilling the Columbus prospect. BG has an equity holding in part of the adjacent Block 23/21 (Part Block 23/21) into which Serica believes the Columbus prospect may extend.

Serica and BG have entered into a cross-assignment agreement that provides, in certain specific circumstances, for Serica to exchange with BG a 25% interest in Block 23/16f for a 25% interest in Part Block 23/21, excluding Lomond field. The agreement also allows for BG to participate in the costs of the Columbus well—23/16f-11. The assignments of interest will be subject to regulatory and partner approvals.

Eric Watkins, Senior Correspondent

A new desert energy source

"He had been eight years upon a project for extracting sunbeams out of cucumbers..."
—Jonathan Swift, from Gulliver's Travels

Chinese Petroleum Corp. Gen. Manager Chen Pao-lang last week returned to Taiwan from a 13-day trip to Libya, where—supposedly—he was laying the groundwork for a bid to explore for oil.

CPC was pretty tight-lipped over what Chen actually did in Libya, saying only it would provide more information about his trip to Libya after he had come back.

A day earlier, CPC Chairman Pan Wenent said, "CPC is preparing to bid for oil exploration rights in Libya this December, and hopefully the CPC can win the bid to explore more crude oil resources."

We have our doubts about that. We believe CPC officials were in Libya for the sunshine. We are not suggesting they went there on vacation. We think they went there in connection with sunshine as a source of energy.

Smoke and mirrors

We were alerted to this possibility by the publication of a report commissioned by the German government, which found that solar energy from North Africa could help reduce emissions from European power stations by 70% by 2050.

Franz Trieb of the Trans-Mediterranean Renewable Energy Cooperation (TREC), who also works for the German Center for Air and Space Technology, gave the upbeat side of the report.

"Every year, each square kilometer of desert receives solar energy equivalent to 1.5 million bbl of oil," he said. "Multiplying by the area of deserts worldwide, this is nearly 1,000 times the current energy consumption of the world."

He added, "We can tap into this energy by using mirrors to concentrate sunlight and create heat to drive a generator."

The German expert envisages the use of concentrating solar power (CSP) systems—in which mirrors focus sunlight on a boiler to create steam that drives a turbine—and transporting the electricity produced on a vast network of highly efficient power lines.

Sunshine from cucumbers

The real eye catcher, though, is price. Trieb said it costs about $50 for a CSP plant to produce the same amount of energy as contained in a barrel of oil, but he said this figure was "likely" to fall to around $20—a likelihood he did not explain in detail.

Gerry Wolff, of TREC-UK, said: "Many people are saying there is not enough renewable energy and that we've got to have nuclear power. This report shows that's absolute nonsense." Of course it is.

Wolff also said there would be "fascinating spin-off benefits" for North African countries beyond the money from supplying Europe with electricity. He said waste heat could be used to desalinate seawater, while the mirrors would provide shade to grow plants, like cucumbers.

Enter the Taiwanese, who, we suspect, were consulted on the best ways of putting the squeeze on those cucumbers for even more sunshine. ✦

Serica Chief Executive Paul Ellis said, "If Columbus is successful, the prospective common interests of Serica and BG in Blocks 23/16f and 23/21 will enable appraisal wells to be drilled and the development of any discovery to be commenced in the most efficient manner."

Petro-Canada divestiture

Petro-Canada's properties to be divested are Chard, Stony Mountain, Liege, Thornbury, and Ipiatik. Petro-Canada's interest in these properties is estimated to cover 1.7 billion bbl of bitumen.

Petro-Canada opened a data room Nov. 20. It hired Harrison Lovegrove, London, to manage the auction.

"Over the next 10 years or so, we'll be focusing all of our efforts on developing Fort Hills and our in situ properties of MacKay River, Lewis, and Meadow Creek," said Neil Camarta, Petro-Canada's senior vice-president, oil sands.

With this sale, Petro-Canada has an estimated 3 billion bbl of total bitumen resource at Syncrude and Fort Hills and more than 5 billion bbl in the in situ properties at MacKay River, Lewis, and Meadow Creek.

The company had earlier reported plans to submit a commercial application for the Fort Hills project by yearend, with a regulatory decision expected by late 2007 to be followed by construction lasting 3 years and oil production starting in 2011.

An expansion at MacKay River, by 2010, will increase production by 40,000 b/d, the company said.

It has evaluated 130 wells on its Lewis lease, as many as eight wells per section in some areas. Canadian sections are 1 mile square.

It also has delineated the Meadow Creek lease with eight wells per section. For both Lewis and Meadow Creek, Petro-Canada has not announced a definite timetable for initiating production (OGJ Online, Sept. 25, 2006). ✦

DEEPWATER RISKS—1

Challenges, risks can be managed in deepwater oil and gas projects

David Wood
David Wood & Associates
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Saeid Mokhatab
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Laramie

Deepwater projects typically face technical and financial challenges to their viability. Such challenges are now increasingly significant for operators, consultants, and contractors as exploration moves into ever deeper water.

It is essential that these challenges are assessed, mitigated, and managed throughout project execution by selecting appropriate field development plans, risk management, and modifying project implementation methods. A clear understanding of risks throughout project execution is a key component of deepwater development.

The aims of this two-part article are to provide an insight into the various risks involved in deepwater field development as well as to help engineers and managers develop strategic risk management models.

Offshore risks

Offshore field development is a complex activity that involves uncertainties from a wide range of sources.

These uncertainties comprise potentially both hazards (unwanted consequences) and opportunities (desired consequences) for success. Managing these uncertainties in a systematic and efficient manner with higher focus on the most critical uncertainties is the objective of project risk management.

The uncertainties come from a wide range of areas and disciplines, and may be of a complete different nature:

1. Technical.
2. Financial.
3. Organizational.
4. Contract/procurement.
5. Subcontractors.
6. Political/cultural, etc.

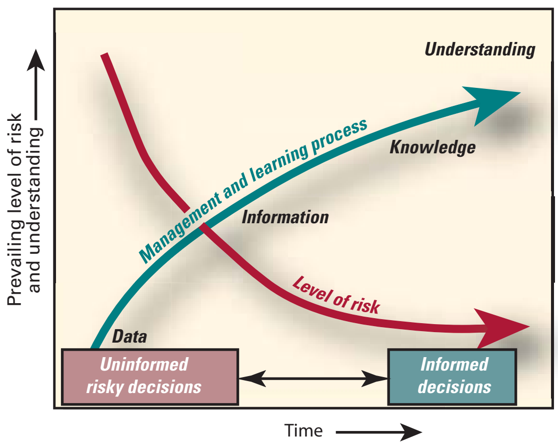
Nevertheless, they all contribute to the overall uncertainty in the planning and execution of the project as well as the success of the final product.[1]

Deepwater field development projects face special challenges, specifically:

- High investment costs (capex).
- Introduction of new technology elements or usage of known technology in new conditions.

RISK MANAGEMENT LEARNING CURVE

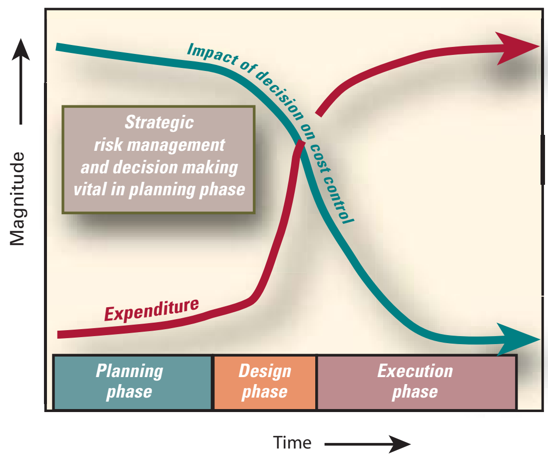
Fig. 1



Source: David Wood & Associates

EARLY DECISION MAXIMIZES COST IMPACT

Fig. 2



Source: David Wood & Associates

- Long lead times for spares and installation resources.
- High consequences of operational failure.
- Flow assurance.
- Fabrication, installation, and operation in new deepwater frontier basins.
- Deepwater development may be located in countries with high political instability.

Deepwater developments require large reserves, and the total number of wells needs to be kept small in order to make the project economically viable. The drilling capex can be typically in excess of 50% of the total capital expenditure. Hence, the oil recovery per well needs to be high along with a high production rate per well, typically 10,000-15,000 b/d of oil.

Today's deepwater completions must maximize ultimate recovery for projects to be economically viable. Newly discovered deepwater reservoirs are capable of high flow rates, and the wells must be designed accordingly.

The cost and inaccessibility of deepwater subsea wells also require the industry to rely heavily on new technology to optimize the capital expenses on projects. Completion design and equipment reliability are critical to the success of a development. While new technology is essential, there are risks in using technology that has not been rigorously tested for reliability in the environments in which it is being deployed.

Reliability problems during the life of a well show up in the form of reentry and workovers, which must be minimized to achieve project economics. Problems may result in formation damage, lost reserves, safety, and environmental exposure.[2]

A project risk management methodology addresses the management of uncertainties at different project phases depending on the level of information that is available and the type of decisions to be made.[1]

Effectively understanding risk is all about moving up the learning curve and being in a position to make informed decisions (Fig. 1). However, in the project-managed field development context some key decisions must be made early in the planning process if they are to ultimately influence project schedules and costs (Fig. 2).

Figs. 1 and 2 show that risk management is a crucial early phase activity in the project cycle if we are to reap the benefits of the knowledge it provides in time to inform decisions that will prove crucial in the ultimate cost, time, and quality performance of a project. The importance and urgency of risk management in deepwater projects cannot therefore be overestimated.

On technically complex deepwater projects that require large sums of capital expended over long periods of time, there is no substitute for closely monitoring costs, assessing financial risks, and implementing mitigation plans based on robust decision intelligence as early as possible in the project. Yale and Knudsen[3] illustrate how the influence of strategic planning and risk assessment on project expenditures decreases over time using cost-risk analysis performed on a midsize subsea tieback project in the Gulf of Mexico.

Oil and gas exploration and exploitation is generally a high-risk but highly rewarding business. The uncertainties with regard to the presence and quantities of recoverable reserves, the cost of developing reservoirs, and the product prices are enormous. Cost-risk curves demonstrate that investment in reservoir identification and delineation, plus early engineering studies, are the best way to mitigate risks. The risks may be broadly classified[4] as:

1. Revenue risks: uncertainties in the quantity of recoverable reserves (initial-oil-in-place and recovery factor), the rate of recovery (plateau rate, early production, etc.), and the product price (oil and gas sales price).
2. Cost risks: uncertainties related to the cost of developing the field through the value chain and the income recovered at market prices.

Technological risks can be considered a third type of risk. However, the use of new technology is considered either to reduce costs relative to traditional technology or increase the uncertainty and potentially the costs on the performance and reliability of the new technology.

Technology risk is therefore in this discussion included as a cost risk. An offshore development project generally goes through three distinct phases:[4]

1. The exploration phase, in which the focus is on revenue risk, i.e., determining the reservoir production potential.
2. The development phase, during which most of the investment takes place, focuses on the cost risk and the technology needed to develop the field in an economically robust manner.
3. The production phase, during which the revenue risk is represented by the product price and the production profile.

Deepwater project revenue and cost risks are influenced by the following factors: field reserves; reservoir complexity; development design and engineering; oil and gas price volatility; drilling and well completions; subsea infrastructure, flowlines, and risers; processing facilities and support structures; transportation and storage; and project schedule.

The risks can, to a certain degree, be managed and mitigated by selection of different field development plans, as well as project implementation methods.[4] Under discussion of each type of risk, the potential for risk mitigation will be briefly addressed.

Risks that are specific to deepwater developments and to the specific technology that can mitigate them are identified in more detail. It is also essential to take a broader and more holistic view of risk (including opportunity) that goes beyond the subsurface, technological, and project risks when assessing project feasibilities. Fig. 3 illustrates the spectrum of risks that oil and gas projects encounter and must accommodate.

While our focus here is upon the technical and project risks that are most readily managed from an engineering perspective there is no doubt that risk management has to go beyond the engineering level. The more holistic approaches to risk are beyond the scope of this article but are covered elsewhere.[5, 6]

It is impossible to identify and mitigate against all facets of risk, but it helps to be aware of as many as possible and formulate contingency plans and strategies.

Project risk management can employ a range of analytical techniques and software. There is no one right way to do it but plenty of inconsistent and haphazard approaches that hinder rather than help in risk management. The key is to be systematic and consistent.

Development framework

A stages and gates approach (Fig. 4) to the project management of oil and gas field and facilities emphasizes the importance of the planning stages (feasibility, FEED) leading into engineering, procurement, and construction (EPC) contracting, construction and fabrication activity, on to HAZOP and ultimately plant commissioning.

To move from one stage to another requires a gate to be passed where decisions and approvals have to be made associated with funding, technical design, and project priority. Such approvals are usually structured in the form of authorities for expenditure (AFEs) to be signed-off by the project owners (and often other stakeholders—e.g., government authorities) as positive approval to proceed under stages of a project budget. Although the diagram for simplicity suggests a linear process proceeding from one stage to another, in practice there are often loops and feedbacks to the work of earlier stages that require adjustments to design, etc.

Design criteria and options

Design criteria must be robust and flexible, with the development concept demonstrating operating flexibility and operability. It should include the establishment and management of a facilities weight budget and address how the facilities are to be controlled.

A key pre-FEED question is how much redundancy is needed to accommodate potential production capacity expansion? A high degree of redundancy automatically entails a high degree of complexity.

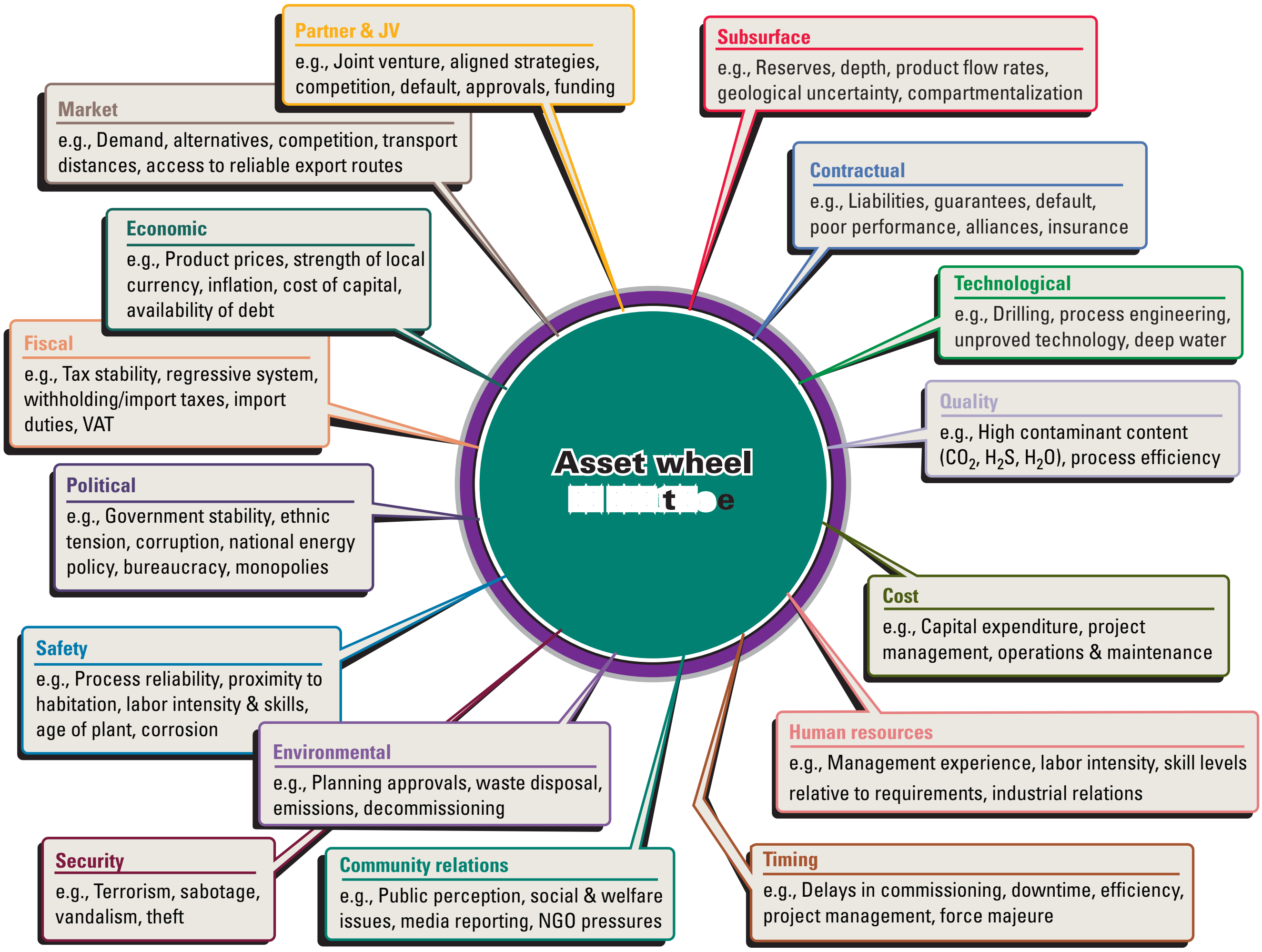
Some design tradeoffs in a field development framework can substantially impact the weight of the structure, (e.g., dual versus single process trains) with negative weight gains, but positive flexibility gains. In general terms, to reduce the total installed capital cost of an offshore facility; it should be made smaller and lighter.

The skidded or modular approach is common in the Gulf of Mexico, where there is an abundance of quality speciality fabricators in the region. While adding weight, modular construction can have overall benefits to the project in terms of distributing the project workforce, improving the competitive bidding process and quality of the facilities and dramatically shortening fabrication schedules.

Offshore processing can be prohibitively expensive. In

FACTORS THAT CONTRIBUTE TO OIL AND GAS ASSET RISK

Fig. 3



Since first published (Wood, 2002), this diagram has been made more comprehensive by identifying security, community relations, human resources, and partner/joint venture risks. It does not lay claim to be exhaustive, but it highlights the fact that risks to which field developments are exposed go far beyond the technical and project level.
Source: David Wood & Associates, updated January 2005

extremely remote locations it may be the only option but, depending on the distance to shore, a subsea development may be the least expensive solution for gas field developments.

Tying back deepwater subsea field developments long distances to shallow water or even to shore is becoming an increasingly attractive design option in some areas. For example, in the Gulf of Mexico, Mensa field developed by Shell in 1,600 m of water is quite an innovative development with subsea wells tied back 100 km to a shallow water platform, West Delta 143.

Giant Ormen Lange gas field in 800-1,200 m of water in the Norwegian North Sea lies 140 km west of Kristiansund and is being developed with a subsea template linked to shore-based processing facilities. Farther north, in the Barents Sea, the Snohvit gas field complex is also being developed with subsea facilities to a land-based LNG facility under construction. Such a design concept is being considered for the Shtokman field 560 km north of Murmansk in the Russian Barents Sea.

Scarab and Saffron gas fields form part of the West Delta Deep development in 650 m of water 90 km off Egypt. They were also developed using subsea manifolds with wells tied in and lines to shore. This development came on-stream in 2003. Popular design concepts for fields in hostile and remote (including deepwater) environments are to exploit subsea technology with pipelines to shore where possible.

Understanding how the risks and technical challenges (discussed below) fit and are to be addressed within the field development project framework and with specific design concepts are essential to achieving projects on-time and within budget without major surprises and to mitigate threats and exploit opportunities.

Reservoir uncertainties

The process of estimating oil and gas reserves is complex and involves a significant number of assumptions in evaluating available geological, geophysical, petroleum engineering, and economic data. Therefore, reserves estimates are inherently uncertain.

The reservoir size field reserves pose the fundamental technical aspect to revenue risk. Reservoir complexity, depth, and remoteness from existing infrastructure are the major factors that influence cost risk. Reservoir models that link engineering and 3D seismic data sets help mitigate risk by optimizing reserves recovery through careful well location and spacing.

Some reservoir types, such as narrow channels, can be hard to resolve which means that such models are far from foolproof. Invariably reservoir characteristic assumptions used at the planning stage differ from those that manifest themselves during a field's production life.[4] Post first oil production, reservoir dynamic behavior determines reserves size.

A phased field development can often offer an attractive development strategy in deepwater environments as such an approach can eliminate many of the recoverable volume and production flow risks and issues confronting reservoir engineers. Even though it may cost more in total it can effectively spread risks and costs.

Oil and gas prices

Product prices represent the fundamental commercial aspect of revenue risk.

Estimates for life of field product prices should be conservative enough to mitigate the impacts of low price intervals in volatile product markets.

In risked economic evaluations and justifications for sanctioning deepwater field developments, sensitivity cases and/or a probabilistic approach help to identify potential product price impacts on life of field investment returns.[4]

Wells and completions

Drilling and completion costs account for some 50% of total deepwater field development costs (much more than for shallow water fields). Hence drilling and completion activities make a significant contribution to overall risk.

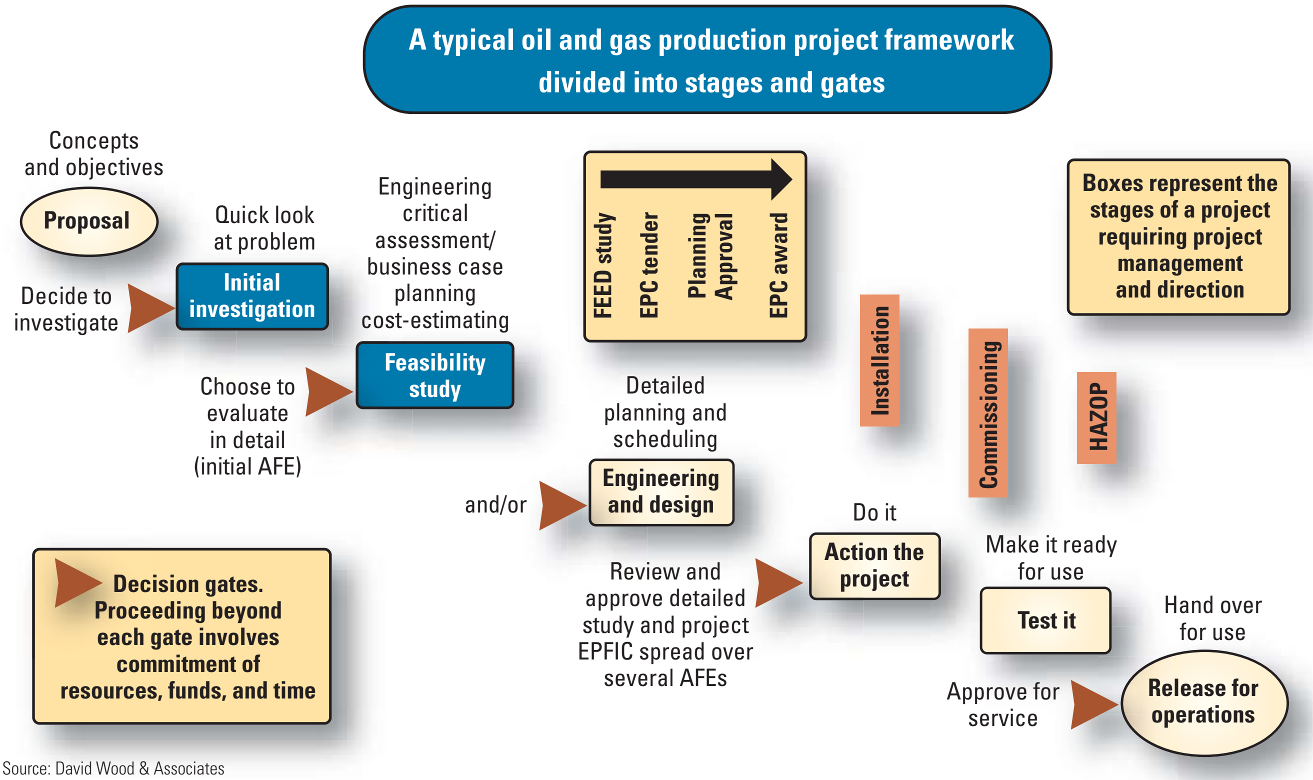
In addition, subsea well technology and services commonly account for some 25% of the overall cost. Up to 75% of the costs are therefore incurred on items at the sea bed or below. With rigs commanding premium prices for deepwater operations, making full use of reservoir models to optimize well locations becomes an essential means of reducing well risks.

The cost and resources deployed in building quality reservoir models is justified by reducing the number of wells required and optimising the performance of those wells drilled.

Costs and risks associated with production and injection wells will depend on the technologies deployed and the environment. Platform-drilled wells generally pose less risk and are more flexible in design than wells drilled from mobile drilling units. Large wellbore subsea wells are more risky and

STAGES AND GATES APPROACH TO PROJECT MANAGEMENT

Fig. 4



Source: David Wood & Associates

costly to drill with fewer contractors offering proven capabilities.

International deepwater wells frequently cost more than $25 million to drill and complete. In such cases technologies and models that facilitate increased recovery from individual wells and enable a reduction in the number of wells can offer huge cost and risk reduction benefits.

Cromb[2] was adamant: "Complex drilling/completion systems should not be acceptable for subsea equipment—period." To ignore this undoubtedly increases risk and cost over the life of the well, which invariably offset any engineering gains made by doing so.

Technological demands that are frequently crucial for deepwater drilling are:

• Drilling of extended reach and multilateral wells.

• Drilling and completion of wells in deep and ultradeep water, especially using smart/slender wells and underbalanced drilling.

• Design, construction and installation of lighter and smaller subsea equipment for ultradeep water.

Plans that call for fewer deepwater wells (assuming higher unit recovery can be achieved from each well) are an obvious way to try to reduce capital and operating cost requirements. With a good reservoir and model, it should be possible to optimally locate wells and by employing large-offset subsea wells the total number of wells (and floating facilities) can be reduced.

Flowlines and risers

Long-reach satellite developments (more than 100 km in some cases) of fields in deep and ultradeep water rely heavily on flowlines and risers to make production possible.

The maintenance and integrity of these facilities is a risk and a cost that cannot be ignored for deepwater fields. Generic characteristics of deepwater fields include:

• Remote locations.

• Deep columns of cold water with strong ocean currents.

• Limited or difficult to access infrastructure.

• Complex supply, manpower, and service logistics.

• Costly support vessels.

• Long flowline tiebacks to floating production and storage systems from outlying wells.

Flow assurance is critical for flowlines and risers in deep and cold water and can be costly. Blockages due to wax, hydrates, and sand can shut down production and be expensive to remedy unless remedial measures are designed into the facilities.

Potential multifunction of risers, flowlines, and umbilical cables are undoubtedly some of the most critical concerns associated with equipment components of the floating production systems being developed for ultradeep water field developments.[4]

Next: More aspects discussed on managing risks in deepwater projects. ✦

Independence Hub nears production from eastern Gulf of Mexico leases

Guntis Moritis
Production Editor

Gas production from the eastern Gulf of Mexico will start in 2007 from 10 deepwater fields tied into a floating central processing facility, Independence Hub, moored in about 8,000 ft of water.

Five of these fields are on leases acquired during Lease Sale 181 in December 2001. The sale was controversial and was reduced in size by nearly 75% because of environmental concerns in Florida (OGJ, Dec. 17, 2001, p. 32). Currently various federal legislative proposals seek to lease the acreage removed in 2001 (OGJ, Oct. 9, 2006, p. 27).

Fig. 1 shows the distances to shore for the blocks in the original lease sale.

Independence Hub ties together multiple deepwater gas fields lying in 8,000-9,000 ft of water that otherwise would be uneconomical to develop on a standalone basis. Initially 10 fields will anchor the project and produce about 1 bcfd to the hub platform, in about 8,000 ft of water on Mississippi Canyon Block 920. A high-pressure, 132-mile pipeline will transport the gas ashore.

The development has different owners for the processing platform, pipeline to shore, and producing gas fields.

Owning the hub is Independence Hub LLC, a venture of Enterprise Field Services LLC (80%) and Helix Energy Solutions (20%).

Anadarko Petroleum Corp. will operate the processing on the hub on behalf of the gas field owners that include Anadarko, Dominion Exploration & Production, Devon Energy Corp., Hydro Gulf of Mexico, and Murphy Oil Corp.

Enterprise Products Partners LP owns the Independence Trail pipeline that will transport gas ashore.

Initially, the platform will process production from fields shown in the accompanying box and in Fig. 2.

Anadarko is the operator of all of the fields except for two. Dominion operates San Jacinto, and Hydro operates Q. The company estimates that the area has a resource potential of more than 2 tcf.

Project highlights

Independence Hub semi will be moored 165 miles east of New Orleans in 8,000 ft waters. The fields are in the deepest water depths to date for producing fields. Also they have the longest tie-back flowlines, longer than 45 miles.

The project includes:

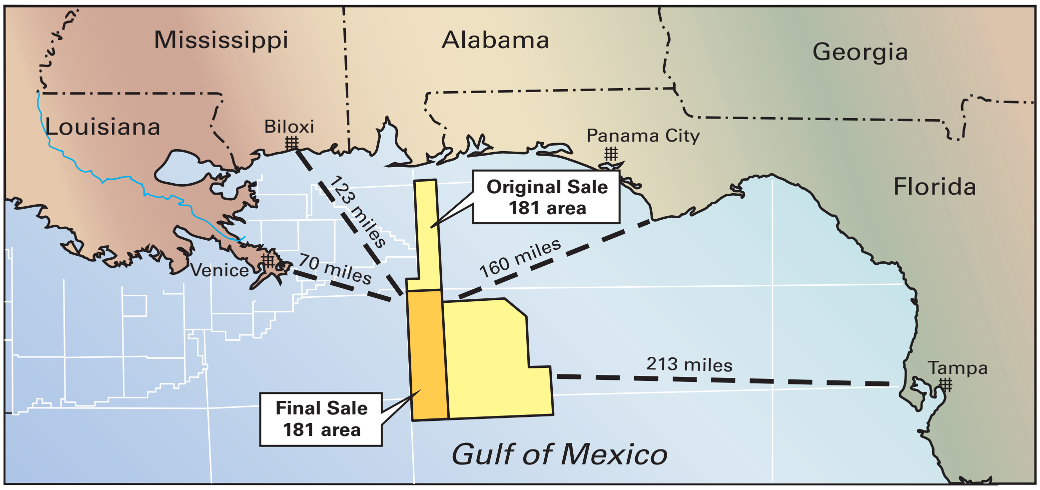
• Topsides with 1-bcfd processing

Fields producing for Independence Hub

1. Atlas (Lloyd Ridge Blocks 49 and 50, Lease Sale 181), Anadarko 100%.
2. Atlas NW (Lloyd Ridge Block 5, Lease Sale 181), Anadarko 100%.
3. Jubilee (Atwater Valley Blocks 305 and 349 and Lloyd Ridge Blocks 265 and 309, Lease Sale 166), Anadarko 100%.
4. Merganser (Atwater Valley Blocks 36 and 37, Lease Sale 175), Anadarko 50% and Devon 50%.
5. San Jacinto (DeSoto Canyon Blocks 618 and 619, Lease Sale 181), Dominion 53.3%, Anadarko 20%, and Hydro 26.7%.
6. Spiderman (DeSoto Canyon Blocks 620 and 621, Lease Sale 181), Anadarko 45%, Dominion 36.7% and Hydro 18.3 %.
7. Vortex (Atwater Valley Blocks 217 and 261 and Lloyd Ridge Blocks 177 and 221, Lease Sale 157), Anadarko 100%.
8. Mondo NW (Lloyd Ridge Block 1, Lease Sale 116), Dominion 53.3%, Anadarko 20%, and Hydro 26.7%.
9. Cheyenne (Lloyd Ridge Block 399, Lease Sale 181), Anadarko 100%.
10. Q (Mississippi Canyon Blocks 960, 961, 1004, and 1005, Lease Sale 175), Hydro 50% and Dominion 50%.

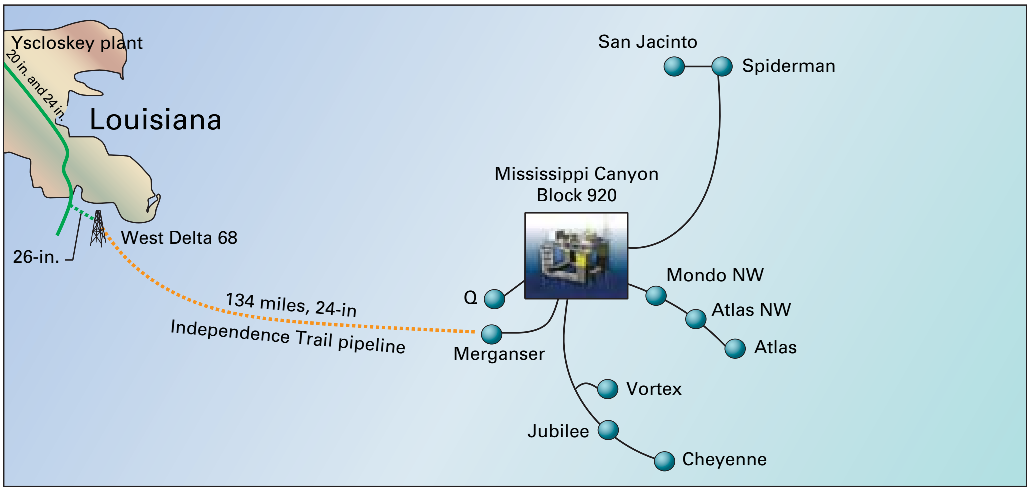
LEASE SALE 181

Fig. 1



INDEPENDENCE HUB PROJECT

Fig. 2



capacity, largest in the gulf.

• 2.4 miles of mooring lines.

• Deepest suction pile installation.

• Largest monoethylene glycol (MEG) reclamation unit.

• Deepest pipeline inline future tie-in subsea structure.

• Longest single subsea umbilical order. Instead of steel rods, the umbilicals contain carbon rods that reduce the umbilical weight.

• The flowlines are 210 miles in total length, and the umbilicals contain about 1,100 miles of stainless steel tubing.

Field discoveries

According to the US Minerals Management Service's Environmental Assessment for Independence Hub, November 2005, and OCS Report MMS 2006-022 the fields were discovered as follows:

• In 2001, Kerr-McGee Oil and Gas Corp. discovered gas at Merganser in 8,015 ft of water, reporting four reservoir sands. Kerr-McGee is now part of Anadarko.

• In December 2002, BHP discovered gas at Vortex in 8,344 ft of water, reporting 75 ft of pay. Anadarko now owns the field.

• In April 2003, Anadarko discovered gas at Jubilee prospect in 8,824 ft of water, reporting 83 ft of pay.

• In June 2003, Anadarko discovered gas at Atlas in 8,934 ft of water, reporting 180 ft of pay.

• In November 2003, Anadarko discovered gas at Spiderman in 8,087 ft of water, reporting 140 ft of pay.

• In January 2004, Anadarko discovered gas at Atlas Northwest in 8,810 ft of water, reporting 50 ft of pay.

• In April 2004, Dominion discovered gas at San Jacinto in 7,850 ft of water, reporting 100 ft of pay.

• In 2004, Shell Exploration and Production discovered gas at Cheyenne in 8,897 ft of water. Anadarko now owns Cheyenne

• In December 2004, Murphy discovered gas at South Dachshund in 8,340 ft of water, reporting 70 ft of pay. Anadarko now operates the field that has been renamed Mondo Northwest.

Not mentioned in the MMS report is the Q field discovered by Spinnaker Exploration Co. in mid-2005. Hydro bought Spinnaker in late 2005 and now operates Q. Water depth at Q is 7,925 ft.

Platform

The companies proposed to build the platform and pipeline in 2003, with procurement starting in 2004 along with the agreements for the ownership infrastructure, processing, and transportation. Topsides construction started in 2004, with hull construction starting in 2005.

The Atlantia Offshore Ltd. deep-draft semisubmersible hull has a 12-leg mooring system consisting of 9-in. polymer ropes. The hull displaces 45,800 tons and accommodates a payload of deck, facilities, and risers of 19,300 tons. It has a 105-ft draft.

Hull dimensions are 232 ft by 232 ft by 180 ft, with column dimensions of 46 ft by 46 ft. Pontoon dimensions are 38 by 26 ft.

The topsides operating weight of the deck and facilities is 10,250 tons. Each of the two decks is 140 ft by 220 ft.

Alliance Engineering designed the topsides that can process 1 bcfd of gas with 5,000 b/d of condensate and 2,960 b/d of produced water.

The platform accommodates twelve 10-in. and four 8-in. steel catenary production risers (SCRs). Gas export is through a 24-in. SCR. Initially the platform will have 5 production risers for the 10 fields.

Atlantia delivered the hull and mooring system under a lump-sum, turnkey engineering, procurement, and contraction (EPC) contract.

The hull, built in the Jurong shipyards in Singapore, left there on May 8, 2006, and arrived on June 23 at the Kiewit Offshore Services yard at Ingleside, Tex., which constructed the

The hull, constructed in Singapore, left there on May 8, 2006, arriving in Ingleside, Tex., on June 23 (Fig. 3). Photo from Enterprise.

Stationary cranes lifted the topsides onto the hull on Sept. 19 (Fig. 4). Photo from Enterprise.

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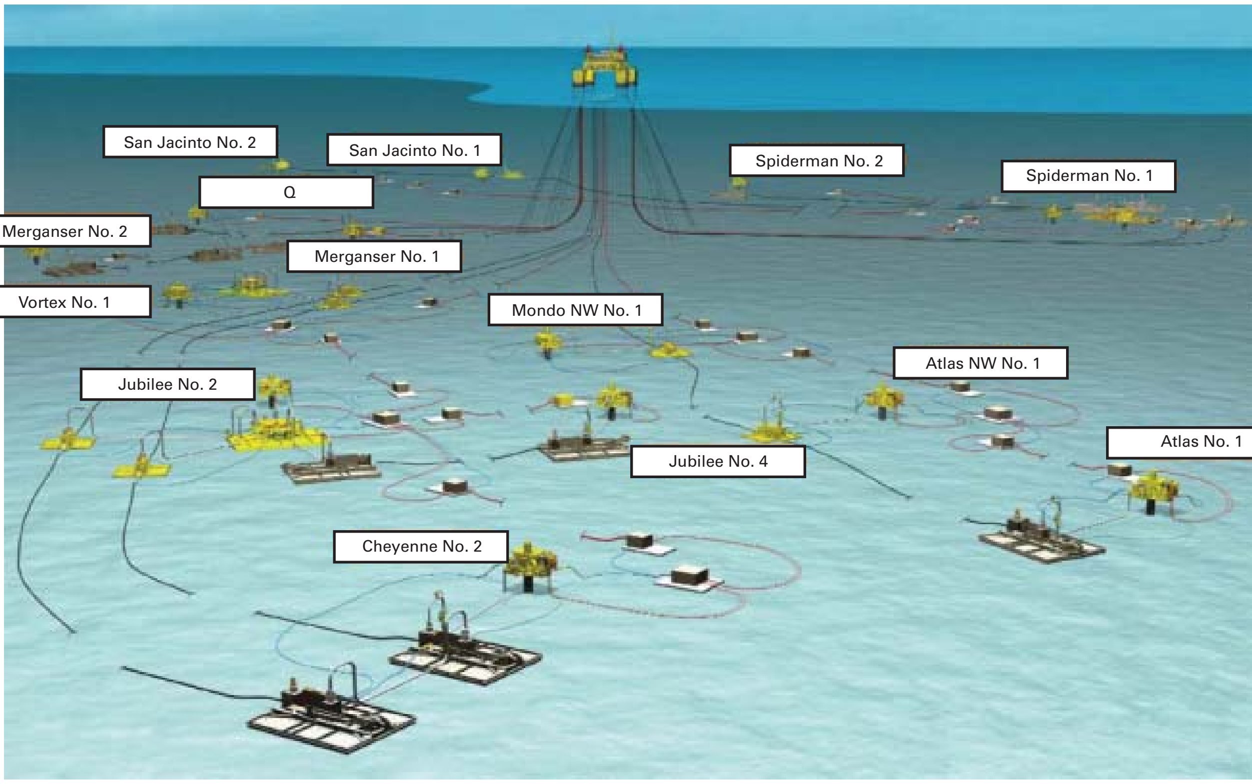
Subsea layout

Fig. 5



topsides (Fig. 3).

The Kiewit yard integrated the hull and topsides in September (Fig. 4).

Anadarko expects tow of the platform to its Mississippi Canyon Block 920 location to take place in late November.

Well completions

The projects initially will tie in 15 wells, with ad-

Allseas Solitaire S-laid the 24-in. high-pressure gas pipeline (Fig. 6). Photo from Enterprise.

ditional wells to come later. Anadarko expects production from each well initially to be 50-70 MMcfd. All wells target Miocene reservoirs.

The Transocean Deepwater Millennium and the Noble Amos Runner are the two rigs currently completing the predrilled wells. FMC provided the subsea wellheads and manifolds.

The 10 fields initially will have the following number of wells (Fig. 5).

- Atlas, 1.
- Atlas NW, 1.
- Jubilee, 2.
- Merganser, 2.
- San Jacinto, 2.
- Spiderman, 3.
- Vortex, 1.
- Mondo NW, 1.
- Cheyenne, 1.
- Q, 1.

The wells include a mix of single, two, and three-zone completions.

Anadarko wells are cased and perforated and completed with frac packs of 40-80,000 lb of 30/50 lightweight ceramic proppant and 8-gauge wire-wrapped screens.

The wells incorporate multiphase metering technology and other sensors downhole, incorporating sand detection technology, and developing an intelligent downhole instrumentation network of sensors (OGJ, Feb. 27, 2006, p. 51).

The fields include Roxar's wet-gas meters for integrating different well streams from the multiple fields. Roxar says the meters allow accurate detection and measurement in real-time of the hydrocarbon flow rates and water production as well as flow-assurance input through the meters' online detection of formation water.

In Anadarko's operated fields, six wells have smart completions. Four wells have two completed zones while the remaining two have three zones completed.

Baker Oil Tools said the wells include its intelligent wells systems (IWS) placed in wells in 8,000 ft of water, the deepest water depth to date. The long 93-ft single subassembly included three IWS lines, one tubing-encased conductor (TEC) line, and two chemical injection lines.

Anadarko described a Spiderman three-zone well as having "smart" completions on two zones that would allow control of the zones from surface, while the middle zone would require rig intervention to open or close.

Anadarko said the wells are completed with either 5½-in. or 4½-in. 13-chrome tubing because of the CO_2 content in the gas. The fields do not produce any H_2S.

Wellhead shut-in pressure is about 6,000 psi, and the bottomhole shut-in pressures are 7,900-8,700 psi. Bottomhold temperatures are 132-172° F.

Pipeline

The Independence Trail Natural Gas Pipeline is a wholly owned affiliate of Enterprise Products Partners LP. The 134 mile, 24-in. pipeline connects the Independence Hub Mexico to an interconnect with Tennessee Gas Pipeline in West Delta Block 68. The West Delta 68 jacket was installed in July 2006 with the topsides integration taking place in October. The jacket is in 115 ft of water. Topsides weight is 850 tons and jacket weight is 350 tons

Allseas Solitaire completed the S-lay of the pipeline in August 2006 (Fig. 6).

The pipeline has a maximum operating pressure of 3,640 psi and a capacity of 1 bcfd. It has two subsea dual tees of 16-in. and 12-in. in water depths of about 6,500 and 4,500 ft, respectively, for future tie ins.

The 24-in. line consists of API 5L X-65 DSAW (double submerged arc welded) pipe coated with 14-16 mils thin film fusion-bonded epoxy (FBE) and an additional 2-3 mils rough coat FBE. Wall thickness and bare weight in air vary as follows:

- 1.350-in. WT, 326.9 lb/ft.
- 1.220-in. WT, 297.1 lb/ft.
- 1.070-in. WT, 262.3 lb/ft.
- 0.950-in. WT, 234.1 lb/ft. ✦

Well-specific guidelines adopted for dynamic positioning

Alan Adamson
Middle East Navigation Aids Service
Manama, Bahrain

In the last decade, offshore operators have developed and refined an emergency response system with standardized format and nomenclature for dynamically positioned drilling operations.

For each well or location, a dynamically positioned rig is given well-specific operational guidelines (WSOG), which determine when alerts should be given and what action is appropriate.

This article discusses the issue of operational limit setting used in DP operations. It traces the history of WSOG since 1998 and also examines the reasons behind its widespread use in DP drilling and other operations.

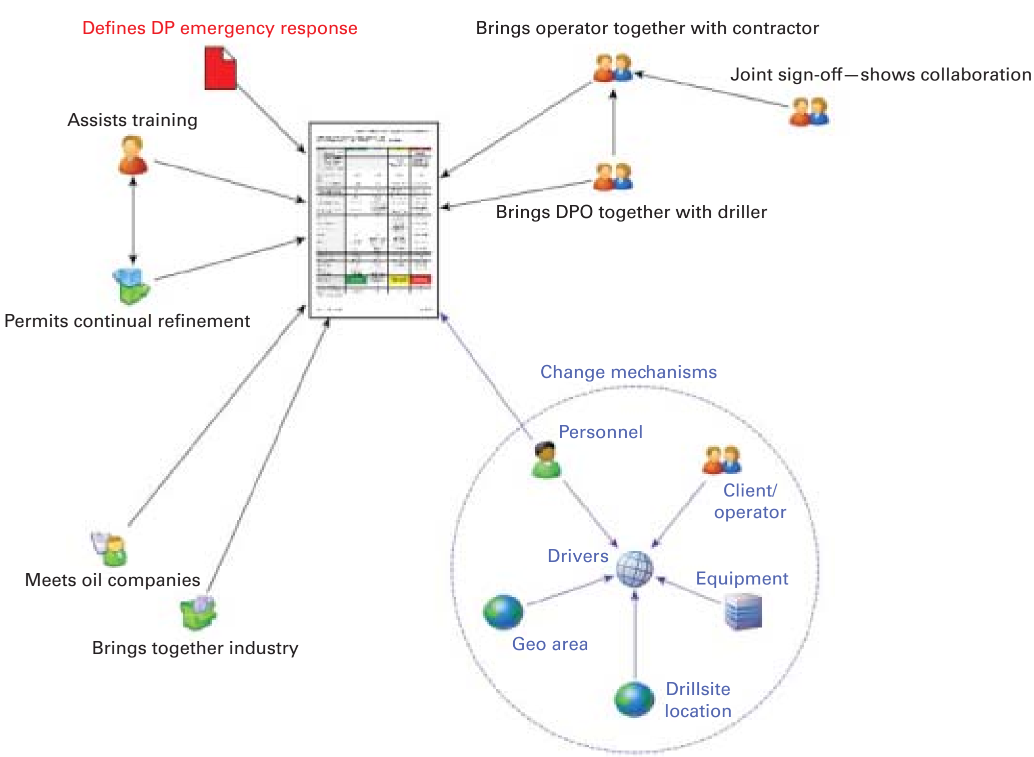
Modern WSOG has its origins with the Ocean Alliance campaign in the late 1990s on the Nyk High, Vema Dome, and Helland Hansen prospects in the Norwegian Sea.

The WSOG principle was further developed during the 1998-2000 commissioning of the drillship West Navion. WSOG became a cornerstone of the Statoil DP work requirements document that became the company's principal corporate DP requirement document, TR1029, in 2000.

Since then, other major operators have introduced corporate dynamic positioning requirements, all of which contain

OFFSHORE INTERACTIONS, WSOG

Fig. 1



WSOG as the chosen regime for limit setting offshore.

The examples cite the European approach to deepwater drilling risk management in terms of limit settings. It also discusses two incidents: one in which WSOG worked as intended and one in which WSOG failed in its objectives.

The article concludes with a summary of the reasons WSOG has had such widespread use and challenges the industry to ensure its continued effective use.

STATOIL WSOG, FEBRUARY 2000

Fig. 2

STATOIL	Rev. 3	Date 21.02.00	Page 31 of 36
DP requirements for drilling operations	Made 18.01.00	Reviewed 18.01.00	Approved 21.02.00

STATOIL **Drilling operations DP operational guidance form**

Condition	Green Figures used as guidance only	Advisory	Yellow	Red
Unit offset deviation (WD <350 m)	Ref. § 4.4.4 & 4.4.5			
Unit offset deviation (WD 350-500 m)	<3 m	5 m ROE ∠	5 m ROE ∠	20 m ROE∠
Unit offset deviation (WD 500-1,000 m)	<4 m	10 m ROE ∠	20 m ROE ∠	35 m ROE ∠
Unit offset deviation (WD >1,000 m)	<5 m	15 m ROE ∠	25 m ROE ∠	50 m ROE ∠
Power consumption each HV network	<50%	50%	<70% or consequence alarm whichever occurs first	Situation specific
Thrust consumption each online unit	<50%	Any sudden change	<70% or sudden change	Situation specific
DP position footprint (5 min. average radius from setpoint)	<2 m	5 m	Situation specific	Situation specific
DP heading footprint (5 min. maximum from setpoint) ROE1	$<3^{+}$	3^{+}	12^{+} depth dependant	If threat to position
Position reference availability (<350 m WD)	3 independent	Any failure or loss of performance in any system	2, if same type is DGPS	If threat to position
Position reference availability (<350 m WD)	3 independent	Any failure or loss of performance in any system	2, if same type is DGPS	If threat to position
Online Position Reference type requirements	3 Online during connected drilling	Any failure or loss of performance in any system	2, if same type is DGPS	If threat to position
DP control system	3	2	1	0
Wind sensors	3	2	1	If threat to position
Motion sensors	3	2	1	If threat to position

What is WSOG?

The well-specific operating guidelines document is used to define actions to be taken by a dynamic-positioning operator (DPO) in the event of certain changes to the DP unit's station-keeping capability (ability to maintain position and heading). WSOG also serves as a DP emergency response primer and ready-reckoning checklist for DP operators and facilitates collaboration and understanding between all parties (Fig. 1).

WSOG is used widely across the DP drilling industry today, in a number of different forms. The majority of the world's DP drilling contractors are making use of WSOG in the format discussed in this article. All DP drilling activities on the Norwegian Shelf are conducted with WSOG procedures, and it is the primary method of conducting the station-keeping hazard and operability analysis (HAZOP) and limit setting exercise.

The central tenet of WSOG is that it clearly defines, prior to operations, the four different DP operating-status conditions against known possible failure modes. WSOG brings together the rigs design basis, changes during design, personnel, clients, and so forth.

WSOG is effectively a purpose-built HAZOP for DP drilling that, because of its design simplicity, has been widely adopted around the world. As well as being a simple and effective tool, it provides the following advantages:

- Defines an emergency response matrix for DP.
- Assists training of key personnel without the need to retrain across contractors.
- Brings together driller and DPO (drilling and marine).
- Brings together contractor and client.
- Shows that the contractor has a credible system.
- Demonstrates a case of operational risk management.
- Allows for and is designed to handle change, e.g., new personnel or equipment, change of site, geographic location, or client.

One of the major benefits of WSOG to the DP drilling industry is that drilling supervisors should be able to build a body of experience from operating on different DP units across different contractors. This was seen by Statoil as a great advantage early on.

WSOG is, effectively, a link between known failure events and operating conditions of different type of actions. Each action—green, advisory, yellow, and red—have defined, agreed responses. The WSOG form can be amended or expanded to capture additional conditions. WSOG is also valid for use in HAZOPs for operations such as drill-stem testing and dual activities where additional safeguards may be needed.

WSOG history

The UK Department of Energy produced one of the first semi-formal guidance documents for DP drilling in March 1982. It came out at a time when the first Pelican-class DP ships were drilling in the UK sector of the North Sea. Basic by today's standards, the document nonetheless highlighted the need for effective operational limits to be defined. The concept of well specific limits was included in the document.

Ocean Alliance conducted a drilling campaign in the Norwegian sector of the North Sea in 1997 and 1998. A great deal of risk analysis was carried out prior to the rig operating. The first version of the Ocean Alliance WSOG was four pages long and clearly defined the use of the "advisory" condition to allow for reporting events that could lead to higher alert status levels.

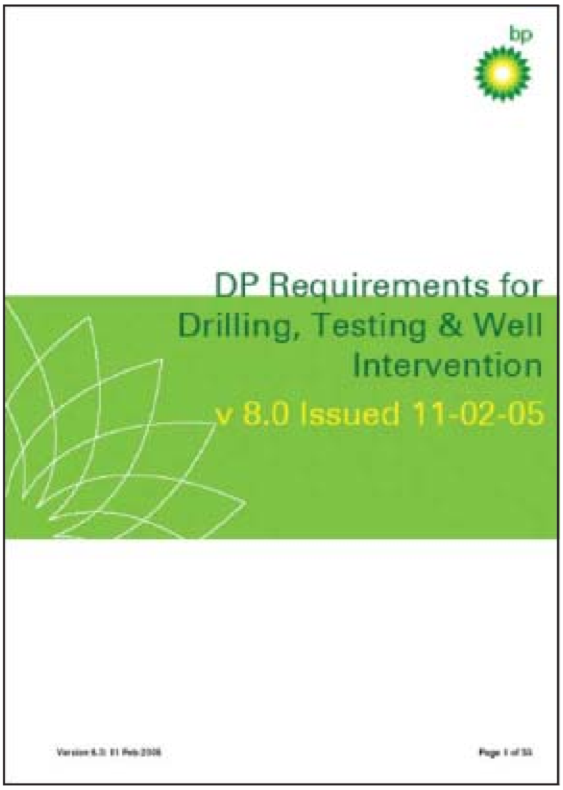
The three wells drilled by Ocean Alliance during the campaign were:[1]

1997: Ormen Lange (886 m, operator: Norsk Hydro/BP); original Ormen Lange gas field discovery; wellbore entry July 27, 1997; exit Oct. 7, 1997.

1997: Vema Dome (1,238 m, Statoil); wellbore entry Oct. 12, 1997; exit Mar. 22, 1998.

1998: Helland Hansen prospect (684 m, Norske Shell); wellbore entry Mar. 28, 1998; exit July 4, 1998.

BP WSOG DOCUMENT, FEB. 2005 Fig. 3



Statoil development—1998

The challenges in 1998 were the acceptance and compliance issues surrounding the entry into service of the Class 3 drillship, West Navion.

Within Statoil, a review process began during 1998 following the Ocean Alliance DP campaign. The DP-related verification work included the Ocean Alliance joint venture (Norway), using Doc. 1.0 (Sept. 22, 1997) as the start point.

In late 1999, the station keeping case for West Navion was accepted by the regulator and WSOG was used from the beginning of operations on the vessel.

Statoil DP requirements

- Rev 1—Statoil's B&B-TB-10-20E dynamic positioning requirements were issued on Jan. 20, 2000, and approved on Feb. 21, 2000. The first revision of the Statoil DP requirements document mandated an early version of the WSOG (Fig. 2).
- Rev 2—Following further involvement within worldwide asset teams, Statoil published the second edition of the corporate requirements document, entitled WR0581, Version 4 on Aug. 29, 2001.
- Rev 3—Statoil republished the DP requirements as "TR1029" technical requirements in early 2002.

Other operators, such as Norsk Hydro and BP PLC (2005), have since issued corporate requirements for dynamically positioned drilling and well-intervention operations.

It should be noted that all corporate DP requirements issued by oil majors use the same WSOG process as the principle means of establishing alerts (common definitions of green, advisory, yellow, and red).

BP issued a set of corporate DP requirements for drilling, testing, and well intervention in late 2004. Following extensive internal review, this became Version 8 and was issued in February 2005 (Fig. 3). The BP standard uses the same WSOG process as the earlier Statoil document. Version 9 is due to be released in late 2006.

2001 presentation

The WSOG process and wider verification model was presented at the International Association of Drilling Contractors Northern Deepwater conference in Stavanger, May 2001. The technical paper presented at IADC used case studies to show how different oil companies and drilling contractors are adopting the processes begun in Norway for the benefit of proving an effective operational risk management case for their DP operations.

The WSOG model form has had a significant influence worldwide. In 2004, det Norske Veritas prepared a report for the US Minerals Management Service titled, "Guidance on safety of well testing."[2] The report includes reference to WSOG in the form presently used.

Many operators—Shell/Enterprise, BP, ExxonMobil, ConocoPhillips, Marathon, Amerada Hess, Elf Exploration Angola, Woodside, BHP Billiton, and Apache Corp.—have made use of the WSOG form during their drilling campaigns. A number of drilling contractors have also adopted this process, in one form or another, in their DP operations manuals (Fig. 4).

Additional uses of WSOG

The WSOG alert and reporting protocol is being used on well-intervention units Regalia, Seawell, and Island Frontier, working for Statoil in the North Sea.

The DP floatel industry in the Norwegian sector of the North Sea has developed FOGS (floatel operating guidelines) along the same principles as WSOG.

In addition, Statoil is currently working on updated requirements for

WELL SPECIFIC OPERATING GUIDELINES (WSOG)

Fig. 4

Unit/Vessel: Vessel X Well: Well_Y Operator: Z Depth 1,000 m

	Condition	Green	Advisory	Yellow	Red
Any DP incident	Black-out of all HV networks				Immediately
Any DP incident	Drive off incident or drift off incident or force off incident Unit offset deviation from start point Water depth: 1,000 m			6.5 meters or immediately when recognised by DPO	Immediately when confirmed that situation cannot be controlled or not > 15 meters
Intact DP system	DP position footprint	< 5 meters	< 5 meters	10 meters	15 meters
Intact DP system	DP heading footprint	< 2 deg	2 - 3 deg	If threat to position	If threat to position
	Power consumption each network (3-split configuration)	< 50%	Any PMS warnings	> 70% or loss of one power station + consequence alarm	Situation specific
	Thrust consumption each online unit	< 50%	Thruster & PMS warnings	Consequence alarm	Situation specific
	Position reference available	3 independent	Loss of a system or performance limitation	2 (situation specific)	If threat to position
	DP control system (including IAS-DP controllers)	2 + 1 backup	Any failure or loss of performance in any system	1 or loss of failure of backup controller	Loss of all system or unable to maintain position
	Wind sensors	3	2	1 or loss of backup wind sensor (stb.aft)	If threat to position
	Motion sensors (MRU)	3	2	1 or loss of backup MRU (No. 1)	If threat to position
	Heading sensors (Gyro)	3	2	2 or loss of backup gyro (No. 1)	If threat to position
	DP-UPS	3	2	2 or loss of backup UPS (No. 1)	If threat to position
	IAS system	No controllers or network alarms	Loss of one network or one of redundant controllers/servers	Loss of 2 of the redundant controllers/ server in any system	If threat to position
	Comms system	3 system	1 system not operating	Situation specific	Situation specific
	Riser limitation UFJ	0-1.5 deg	2 deg	Situation specific	Situation specific
	Riser limitation LFJ	0-1.5 deg	2 deg	> 2 deg	4 deg
	Wind speed (10 m/10 sec)	0-4 m	5 m	Situation specific	Situation specific
	Wind direction	Situation specific	Situation specific	Situation specific	Situation specific
	Sign. wave height	0-4 m	5 m	Situation specific	Situation specific
	Riser twist	+/– 17 deg from BOP landout	> 17 deg advice BP group	Situation specific	Situation specific
	Slip ring/slip joint	Fully operable	Any failure or problem		
	Action required	**Normal status**	**Advise master, driller, toolpusher, group rep.**	**Issue alarm and follow procedures**	**Issue alarm and follow procedures**
	Notify OIM immediately (Y/N)		Yes	Yes	Yes
	Notify Operator immediately (Y/N)	Normal condition	Yes	Yes	Yes

moored units, due to the large number of incidents with dropped chains and dragged anchors. The group is proposing WSOG principles to be implemented on moored units as an efficient early warning and HAZOP tool.

The non-DP moored unit sector in the US may find advantages in this approach, given the complexity of seabed pipelines and installations throughout the hurricane-prone Gulf of Mexico.

Observations

WSOG has proven that it has an important role to play in the establishment of safe working practices for offshore drilling units. There are a great number of lessons to be captured from its use, fostering continual improvement.

Having drilling personnel trained in one process has great appeal to oil majors. It means that experience can build between rigs or ships of different contractors.

Contractors must accept that operators have a vested interest in operational risk issues (procedures, reporting). This will always increase because station-keeping incidents will continue.

Effective operating limits must be agreed between the contractor and operator before spudding a well in order to avoid confusion caused by offshore contractual arrangements.

WSOG eliminates negative reporting if followed correctly (see incident No. 2). But incorrect figures written into the WSOG can make the DP drilling operations less safe. There have been incidents caused by incorrect figures.

WSOG is an ideal tool for HAZOP and has been successfully used in other nondrilling DP scenarios.

Limit-setting HAZOP should take

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place before each well (even if everything is the same). The limit setting exercise should involve, as far as possible, personnel who have working knowledge of the rigs operating criteria. The supply of experienced and competent crew is central here and further reenforces worries in the industry.

There must be consensus following the WSOG limit setting exercise and sign-off.

In the US Gulf of Mexico, some operators view advisories as crucial, therefore fundamentally supporting the use of WSOG.

WSOG clearly works equally well with drillships and semisubmersible drilling units and has also been introduced in nondrilling DP sectors such as the floatel market. Norway is even advancing the WSOG concept for use in moored operations as an early warning HAZOP process.

History has shown that having a mature WSOG system aboard will satisfy oil operator's and regulator's verification processes. There has been wide use of this simple form since 1999, suggesting that the process works. ✦

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The author

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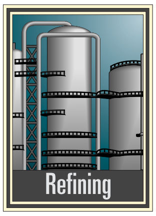
FACTS: Asia-Pacific refined product demand to rebound in 2006 and later



After experiencing strong growth in 2004, the Asia-Pacific region's oil demand growth slowed in 2005, particularly during the second half of the year, according to a July 2006 study from FACTS Inc., Honolulu. For 2006 and beyond, the study predicts stronger demand growth, especially in China, South Korea, Indonesia, Malaysia, and Vietnam.

In its "Energy Briefs, Asia-Pacific Petroleum Product Demand: An Update," FACTS revised downward its 2005 preliminary estimate for the region's oil demand growth to 445,000 b/d (Fig. 1).

The International Energy Agency revised downward global demand for 2005 to 1.05 million b/d from 1.6 million b/d in mid-2005. The study states that the current slowdown in demand growth is temporary and growth will "rebound to the level of the historical average amid the region's strong economic conditions."

High oil prices

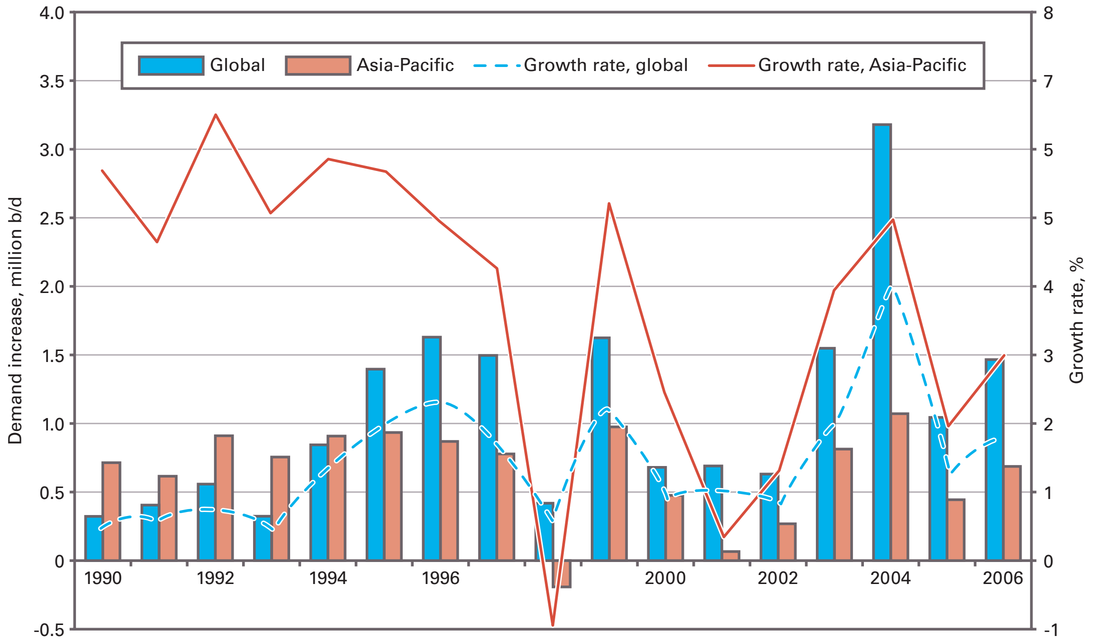
There are two major reasons for the sudden slowdown in Asia-Pacific's oil demand growth, according to the study. First, although oil prices have been rising during the past few years, oil prices stayed at the historically highest levels ever (in nominal terms) in second-half 2005.

Second, although many governments were initially reluctant to take immediate and strong action due to fear of a political backlash, they realized that they must terminate or significantly reduce subsidies due to budgetary constraints (e.g., Thailand and Indonesia).

Subsidies also create another problem, according to the study: "A considerable imbalance between domestic and international prices, created by subsidies, has been causing smuggling or the illegal use of oil products in a few countries, such as Malaysia, Vietnam,

REFINED PRODUCT DEMAND

Fig. 1

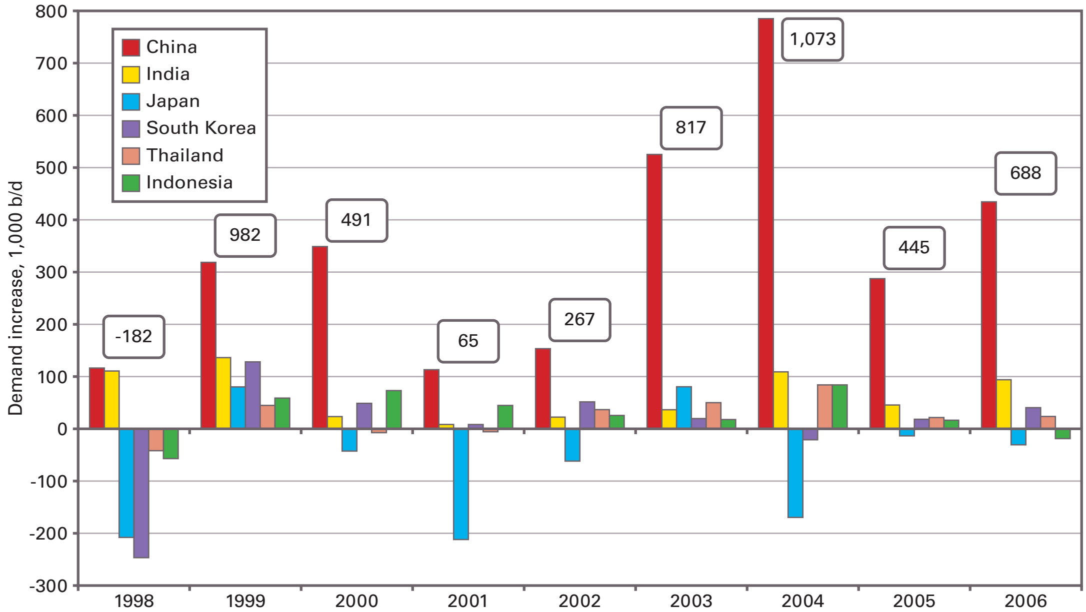


and China. As a result, efforts by those countries to reduce budgetary burdens from subsidizing products were diluted."

In contrast, Indonesia's smuggling seems to have been eliminated after the government substantially raised retail product prices in late 2005. Because subsidies increase a country's budgetary burden and indirectly cause smuggling or the illegal use of oil products, the study recommends their elimination soon.

DEMAND GROWTH IN SELECTED COUNTRIES*

Fig. 2



* The box indicates annual demand growth of the entire Asia-Pacific region

Removal or reduction of subsidies has led to higher domestic product prices in several countries, which has dampened oil product demand. For example, Thailand's diesel subsidy was removed in July 2005; subsequently, demand growth was revised down by about 25,000 b/d for 2005 and 2006.

Indonesia's government more than doubled retail gasoline and diesel prices for residents, resulting in a sharp decrease in oil product demand growth; the study revised downward demand growth in 2005 to 18,000 b/d from 71,000 b/d. Demand in 2006 will decline about 20,000 b/d; previous updates projected it to increase 56,000 b/d.

Rising demand and high domestic product prices have accelerated the substitution of fuels, according to the study. In 2005, a few countries (Thailand, Pakistan, and Malaysia) started promoting biofuels and natural gas vehicles to reduce their dependency on oil even though transportation fuels are usually considered the least substitutable.

Country prospects

China is the major driving force of the region's demand growth; its oil demand growth accounts for about two-thirds of growth in the entire Asia-Pacific region. Fig. 2 shows demand growth for selected Asian countries.

One unique issue has emerged again for China, apparent demand vs. true demand. Apparent demand, used by the IEA in its "Monthly Oil Market Report," stated that China's demand growth in 2005 was only about 150,000 b/d (or 2.4%). Accounting for increases in China's inventories in 2004 and a drawdown in 2005, true demand growth in 2005 was about 290,000 b/d (or 4.7%), according to the study.

This gap in growth rates significantly affects the region's demand-growth expectations. Although the FACTS estimate for China's actual growth in 2005 is higher than IEA's estimate, it is still significantly lower than its 2004 growth (which was almost 800,000 b/d or 14.6%).

The study predicts stronger growth (some 420,000-450,000 b/d) in China's overall oil demand in 2006.

Subsidies in China have also created market distortions. Because the government-regulated domestic product prices in China are still lower than international market prices, subsidies give incentives to China's refiners and wholesalers to export or smuggle oil products abroad to reap higher profits, despite the economy's needing them for growth, thus resulting in product shortages.

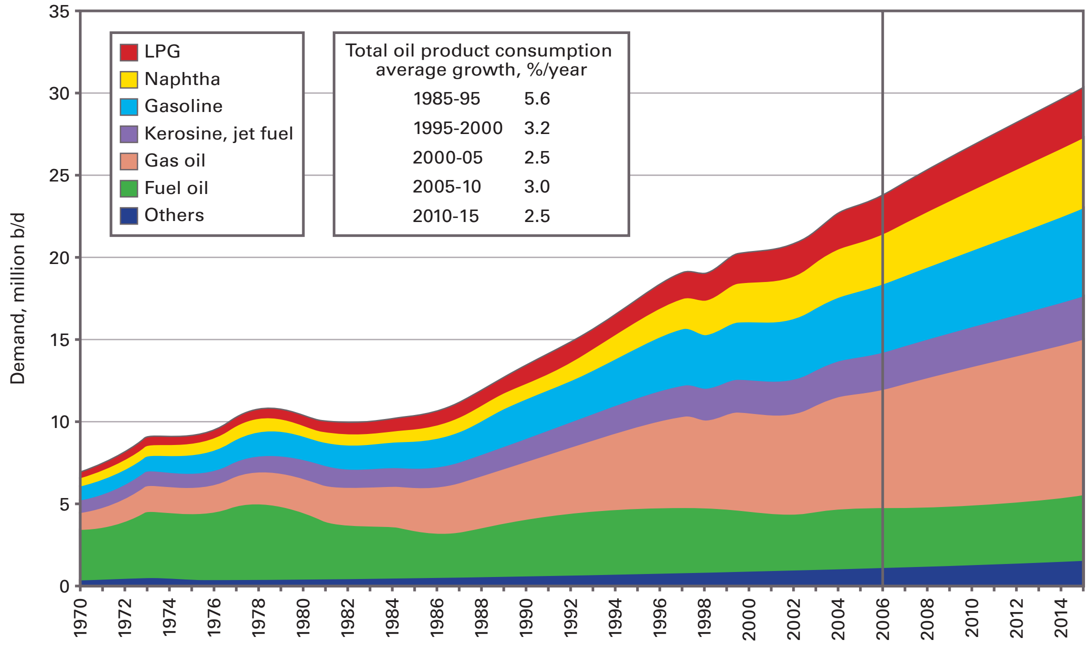
For example, truckers and other diesel consumers in Hong Kong purchased diesel in Guangdong, China, which led to an overall decline in Hong Kong's diesel consumption of 34,000 b/d in 2005. A net result was that Hong Kong's overall demand declined by about 20,000 b/d in 2005, according to the study.

In 2006, the price imbalance between mainland China and Hong Kong will fall. The decline in Hong Kong's diesel demand will be offset by a rebounding of diesel demand (about 11,000 b/d) in 2006.

Given India's high oil-demand growth in 2004 of 111,000 b/d, FACTS expected the country to maintain steady, strong growth of 90,000-110,000

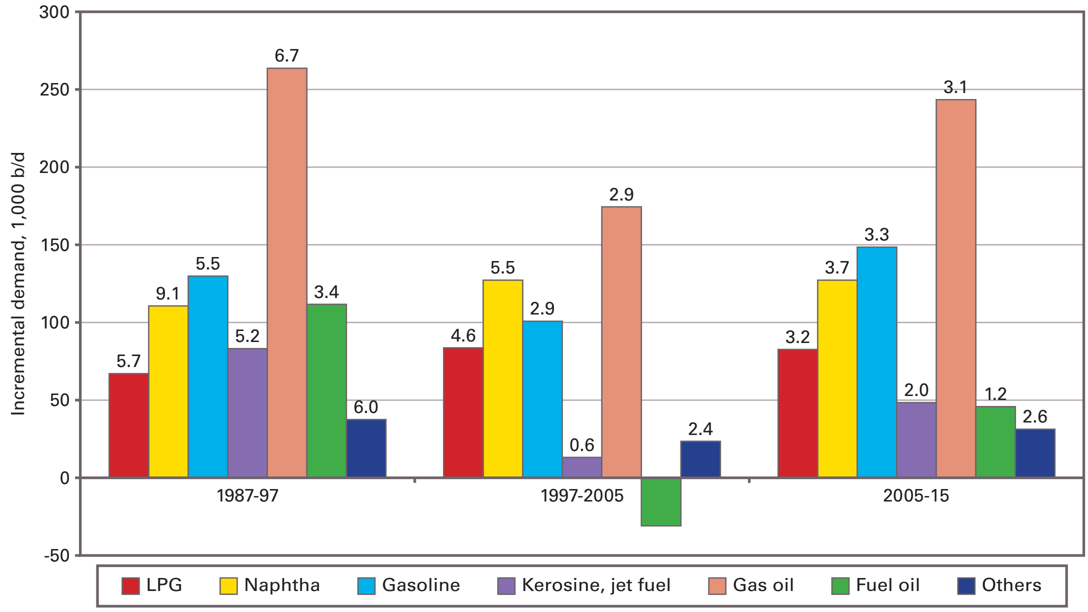
DEMAND BY PRODUCT

Fig. 3



DEMAND GROWTH BY PERIOD*

Fig. 4



* Numbers indicate average growth, %/year

b/d/year during the next decade. Its growth in 2005, however, was revised down to slightly less than 50,000 b/d, despite maintaining its economic growth, most of which is in the less-energy-intensive service sector.

The study also revised downward Pakistan's oil demand to a decline of 22,000 b/d from a 22,000 b/d increase.

India and Pakistan curbed oil-demand growth primarily by substituting natural gas for oil and improving vehicle efficiency. Easier access to natural gas than other countries in Asia-Pacific will allow the continued substitution of natural gas for oil, such as through the use of compressed natural gas in automobiles.

Oil-demand growth in Japan and South Korea moved in opposite directions. Japan's oil demand declined 11,000 b/d in 2005 and will decline by another 30,000 b/d in 2006, according to the study.

South Korea's oil-demand growth turned positive in 2005 and is increasing in 2006 due to its balanced economic conditions and greater consumer confidence; the effects of high oil prices and fuel substitution seems to have peaked.

Australia and New Zealand are posting modest demand growth, about 3% in 2005 and slightly below 2% in 2006, the study predicts. Singapore's demand growth of 34,000 b/d (4.7%) in 2005 was mostly due to strong demand for fuel oil; FACTS expects this growth to slow to about 10,000 b/d (1.2%) in 2006.

Taiwan's demand growth in 2005 was 16,000 b/d (1.7%), led by LPG but offset by substitution of natural gas, coal, and hydropower for fuel oil. In 2006, demand growth will bounce back to 28,000 b/d (2.9%), primarily due to a rebound in naphtha demand and a slowdown in natural gas substitution.

Considerable increases in domestic product prices in late 2005 have made Indonesia the only country, other than Japan, registering a decline (19,000 b/d) in 2006. The study expects Indonesia's oil demand to return to the historical trend (41,000-46,000 b/d/year or an average growth of 3%/year) during 2007-15.

The study projects Thailand's demand growth to be sluggish through 2010 (about 22,000-25,000 b/d/year or 2.4%/year) after the removal of subsidies for gasoline and diesel in 2004 and 2005, respectively.

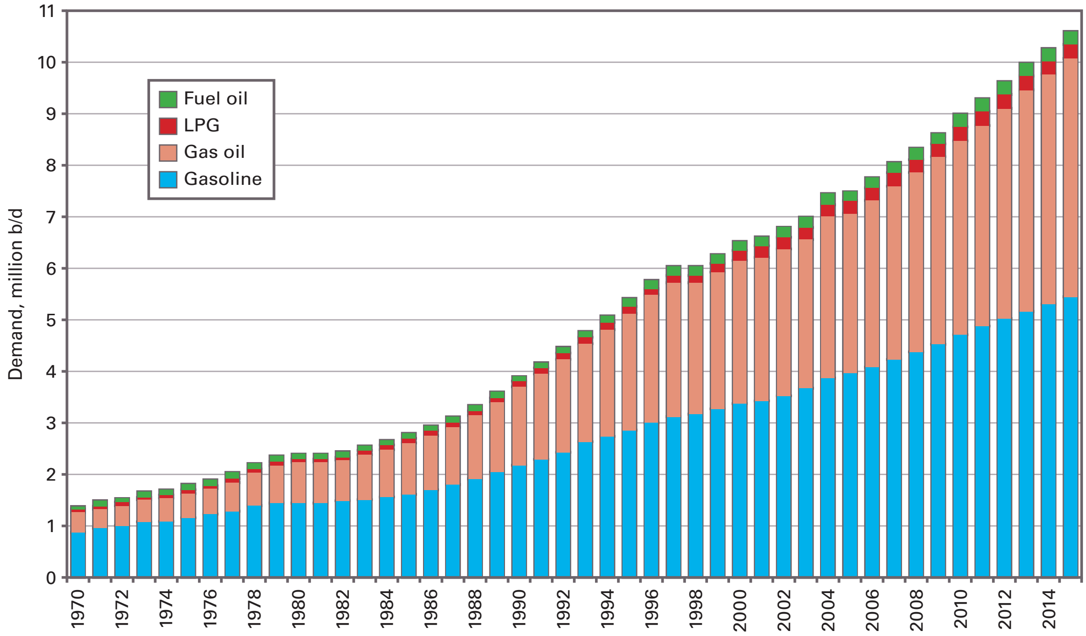
Because the Philippines no longer has a subsidy shield to protect its economy from the rising oil prices, its oil demand declined by nearly 8% (or 25,000 b/d) in 2005, according to the study. Because the country is promoting biodiesel and natural gas, oil demand should be flat or modestly increase in the near future.

Because the Malaysian and Vietnam governments are enjoying substantial revenues from crude exports, their concerns about budgetary burdens from subsidies may not be that serious. Despite increases in 2005, retail prices are still low relative to other countries in the region, thereby sustaining smuggling.

The study therefore expects that oil-product demand growth will remain strong in 2005-06: 20,000-22,000 b/d (about 4%) for Malaysia and 16,000-18,000 b/d (about 7%) for Vietnam.

TRANSPORTATION FUEL DEMAND

Fig. 5



Product prospects

Asia-Pacific's petroleum product demand is becoming lighter (Fig. 3). In 2005, about 30% of product demand was gas oil, followed by gasoline (17%), and fuel oil (16%, including the direct use of crude oil and NGL), according to the study. Shares of naphtha, LPG, kerosine-jet fuel, and others were 12.7%, 9.7%, 9.6%, and 4.6%, respectively.

Fig. 4 shows the average annual demand growth for each petroleum product in three different periods: 1987-97, 1997-2005, and 2005-15. Overall demand growth was fastest during 1987-97 (about 810,000 b/d/year or 5.7%/year) and slowest during 1997-2005 (about 500,000 b/d/year or 2.4%/year) due to the Asian financial crisis and a worldwide recession during 2001-02.

Fig. 4 also shows that gas oil's average growth (in volume) was highest among the products during 1987-2005 and will also be the highest in the future.

In terms of average growth rate, naphtha was the highest during all periods, according to the study. The average growth of fuel oil was –0.8%/year during 1997-2005 due to the substitution of natural gas and other energy sources, particularly in the power sector.

Transportation fuels

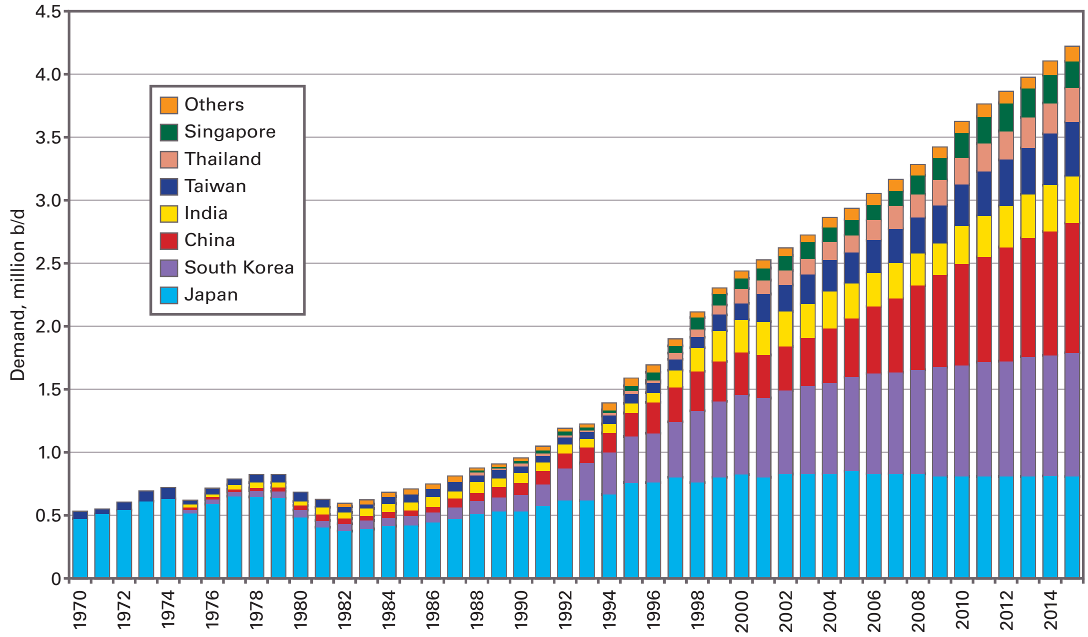
Fig. 5 shows that gasoline has a stable share of 51-53% of the growth in transportation fuels, while gas oil's share has been around 42%, according to the study.

Combined with the removal or reduction of subsidies for transportation fuels in several countries (Thailand, China, Indonesia, and Vietnam), recent persistent high oil prices have slowed demand growth for both gasoline and diesel. In 2005, demand growth for gasoline and diesel were 1.4% and 1.8%, respectively; however, FACTS expects demand growth for both products to bounce back to 3.6-3.7% in 2006.

In the mid-term, demand for these products will continue to grow at similar rates, according to the study. And

NAPHTHA DEMAND

Fig. 6



because low-sulfur diesel specifications are becoming popular (Japan, South Korea, and Singapore), diesel will continue to register higher consumption rates in the region.

Average growth for gasoline and diesel demand should be about 3.1-3.7%/year by 2010 and should continue to be about 3%/year after that, according to the study.

Kerosine-jet fuel

Jet-fuel demand grew 11% in 2004 and 6% in 2005 due to the surge in international aviation. Similar to transportation fuels, there are no immediate substitutes for jet fuel, and its demand will grow at about 4%/year during 2005-10 despite high oil prices.

Due to its easy substitution, kerosine's demand has been declining slightly (about 1%/year during 2000-03). The study notes, however, that kerosine consumption increased almost 3% in 2005 due to unexpectedly cold weather in Japan and South Korea during November and December, followed by an expected decline of about 4% in early 2006 due to warmer weather in these two countries.

Fuel oil

Japan, South Korea, Taiwan, Singapore, and even Hong Kong are switching or planning to switch from fuel oil to natural gas for electricity generation. Although they are leaning more towards LNG, however, a further increase in natural gas consumption through LNG might be limited, due to the recent tight supply, according to the study.

Fuel oil used in the industrial sector exhibits a pattern similar to that of the power sector—it has been declining by about 1%/year in the last decade due to substitution of natural gas and other sources. Fuel oil used for bunkering, however, has been steadily increasing since the mid-1980s, with an average growth of about 6%/year. The study projects that fuel oil demand in the industrial sector will grow about 2.4%/year through 2015.

Other uses accounted for about 14% of total fuel oil consumption in 2005; this demand will only slightly increase. The region's overall demand for fuel oil increased 0.5% in 2005 and will grow modestly (about 1.2%/year) during 2005-15.

LPG

Although LPG's share of Asia-Pacific's oil demand is slightly less than 10%, its demand has been growing rapidly in the past 10 years. In 2005, LPG demand grew about 100,000 b/d (or 4.6%), according to the study. Overall, LPG demand will grow at about 4.5%/year through 2010 and 3%/year during 2010-15.

Naphtha

Demand growth for naphtha was the fastest among all products at 9.1%/year and 5.5%/year during 1987-97 and 1997-2005, respectively. Naphtha-demand growth in 2005 was relatively weak because of a significant decline in India due to substitution and a slump in Taiwan, according to the study.

Fig. 6 shows that Japan dominated naphtha consumption before 1990 and that South Korea and China are rapidly catching up. In 2005, Japan and South Korea had nearly equal shares of Asia-Pacific's naphtha market (29% and 26%, respectively), followed by China (16%), India (9%), and Taiwan (8%).

The study predicts that naphtha demand will continue to increase and show the highest growth rate in the next decade due to rising demand for the product as a petrochemical feedstock. Its demand will to grow about 4.4%/year (or 140,000 b/d/year) during 2005-10, and about 3%/year during 2010-15. ✦

PIPELINE FAILURE RATES—CONCLUSION

Pipeline grouping method improves aggregate data

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This concluding part of an article exploring a model for reducing statistical uncertainty when pooling pipeline data applies Part 1's methodology to actual pipeline-failure data compiled by the US Office of Pipeline Safety (OPS) 1994-2005. It also applies the methodology to estimate the failure rates in multiple onshore pipeline systems in Southern Mexico, for which failure data were gathered 1995-2004.

Pipeline reliability analyses struggle between the need to increase the number of km-years from which failure data are gathered in an effort to reduce statistical uncertainty and the need to avoid statistical uncertainties caused by pooling disparate data.

Part 1 of this article described a usable method for considering both the statistical and tolerance uncertainties of merged data to produce more accurate reliability predictions (OGJ, Sept. 25, 2006, p. 64). The methodology Part 1 outlined should be able to address failure processes with constant and time-dependent rates, test whether pooling of failure data across systems can occur, and reduce the statistical uncertainties in the estimation.

The primary pipeline attribute considered by this article is location of facilities. Future studies will analyze annual failure rates in terms of diameter, wall thickness, stress level, and age.

This article first applies Part 1's methodology to pipeline failure data reported by the OPS. A homogeneous Poisson process [HPP] model calculates the average failure rates and confidence intervals, leading to the functional form (Power Law Process) of the failure intensity and identifying data that can be merged under both assumptions. The article will next apply the same procedure to the Mexican data.

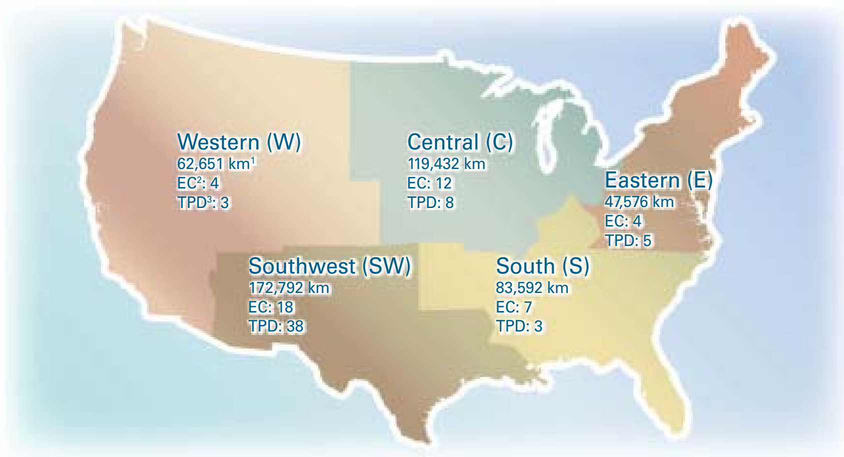
System identification, statistics

The information reported by OPS identifies 10 clearly defined US systems according to location: 5 gas transmission pipeline systems in the southern region (S), southwest region (SW), western region (W), center region (C), and eastern region (E); and 5 oil transmission systems in the same regions. The states which comprise each of these systems can be determined from the OPS web page.[1]

This article focuses on two failure causes: external corrosion (EC) and third-party damage (TPD), two of the three leading causes of incidents in the US (along with internal corrosion; IC).

FAILURE STATISTICS BY OPS REGION, 1994-2005

Fig. 1



[1]Total gas transmission km in region. [2]Number of external corrosion failures. [3]Number of third-party damage failures.

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Equations

$$\bar{\hat{\lambda}}_{np} = \frac{N(T_{exp})}{L_{exp} T_{exp}} \quad (1)$$

$$F = \frac{\hat{\lambda}_1}{\hat{\lambda}_2} \approx F(2N_1, 2N_2)$$

Where:

N_1 and N_2 = the total number of failures in systems 1and 2, respectively, during the observation period.

$$N(t) = (t/\theta)\,\beta \quad (3)$$

Where:

θ and β = the scale and shape parameter respectively.

$$N(t)_{TPD} = 3.322t^{1.143} \text{ and } N(t)_{EC} = 0.003t^{3.904} \quad (4)$$

$$\chi^2_{\alpha/2}(2N(T_{exp})) < \frac{2N(T_{exp})}{\hat{\beta}}$$

or (5)

$$\frac{2N(T_{exp})}{\hat{\beta}} < \chi^2_{\alpha/2}(N(T_{exp}))$$

$$LR = -2N_T(T_{exp})\ln\left(\frac{N_T(T_{exp})}{T_{exp} L^T_{exp}}\right) + 2\sum_{i=1}^{k} N_i(T_{exp})\ln\hat{\lambda}_i \quad (6)$$

Where:

$N_i(T_{exp})$ and $N_T(T_{exp})$ = the number of failures in the i–th system and in all systems over the observation period T_{exp}, respectively.

L^T_{exp} = the total length of these systems.

$$LRM = \frac{LR}{1 + \left(\sum_{i=1}^{k} N_i(T_{exp})^{-1} - N_T(T_{exp})^{-1}\right)(6(k-1))^{-1}} \quad (7)$$

$$LRK = \frac{2\sum_{i=1}^{k} N_i(T_{exp})\ln\hat{\beta} - N_T(T_{exp})\ln\beta^*_i}{1 + \left(\sum_{i=1}^{k} N_i(T_{exp})^{-1} - N_T(T_{exp})^{-1}\right)(6(k-1))^{-1}} \quad (8)$$

$$\beta^*_i = \frac{N_T(T_{exp})}{\sum_{i=1}^{k} N_i(T_{exp})\hat{\beta}^{-1}} \quad (9)$$

$$\hat{d} = \sum_{i=1}^{k}(N_i(T_{exp}) - \bar{N}(T_{exp}))^2/N(T_{exp}) \quad (10)$$

Where:

$$\bar{N}(T_{exp}) = \frac{1}{k}\sum_{i=1}^{k}(N_i(T_{exp})$$

$$\lambda(t) = (2x10^{-8})\,t^{2.90} \quad (11)$$

$$N(T_{exp}) = \sum_{i=1}^{n_d} ?_i \text{ and } L_{exp} = \sum_{i=1}^{n_d} l_i \quad (12)$$

$$\frac{\chi^2_{\alpha/2}(2N(T_{exp}))}{2L_{exp} T_{exp}} < \lambda < \frac{\chi^2_{\alpha/2}(2N(T_{exp}))}{2L_{exp} T_{exp}} \quad (13)$$

Where:

$\chi^2_v(N)$ = the value of the chi–square with n degrees of freedom distribution that produces a probability v.

$$\hat{\beta} = \frac{N(T_{exp})}{N(T_{exp})\ln(T_{exp}) - \sum_{i-1}^{N(T_{exp})}\ln(t_i)} \quad (14)$$

Where:

t_i = the time of the i–th failure

$N(T_{exp})$ = the total number of failures occurring in all pipelines in exposition time, T_{exp}.

$$\frac{\chi^2_{1-\alpha/2}(2N(T_{exp}))\hat{\beta}}{2N(T_{exp})} < \beta < \frac{\chi^2_{\alpha/2}(2N(T_{exp}))}{2N(T_{exp})} \quad (15)$$

$$F = \frac{\hat{\beta}}{\hat{\beta}_1} \approx F(2N_1, 2N_2) \quad (16)$$

Where:

N_1 and N_2 = the total number of failures in systems 1and 2, respectively, over the observaton period.

$$\hat{P} = 2P(n_{\geq} N_1(T_{exp})\,|\,N_T(T_{exp}), S) =$$
$$2(1 - P(n_1 < N_1(T_{exp})\,|\,N_T(T_{exp}), S))$$
$$Pn_1 < N_1(T_{exp})\,|\,N_T(T_{exp}), S) = \quad (17)$$

$$\frac{1}{c}\sum_{n-0}^{n_i}\left\{Bin(N_T(T_{exp}), n)\begin{pmatrix} n\ln(L^1_{exp}/L^2_{exp} + \\ N_T(T_{exp})\ln(T_{exp}L^2_{exp}) - S \end{pmatrix}^{N_T(T_{exp})-1}\right\}$$

with:

$$c = \sum_{n-0}^{N_T(T_{exp})}\left\{Bin(N_T(T_{exp}), n)\begin{pmatrix} n\ln(L^1_{exp}/L^2_{exp} + \\ N_T(T_{exp})\ln(T_{exp}L^2_{exp}) - S \end{pmatrix}^{N_T(T_{exp})-1}\right\}$$

$$S = \sum_{i-1}^{N_T(T_{exp})}\ln(t_i - 0.5)$$

Where:

Bin ( ) = the binominal coefficient.

Results of EC null hypothesis test H_0: HPP, with $\alpha = 5\%$

Table 1

OPS system	Gas Transmission Experimental statistics $t = \frac{2N(T_{exp})}{\hat{\beta}}$	$(\chi^2\alpha/2(2N(T_{exp})), \chi^2 1-\alpha/2((2N(T_{exp})))$	Reject H_0: HPP with α = 0.05?
S	2.11	(5.62, 26.11)	Yes
SW	14.02	(21.33, 54.43)	Yes
W	1.28	(2.17, 17.53)	Yes
E	1.28	(2.17, 17.53)	Yes
C	4.34	(12.40, 39.36)	Yes

TPD accounted for 308 incidents of a total 1,084 reportable incidents on US gas transmission and gathering systems 1985-97.[2] EC accounted for 109 incidents in the same period, while reportable failure incidents from IC numbered 130.

The article focuses only on onshore pipelines, since offshore mileage is a minor fraction of the total reported by OPS. There are 288,388 miles of onshore transmission pipelines but only 8,101 miles of offshore transmission lines; 2.73% of the total.

Fig. 1 shows the total number of failures in each region 1994-2005 for the two failure causes considered.

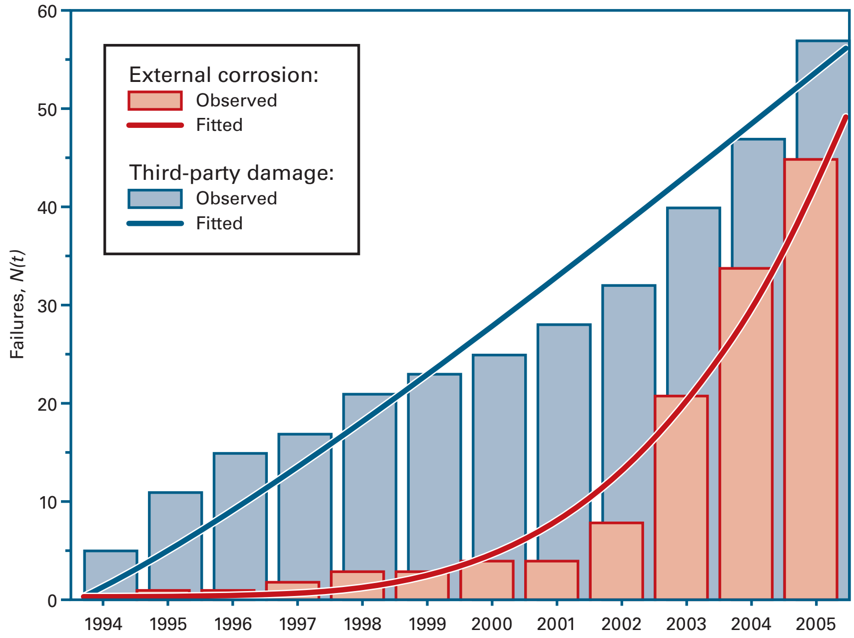
HPP estimates

Equation 1 estimates the average failure data for US pipelines. EC led to roughly 8 failures/million km-years, and TPD to about 1 failure/100,000 km-years. The breadth of the 95% confidence level of the estimated rates makes the statistical uncertainties in these estimates satisfactory.

The failure rates estimated by Kiefner et al. for incidents produced by external corrosion and third-party damage 1985-97 in gas transmission pipelines are similar.[2] They found an estimated

US gas transmission failures, cumulative

Fig. 2



Nonparametric estimates, average failure rate for each cause

Table 2

Cause	System	$\bar{\Lambda}$ (λ[1])	95% CI	Error (%)[2]
External corrosion	AG	1.8×10^{-3}	$[1.1, 2.6] \times 10^{-3}$	4
	BG	1.7×10^{-3}	$[1.2, 2.3] \times 10^{-3}$	3
Internal corrosion	AG	3.9×10^{-4}	$[1.2, 8.0] \times 10^{-4}$	19
	BG	6.4×10^{-4}	$[0.3, 1.0] \times 10^{-3}$	8
Mechanical damage	AG	7.8×10^{-5}	$[0.02, 2.9] \times 10^{-4}$	91
	BG	5.3×10^{-5}	$[0.01, 2.9] \times 10^{-4}$	92
Materials, construction	AG	3.9×10^{-4}	$[1.2, 8.0] \times 10^{-4}$	19
	BG	1.6×10^{-4}	$[0.3, 3.9] \times 10^{-4}$	32
Other	AG	1.6×10^{-4}	$[0.2, 4.3] \times 10^{-4}$	47
	BG	5.3×10^{-4}	$[2.6, 9.1] \times 10^{-4}$	10
All	AG	2.8×10^{-3}	$[1.9, 3.7] \times 10^{-3}$	3
	BG	3.0×10^{-3}	$[1.9, 3.7] \times 10^{-3}$	3

[1]From Equation 1. [2]Computed as the width of the 95% CI divided by four times the estimated value.

failure rate for external corrosion equal to 1.5×10^{-5} km-year and a corresponding estimation for third-party damage of 4.2×10^{-5} km-year. Both failure causes allow postulation of a reduction in failure rate from one period to the other.

Applying the Fisher (F) test (Equation 2) to this case demonstrates that the data collected for these two time periods cannot be merged. The P-value associated with rejecting the null hypothesis H_0: $\lambda_1 = \lambda_2$ is less than 0.1%, meaning that the reduction in the average failure rate with time is statistically significant at 95% confidence. Better operating and maintenance practices, changes in pipeline safety regulations, and new reporting criteria for incidents are among the possible explanations for this change.

NHPP analysis

Incidents due to external corrosion reduce pipeline reliability. A nonhomogeneous Poisson process (NHPP) can model corrosion-related processes. Fig. 2 shows the relationship of the cumulative number of incidents to their years of occurrence for gas transmission pipelines. Data analysis suggests that failures produced by third-party damage have a constant failure rate, while external corrosion deteriorates the reliability of these pipelines.

Equation 3 fits the data to the law, and the 95% confidence for the calculated shape parameter β was calculated and then used to test the adequacy of the homogeneous Poisson process against the power law model (PLP). Equation 4 shows the final expressions for the cumulative number of failures for TPD and EC.

Formally applying the homogeneity test (Equation 5) to the data corroborates the trends observed in Fig. 2 and allows for rejection of the null hypothesis H_0: $\beta = 1$ for external corrosion with $\alpha = 0.05$. The null hypothesis cannot be rejected at the chosen significance level for TPD.

Strong evidence exists against the hypothesis that failures due to EC occur with constant failure rate, while the opposite holds true for TPD.

Merging assumptions

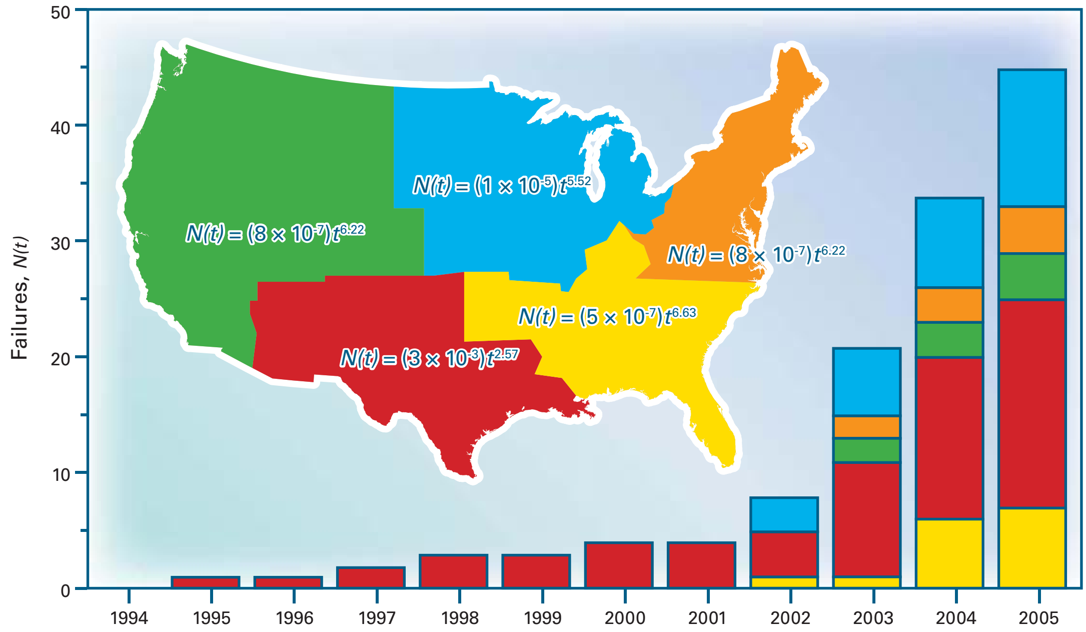
Assuming HPP, Equations 2, 6, and 7 test if data from different systems can be aggregated. The assumption that the five OPS systems follow NHPP determined the applicability of pooling their failure data. The time evolution of failures suggests that, regarding external corrosion, the five OPS regions suffer from deteriorating reliability with different trends. Fig. 3 checks the parameters of the power law process for the analyzed regions. The southwest region follows a different deteriorating process from the others.

Applying the homogeneity test and statistical test (Equation 5 and Equations 8-10) corroborates the gathered data formally. The null hypothesis, H_0: $\beta = 1$, can be rejected for the five systems with a 5% confidence level (Table 1). The null hypothesis H_0: $\beta_1 = \beta_2 = \ldots \beta 5$ cannot be rejected at a 5% significance level (Equation 8), but the hypothesis H_0: $\lambda_1 = \lambda_2 = \ldots \lambda_5$ can be rejected at the chosen significance level. Doing so allows the failure rates of these systems to be treated as identical.

Data corroborated that failure rates due to TPF were improving in the

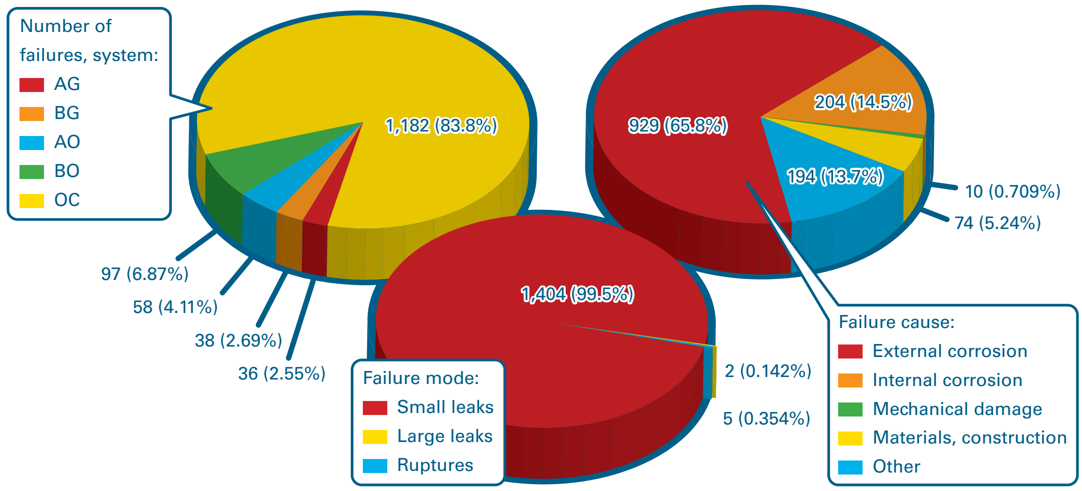
REGIONAL CUMULATIVE EC FAILURES, RATES

Fig. 3



SOUTHERN MEXICO FAILURES, 1995-2004

Fig. 4



southwest region but were steady in the other OPS regions.

OPS summary

External corrosion is deteriorating the reliability of onshore gas pipelines in the US, with different trends in the five OPS regions. Equation 11 describes the intensity function of the pooled data. Fig. 3 displays the intensity functions for each analyzed region.

Third-party damages show a constant failure rate for four of the five OPS regions, and growing reliability in the Southwest. Pooling failure data across OPS regions and gathering failure data from different time periods should be done with extreme caution.

Southern Mexico

Five systems are in place in Southern Mexico; two gas transmission pipeline systems, one managed by Operator A and the other managed by Operator B (AG and BG); two oil transmission systems (AO and BO) and one oil gathering system managed by Operator C (CO).

Four principal failure causes affect the systems:

- External corrosion (EC).
- Internal corrosion (IC).
- Mechanical damage (MD).
- Defective materials or bad construction practices (MC).

The category "other" (OT) captures all other failure causes.

Failures classifications include:

- Small leaks (SL).
- Large leaks (LL).
- Ruptures (RU).

Fig. 4 shows the combined failure statistics of the five pipeline systems from 1995 to 2004. The largest number of incidents occurred in the OC system, making it an easy system to identity.

Fig. 4 also shows that most of the reported incidents were small leaks. Given this, and for the sake of simplification, the balance of this article will assess the failure data without regard to failure mode.

EC and IC (in that order) caused the largest number of pipeline incidents in the combined statistic. This also occurred in each of the identified systems.

Average failure rates

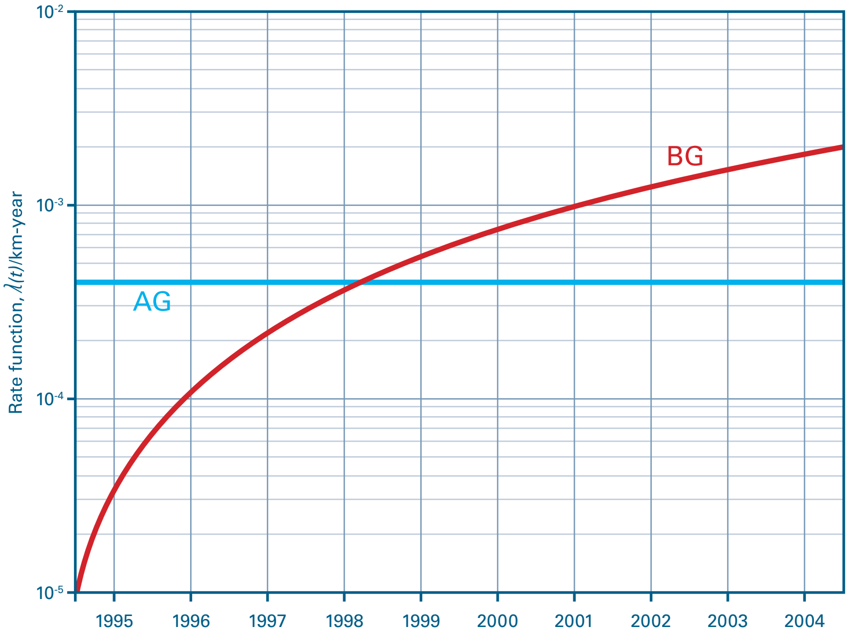
The assumption that the reported incidents follow homogeneous Poisson processes provided the basis for 1995-2004 average failure-rate estimates associated with the failure causes for the five systems. This stage of the analysis used Equations 1, 12, and 13, computing confidence intervals (CI) for a 5% significance level with the error of estimation. Table 2 shows the results of the estimations for the two gas systems (AG and BG).

In agreement with Fig. 4, corrosion-related incidents show the highest failure rate in these systems, while incidents due to mechanical damage show the lowest rate. MD, however, also has the largest statistical uncertainty, likely due to the small number of incidents reported for this cause during the observation period.

Table 2 gives failure-rate values larger than those previously published.[2 3] The majority of the reported incidents studied here are small leaks, leading to larger failure rate values, while previous works focused on large leaks and ruptures.[3] Table 2's results allow identification of unreliable estimates as measured by the width of the prediction's confidence intervals.

Examples of inaccurate estimates include those produced for mechanical damage in systems AG and BG.

EC FAILURE RATES; AG, BG SYSTEMS Fig. 5



Merging data

Under an assumption of an HPP, testing occurred at a 5% significance level for all failure causes. No reason exists to reject the hypothesis that the failure rates in both systems are equal for all failure causes.

The tests conducted for the oil pipeline systems, however, show that the failure data gathered cannot be aggregated, as doing so would produce a large tolerance uncertainty in the failure rate estimate for the merged data.

Testing the oil systems both in pairs and with all three together corroborated this result.

Merging the failure data gathered for these oil pipeline systems in an effort to reduce the statistical uncertainty of the failure rate estimation should be strongly discouraged because of the physical, environmental, and maintenance differences between these systems. Testing formally corroborated these differences, apparent from the beginning of the analysis. Merging the data will introduce a large tolerance uncertainty in the failure rate estimation of the merged datasets.

The results for gas pipeline systems, however, recommend merging the failure datasets. Doing so will reduce statistical uncertainty in estimating failure rates without introducing a significant tolerance uncertainty.

Table 3 shows average failure rate estimates for all the gas pipelines studied. Detailed comparison of these results with those given in Table 2 shows that, for all the failure causes, the error in estimating the corresponding failure rate diminishes for the merged data. The failure rate estimated for MD-related incidents, however, continues to have a large statistical uncertainty, with only two incidents for this cause reported in the merged data.

AVERAGE MERGED-DATA FAILURE RATES BY CAUSE Table 3

Cause	$(\hat{\lambda})$[1]	95% CI	Error (%)[2]
External corrosion	1.8×10^{-3}	$[1.3, 2.2] \times 10^{-3}$	2
Internal corrosion	5.4×10^{-4}	$[3.1, 8.2] \times 10^{-4}$	6
Mechanical damage	6.3×10^{-5}	$[0.8, 18] \times 10^{-5}$	48
Materials, construction	2.5×10^{-4}	$[1.1, 4.6] \times 10^{-4}$	12
Other	3.8×10^{-4}	$[2.0, 6.2] \times 10^{-4}$	11
All	3.0×10^{-3}	$[2.4, 3.6] \times 10^{-3}$	1

[1]From Equation 1. [2]Computed as the width of the 95% CI divided by four times the estimated value.

Power law model

Applying the data gathered in each system for failures caused by external and internal corrosion offered insight into the possibility that the power law model defined in Equation 3 could fit the corrosion-related failure data better than the homogeneous Poisson model. Equations 14 and 15 respectively produced the 95% confidence interval for the shape parameter β and tested the adequacy

Parameters of intensity functions ($\lambda(t)$)

Table 4

System	Cause	$\hat{\beta}$ *	$\hat{\theta}$	95% CI for β	Best model
AG	EC	1.695	1.510	[1.052, 2.403]	NHPP, $\beta > 1$
	IC	2.614	5.402	[0.849, 5.354]	HPP, $\beta = 1$
AO	EC	1.055	0.614	[0.636, 1.580]	HPP, $\beta = 1$
	IC	0.551	0.230	[0.238, 0.993]	NHPP, $\beta < 1$
BG	EC	1.556	1.079	[1.065, 2.141]	NHPP, $\beta > 1$
	IC	2.716	4.005	[1.404, 4.455]	NHPP, $\beta > 1$
BO	EC	1.585	0.772	[1.204, 2.019]	NHPP, $\beta > 1$
	IC	1.340	1.067	[0.818, 1.99]	HPP, $\beta = 1$
CO	EC	0.825	0.003	[0.767, 0.883]	NHPP, $\beta < 1$
	IC	0.891	0.334	[0.758, 1.035]	HPP, $\beta = 1$

*From Equation 14.

of the homogenous Poisson process against the power model.

Table 4 shows the results of this analysis, distinguishing the pipeline systems that follow a power law process from those that are best modeled by a homogeneous (stationary, with $\beta = 1$) Poisson process. The power law model allows corroboration of systems both in which maintenance has not been adequate to avoid reliability deterioration ($\beta > 1$) and in which maintenance has lead to reliability improvement ($\beta < 1$).

Fig. 5 shows the time evolution of the cumulative number of failures caused by external corrosion in the BG system. It also plots the intensity function for the AG system, which shows stationary behavior.

Table 4 also identifies the failure datasets that follow a power law process and could be merged following the methods outlined in Part 1 to reduce the statistical uncertainty associated with the estimation of the corresponding failure intensity function. Analysis of this information reveals that the only possibility is to test whether the failure data gathered in the gas pipeline systems for EC-caused incidents can be merged.

Equations 16 and 17 tested gas pipeline systems AG and BG (numbered 1 and 2, respectively). This computation scheme found $N_1(T_{exp}) = 23$, $N_2(T_{exp}) = 32$, and the experimental statistics $F\beta = 0.91$ (Equation 16), concluding that there are no arguments to reject the hypothesis that the shape parameters (β's) are equal at the 5% significance level.

In a second step, Equation 17 investigated if the failure intensity function of the two systems could be assumed to follow the same power law. The value of the experimental statistic was found to be 0.36, leading to acceptance of the hypothesis that the failures caused by EC in the two gas pipelines systems follow the same power law process, with intensity ($\lambda(t) = (4.4 \times 10^{-4})t^{0.598})$/km-year.

This prediction has a reduced statistical uncertainty for the failure caused by external corrosion in gas pipeline systems, as compared to Table 4.

Acknowledgments

The authors thank Hugo Huescas who gathered part of the failure data used in this work. They are also grateful to Petróleos Mexicanos (Pemex) for permission to publish these results. ✦

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2. Kiefner, F., Mesloh, R. E., and Kiefner, B. A., "Analysis of DOT Reportable Incidents for Gas Transmission and Gathering System Pipelines: 1985 Through 1997," Pipeline Research Council International, Catalogue No. L51830E, 2001.

3. Nessim, M., Zhou, W., Zhou, J., Rothwell, B., and McLamb, M., 2004, "Target Reliability Levels for Design and Assessment of onshore Natural Gas Pipelines," International Pipeline Conference, Paper IPC04-0321, Calgary, Oct. 4-8, 2004.

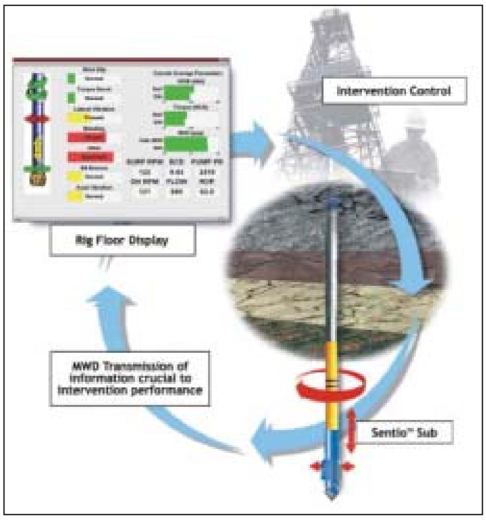
Equipment/Software/Literature

New system acquires critical data downhole

This new Smart Intervention service system acquires critical data downhole and transmits that data to the surface to provide information on intervention parameters.

The company says the information gives well teams a better understanding of what is happening at the business end of the intervention bottomhole assembly. Armed with this knowledge, well teams can make informed, just-in-time decisions that can optimize well intervention operations and significantly reduce nonproductive time and risk exposure, the firm notes.

The enabling technology for the service is the Sentio tool, a downhole acquisition tool. The tool contains an array of sensors that measures weight or pull on tool, torque, rpm, bending stress, vibration, and pressure simultaneously at a high data rate. A digital signal processor analyzes the data stream and provides static parameters and diagnostics that are transmitted to a rig-floor monitor and can also be sent to a remote real-time operating center. Portions of the information can also be recorded in the on-board memory and stored, then retrieved later at the surface for detailed evaluation.



At the surface, data are presented to the intervention operator, and based on the feedback, the team and the operator determine how to advance the intervention operation. Choices may include parameter changes in a milling operation, pulling out of hole after confirming successful connection to a fish, or working the pipe to overcome a weight transfer problem.

Depending on the type of intervention operation, the engineer may require different types of downhole information. For efficiency, customized transmission formats are being developed. In addition to the up-hole data transmission, the bottomhole assembly is capable of receiving downlink signals and provides a link for remote control of future intervention tools. A rig-floor display screen presents the downhole parameters in the clearest and most meaningful manner and can be linked to a remote real-time operations center.

Source: **Baker Oil Tools**, 9100 Emmott Rd., Houston, TX 77040.

Services/Suppliers

Gray Energy Services LLC

Fort Worth, has announced the acquisition by its subsidiary, Gray Wireline Service Inc., of Southern Wireline Service Inc., a longstanding independent provider of cased-hole wireline services in the onshore and transition zone regions of the Gulf Coast and offshore Gulf of Mexico.

Southern Wireline Service Inc., founded in 1968, is based in Lafayette, La.

Gray Energy Services LLC was formed in early 2006 by Centre Partners, Centre Southwest Partners, and Gray Wireline Service Inc., as a platform to build a leading diversified provider of production enhancement solutions across the North American natural gas and oil production industry.

Invensys Group

Foxboro, Mass., has announced the appointment of Tom Kinney as director of performance services for the Process Systems Div. Kinney returns to Invensys after a stint as sales vice-president at ExperTune Inc. He had previously worked for Foxboro and Invensys for 22 years.

Invensys Group, headquartered in London, is a leading provider of industrial asset performance management products used in upstream projects, refineries, gas plants, petrochemical plants, power plants, and pulp and paper mills.

Willbros Group Inc.

Houston, has announced the resignations of Clay Etheridge, president of Willbros International Inc. (WII), and James R. Wiggins, vice-president of WII and country manager for Nigeria.

Jerrit Coward, formerly senior manager in Nigeria, will serve as country manager for the area. Coward has over 14 years of experience, including multiple assignments in West Africa.

John Allcorn, executive vice-president, will have executive management responsibilities for operations in America, Oman, and other international venues addressed by the company.

Willbros President and COO, Randy Harl, will assume direct management of the four major projects in Nigeria, with managers reporting directly to him.

Willbros Group Inc. is an independent contractor serving the oil, gas, and power industries. The company provides engineering and construction services worldwide.

Wood Group ESP

Houston, has appointed Harry Pollemans as region manager, Asia Pacific, based in Perth. Pollemans has 32 years of experience in industrial and electrical submersible pumping markets. He holds bachelor's degrees in electrical engineering, marketing, and management.

Wood Group ESP, a part of John Wood Group PLC, is a leading service provider and manufacturer of electric submersible and surface pumps.

Editor's note: Due to a holiday in the US, API data were not available at presstime.

OGJ GASOLINE PRICES

	Price ex tax 11-15-06	Pump price* 11-15-06	Pump price 11-16-05
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	174.6	214.3	239.0
Baltimore	173.3	215.2	222.5
Boston	175.5	217.4	215.2
Buffalo	180.1	240.2	228.9
Miami	187.1	237.4	222.2
Newark	175.6	208.5	228.4
New York	171.3	231.4	234.2
Norfolk	172.2	209.8	240.2
Philadelphia	182.4	233.1	237.1
Pittsburgh	171.6	222.3	228.5
Wash., DC	187.9	226.3	238.7
PAD I avg.	177.4	223.3	230.4
Chicago	207.6	258.5	236.8
Cleveland	173.6	220.0	222.1
Des Moines	167.7	208.1	218.3
Detroit	177.4	226.6	222.7
Indianapolis	177.8	222.8	218.3
Kansas City	173.9	209.9	211.2
Louisville	180.7	217.6	218.6
Memphis	171.1	210.9	227.3
Milwaukee	182.1	233.4	241.0
Minn.-St. Paul	180.4	220.8	214.4
Oklahoma City	172.5	207.9	202.7
Omaha	177.1	223.5	212.7
St. Louis	179.0	215.0	228.7
Tulsa	173.9	209.3	199.8
Wichita	173.1	216.5	201.7
PAD II avg.	177.9	220.0	218.4
Albuquerque	180.7	217.1	231.1
Birmingham	174.9	213.6	220.9
Dallas-Fort Worth	174.6	213.0	230.3
Houston	168.8	207.2	222.5
Little Rock	171.9	212.1	216.0
New Orleans	174.9	213.3	263.2
San Antonio	170.9	209.3	225.0
PAD III avg.	173.8	212.3	229.9
Cheyenne	184.0	216.4	223.5
Denver	172.1	212.5	233.2
Salt Lake City	184.2	227.1	239.5
PAD IV avg.	180.1	218.6	232.1
Los Angeles	189.0	247.5	262.3
Phoenix	186.4	223.8	241.8
Portland	206.7	250.0	229.9
San Diego	193.5	252.0	263.5
San Francisco	211.6	270.1	268.3
Seattle	207.6	260.0	246.0
PAD V avg.	199.1	250.6	252.0
Week's avg.	**180.3**	**223.9**	**229.2**
Oct. avg.	**183.8**	**228.0**	**263.9**
Sept. avg.	**208.9**	**253.3**	**282.5**
2006 to date	**216.0**	**259.6**	—
2005 to date	**182.5**	**224.5**	—

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

REFINED PRODUCT PRICES

	11-10-06 ¢/gal		11-10-06 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	157.85	New York Harbor	164.38
Gulf Coast	157.35	Gulf Coast	164.38
Los Angeles	179.10	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	147.30	ARA	171.77
Singapore	151.76	Singapore	167.10
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	156.85	New York Harbor	103.05
Gulf Coast	155.35	Gulf Coast	91.07
Los Angeles	187.10	Los Angeles	113.07
		ARA	94.23
		Singapore	104.07

Source: DOE Weekly Petroleum Status Report.
Data available in Oil & Gas Journal Energy Database.

BAKER HUGHES RIG COUNT

	11-17-06	11-18-05
Alabama	5	6
Alaska	6	9
Arkansas	25	14
California	35	30
Land	31	26
Offshore	4	4
Colorado	83	83
Florida	0	2
Illinois	0	0
Indiana	0	0
Kansas	14	6
Kentucky	11	5
Louisiana	193	181
N. Land	56	52
S. Inland waters	19	20
S. Land	46	38
Offshore	72	71
Maryland	0	0
Michigan	2	1
Mississippi	14	11
Montana	17	25
Nebraska	0	0
New Mexico	92	88
New York	12	5
North Dakota	39	25
Ohio	8	9
Oklahoma	178	156
Pennsylvania	15	14
South Dakota	1	2
Texas	771	657
Offshore	9	6
Inland waters	3	1
Dist. 1	16	18
Dist. 2	24	29
Dist. 3	60	64
Dist. 4	93	64
Dist. 5	140	115
Dist. 6	120	98
Dist. 7B	37	23
Dist. 7C	41	35
Dist. 8	107	84
Dist. 8A	24	25
Dist. 9	38	29
Dist. 10	59	66
Utah	47	30
West Virginia	29	25
Wyoming	91	89
Others—HI-1; ID-1; NV–1; OR-1; TN-2; VA-1; WA-1	8	5
Total US	**1,696**	**1,478**
Total Canada	**452**	**619**
Grand total	**2,148**	**2,097**
Oil rigs	289	265
Gas rigs	1,402	1,209
Total offshore	86	83
Total cum. avg. YTD	**1,640**	**1,371**

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

Source: Baker Hughes Inc.
Data available in Oil & Gas Journal Energy Database.

SMITH RIG COUNT

Proposed depth, ft	11-17-06 Rig count	11-17-06 Percent footage*	11-18-05 Rig count	11-18-05 Percent footage*
0-2,500	50	2.0	20	—
2,501-5,000	95	50.5	80	38.7
5,001-7,500	226	21.6	175	21.7
7,501-10,000	421	3.0	313	5.7
10,001-12,500	433	1.3	327	2.1
12,501-15,000	247	0.8	289	0.3
15,001-17,500	120	—	114	—
17,501-20,000	72	—	48	—
20,001-over	33	—	21	—
Total	**1,697**	**7.0**	**1,387**	**6.8**
INLAND	37		30	
LAND	1,601		1,310	
OFFSHORE	59		47	

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

Source: Smith International Inc.
Data available in Oil & Gas Journal Energy Database.

OGJ PRODUCTION REPORT

	[1]11-17-06	[2]11-18-05
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	22	22
Alaska	785	870
California	697	700
Colorado	60	62
Florida	7	6
Illinois	29	27
Kansas	96	93
Louisiana	1,379	871
Michigan	15	15
Mississippi	54	49
Montana	95	97
New Mexico	164	164
North Dakota	107	105
Oklahoma	174	169
Texas	1,368	1,244
Utah	45	48
Wyoming	142	145
All others	66	74
Total	**5,305**	**4,761**

[1]OGJ estimate. [2]Revised.

Source: Oil & Gas Journal.
Data available in Oil & Gas Journal Energy Database.

US CRUDE PRICES

$/bbl*	11-17-06
Alaska-North Slope 27°	56.72
South Louisiana Sweet	51.50
California-Kern River 13°	44.05
Lost Hills 30°	51.45
Wyoming Sweet	53.31
East Texas Sweet	53.55
West Texas Sour 34°	43.75
West Texas Intermediate	52.50
Oklahoma Sweet	52.50
Texas Upper Gulf Coast	49.25
Michigan Sour	45.50
Kansas Common	51.50
North Dakota Sweet	41.50

*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 Oil & Gas Journal Energy Database.

WORLD CRUDE PRICES

$/bbl[1]	11-10-06
United Kingdom-Brent 38°	59.33
Russia-Urals 32°	55.77
Saudi Light 34°	54.42
Dubai Fateh 32°	56.72
Algeria Saharan 44°	59.66
Nigeria-Bonny Light 37°	60.78
Indonesia-Minas 34°	56.23
Venezuela-Tia Juana Light 31°	53.60
Mexico-Isthmus 33°	53.49
OPEC basket	56.41
Total OPEC[2]	55.80
Total non-OPEC[2]	53.36
Total world[2]	54.36
US imports[3]	51.71

[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 Oil & Gas Journal Energy Database.

US NATURAL GAS STORAGE[1]

	11-10-06	11-3-06	Change
	Bcf		
Producing region	1,015	1,010	5
Consuming region east	1,962	1,966	–4
Consuming region west	473	469	4
Total US	**3,450**	**3,445**	**5**
	Aug. 05	**Aug. 05**	**Change, %**
Total US[2]	**2,969**	**2,662**	**11.5**

[1]Working gas. [2]At end of period.
Source: Energy Information Administration
Data available in Oil & Gas Journal Energy Database

Statistics

World oil balance

	2006 2nd qtr.	2006 1st qtr.	2005 4th qtr.	2005 3rd qtr.	2005 2nd qtr.	2005 1st qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	20.88	20.76	21.16	21.24	21.02	21.20
Canada	2.15	2.18	2.23	2.24	2.24	2.36
Mexico	2.01	2.08	2.10	2.06	2.11	2.04
Japan	4.78	5.96	5.46	5.03	4.94	6.00
South Korea	2.03	2.28	2.23	2.0	2.07	2.40
France	1.89	2.10	1.96	2.00	1.93	2.11
Italy	1.63	1.86	1.78	1.68	1.69	1.77
United Kingdom	1.83	1.85	1.81	1.81	1.77	1.83
Germany	2.55	2.56	2.63	2.75	2.55	2.54
Other OECD Europe	7.14	7.35	7.45	7.31	7.21	7.34
Australia & New Zealand	1.06	1.06	1.10	1.04	1.06	1.04
Total OECD	**47.95**	**50.04**	**49.91**	**49.17**	**48.59**	**50.63**
NON-OECD						
China	7.34	7.15	7.14	6.93	6.89	6.62
FSU	3.90	4.40	4.60	4.04	3.81	4.30
Non-OECD Europe	0.69	0.74	0.69	0.64	0.69	0.74
Other Asia	8.81	8.43	9.06	8.43	8.71	8.34
Other non-OECD	14.47	14.41	14.14	14.14	13.91	13.84
Total non-OECD	**35.21**	**35.13**	**35.63**	**34.18**	**34.01**	**33.84**
TOTAL DEMAND	**83.16**	**85.17**	**85.54**	**83.35**	**82.60**	**84.47**
SUPPLY						
OECD						
US	8.35	8.18	7.74	7.95	8.84	8.78
Canada	3.13	3.22	3.28	3.02	3.06	3.01
Mexico	3,79	3.80	3.75	3.72	3.89	3.77
North Sea	4.71	5.11	5.05	4.95	5.22	5.46
Other OECD	1.41	1.41	1.51	1.55	1.57	1.49
Total OECD	**21.39**	**21.72**	**21.33**	**21.19**	**22.58**	**22.51**
NON-OECD						
FSU	11.98	11.76	11.97	11.72	11.62	11.53
China	3.85	3.83	3.75	3.80	3.76	3.73
Other non-OECD	12.97	12.98	13.26	13.03	12.59	12.41
Total non-OECD, non-OPEC	**28.80**	**28.57**	**28.98**	**28.55**	**27.97**	**27.67**
OPEC	**33.76**	**33.84**	**34.23**	**34.48**	**34.18**	**33.99**
TOTAL SUPPLY	**83.95**	**84.13**	**84.54**	**84.22**	**84.73**	**84.17**
Stock change	**0.79**	**–1.04**	**–1.00**	**0.87**	**2.13**	**–0.30**

Source: DOE International Petroleum Monthly.
Data available in OGJ Online Research Center.

US petroleum imports from source country

	Aug. 2006	July 2006	Average YTD 2006	Average YTD 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	803	743	631	487	144	29.6
Kuwait	155	155	164	221	–57	–25.8
Nigeria	1,026	1,073	1,152	1,153	–1	–0.1
Saudi Arabia	1,514	1,313	1,451	1,607	–156	–9.7
Venezuela	1,438	1,467	1,453	1,617	–164	–10.1
Other OPEC	782	754	680	631	49	7.8
Total OPEC	**5,718**	**5,505**	**5,531**	**5,716**	**–185**	**–3.2**
Angola	544	695	506	440	66	15.0
Canada	2,468	2,114	2,278	2,127	151	7.1
Mexico	1,758	1,709	1,781	1,682	99	5.9
Norway	255	236	207	231	–24	–10.4
United Kingdom	262	340	290	392	–102	–26.0
Virgin Islands	377	353	314	323	–9	–2.8
Other non-OPEC	3,230	2,885	2,844	2,773	71	2.6
Total non-OPEC	**8,894**	**8,332**	**8,220**	**7,968**	**252**	**3.2**
TOTAL IMPORTS	**14,612**	**13,837**	**13,751**	**13,684**	**67**	**0.5**

Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

OECD total net oil imports

	July 2006	June 2006	May 2006	July 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–984	–995	–1,182	–838	–146	17.4
US	12,441	12,801	12,862	12,458	–17	–0.1
Mexico	–1,614	–1,677	–1,761	–1,646	32	–1.9
France	2.055	1.746	1,762	1,974	81	4.1
Germany	2,367	2,465	2,358	2,344	23	1.0
Italy	1,555	1,536	1,379	1,633	–78	–4.8
Netherlands	1,114	1,152	868	1,007	107	10.6
Spain	1,723	1,521	1,457	1,685	38	2.3
Other importers	3,951	3,747	3,994	3,953	–2	–0.1
Norway	–2,636	–2,836	–2,326	–2,679	43	–1.6
United Kingdom	270	44	240	45	225	500.0
Total OECD Europe	**10,399**	**9,375**	**9,732**	**9,962**	**437**	**4.4**
Japan	5,122	4,443	4,970	5,315	–193	–3.6
South Korea	1,974	2,128	2,374	2,156	–182	–8.4
Other OECD	731	974	1,060	675	56	8.3
Total OECD	**28,069**	**27,049**	**28,055**	**28,082**	**–13**	**—**

Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD* total gross imports from OPEC

	July 2006	June 2006	May 2006	July 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	447	435	245	437	10	2.3
US	5,505	5,649	5,782	5,957	–452	–7.6
Mexico	—	5	10	—	—	—
France	939	916	779	857	82	9.6
Germany	523	522	494	561	–38	–6.8
Italy	1,372	1,246	985	1,409	–37	–2.6
Netherlands	604	652	517	566	38	6.7
Spain	844	807	674	740	104	14.1
Other importers	1,473	1,341	1,217	1,395	78	5.6
United Kingdom	212	253	267	306	–94	–30.7
Total OECD Europe	**5,967**	**5,737**	**4,933**	**5,834**	**133**	**2.3**
Japan	4,484	4,007	4,277	4,365	119	2.7
South Korea	2,309	2,273	2,469	2,254	55	2.4
Other OECD	677	678	749	619	58	9.4
Total OECD	**19,389**	**18,784**	**18,465**	**19,466**	**–77**	**–0.4**

*Organization for Economic Cooperation and Development.
Source: DOE International Petroleum Monthly.
Data available in OGJ Online Research Center.

Oil stocks in OECD countries*

	July 2006	June 2005	May 2006	July 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	192	189	194	191	1	0.5
Germany	281	281	280	278	3	1.1
Italy	131	126	130	131	—	—
United Kingdom	100	101	105	101	–1	–1.0
Other OECD Europe	672	656	657	648	24	3.7
Total OECD Europe	**1,376**	**1,353**	**1,366**	**1,349**	**27**	**2.0**
Canada	177	168	168	170	7	4.1
US	1,745	1,730	1,724	1,743	2	0.1
Japan	631	627	634	640	–9	–1.4
South Korea	158	155	152	151	7	4.6
Other OECD	112	108	106	106	6	5.7
Total OECD	**4,199**	**4,141**	**4,150**	**4,159**	**40**	**1.0**

*End of period.
Source: DOE International Petroleum Monthly Report.
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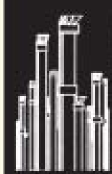

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Energy represents a belief test for new party leaders

The Editor's Perspective

by Bob Tippee, Editor

Political-party leadership choices portend much about energy issues in the 110th Congress. In turn, energy choices will say much about what the parties believe.

For Democrats, there's no mystery. With Nancy Pelosi of California as speaker of the House and Harry Reid of Nevada as Senate majority leader, energy markets will be under siege.

Liberal Democrats like Pelosi and Reid treat energy as a menu of political choices and energy problems as evidence of lapsed political will—rather than the results of past policy failures that they most often are.

Republicans will be more interesting. The question is whether they learned from their electoral drubbing Nov. 7 that they can't win elections by acting like Democrats. Energy issues give them a good way to reassert an ideological difference.

Having lost the initiative on energy issues, Republicans now must defend the nation against the new majority party's worst compulsions. But will they?

Leadership choices this week provide some comfort. The new House minority leader, John Boehner of Ohio, showed mettle last April by helping to block a windfall profit tax on oil companies.

The new Senate minority leader, Mitch McConnell of Kentucky, was a cosponsor this year of an effort to expand oil and gas leasing of the Outer Continental Shelf. The Senate bill was a faint echo of its House counterpart. But political resistance was tough in the Senate, and at least McConnell took part in a righteous effort.

Then there's Trent Lott, the former majority leader from Mississippi deposed after making remarks taken to be racially insensitive. Lott said he didn't intend for the comments to be offensive and apparently has served his penance; he's back in Republican leadership as McConnell's assistant.

There can be no mistaking the intent of comments Lott made in October 2005, when gasoline prices were high following Hurricanes Katrina and Rita and oil company profits were leaping.

Calling for "voluntary or mandatory profit controls," Lott issued a manifesto: "Either the oil companies must take steps to help America, or America will do it for them."

A Democrat couldn't have said it better.

(Online Nov. 17, 2006; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Crude prices hit new low for the year

The December contract for benchmark US light, sweet crudes plunged to $56.26/bbl, the lowest close for a front-month contract since Nov. 18, 2005, on the New York Mercantile Exchange after the Energy Information Administration reported the injection of 5 bcf of gas into US underground storage during the week ended Nov. 10.

That injection figure was at the low end of consensus expectations among Wall Street analysts. It compared with a withdrawal of 7 bcf the previous week and the injection of 51 bcf during the same period in 2005. US gas storage was then at 3.45 tcf, up by 176 bcf from year-ago levels and 238 bcf above the 5-year average.

It also was the first increase in US winter gas supplies in 3 weeks, ending a 3-week rally on the natural gas futures market that had boosted the December gas contract to $8.12/MMbtu Nov. 15 on NYMEX. That contract traded at $7.70-8.24/MMbtu on Nov. 16 before closing at $7.76/MMbtu. "On the natural gas front, prices have held within a 98¢/Mcfe range during [most of] November (with a high of $8.26/MMbtu), after months of intense volatility. Frigid weather is the most likely catalyst needed for oil and gas prices to break out of their respective trading ranges," said analysts in the Houston office of Raymond James & Associates Inc. earlier that week.

On Nov. 17 Raymond James said, "A spell of forecasts—mild weather, slowing economy, higher fuel inventories, etc.—prompted a wide sell-off as traders switched over to the January [crude] contract," with the December contract to expire at the end of trading Nov. 17.

The December crude contract had rebounded by 48¢ to $58.76/bbl Nov. 15 after falling for three consecutive trading sessions on NYMEX. That increase was sparked by an EIA report that commercial inventories of US crude rose by 1.3 million bbl to 336 million bbl during the week ended Nov. 10. US gasoline stocks, however, fell 3.7 million bbl to 200.3 million bbl during the same period to the lower half of the average range. Distillate fuel inventories dropped 3.6 million bbl to 135 million bbl, with a slight increase in heating oil buried by a large decline in diesel fuel. The US market had watched distillate inventories drop during the previous 2 months, Raymond James reported.

"The administration reported a large decline in total refined product inventories, driven by strong consumption and reduced supplies. Over the past 4 weeks, total refined product demand has been, on average, 4.5% above comparable year-ago levels. Total refined product inventories, adjusted for demand, are now only 1% above the historical 3-year average," said Jacques Rousseau, senior energy analyst at Friedman, Billings, Ramsey Group Inc., Arlington, Va., in a Nov. 15 report.

"US inventories have been falling like a stone relative to their normal patterns," said Paul Horsnell at Barclays Capital Inc., London. "The latest US data have continued the very strong pattern of previous weeks, producing the fastest rate of decline relative to normal patterns in any 5-week period that we can find," Horsnell said. "US oil product inventories, (excluding the 'other oils' category, which is estimated rather than observed), now stand 17.3 million bbl higher than their 5-year average. Five weeks ago, they stood 56.8 million bbl higher, i.e., they have fallen by 39.5 million bbl relative to the 5-year average, which is a rate of descent of more than 1.3 million b/d. In terms of forward cover, product inventories are now lower than their 5-year average."

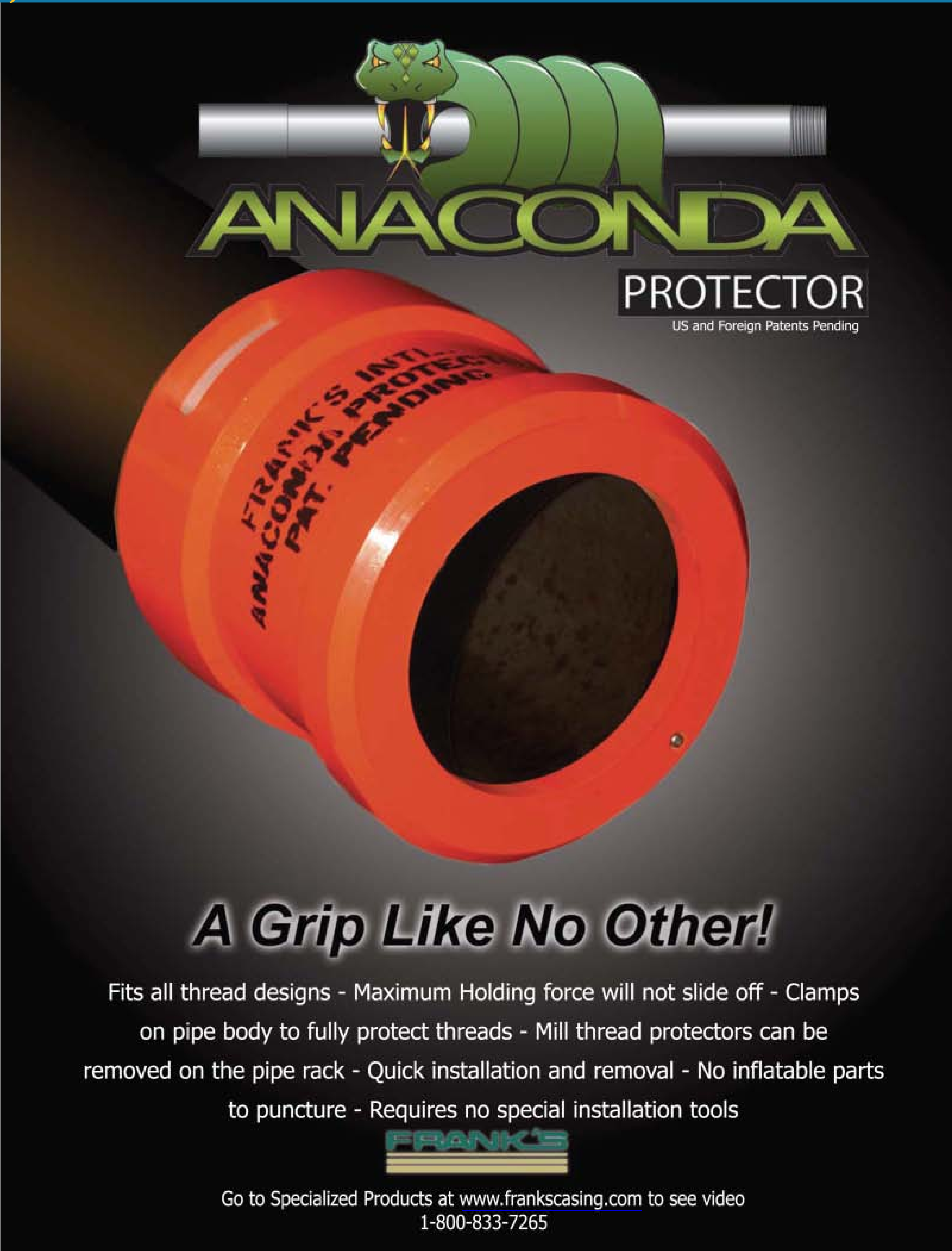
Seasonal effects

Analysts at Enerfax Daily noted that temperatures were above average across most of the US during the week ended Nov. 10, reducing demand and allowing utilities to add gas to storage that already was at a record high. The Nov. 23 US Thanksgiving holiday was expected to cut demand even further with offices and businesses closed.

However, energy prices had climbed Nov. 15 partially in anticipation of Thanksgiving holiday travel. "More people travel over the Thanksgiving holiday than any other holiday in the US. The American Automobile Association, the nation's largest motoring organization, expects 31.7 million travelers to hit the road. That number of motorists is about 83% of the total number of travelers expected over the Nov. 23-26 period," said Raymond James analysts.

Meanwhile, the Organization of Petroleum Exporting Countries warned in its latest monthly oil market report that, if it continues producing at current levels, there would be a bigger than usual build in oil inventories among consumer nations in the second quarter of 2007.

(Online Nov. 17, 2006; author's e-mail: samf@ogjonline.com)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OIL&GAS JOURNAL

Market Focus

Gulf of Mexico

Supplement to Oil & Gas Journal


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Market Focus

Gulf of Mexico

Supplement to Oil & Gas Journal

Exploration and production facilities shown on the cover represent the leading edge of deepwater technology that helped make the Gulf of Mexico the world's hottest E&P play. At upper left is the production facility for Devil's Tower field, the world's deepest dry-tree truss spar and located in 5,610 ft of water on Mississippi Canyon Block 773. At upper right is Transocean Inc.'s Cajun Express semisubmersible, which was on hand for the record-setting extended drillstem test of the Jack 2 appraisal well on Walker Ridge Block 758 in June 2006 by Chevron Corp., Oklahoma City-based Devon Energy Corp., and Norway's Statoil ASA. Three other drilling vessels currently or recently active in the deepwater gulf include (from left to right at bottom) the Discoverer Spirit and Discoverer Enterprise drillships and the Deepwater Horizon semi-submersible. The Devil's Tower photo is courtesy of field operator Dominion Exploration & Production, a unit of Richmond, Va.-based Dominion Resources Inc. The other photos are courtesy of Transocean.

Gulf of Mexico world's hottest play, but challenges still loom

The US Gulf of Mexico is the world's hottest exploration and development play and the most important source of US oil and natural gas supply.

Both superlatives are likely to be reaffirmed in the years to come. Factors in that outlook include recent tests confirming the producibility of giant reservoirs in the Lower Tertiary trend in the gulf's deep water, the extension of royalty incentives for deepwater and deep-pay production, and the growing importance of the underexplored deep-shelf gas play.

The resource target is huge, according to Chris Oynes, regional director, Gulf of Mexico region, US Minerals Management Service.

"The 2006 resource estimate issued by MMS estimates that there is a mean esimate of 86.3 billion bbl of oil equivalent remaining to be discovered in the gulf—about 44.9 billion bbl of oil and 232.5 tcf of gas," he says.

Couple that impressive potential with the diminished access to giant-scale prospects elsewhere in the US and the gulf's low political risk, and the resulting outlook is bright.

"The Gulf of Mexico—and more specifically the deepwater Gulf of Mexico—is not only important to current US oil and gas supply, it is critical to future US oil and gas supplies," says Jean P. Cahuzac, executive vice-president and chief operating officer of Transocean Inc., Houston. "Yet-to-find (YTF) estimates in the range of 23 billion bbl of oil and 80 tcf of gas…make the deepwater Gulf of Mexico by far the largest YTF estimate in the US.

Devil's Tower truss spar in the ultradeepwater Gulf of Mexico has capacity for 60,000 b/d of oil and 110 MMcfd of natural gas. Photo courtesy of Dominion Exploration & Production.

"Additionally, deepwater Gulf of Mexico fields compete very favorably with oil producing provinces around the world, owing to the high rate of geologic success and relatively more favorable royalty and fiscal regime."

The gulf is one of the few remaining areas in North America with vast resource potential, notes Steve Hadden, senior vice-president, exploration and production, Devon Energy Corp., Oklahoma City: "The gulf produces 2.2 million boe/d—25% of US production."

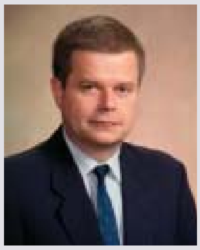
Devon is a key player in the suddenly sizzling Lower Tertiary trend, which netted widespread headlines with the recent announcement of the first successful extended well test of the play—one that could hold 9-15 billion boe of potential reserves. Hadden says that Devon's currently identified Lower Tertiary prospects could be as much as 300-500 MMboe each.

"Since access to hydrocarbon-bearing regions in the United States is limited, it is a significant accomplishment that the industry is able to use technology to tap into an area with this amount of resource potential," he adds.

A 'technology' play

The Lower Tertiary play is a prime example of why Gulf of Mexico E&D today is driven by technology rather than traditional geology approaches.

> "The Gulf of Mexico—and more specifically the deepwater Gulf of Mexico—is not only important to current US oil and gas supply, it is critical to future US oil and gas supplies."
>
> — *Jean P. Cahuzac, executive vice-president and COO, Transocean Inc.*



Much of the Lower Tertiary trend lies in ultradeep—5,000-10,000 ft—waters and at great depths below the seabed. And the structures in question are elusive to conventional seismic imaging, obscured by vast salt canopies. Until very recently, the industry consensus was against the notion that Lower Tertiary sands would be present or producible at such great depths.

"Today, seismic imaging is more advanced, allowing us to see past salt canopies and get much clearer images of formations as deep as 30,000 ft or more," Hadden notes. "Additionally, fifth-generation drilling vessels have made it possible to penetrate 10,000 ft of water to a total depth of 35,000 ft, overcoming the drilling challenges of just a few years ago."

Advances in technology and materials enabling the drilling of high-temperature/high-pressure wells in corrosive environments are helping to unlock the huge gas potential of the deep shelf in shallow gulf waters. MMS has estimated deep-shelf gas potential at as much as 20 tcf.

Of course, robust drilling activity in the Gulf of Mexico also is driven by expectations of continued high oil and gas prices as well.

"In my view, the Gulf of Mexico will continue playing a very significant role in US oil and gas supply," says Renaldo Bertani, vice-president, Petrobras America Inc. "And the reason is simple: New technology and the new market reality are making it feasible and attractive to continue exploring and developing reserves that were beyond reach just a few years ago."

While the technology challenges for expanding the deepwater and deep-shelf plays are substantial, the biggest concerns for Gulf of Mexico operators and service/supply operators are nontechnical in nature: shortages of rigs and personnel, rising costs, leasing hurdles, and coping with natural disasters.

Rig availability

Drilling activity in the Gulf of Mexico could be constrained by the lack of available rigs worsening from today's already tight market.

Despite strong demand, rig supply in the gulf has slumped in the past 5 years. Almost 150 rigs were available for work in the gulf in 2001. Today, there are about 90. The upturn in oil prices in recent years has pulled rigs from the gulf to other areas of the world, drawn by more lucrative day rates and longer-term contracts elsewhere.

In the short term (2006-08), says Cahuzac, "activity in the Gulf of Mexico will be constrained by the number of rigs available; this is at a time when there is an anomalously high turnover of leases, prompting a demand with a critical timing component."

Bill Coates, president, Schlumberger north America, warns that "a chronic shortage of jack up rigs is about to develop, which will further depress shelf production for oil or gas."

Personnel concerns

In both the short and medium term, the most critical issue is human capital, Cahuzac says.

"This will be an industry-wide problem but perhaps most challenging for the drilling contracting industry.

"The ultradeepwater fleet of rigs operating in the US Gulf of Mexico is projected to double in size by 2009. The industry will be challenged to recruit top talent, both fresh-out and midcareer hires, and accelerate their development to produce supervisors in a substantially shorter time than has ever been achieved before."

Among other measures, Transocean is taking steps to deal with the shortage of qualified personnel in Gulf of Mexico operations through recruiting, accelerated development, and retention initiatives, says David Mullen, the company's vice-president, North and South America:

- "Broadening the areas in which we recruit in an effort to enrich the talent pool of fresh-outs. We are expanding beyond the Gulf Coast states, which have been our main recruiting areas in the past.
- "Constantly looking at industries where we can achieve synergistic development. For example, we are targeting the aeronautical industry for subsea engineers.
- "Invested heavily in accelerated training programs, training tools, training schools, and dedicated mentors.
- "Management commitment to accelerated development. We monitor and reward supervisors and rigs for success in the program. Also, we continually remind everybody of the criticality of this function for the future success of the company.
- "Retention of our existing strong experience base is achieved through constantly monitoring compensation to ensure we have a competitive compensation package. In addition, management maintains visibility on the rigs to facilitate a healthy two-way communication.
- "Morale-building tools are utilized such as a well-understood career development process."

Dealing with personnel concerns also is related to a key issue facing the industry, says Lew Mologne, president of oil and gas treating services company ProSep Technologies Inc., Houston—"that being the need to use much better partnering-based relationships to streamline projects and reduce time and costs."

Regulatory issues

Access remains a key concern even in this busiest of offshore provinces—considering that almost a third of the gulf, the eastern portion, remains off-limits to leasing.

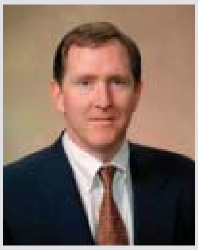
"Although a host of new technologies has opened the Gulf of Mexico to possible development development, government-imposed moratoriums are limiting the amount of exploration and production activity that can be completed in the area," says Hadden.

Bertani is concerned about the duration of shallow-water leases in which ultradeep reservoirs are being explored and developed: "The new technological developments that will be required to explore for and bring on stream such extremely deep reservoirs will take some time to develop, and the current lease terms may not be sufficiently long."

In addition to easing access to exploration acreage in the eastern gulf, Cahuzac favors more flexibility on revenue sharing with the Gulf Coast states on deepwater royalties and lease payments.

Another regulatory snafu, adds Cahuzac, is that "limited flexibility in using non-US nationals for offshore work on MODUs

> "Transocean is taking steps to deal with the shortage of qualified personnel in Gulf of Mexico operations through recruiting, accelerated development, and retention initiatives."
>
> *— David Mullen, vice-president, North and South America, Transocean Inc.*



[mobile offshore drilling units] makes it very difficult to bring a unit into US coastal waters for a short-duration period."

Coates worries about "the tension between state and federal governments and the change to royalty regimes.

"We cannot afford any delay in the large-scale deepwater development of oil and gas."

Disaster planning

Gulf of Mexico players learned some grim lessons about disaster planning in the wake of 2005's devastating Hurricanes Katrina and Rita, which destroyed more than 100 gulf platforms, set 19 MODUs adrift, and shut in 92% of the gulf's oil production and 83% of its gas output.

Gulf operators and service/supply companies have formed a joint industry project on mooring systems to advise the industry on risk-mitigating factors and provide input for impending new regulations.

Mullen cites the following steps Transocean has taken in its disaster-planning iniative:

- Improving stationkeeping capacity of moored deepwater semisubmersibles.
- Conducting site-specific assessments for each location during storm season to assess the potential consequences of mooring failure.
- Continually updating and modifying tropical storm evacuation plans to minimize risk to people on both dynamically positioned and moored units.

Importing technology is one approach Petrobras, with its extensive deepwater experience off Brazil, is taking, says Bertani:

"We are bringing the expertise that we developed offshore Brazil, particularly with the utilization of FPSOs [floating production, storage, and offloading units], customized to the Gulf of Mexico conditions.

"We are planning to deploy an FPSO with a disconnectable turret in our operated developments of Cascade and Chinook [ultradeepwater fields]. This will allow quick disconnection in case of imminent hurricanes so that the vessel can move away from the storm and reconnect once the sea conditions allow."]

Technology challenges daunting for deepwater GOM bonanza

Overcoming technology challenges in the deepwater Gulf of Mexico is critical to future US energy supply.

The deepwater (especially the ultradeepwater) areas of the Gulf of Mexico offer the greatest near-term potential for significantly adding to US oil and natural gas reserves and production.

The US Minerals Management Service estimates the deep waters of the gulf contain resources totaling about 45 billion bbl of oil and 232 tcf of gas. And the individual prospects are more prolific: According to MMS, in the past 10 years, the average deepwater field added over 67 MMboe of reserves vs. about 5 MMboe for shallow-water fields. The successes are even more substantial as the play has expanded into ever-deeper waters in recent years. Since early 2000, new deepwater drilling added more than 6.2 billion boe of reserves, up 50% from the total deepwater reserves discovered during 1974-99.

That trend is further borne out by the recent extended well test of the Jack discovery by Chevron Corp. with partners Devon Energy Corp. and Statoil ASA, according to Chris Oynes, regional director, Gulf of Mexico region, US Minerals Management Service.

The successful flow test "increased confidence in discovering and producing oil and gas from deep Lower Tertiary formations in the deepwater Gulf of Mexico," he says. "This announcement and other deepwater successes provide support for a significantly large impact on the country's reserves."

The Lower Tertiary trend could be as wide as 300 miles and involve as many as 3,000 blocks,

"This [Jack discovery well test] announcement and other deepwater successes provide support for a significantly large impact on the country's reserves."

— Chris Oynes, regional director, Gulf of Mexico, MMS

according to MMS. After 12 discoveries, industry estimates put the trend's potential recoverable resources at 9-15 billion boe. The discoveries, all in more than 5,000 ft of water and with some wells approaching or exceeding 30,000 ft total depth, demonstrate how the deepwater Gulf of Mexico is a technology-driven play.

"To date, 99% of the oil and gas produced from the gulf has come from relatively young rock, down in geologic age to the Miocene," notes Steven Hadden, senior vice-president, exploration and production, Devon. "Until a few years ago, the industry did not have the technology in place to find or develop resources found in deeper formations in the ultradeep waters of the gulf."

> "Until a few years ago, the industry did not have the technology in place to find or develop resources found in deeper formations in the ultradeep waters of the gulf."
>
> *— Steven Hadden, senior vice-president, exploration and production, Devon Energy Corp..*

"These structures have not been clearly imaged due to the presence of salt canopies covering much of the gulf's Lower Tertiary prospects," Hadden adds. "As with many of our opportunities, we've turned to high technology to unlock this potential.

Technology challenges

Despite the milestone achieved with the Lower Tertiary successes, there remain daunting technology challenges in the deepwater gulf.

Bill Coates, president, Schlumberger North America, says, "Key hurdles when working in deep water are the resolution below salt for seismic and the costs associated with ultradeepwater development due to high reservoir pressures and the need for strong flow assurance programs."

Among deepwater exploration technology challenges, Coates singles out seismic below 10,000 ft of salt, as well as high-pressure/high-temperature drilling and evaluation. In deepwater drilling, he cites drill string harmonics—shock and vibration in deep, extended-reach wells. The main challenges in deepwater production are flow assurance and premature failure of deepwater completions, Coates says.

Improved seismic needed

Improvements in seismic imaging below the salt canopies of the deepwater gulf are critical, says Newfield Exploration Co. Vice-Pres. Elliott Pew.

"In regards to technology, subsalt imaging is the probably is the single largest improvement that can reduce risk," he says. "Wide-azimuth towed streamer data show good promise in this area."

Rick Fowler, vice-predident and general manager, Gulf of Mexico operations, Dominion Exploration & Production, a unit of Dominion Resources Inc., Richmond, VA. elaborated on the seismic challenges in the deepwater gulf: "Most of the high-quality opportunities available are in subsalt horizons, where applying seismic methods can be challenging," he says. "We can use seismic to identify structures below the salt; however, our seismic images are not yet accurate enough to adequately predict continuity within these structures."

Fowler notes that once a subsalt discovery is made, it is extremely difficult to adequately appraise the reservoirs, thus requiring many wells to ascertain their size. Not only is such appraisal drilling costly, it delays a development decision.

"If the seismic data could be improved to enable quicker, more accurate appraisals, we could drill fewer wells, better optimize the size and type of facility, and improve cycle time," Fowler contends. "Accurate seismic depth migrations using proper velocity and salt models are key to improving the images of these structures below salt."

Drilling challenges

Transocean Inc.'s David Mullen, vice-president, North and South America, cites these drilling challenges in the deepwater gulf:

- "Extreme well depth requires rigs with an improved critical-path load capacity beyond what currently exists with the very high-end fifth-generation [drilling] vessels.
- "The narrow window on the allowable frac and pore pressure gradient complicates well construction to the point that a number of prospects are undrillable with current technology.
- "Extrene pressure encountered in some ultradeep prospects will require a BOP with a pressure rating beyond 15,000 [psi].
- "Technology [is needed] to overcome the problems in running and retrieving riser string in a high-current environment."

Oynes presses the issues surrounding the difficulties in drilling high-pressure/high-temperature wells in the deepwater gulf.

"Before these wells can be drilled, completed, and produced, materials that can withstand these extreme conditions must be developed," he notes, citing "drilling fluids with rheologies that will withstand temperatures in excess of 350° F., elastomeric seals and downhole tools with electronics that can withstand elevated temperatures, and blowout preventers that can handle the extreme pressures."

New completion technologies needed include extra-high-strength tubulars that can withstand partial hydrogen sulfide and carbon dioxide levels that require certification by the National Association of Corrosion Engineers, Oynes points out.

On the production side, Oynes calls for christmas trees made of steels that can sustain high temperature differentials between the outside seawater and the internal fluid temperatures, as well as the corrosive nature of the produced oil and gas.

"Alloys for flowlines and risers subjected to the same elevated pressures, corrosive environment, and differential temperatures will need to be developed as well," he adds.

Oynes also points to the production technology challenges involved in subsea pumping and processing.

"Both of these issues would increase ultimate recovery of producing properties," he says. "Multiphase metering on a platform and subsea is also a challenge that has not been completely conquered."]

Deep shelf gas: big potential but high risks

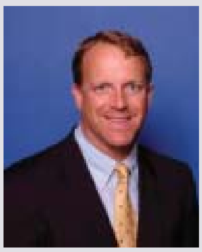
The deep geologic horizons of the shallow-water Gulf of Mexico Outer Continental Shelf offer the best near-term opportunity for increasing US natural gas production.

While the shallow-water gulf OCS has been heavily explored, sediments at depths of greater than 15,000 ft in water depths less than 200 m are relatively unexplored. Only about 5% of all wells drilled on the OCS have penetrated below 15,000 ft subsea.

To be economic, deep gas finds on the shelf require larger structures and high flow rates.

"Deep shelf gas involves a complicated blend of well planning, pressure management, and completion techniques."

— Bill Coates, president, Schlumberger North America



But deep gas potential on the gulf shelf is sizable. The US Minerals Management Service has estimated the gulf's deep gas resource potential at as much as 20 tcf. Recent deep gas discoveries on the shelf have provided completions producing as much as 20-80 MMcfd. The average deep gas discovery is about 20 bcf, with finds in the Norphlet trend averaging 105 bcf.

And the abundance of platforms and pipelines already on the shelf ensures that any economic deep shelf gas finds will flow to market quickly.

Technology challenges

In tackling the deep shelf gas opportunity, industry must overcome the major technology challenges associated with drilling wells encountering high temperatures, high pressures, and corrosive environments.

In deep shelf areas with salt intrusion, there are concerns with lost circulation of drilling mud systems when drilling through salt.

Bill Coates, president, Schlumberger North America, contends that, in many ways, drilling for deep shelf gas is more difficult than drilling in the deepwater Gulf of Mexico.

Accordingly, operators must weigh prospect size against drilling risk: "Deep shelf gas involves a complicated blend of well planning, pressure management, and completion techniques."

Such complications can mean a costly dry hole. "These [extreme] pressures resulted in a premature P&A of the Blackbeard well," notes David Mullen, vice-president, North and South America, Transocean Inc.

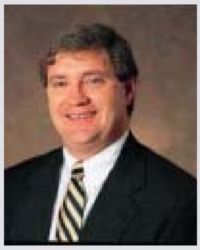
Mullen also cites as crucial technology hurdles the lack of knowledge about deep shelf gas reservoir characteristics, concerns over the drilling window on frac and pore pressure gradients, and the fact that depleted zones "further complicate the well-construction process, especialy with respect to the number of casing strings."

Elliott Pew, Newfield Exploration Co. executive vice-president, exploration, contends, however, that technology is not the major hurdle in finding, developing, and producing deep shelf gas.

"Rather, costs need to decline to economically develop smaller fields on the shelf. We know pretty well how to find these prospects and risk them appropriately."

"Costs need to decline to economically develop smaller fields on the shelf. We know pretty well how to find these prospects and risk them appropriately."

— Elliott Pew, executive vice-president, exploration, Newfield Exploration Co.



Seismic concerns

With greater target depth comes the need for better seismic imaging, points out Steve Hadden, senior vice-president, exploration and production, Devon Energy Corp.

"For example, pore pressure affects our ability to develop deep shelf resources. With only a few scattered deep wells and poor seismic velocities, at these depths it can be difficult to properly design casing programs."

He also notes that "legacy seismic data are not adequate to image the deeper section. Increasingly, however, new data are being acquired on the shelf with depth migration as a final product.

"There also is no risk reducer in the deep shelf. Traditionally, shallow shelf prospects carried low risk due to having amplitude-supported targets. With increasing depth, amplitudes diminish because the sand and shale seismic velocities become very similar.

Hadden also contends that the lease term for shelf blocks (5 years) is too short in order to better image deep prospects and let them mature to a drillable stage.

"Although the MMS has allowed term extensions under certain conditions, these conditions—and the [deep gas production] royalty suspension program—should be significantly upgraded, given current risks…and results of deep wells drilled to date."

Drilling issues

Drilling high-pressure/high-temperature (HP/HT) wells in tandem with drilling through salt layers pose especially daunting technology challenges, according to Chris Oynes, MMS regional director, Gulf of Mexico.

"Ultradeep shelf operators and contractors are evaluating high-cost metal alloys such as nickel-chromium and titanium as options for downhole production equipment to withstand corrosion and HP/HT," he says.

"Additionally, drilling through layers of sediments and salt combined with variations in HP/HT may require drillers to use as many as 10 different runs of casing to line the walls of a single well drilled to 30,000 ft subsea on the shelf. These wells may take more than a year to drill and cost in excess of $100 million."

Dominion's Rick Fowler contends that industry's challenge on the deep shelf is to drill deep, high-pressure wells at a reasonable cost.

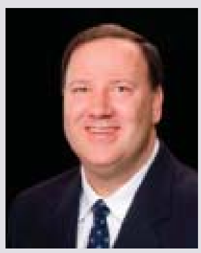
"The main technology hurdle involves developing the ability to predict formation pressures accurately before drilling," he says. "With existing technology, we often must design for contingency casing strings that requier larger hole sizes throughout the well at significantly increased cost. We need enhanced drilling procedures and equipment that will allow higher penetration rates in the deeper rock.

"We've had some success with underreaming while drilling in this area. Managed pressure drilling has proven successful in other parts of the world and may be helpful in the Gulf of Mexico in the future."

Downhole conditions also can present added risks, Hadden notes: "In addition to this play being in a high-cost environment, an increased level of operational risk is present. This additional risk component must be factored into the overall risk profile of the play.

"The main technology hurdle [in drilling deep shelf gas] involves developing the ability to predict formation pressures accurately before drilling."

— Rick Fowler, vice-president and general manager, Gulf of Mexico operations, Dominion E&P



"Finally, issues such as rig and service ability can impede production of deep shelf resources. The current rig fleet capable of drilling these types of wells is limited."]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