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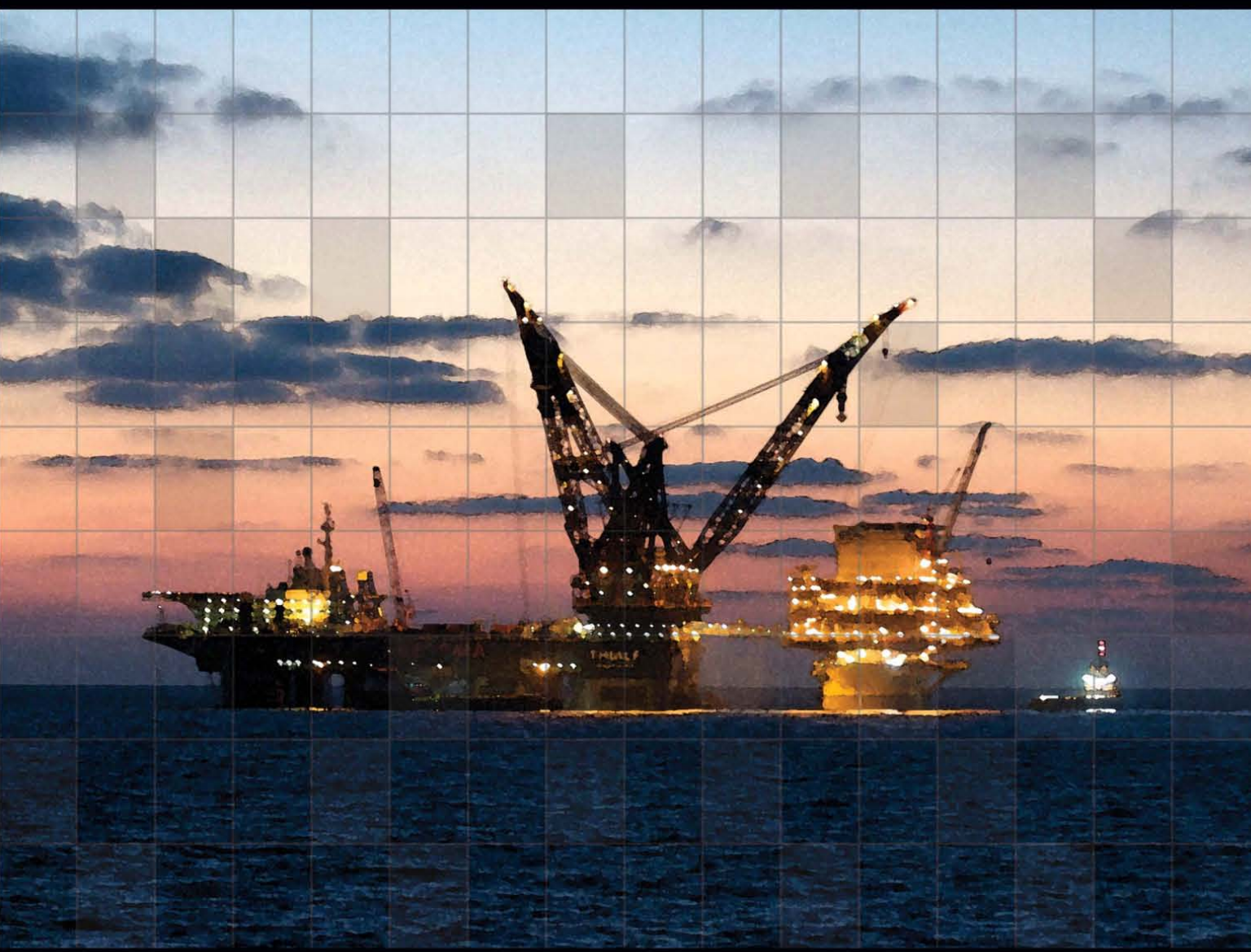

Offshore Petroleum Operations

Oil linked to US move toward thaw with Cuba
Afghanistan blocks offer unproduced discoveries
US propane supply pushes to season-ending surplus

OIL&GAS JOURNAL®

May 4, 2009
Volume 107.17

OFFSHORE PETROLEUM OPERATIONS

REGULAR FEATURES

COVER

In March, Heerema DCV Thialf installed the topsides and living quarters for the Shell-operated Perdido project in the US Gulf of Mexico. Shell operates Perdido on behalf of partners BP and Chevron. Peridido is the deepest spar yet installed (7,817 ft seawater) and includes the deepest producing subsea well (9,627 ft), pumping 130,000 boe/d. This issue's special report on Offshore Petroleum Operations, beginning on p. 58, looks at Vietnam's Su Tu Vang project as an example of overcoming current difficult economics in completing a new development, presents the first part of a study on using real-time data and models to optimize production off Trinidad and Tobago, and details a new offshore one-call system for the US Gulf of Mexico. Photo by Jan Berghuis Terschelling, courtesy of Shell.

In January, Petrobras installed the P-51 semisubmersible production unit (see photo above) in Marlim Sul field off Brazil. The unit, the first built entirely in Brazil, is moored in 1,255 m of water and can process up to 180,000 bo/d. Photo from Petrobras.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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May 4, 2009

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General Interest — Quick Takes

Ex-Im Bank approves $900 million in loans to Pemex

The US Export-Import Bank has approved $900 million worth of 10-year direct loans to Mexico's state-owned Petroleos Mexicanos to support purchase of US goods.

The official US government export credit agency said the loans consisted of $600 million for purchases to be used in the new projects of PEP, formerly known as the New Pidiregas Projects, which are 18 onshore and offshore oil and gas exploration sites, and $300 million for the Canterelli oil fields. Both activities involve work in and around the Bay of Campeche off the northern Yucutan coast, it noted.

Ex-Im Bank said its financing will help assure that US products would be competitive, adding that exports of engineering services, oil field equipment, offshore platforms, drilling and upgrade services, and upgrade and rehabilitation services are expected to come from suppliers in Texas, Louisiana, Florida, Ohio, Pennsylvania, and other states.

Pemex is its largest borrower, the bank noted. Since 1998, it has approved $8.3 billion of financing for the company to buy US goods and services for its oil and gas exploration, development, and processing projects. This included a $150 million small business facility in August supporting Pemex's purchases of equipment and services from US companies with 100 or fewer employees, the export credit agency said.

It noted that it authorized $1.5 billion of loans to support foreign purchases of US goods and services for oil and gas projects in fiscal 2008. During that year, the bank authorized a total of $14.4 billion in loans to support the purchase of $19.6 billion of US exports worldwide, it said.

EU parliament approves energy compromise

The European Union's Parliament approved by a large majority the energy market liberalization compromise reached in October 2008 by the Energy Council.

Parliament earlier rejected the compromise in its first reading and insisted that integrated companies fully unbundle production and sale of natural gas and electricity, while the council battled for the choice among three options for separating supply and production activities from network operators.

Brokered by the current Czech presidency of the EU, full acceptance by the Council of Ministers and parliament was reached on the third legislative package on energy aimed at bolstering the internal gas and electricity markets. But the parliamentary vote has strengthened the role of both national and transmission system regulators and put citizens at the center of the market through a protective energy consumer checklist and special attention to vulnerable clients.

Both European Commission Pres. Jose Manuel Barroso and Energy Commissioner Andris Piebalgs welcomed the vote, which they said ensures more effective regulatory oversight "from truly independent and competent national energy regulators" and "facilitates crossborder collaboration and investment with a new European Network for Transmission System Operators."

They said grid operators will cooperate and develop common commercial and technical codes and security standards, as well as plan and coordinate the investments needed for the EU, easing crossborder trade and creating a level playing field.

"By bringing national markets together, member states will be better able to assist one another to face energy supply threats," they added. The main objective of the energy package is to put in place the regulatory framework to make the market fully effective and create a single EU gas and electricity market to achieve the lowest possible energy prices and better security.

The legislative package includes provisions to prevent control of transmission systems by companies from non-EU countries until they fulfill certain conditions. A national regulator could refuse certification of a transmission system operator controlled by "a person or persons from a third country" if the company does not comply with the unbundling requirements, and its market entry would jeopardize supply security for one or more EU members.

EU countries have 3½ years to implement these provisions.

The council is expected to formally endorse the legislative text within the next few months. The legislation seems sure to be implemented as specified in 2011. ✦

Exploration & Development — Quick Takes

ConocoPhillips finds gas with Poseidon-1

ConocoPhillips made an apparent natural gas discovery in the Browse basin off Western Australia during the drilling of its Poseidon-1 wildcat in permit WA-315-P about 480 km north of Broome.

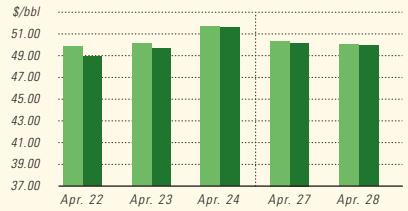
The company intersected a 10 m hydrocarbon-bearing sand at a depth of 4,796 m just below the top of the Mid-Jurassic Plover formation, followed by two additional hydrocarbon-bearing intervals of 67 m and 114 m deeper in the stratigraphic section. Mud logs and logging-while-drilling equipment indicated hydrocarbons are present. The shows have yet to be fully evaluated but will be analyzed on completion of drilling and wireline logging operations.

The find, which is likely to be gas and condensate, lies just to the north of Woodside Energy Ltd.'s giant Torosa gas-condensate field and northwest of Inpex Corp.'s Ichthys gas-condensate field.

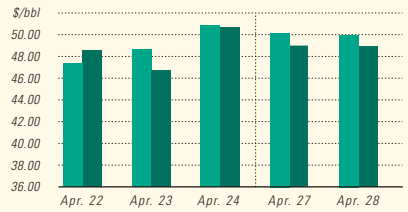
The well is being drilled by semisubmersible Sedco 703 and

Industry Scoreboard

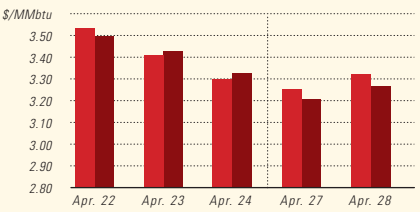
IPE BRENT / NYMEX LIGHT SWEET CRUDE



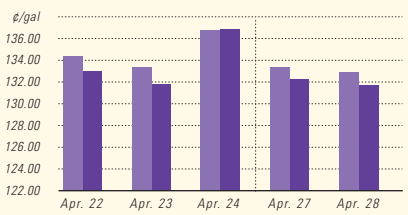
WTI CUSHING / BRENT SPOT



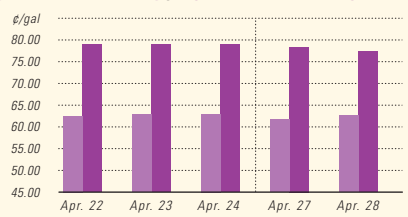
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



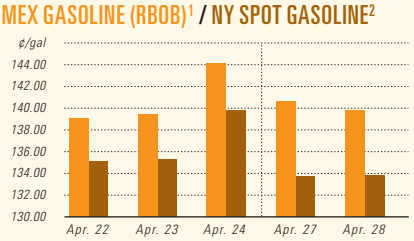
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

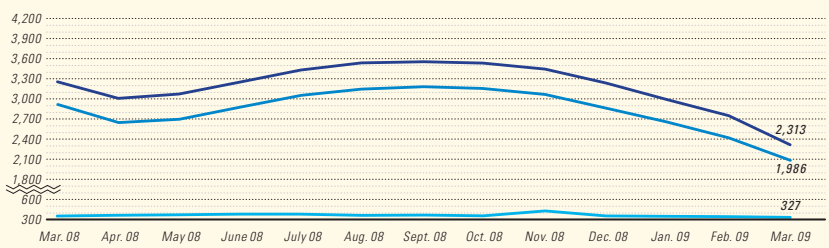
US INDUSTRY SCOREBOARD — 5/4

Latest week 4/17	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,057	9,097	–0.4	8,935	8,941	–0.1
Distillate	3,735	4,122	–9.4	3,927	4,185	–6.2
Jet fuel	1,422	1,567	–9.3	1,394	1,547	–9.9
Residual	449	636	–29.4	567	612	–7.4
Other products	3,801	4,331	–12.2	4,194	4,577	–8.4
TOTAL DEMAND	18,464	19,753	–6.5	19,017	19,862	–4.3
Supply, 1,000 b/d						
Crude production	5,463	5,152	6.0	5,358	5,122	4.6
NGL production[2]	1,795	2,194	–18.2	1,890	2,180	–13.3
Crude imports	9,533	9,767	–2.4	9,439	9,758	–3.3
Product imports	2,991	3,160	–5.3	3,131	3,172	–1.3
Other supply[3]	1,644	1,373	19.7	1,591	1,430	11.3
TOTAL SUPPLY	21,426	21,646	–1.0	21,409	21,662	–1.2
Refining, 1,000 b/d						
Crude runs to stills	14,210	14,627	–2.9	14,210	14,645	–3.0
Input to crude stills	14,550	14,953	–2.7	14,550	14,958	–2.7
% utilization	82.5	85.0	—	82.5	85.1	—

Latest week 4/17	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	366,743	361,072	5,671	313,660	53,083	16.9
Motor gasoline	216,505	217,449	–944	215,751	754	0.3
Distillate	139,629	140,799	–1,170	106,079	33,550	31.6
Jet fuel–kerosine	39,338	39,061	277	39,709	–371	–0.9
Residual	36,170	36,235	–65	38,339	–2,169	–5.7
Stock cover (days)[4]			Change, %		Change, %	
Crude	25.9	25.4	2.0	22.0	17.7	
Motor gasoline	23.9	24.0	–0.4	23.3	2.6	
Distillate	36.2	36.6	–1.1	25.0	44.8	
Propane	38.9	33.5	16.1	20.6	88.8	
Futures prices[5] **4/24**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	49.80	50.46	–0.66	109.74	–59.94	–54.6
Natural gas, $/MMbtu	3.67	3.63	0.03	9.91	–6.24	–63.0

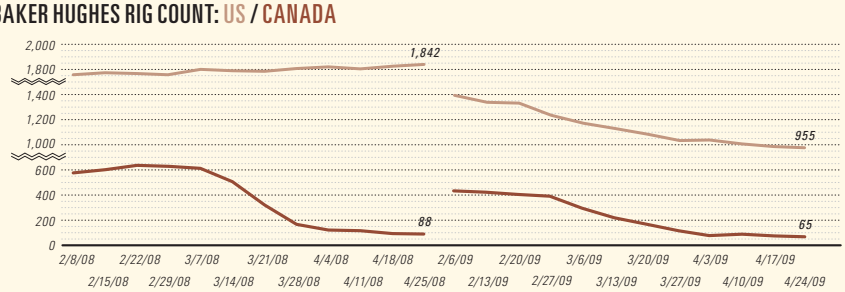
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



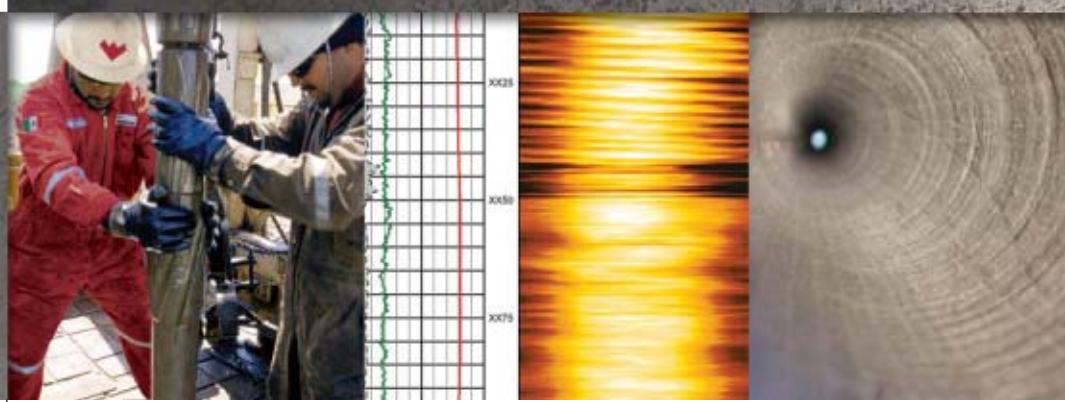
Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

Build better boreholes.



Weatherford's Revolution Rotary-Steerable Service helped BP Indonesia achieve better than anticipated production, incident-free, from a multi-well, shallow-gas, extended-reach project while saving more than $1.25 million.

Better boreholes mean better wells. Weatherford's **Revolution® Rotary-Steerable** Service integrates point-the-bit rotary-steerable technology with the industry's most robust MWD and LWD tools, global real-time operations and drilling optimization support. So, you can steer precisely and efficiently to target and leave a borehole that is smoother, cleaner and easier to case and complete. That means you can get production on line faster, with fewer problems. And, the Revolution system's compactness and design simplicity reduce cost and ease logistics – all to help you build **better recovery, better profit and better value** for your asset.

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is the first of a six-well program by ConocoPhillips and its joint venture partner Karoon Gas Ltd. of Melbourne in three adjacent permits.

ConocoPhillips has 51% interest in WA-315-P with Karoon holding the remaining 49%.

Africa Oil gets blocks in Ethiopia, Kenya

Africa Oil Corp., Vancouver, BC, acquired Lundin Petroleum AB's portfolio of exploration block interests in Ethiopia and Kenya for $23.7 million.

The blocks are in the underexplored East African rift basin petroleum system.

The acquisition included an 85% working interest in Blocks 2, 6, 7, and 8 and a 50% working interest in the Adigala block in Ethiopia and a 100% interest in Block 10A and a 30% interest in Block 9 in Kenya (see map, OGJ, Apr. 14, 2008, p. 40). Africa Oil will become operator except on Block 9.

The deal brings Africa Oil's total holding to more than 200,000 sq km. Good quality seismic data show robust leads and prospects throughout the blocks, Africa Oil said.

The exploration program for the next 2 years includes seismic and drilling in both countries. Africa Oil also plans to drill in Puntland, Somalia.

ENH, Kalila Energy sign gas exploration deal

Mozambique's state-owned Empresa Nacional de Hidrocarbonetos de Mocambique has sold Indonesia's PT Kalila Energy Ltd. a 75% stake in the Buzi Block for $30 million.

The partners will undertake natural gas exploration in the central Sofala province for the next 8 years and will drill two exploration and two appraisal wells.

The contract also provides for funding for social responsibility and staff-training programs.

According to reports, Buzi holds estimated reserves of 10-17 bcf of gas.

Petrotrin to explore Trinidad's Galeota block

Trinidad and Tobago's state-owned Petrotrin LLC signed an exploration and production contract with Bayfield Energy (Galeota) Ltd. for exploration of Galeota block and revitalization of Trintes oil field.

Malcolm Jones, Petrotrin executive chairman, said Bayfield will pay all of Petrotrin's capital investment and operating expenses in respect of the minimum work obligations for the first 4 years.

"This work obligation consists of both seismic and exploration wells together with production enhancement facilities," Jones said. He said Trintes oil field, which was discovered in the 1960s and had so far produced 22 million bbl of oil, will be revitalized and that recent seismic surveys had revealed the real possibility of another Trintes look-alike field in the southwest quadrant of the block.

"There is a high probability of finding additional hydrocarbons in commercial quantities," Jones said. Burren Energy won the bid to explore Galeota block, but UK-based oil company was sold in 2007 to the Italy's ENI SPA for $3.5 billion. Burren Energy's operations include oil fields in Turkmenistan, Congo, Egypt, and Yemen. Burren's shareholders then invested in Bayfield.

Jones said the exploration program will involve the acquisition of 120 sq km of full-fold 3D seismic and drilling of at least seven exploration wells to depths ranging 6,500-12,000 ft. "Through this aggressive exploration development program, both Petrotrin and Bayfield remain hopeful that production can be optimised and that there will be major successes in Galeota.

Bayfield Chief Operating Officer Simon Gill said, "By that time, we think the world economy should be improving and the oil price should improve. Now is a good time for us to get in and do the work. Hopefully, we'll get good prices for doing the work and you get your reserves in the future."

Galeota block lies 6 nautical miles east of Galeota Point in southeastern Trinidad. Bayfield will hold a 65% working interest in the new licence and be the operator of the asset and Petrotrin will hold a 35% nonoperating interest.

Bayfield plans to spend $110 million on the project. ✦

Drilling & Production — *Quick Takes*

Kentucky sets CO_2 EOR, sequestration projects

Projects to sequester carbon dioxide and test its use in enhanced oil recovery are under way in western Kentucky.

As much as 8,000 tons of CO_2 is to be injected for 6 months into the Mississippian Jackson sandstone at 1,870 ft in a well in Sugar Creek field in Hopkins County.

Three producing wells operated by Gallagher Drilling Inc., Evansville, Ind., will be monitored for changes in production as the result of the CO_2 injection, which is to start in mid-May. The geological surveys of Kentucky and Illinois are cooperating in the project.

Meanwhile, the Kentucky Geological Survey spud a well Apr. 23 in southeastern Hancock County, Ky., 8 miles southeast of Hawesville, with a projected total depth of 8,300 ft. Later CO_2 is to be injected to test the capacity of various formations to serve as permanent storage for the substance, which is expected to turn supercritical.

The drilling follows the shooting of reflection seismic surveys in December 2008. Both projects are in the Illinois basin.

PTT could buy gas from Natuna D Alpha block

Indonesia is negotiating with Thailand's PTT PLC for the purchase of undisclosed volumes of natural gas from the Natuna D Alpha block, according to a senior government official.

"We are currently still negotiating the gas price and the possibility of transporting it to Rayong, [Thailand,]" said Indonesia's Energy and Mineral Resources Minister Purnomo Yusigantoro.

Purnomo, speaking before the Indonesian Association of Petroleum Engineers, said PTT had earlier been in talks with Indonesia to buy gas from other blocks, but at that time the company decided to obtain its gas supply from Myanmar instead.

"The gas supply [from Myanmar] now seems to be declining, so the company is looking for gas from other sources," said Purnomo, who did not detail how much gas PTT might buy, saying the volume was still under negotiation, along with pricing.

Meanwhile, state-owned PT Pertamina has still not decided on its new partner for the development of Natuna D Alpha's reserves, but Purnomo said the state firm and the Indonesian government would offer the block's natural gas to potential buyers anyway.

"We are always looking for the market, because we don't want to be too late," said Purnomo, who added that buyers must be found before the block enters production, which may begin in 2017.

Initially, Pertamina and ExxonMobil Corp. had rights over the Natuna D Alpha block, but the government decided in 2005 not to extend the US firm's contract, saying it had failed to submit the results of a feasibility study.

In June 2008, the Indonesian government appointed Pertamina to develop the block, and the state firm shortlisted eight potential partners: ExxonMobil, Royal Dutch Shell PLC, Chevron Corp., Eni SPA, Total SA, StatoilHydro, China National Petroleum Corp., and Petronas.

StatoilHydro to refurbish NCS installations

StatoilHydro will shut down 21 production installations on the Norwegian Continental Shelf (NCS) this year to expand capacity, technical improvements, and extend their economic life.

The installations and plants to be revamped include Oseberg, Statfjord, Gullfaks, Snorre, Troll, Kvitebjorn, Visund, Sleipner, Grane, Huldra, Veslefrikk, Brage, Heimdal, Volve, Glitne, Snohvit, Norne, Asgard, Kristin, Njord, Sture, and Karsto.

StatoilHydro will finish the turnarounds by Oct. 1 to meet gas delivery commitments and avoid poor weather.

The company has shut down LNG production from Snohvit following problems with its seawater heat exchangers. Two of the seven were replaced last autumn, and four more are due to go during a lengthy turnaround after the summer.

Many installations on the NCS will be upgraded, the company said. "Compared with 2008, when 26 shutdowns involved 270,000 work-hr in all, this year's program involves fewer but larger operations. Some 313,000 hr are due to be worked."

The first shutdown began Apr. 2 on Statfjord B and is a major program that will be the last on the platform to extend the field's production life.

Oseberg also will be refurbished in June, which includes repairing the flare system at the field center and implementing part of the low-pressure project.

Capacity upgrades are planned for Snorre A, while work on Troll A includes preparations for a new gas pipeline to Kollsnes and expansion of the living quarters.

Statfjord field's life has been extended beyond 2020. This project is estimated at 23 billion kroner, including the Tampen Link pipeline, which delivers Statfjord gas to the UK, and the submersible pumps for Statfjord B and C. But this is higher than the original estimate of 15 billion kroner.

StatoilHydro and its partners are to invest in eight new electrical submersible pumps on the Statfjord C platform, and they are considering adding four pumps on the Statfjord B platform.

Total investment for the submersible pumps on Statfjord B and C is in the range of 3.5 billion kroner, and is subject to approval by the partners. ✦

Processing — *Quick Takes*

BP: End US import tax on Brazilian ethanol

BP PLC has sent a letter to the California Air Resources Board (CARB), calling for its support in ending US import duties on Brazil's sugarcane-based ethanol.

According to the letter, seen by Brazil's state news agency, BP "believes sugarcane-based ethanol will be the lowest-carbon biofuel available in the first years of the Low-Carbon Fuel Standard."

By supporting the end of import taxes on Brazil's ethanol, the letter says, California would send a strong sign to lawmakers in Washington, DC, that the state is seriously committed to meeting emission targets.

The agency said BP is the only oil company in the world that invests in Brazil's ethanol, holding a 50% stake in Tropical Bioenergia, located in Goias state, which started operations in September 2008.

The stake resulted from $683 million investments made jointly with the Maeda Group and SantelisaVale, now controlled by Louis Dreyfus Commodities.

BP Chief Executive Officer Tony Wayward recently said the company will invest $6 million in Brazil's sugarcane-based ethanol over the next 10 years.

CARB was to vote on Apr. 30 regarding new regulations to reduce emissions in the state.

Meanwhile, Brazil's state-run Petroleo Brazileiro SA (Petrobras) plans to begin selling gasoline blended with bioethanol in the Tokyo metropolitan area as early as this summer.

Petrobras has already built a facility to blend fuels at its base in Chiba Prefecture, and the Brazilian firm also will make use of a refinery it acquired last year in Okinawa Prefecture.

Meanwhile, Nippon Oil plans to meet the competition by offering biofuel at 1,000 affiliated gas stations in the Tokyo metropolitan area in June. Along with other domestic wholesalers, Nippon Oil expects to sell fuel containing 360,000 kl of bioethanol in fiscal 2010.

FTC proposes motor fuel economy guide changes

The US Federal Trade Commission has proposed amendments to its fuel economy guide for the first time since it adopted the guide in 1975.

The guide, which FTC developed to prevent deceptive advertising and facilitate the use of fuel economy information, would be amended to reflect technology improvements over the past 34 years and changes in the US Environmental Protection Agency's fuel econ-

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omy labeling rules for new cars, the commission said on Apr. 24.

The changes fall into three separate areas, it said. FTC's guide would adopt EPA's revised fuel economy labeling requirements. It would be modified to expand the scope of existing guidelines to include new vehicle types that run on fuels other than gasoline, such as natural gas and electricity. And it would include guidance related to cruising range information in advertisements for vehicles that run on alternative fuels.

FTC said it would publish a notice about the proposed changes in the Federal Register soon. Comments will be accepted through June 26. ✦

Transportation — *Quick Takes*

Mitsubishi-led LNG project may be shelved

The Japanese-led consortium seeking to build the Senoro LNG plant in Central Sulawesi, Indonesia, may have to delay its plans due to lower reserves of natural gas in the Senoro and Matindok fields than earlier estimated.

"We are now waiting for the operators to decide whether they still want to develop the project with the lower proven reserve," said Indonesia's Energy and Mineral Resources Minister Purnomo Yusgiantoro, in reference to the consortium comprised of state-owned PT Pertamina (Persero), PT Medco E&P, and Mitsubishi Corp.

Purnomo, who said upstream oil and gas regulator BPMigas also would discuss the matter with the consortium, announced Indonesia's state-owned oil and gas research and development center (Lemigas) had found reserves in the fields to be lower than the consortium's estimate of 2.4 tcf.

The minister did not detail Lemigas' findings, saying the institution "might" publish its results later on. But ministry adviser and former BPMigas chairman Kardaya Warnika said the lower proven gas reserves meant the LNG plant could not meet its initial production target.

"Lower proven gas reserves means less LNG production," said Kardaya. "Thus the plant may not be able to meet its initial production target of 2 million tonnes/year of LNG."

The Senoro LNG project came under public scrutiny when PT LNG Energi Utama (LEU) last August filed a lawsuit against Mitsubishi over claims the Japanese firm had unfairly won the project.

LEU, which claims exclusive rights to be involved in the Senoro LNG project, filed its lawsuit with Indonesia's Business Competition Supervisory Agency, which still has the case under review.

Mitsubishi holds a 51% stake in the Senoro LNG project, while Pertamina holds 29% and Medco E&P holds 20%.

Indonesian firms need $6.5 billion for tanker fleet

Indonesian shipping firms, eyeing favorable new legislation, need $6.5 billion to purchase 127 ships to replace foreign-flagged tankers currently carrying oil and gas in that country's waters.

"We need around 5-year $6.5 billion loans to build new ships to substitute for the foreign ships," said Johnson W. Sutjipto, chairperson of the Indonesian National Ship-owners' Association (INSA).

According to Johnson, who spoke before a conference on ship finance, foreign shipping firms earn $1.385 billion/year from the operation of 127 ships for oil and gas transport, as well as offshore activities.

Johnson spoke about changes in Indonesian law regarding the transport of oil and gas in domestic waters. Under the new legislation, which comes into effect in January 2010, foreign ships will not be able to operate in Indonesian waters and must be replaced by Indonesian-flagged ships.

"This offers opportunities for national banks to finance new ship procurement for oil and gas transportation," said Johnson, who also noted key difficulties for local shipbuilders.

"The problem is the national shipping industry still faces difficulty in getting domestic financing since the banking industry demands a long-term transportation contract and a 30% equity financing from a shipyard company," he said.

While foreign banks are ready to finance the ship procurement, Johnson said they are hesitant because Indonesia has not yet ratified international legislation that would enable them to recover their investment through the arrest of ships.

Meanwhile, the state Bank of Indonesia released data showing that shipping loans as of February still represented just 2% of the bank's total loans, despite an 80% increase in shipping loans year-on-year.

BI Deputy Governor Muliaman D. Hadad said the small loan percentage was due to uncertainty in the banking sector over the lack of transparency in the shipping industry. "If there is no transparency regarding the business risk, it will be difficult for banks to give loans," Muliaman said.

Ice-breaker tugs for Kashagan planned

Kazakhstan's JSC Circle Marine Invest has awarded a $113 million contract to STX Europe ASA, the Norwegian unit of South Korea's STX Group, for the construction of three ice-breaker tugs for use in the Kashagan offshore oil field development.

STX Europe's subsidiary Aker Arctic will design the three ice-breakers, which will be built largely in the STX RO Offshore shipyard based in Braila, eastern Romania, with delivery scheduled for 2010 and 2011.

JSC Circle Marine Invest subsidiary Caspian Offshore Construction will operate the vessels, which have a length of 65 meters and a beam of 16.4 meters. The tugs will be equipped and designed for other operations such as fire fighting, rescue operation, and towing in shallow waters.

According to Mikko Niini, President of Aker Arctic Technology Inc., the Caspian icebreaker tugs are based on the technology used in the first Aker Arctic DAS icebreakers which have operated for more than 10 years in the Kashagan oil development.

The Kashagan field holds recoverable oil reserves estimated at 13 billion bbl, and is expected to produce as much as 1.5 million b/d of oil at its peak in the next decade.

However, the field's development has been hindered with delays due to technical difficulties and disputes between the government and foreign firms over costs and profit distribution.

One of the Kashagan consortium partners last month gave assurances that the global economic crisis would not hinder the development of the offshore oilfield and may even help reduce costs.

"The plan is still to have first production as announced, in the fourth quarter of 2012," said Campbell Keir, Royal Dutch Shell manager for the Caspian region. "The economic situation and the low oil price should allow us to bring the cost down." ✦

Calendar

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

OIL&GAS JOURNAL online

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

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EAGE International Petroleum Conference & Exhibition, Shiraz, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 4-6.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. 4-7.

GPA Permian Basin Annual Meeting, Austin, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gasprocessors.com. 5.

Interstate Oil and Gas Compact Commission Midyear Meeting (IOGCC), Anchorage, (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 10-12.

ERTC Asset Maximisation Conference, Prague, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 11-13.

ACHEMA International Exhibition Congress, Frankfurt, +1 5 168690220, +1 5 168690325 (fax), e-mail: amorris77@optonline.net, website: http://achemaworldwide.dechema.de. 11-15.

IADC Environmental Conference & Exhibition, Stavanger, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 12-13.

North American Unconventional Oil & Gas Conference & Exposition, Denver, (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 12-13.

NPRA National Safety Conference, Grapevine, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 12-13.

International School of Hydrocarbon Measurement, Norman, Okla., (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu. Website: www.ishm.info. 12-14.

Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 12-14.

Pipeline Simulation Interest Group (PSIG) Meeting, Galveston, Tex., + 966 3 873 0139, + 966 3 873 7886 (fax), e-mail: info@psig.org, website: www.psig.org. 12-15.

Iraq Oil + Gas Summit, Houston, (202) 536-5000, (202) 280-1239 (fax), e-mail: lwilson@nfemail.com, website: www.New-Fields.com. 13-14.

Louisiana Oil and Gas Symposium, Baton Rouge,

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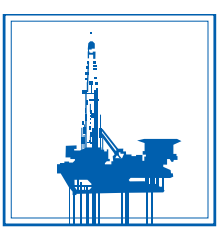

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MANAGING THE DIGITAL TIDAL WAVE WITH PETRIS

Today's exploration and production (E&P) professionals are flooded with what often seems like a tidal wave of digital information.

We are in an unprecedented time in our history with the amount of data that the oil and gas industry collects, stores, accesses and interprets. The accumulation of all this digital information translates into an annual growth of approximately 60 percent each year, according to leading industry estimates.

Data, in all its forms, has truly become the lifeblood of E&P organizations. The entire corporation and every department use data associated with all aspects of exploration, drilling, production, and delivery. Due to this, data in different and incompatible formats, of differing quality and integrity, multiplies explosively and often becomes scattered around the entire organization into an ever-growing and increasing number of datasets and point solutions.

With this volume comes tremendous uncertainty. The lack of accuracy, consistency and completeness of large datasets reduces user confidence and trust in the data that is delivered to the desktop. Data quality issues that were formerly isolated in a functional group can now cause havoc department and company-wide, as the poor data is integrated and propagated across the enterprise. This is why there is such increasing emphasis upon enterprise-wide data quality and integration solutions.

Petris has been at the forefront of data management innovations over the years and has become a leading technology provider, with a proven track record across the globe. The company understands the trend in juxtaposing technical processes and business processes to help E&P organizations better manage and know their data. Over the years, Petris has actively researched data management and data integration approaches and has taken a leadership role in providing solutions.

ECONOMIC REALITIES

Compared to the past, more companies struggle to manage the large wave of data required to make critical decisions, whether it is planning a new well or assigning resources to different projects. An E&P company's success is not proven by the amount of data a company has at its fingertips, but by the manner in which the data is used to add value.

This becomes even more challenging in a volatile economic climate when the survival of E&P companies is highly dependent on how their data can be used to find and produce more, with a lower margin for error. IT budgets are under greater scrutiny and less capital is available to take on optional or "experimental" data management initiatives – it is now universal in operations and management functions that every dollar invested in IT and data management be justified and proven.

An E&P's success is not proven by the amount of data a company has at its fingertips, but by the manner in which the data is used to add value.

Another difficult reality E&P's face is managing the workforce crew change. A large percentage of the industry is expected to retire over the next decade. The next-generation technologists have raw skills, but not the same level of E&P-specific experience and insight of the people they replace. In addition, this "Google generation" will want accurate and trustworthy information with only a few clicks. This means better business processes, workflows, and practices need to be developed in real-time to capture and pass along the institutional knowledge. In addition to the people and processes, oil company physical assets, such as reservoir and equipment, need to be combined to support the business and decision-making within energy companies. IT will likely be expected to become the 'glue' to facilitate this transition, while ensuring proper collaboration in data sharing across the enterprise.

EMERGING TRENDS

The good news is that because the industry has become a leader in stretching the limits of technology, there is tremendous innovation being developed, which is driving:

- More pro-active technology providers to deliver much more value for less cost;
- Advances in master data management and authoritative data stores;
- Increasing integration between technical processes with e-business processes, leading technology providers, to build solutions based on the latest and most flexible technology, such as Java, .NET, Microsoft Office SharePoint Software (MOSS), and service oriented architecture (SOA);

- Cutting-edge approaches for enterprise-wide integration of systems; and,
- A larger choice of industry technology providers.

It is also important that E&P companies choose a partner who is not exclusive and can interoperate with any technology solution. Biggest is not better, as most innovation comes from companies that are cost-effective, dynamic, agile, and able to work with energy organizations as a partner. Flexibility, know-how, and reliability are key.

FINDING THE RIGHT TECHNOLOGY PARTNER

In today's high-tech energy business, projects often function or fail based on the quality of the data, coupled with the quality of the analysis. Petris provides the oil and gas industry with:

- Industry-leading level of domain knowledge required to tackle difficult data challenges;
- Significant research and development focused around ways to identify, aggregate, review, clean, and manage data over its life cycle;
- A more effective way to trust and know the quality of data, automate workflows, track information heritage, recall and integrate borehole data, plan and model drilling data, and access operational information in real-time; and,
- Visualization tools, montaging and computer graphics to improve the overall productivity for oil and gas companies.

The company responds quickly to the industry's challenges and is providing the 'next wave' of innovative, cost effective, and market-driven technology solutions to manage and integrate data. Petris has an extremely strong market understanding, scalable technologies, and proven approaches that help E&P companies extract the most from their existing infrastructure investment and give users access to trustworthy information where they want it, when they want it, and in the format required.

CONTROLLING THE WAVES: CHALLENGES SOLVED BY PETRIS

MANAGING MASTER DATA

Petris' continuous research around industry trends and project requirements has resulted in the development of a proven methodology and tactical processes to undertake Master Data Management (MDM) implementations. Petris has top experts and significant experience in dealing with the different methods of MDM – Master Well Registry, Master Well Repository, and Master Hub.

Well MDM is an evolving approach to E&P enterprise data management. It is not another repository of well information only used by part of an organization. For example, a well database for geological and geophysical (G&G) data is not considered to be MDM. Nor is MDM a data mart, warehouse of well information or an enterprise-wide, single source repository. In other words, just because you have a list of wells, it does not mean you have Master Data Management.

Well MDM is a cross-functional, time dimensional approach to managing well data across the entire life cycle. It has to embrace the whole organization and all its functions, not just one part of it. It has to link those estimating the future with those planning the present, in engineering, production, reservoir estimating, accounting and even HR. Once this is achieved, the operational systems in the enterprise can share this master data and deliver harmonized business intelligence. In other words, users can then access master data as a trusted source of truth, knowing that the linked cross references are correct and accurate.

The PetrisWINDS DataVera™ suite of data quality and MDM tools helps E&P experts implement infrastructures to maintain only one well master registry and retain confidence in the master list through ongoing data quality governance. In addition, DataVera automates arduous tasks that are often performed manually through a repeatable and automated repository of business rules.

Manage Master List with DataVera™

BUILDING AN AUTHORITATIVE DATA SOLUTION

In addition to MDM implementations, today's oil and gas companies experience the pressures of having enterprise-wide data right now, in real time. The company has developed the "Petris OneSource" product and service line to help clients better manage E&P data during the whole interpretation process. OneSource leverages the power of Petris' SOA solution, PetrisWINDS Enterprise®, to provide an open, readily accessible and fully reliable source of information for users, leveraging a wide variety of applications across the enterprise. An authoritative data solution can help users from different departments and functions discover, browse, and access the one source of definitive data, without additional engineering.

Petris has helped clients embark on initiatives to deploy an authoritative data store. The goal of such projects is to create a single repository where users can go to find trustworthy data. Creating simply another database isn't the answer. Petris' solutions provide users with a trusted source of information that is scalable and can accommodate change without modifying the underlying technology infrastructures. This has already proven value in reducing project turnaround time to weeks instead of months.

As a prime technology partner, Petris provides ongoing value-added solutions by quickly responding to changing requirements and specialized client requests. By collaborating on successful projects and documenting the learnings, Petris continuously applies pertinent industry-focused practices into the full technology portfolio, available to the global customer base.

SOLUTIONS COME AND GO, BUT DATA IS FOREVER

The productive life of oil and gas assets often spans decades. Newly acquired assets will likely have years' worth of supporting data. Even if a company owns an asset for only a short time, managing it for the long term is the best way to increase its value. To do this requires access to various types of data - typically held in many formats - to help the owners best decide what to do today.

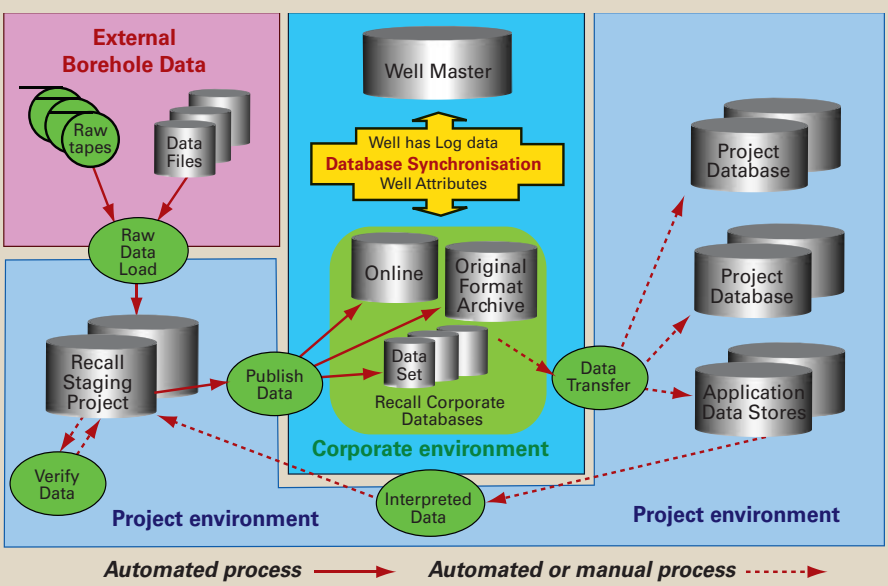
Geoscientists require complete access to a broad range of well bore data - including petrophysical logs, dip meter and core data - to make informed decisions. PetrisWINDS Recall, the world-standard for well bore data management, coupled with its broad array of petrophysical logs, dip, and image processing tools makes it the fastest and easiest way to quality control, store, analyze, and provide access to wellbore data.

Recall leverages a powerful and extensive data dictionary along with a robust and scalable architecture to support all types of borehole data. Recall's petrophysical interpretation and visualization applications are sophisticated tools for imaging and understanding the subsurface on the basis of wellbore data. This understanding is a keystone for building the earth models used to plan drilling and production programs and to stretch every budget dollar to its best outcome.

CONTROLLING THE DELUGE OF CRUCIAL DRILLING DATA

Of all the processes in the lifecycle for an oil and gas asset, drilling is one of the most expensive and certainly one of the most critical. Companies drill exploration wells to define prospects. These wells also provide information, such as logs or core samples, used in conjunction with seismic and other data to better understand the subsurface for optimal placement of production wells. PetrisWINDS DrillNET provides a single, unified environment across a broad range of drilling applications to deliver effective well planning and analysis.

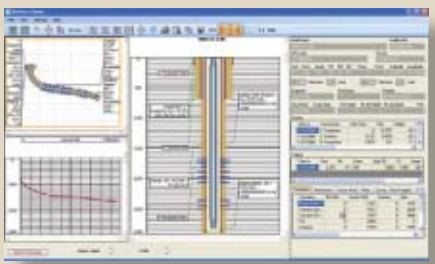
The DrillNET drilling program includes carefully designed well plans that benefit from a sound understanding of the geology, geophysics and fluid flow characteristics of the asset to be produced. Increasingly complex earth models - which incorporate all the data known about the prospect - form the basis of the drilling program. Integration of information and models form a variety of sources and are the basis of the earth models that are drilled 'electronically' prior to, or in conjunction with, drilling operations. Not to be left out, conventional wells can benefit from the same up-front planning as do more complex deep water or non-vertical wells.



Typical Recall integration for a major oil company

OPTIMIZING OPERATIONS– GETTING TO THE LAST RECOVERABLE DOLLAR

Accessing and understanding the volumes of information derived from drilling, completion, well servicing and production activities are significant challenges for energy companies. How you manage the workflow process is increasingly important to overall productivity.



OpCenter Wellbore Viewer

Operational and business data are often gathered from widely dispersed and rapidly changing sources. Financial managers require faster and more accurate reporting than ever before; management criteria and strategies can fluctuate dramatically with changing market conditions and business drivers. As a result, your decision making process must be reliable, flexible and responsive to your company's business workflow cycle.

Petris has designed the industry's first integrated, enterprise solution for optimizing operational real time and near-real time dataflows to enable the digital oilfield. Its foundation is a data management layer that links task-specific centers and user work processes together. The Operations Center (OpCenter) suite of software captures all the detailed information involved in drilling a well, from planning to the last bit run and produces the drilling reports that engineers and managers need.

RIDING THE NEW WAVE: "PETRIS' ONE TOUCH" E&P PORTAL

With of the huge deluge of global information flowing 24 hours a day, 7 days a week, 365 days per year, today's oil and gas companies need an E&P knowledge portal that offers one place for users to access and "touch" all their

data, information, and knowledge. Petris is continually researching new ways to discover and visualize E&P enterprise-wide information, and providing a complete and comprehensive view of every asset, whether it is field, well, seismic, survey, or pipeline information.

Petris also understands the importance for users to view related data from multiple sources and different domains, while maintaining secure, role-based access to data with customized views for each user type and role. Due to this, the company continually invests in rich Business Intelligence (BI) technologies to help users discover previously unknown information, ensure a high level of quality in the data, create user defined visualization tools and templates, and navigate complex references that cross traditional boundaries.

PETRIS: FOCUSED INNOVATION AT ITS BEST

Petris knows that data is the lifeblood of the industry. Since 1994, Petris has pioneered approaches to manage the vast growth of data with its practical solutions for all E&P domains, including borehole, seismic, production, drilling, and engineering. The company has a proven history with over 500 customers around the world and has a deep understanding in data management and the steps to process, interpret, store, safeguard, search, and retrieve data. Petris' core strength is watching the technological trends in the industry and adapting its offerings to meet the precise demands of the times.

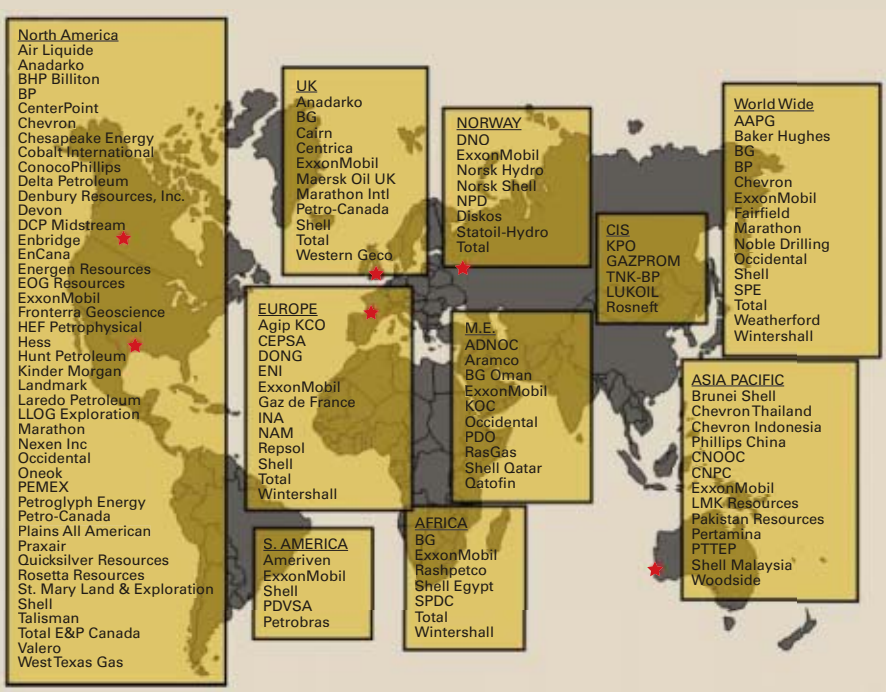
Recognizing the expectations of the "Google generation" and the increasing demands for accurate and trustworthy information, Petris' solutions have embedded specialized E&P information to help with the shift of knowledge from one generation to another. In addition, the company has the right people, support infrastructure, and resources worldwide to help clients fully realize the value of E&P technology investments through training, on-site support, professional services, and custom implementations.

Petris is a dynamic company and continues to grow its portfolio of products and services by making strategic acquisitions with like-minded and compatible solutions providers. But the company doesn't stop there. Petris is perpetually researching cutting-edge approaches so that customers have the freedom to choose the technology components that are most useful for a specific need. In addition, Petris maintains application neutrality to work seamlessly with other applications that are already embedded in a company's operations – or any other new software that a company selects down the road.

Petris has uniquely positioned itself as a key technology solution provider for E&P companies of all sizes, with different business needs. The company's solutions are cost-sensitive so that every dollar invested by an E&P organization adds value. In addition, Petris' users are able to find and visualize information faster and easier, while leveraging a business rules repository across all product lines. Instead of finding the data needed in various places, Petris gives users a single place to find all their information - significantly saving time and resources for E&P's.

High quality integrated data helps users and managers make better decisions. Petris can ensure accuracy, consistency, and completeness to inspire user confidence in the data. The E&P and pipeline sectors of the energy industry have always been Petris' dedicated and key discipline, and the reason why Petris wants to be the premier solutions partner of choice.

Petris has uniquely positioned itself as a key technology solution provider for E&P companies of all sizes, with different business needs



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Calendar

(225) 578-8657, (225) 578-9257 (fax), e-mail: hammer@lsu.edu, website: www.brgs.la.org. 19-20.

NPRA Reliability & Maintenance Conference, Grapevine, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 19-22.

IADC Drilling Onshore Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 21.

Gastech International Conference & Exhibition, Abu Dhabi, +44 (0) 1737 855000, +44 (0) 1737 855482 (fax), website: www.gastech.co.uk. 25-28.

APPEA Conference & Exhibition, Darwin, +61 7 3802 2208, e-mail: jhood@appea.com.au. website: www.appea2009.com.au. May 31-Jun. 3.

SPE Latin American and Caribbean Petroleum Engineering Conference, Cartagena, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. May 31-Jun. 3.

JUNE

Caspian International Oil & Gas/Refining & Petrochemicals Exhibition & Conference, Baku, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 2-5.

Asia Oil & Gas Conference, Kuala Lumpur, 65 62220230, 65 62220121 (fax), e-mail: info@cconnection.org, website: www.cconnection.org. 7-9.

AAPG Annual Meeting, Denver, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 7-10.

PIRA Scenario Planning Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 8.

ILTA Annual International Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 8-10.

International Oil Shale Symposium, Tallinn, Estonia, +372 71 52859, e-mail: Rikki.Hrenko@energia.ee, website: www.oilshalesymposium.com. 8-11.

SPE EUROPEC/EAGE Conference and Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-11.

PIRA Understanding Global Oil Markets Seminar, Houston, (212) 686-6808, (212) 686-6628 (fax), website: www.pira.com. 9-10.

GO-EXPO Gas and Oil Exposition, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 9-11.

Petro.t.ex Africa Exhibition & Conference, Johannesburg, +27 21 713 3360, +27 21 713 3366 (fax), website: www.fairconsultants.com. 9-11.

Oil and Gas Asia Exhibition (OGA), Kuala Lumpur, +60 (0) 3 4041 0311, +60 (0) 3 4043 7241 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com/oil. 10-12.

ASME Turbo Expo, Orlando, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 13-17.

Society of Petroleum Evaluation Engineers (SPEE) Annual Meeting, Santa Fe, NM, (713) 286-5930, (713) 265-8812 (fax), website: www.spee.org. 14-16.

PIRA London Energy Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 15.

IPAA Midyear Meeting, Dana Point, Calif., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 15-17.

PIRA Scenario Planning Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 16.

Atlantic Canada Petroleum Show, St. John's, Newfoundland & Labrador, 403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 16-17.

IADC World Drilling Conference & Exhibition, Dublin, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 17-18.

PIRA Understanding Global Oil Markets Seminar, London, 44 1493 751 316, e-mail: miles@pira.com, website: www.pira.com. 17-18.

AAPL Annual Meeting, Clearwater Beach, Fla., (817) 847-7700, (817) 847-7704 (fax). e-mail: aapl@landman.org, website: www.landman.org. 17-20.

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

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

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

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

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

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

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

JULY

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

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

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

AUGUST

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

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

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

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

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

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

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

SEPTEMBER

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

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

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

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

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

GITA's GIS Annual Oil & Gas Conference, Houston, (303) 337-0513, (303) 337-

Calendar

1001 (fax), e-mail: info@gita.org, website: www.gita.org/ogca. 14-16.

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

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

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

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

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

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

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

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

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

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

OCTOBER

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

Calendar

ok.us, website: www.iogcc.state.ok.us. 4-6.

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

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

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

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

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

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

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

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

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

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

SEG International Exposition and Annual Meeting, Houston, (918) 497-5500, (918) 497-5557 (fax), e-mail: register@seg.org, website: www.seg.org. 25-30.

SPE/IADC Middle East Drilling Conference & Exhibition, Manama, +971 4 390 3540, +971 4 366 4648 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-28.

Louisiana Gulf Coast Oil Exposition (LAGCOE), Lafayette, (337) 235-4055, (337) 237-1030 (fax), e-mail: lynette@lagcoe.com, website: www.lagcoe.com. 27-29.

Offshore Middle East Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoremiddleeast.com. 27-29.

NOVEMBER

Deep Offshore Technology International Conference & Exhibition, Monte Carlo, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepoffshoretechnology.com. 3-5.

IPAA Annual Meeting, New Orleans, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 4-6.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 5.

Capture and Geological Storage of CO_2 Symposium, Paris, +33 1 47 52 67 21, +33 1 47 52 70 96 (fax), e-mail: patricia.fulgoni@ifp.fr, website: www.CO2symposium.com. 5-6.

IADC Annual Meeting, Miami, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

API Fall Refining and Equipment Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 9-11.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 10-12.

SPE International Oil and Gas China Conference & Exhibition, Beijing, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

ASME International Mechanical Engineering Congress and Exposition (IMECE), Lake Buena Vista, Fla., (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 13-19.

IADC Completions Conference, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 17.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 17-19.

IADC Well Control Asia Pacific Conference & Exhibition, Bangkok, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 18-19.

DECEMBER

World LNG Summit, Barcelona, +44 (0)20 7978 0000, +44 (0)20 7978 0099 (fax), e-mail: info@thecwcgroup.com, website: www.thecwcgroup.com. 1-4.

Emerging Unconventional Resources Conference & Exhibition, Shreveport, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.emergingresourcesconference.com. 8-10.

PIRA Natural Gas Markets Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 14-15.

PIRA Understanding Natural Gas and LNG Markets Seminar, New York, (212) 686-6808, (212) 686-6628 (fax), website: www.pira.com. 14-15.

PIRA Understanding Global Oil Markets Seminar, New York, (212) 686-6808, (212) 686-6628 (fax), website: www.pira.com. 16-17.

2010

JANUARY

Oil & Gas Maintenance Technology Conference & Exhibition Co-located with Pipeline Rehabilitation and Maintenance, Cairo, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 19-21.

Pipeline Rehabilitation & Maintenance Co-located with Oil & Gas Maintenance Technology, Cairo, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pipeline-rehab.com. 19-21.

API Exploration and Production Winter Standards Meeting, New Orleans, (202) 682-8000, (202) 682-8222, website: www.api.org. 25-29.

FEBRUARY

Deep Offshore Technology International Conference & Exhibition, Houston, (713) 963-6271, (713) 963 6296 (fax), e-mail: registration@pennwell.com, website: www.dotinternational.net. 2-4.

Annual Petroleum Coke Conference, Seattle, (832) 351-7828, (832) 351-7887 (fax), e-mail: petcoke.conference@jacobs.com, website: www.petcokes.com. 12-13.

Laurance Reid Conditioning Conference, Norman, Okla., (512) 970-5019, (512) 233-2877 (fax), e-mail: bettyk@ou.edu, website: www.lrgcc.org. 21-24.

MARCH

Subsea Tieback Forum & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. 2-4.

GPA Annual Convention, Austin, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.GPAglobal.org. 21-24.

Offshore West Africa Conference & Exhibition, Luanda, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshorewestafrica.com. 23-25.

APRIL

Rocky Mountain Unconventional Resources Conference & Exhibition, Denver, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.RMURconference.com. 6-8.

Oil & Gas West Asia Conference, Muscat, +968 24660124, +968 24660125 (fax), e-mail: omanexpo@omantel.net.om, website: www.ogwaexpo.com. 19-21.

SPE Improved Oil Recovery Symposium, Tulsa, (918) 366-7033, (918) 366-7064 (fax), e-mail: IOR@SPEIOR.ORG, Website: www.speior.org. 24-28.

SEPTEMBER

World Energy Congress, Montreal, (514) 397-1474, (514) 397-9114 (fax), e-mail: info@wecmontreal2010.ca, website: www.wecmontreal2010exhibit.com. 12-16

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Learning languages

Guntis Moritis
Production Editor

The names of oil and gas fields offer a way for Anglophones to acquire some non-English vocabulary. Some field names are similar to English but many are not.

OGJ's style has not been too consistent over the years but in general OGJ style is to change a field's name to an English spelling if the name is similar to an English word. OGJ style also calls for not translating the name to an English word if the meaning is not obvious.

OGJ currently does not add diacritical marks on letters and does not change letters with diacritical marks to their phonetic equivalent. For instance, an "a" with two dots above it in OGJ style is just an "a" and is not written as "aa." In addition, an "o" with a slash through it is an "o" and not "oh."

Portuguese

With much activity off Brazil and Angola, many giant fields have Portuguese names. Off Brazil, field names often relate to the marine environment.

Whale Park or Parque da Baleia is an area currently under development for both heavy oil and lighter oil from the presalt section in the Campos basin off Brazil's Espirito Santo state.

The fields in the area are named for whales. The translations for the names based on information from Wikipedia are:

- Jubarte—Humpback whale.
- Cachalota—Sperm whale.
- Baleia Ana—Minke whale.
- Baleia Azul—Blue whale.
- Baleia Franca—Right whale.

Another area under development in the Campos basin is Shell Park or Parque das Conchas. A unit of Royal Dutch Shell PLC operates the fields in Shell Park that includes Argonauta, Nautilus, Ostra, and Abalone. These field names are the same or easily translate to the English words Argonaut (paper nautilus), Nautilus, Oyster, and Abalone.

Fish names are another theme off Brazil with the English spelling being the same or similar to Portuguese for fields such as Albacora (Albacore Tuna), Barracuda (Barracuda), Marlim (Marlin), and Roncador (Roncador).

According to Wikipedia, Roncador is a fish found on the West Coast of North America, which is news to me.

Another field off Brazil is Golfinho or Dolphin in English.

Not all field names off Brazil relate to the marine environment. For instance, the giant presalt discovery Tupi in the Santos basin is named after a main group of Brazilian indigenous people.

Another presalt discovery in Santos basin Carioca, according to Wikipedia, refers to the city of Rio de Janeiro and originally comes from the word "Kara'i oca," which is from the indigenous Amerindian language of the Tupi people, meaning "white man's house."

The name Iara, another presalt discovery, derives also from the Tupi language. A Brazilian poet made up the name from two Tupi words and in Brazil it refers to a mermaid as well as being a popular girl's name, according to an explanation on the internet.

Portuguese names are also found off Angola. Block 17 has fields named after flowers such as Girassol (Sunflower), Violetta (Violet), Tulipa (Tulip), Rosa (Rose), Orquidea (Orchid), Lirio (Iris), Pazflor (Passion flower), and Cravo (Carnation).

Field names in Block 31 off Angola come from the names of planets such as Plutao (Pluto), Saturna (Saturn), Venus (Venus), and Marte (Mars).

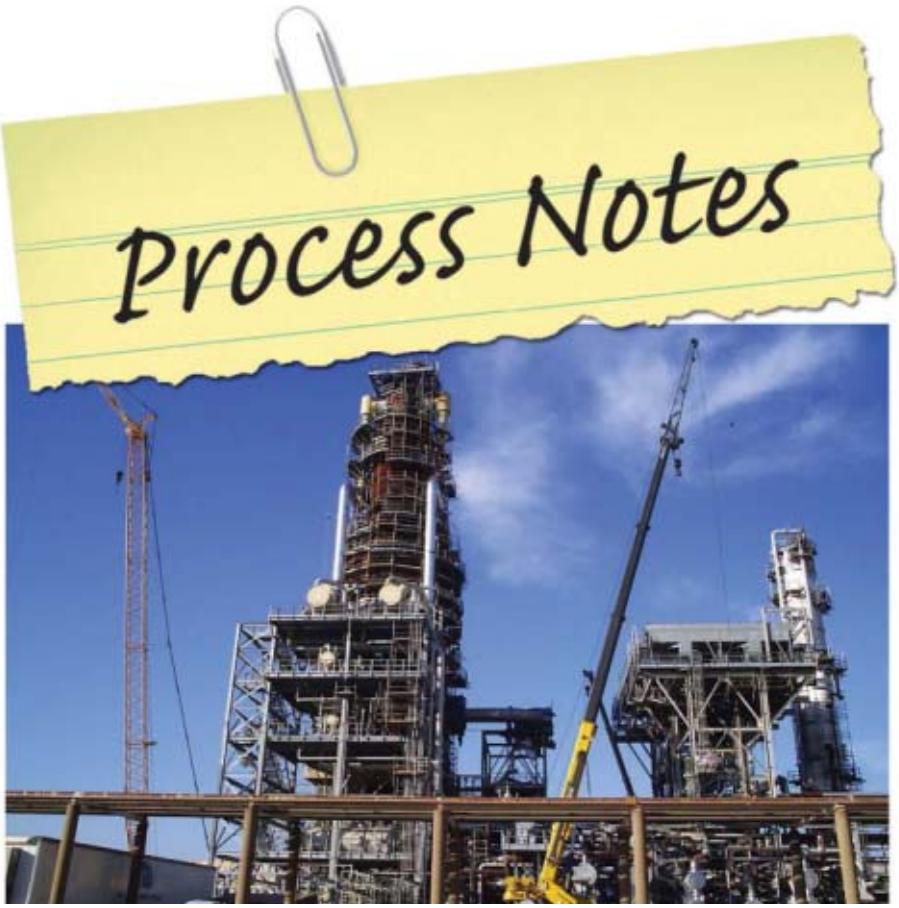
Block 18 discoveries include names of elements such as Plutonio (Plutonium), Paladio (Paladium), Platina (Platinum), Galio (Gallium), Cromio (Chromium), and Cobalto (Cobalt).

Names of spices designate discoveries in Block 32 such as Gindungo (Chili pepper), Canela (Cinnamon), Gengibre (Ginger), and Mostarda (Mustard).

Vietnamese

This week's special report has an article (p. 66) on development of discoveries off Vietnam with such names as Su Tu Den (Black Lion), Su Tu Nua (Brown Lion), Su Tu Vang (Golden Lion), and Su Tu Trang (White Lion).

Other fields in Vietnam include Bach Ho (White Tiger), Ca Ngu Vang (Golden Tuna), Rong Doi (Twin Dragon), and Rong Doi Tay (Twin Dragon West). ✦



Why Do Many Crude/Vacuum Units Perform Poorly?

In many cases it's because the original design was based more on *virtual* than *actual* reality. There is no question: computer simulations have a key role to play but it's equally true that process design needs to be based on what works in the field and not on the ideals of the process simulator. Nor should the designer simply base the equipment selection on vendor-stated performance. The design engineer needs to have actual refinery process engineering experience, not just expertise in office-based modeling. Refinery hands-on experience teaches that fouling, corrosion, asphaltene precipitation, crude variability, and crude thermal instability, and many other non-ideals are the reality. Theoretical outputs of process or equipment models are not. In this era of slick colorful PowerPoint® presentations by well-spoken engineers in Saville Row suits, it's no wonder that units don't work. Shouldn't engineers wearing Nomex® coveralls who have worked with operators and taken field measurements be accorded greater credibility?

Today more than ever before this is important. Gone are the days when a refiner could rely on uninterrupted supplies of light, sweet, easy-to-process crudes. In troubled times fierce global competition for premium crudes means that refinery units must have the flexibility to handle heavy, viscous, dirty crudes that increasingly threaten to dominate markets. And flexibility must extend to products as well as crudes, for refinery product demand has become more and more subject to violent economic and political swings. Thus refiners must have the greatest flexibility in determining yields of naphtha, jet fuel, diesel and vacuum gas oil products.

Rather than a single point process model, the crude/vacuum unit design must provide continuous flexibility to operate reliably over long periods of time. Simply meeting the process guarantee 90 days after start-up is very different than having a unit still operating well after 5 years. Sadly few refiners actually achieve this—no matter all the slick presentations by engineers in business suits!

If you want to explore these issues in technical detail ask for Technical Papers 267 and 268.

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Editorial

Dollars and energy

Because the US government plans to spend heavily on energy over the next decade, taxpayers have reason to wonder what they'll get for their money. Answers won't come easily. The spending will take many forms, from direct payments on activities such as clean-coal research to tax incentives for renewable energy and conservation. No simple accounting will be available.

A new report from the US Energy Information Administration nevertheless suggests where the country is heading in its latest experiment with governmental fuel selection. According to EIA, the American Recovery and Reinvestment Act of 2009 (ARRA)—the stimulus bill signed by President Barack Obama on Feb. 17—definitely will change patterns of energy use and production in the next 2 decades. But it won't meet ambitious goals by which the spending and market intrusions have been marketed.

What ARRA will do is cost money. The administration estimates ARRA spending on energy will total $65 billion through 2019. Against that cost, the EIA report holds up important performance metrics.

Important changes

The report updates EIA's Annual Energy Outlook 2009 to accommodate two important changes: deterioration of the global economy and enactment of ARRA. EIA compares the new projection to 2030 not only with the original report but also with a forecast predicated on new economic conditions without ARRA. "The effect of ARRA alone, including its energy-related provisions and its stimulative impact on the economy, can be roughly estimated by comparing the no-stimulus case to the updated reference case," EIA says.

Relative to the no-stimulus case, the updated forecast incorporating ARRA changes sees major expansion of renewable energy for power generation, of wind generation, and of geothermal and biomass capacities. It also expects lower energy use for buildings and lower household and commercial spending for nontransportation energy. Total energy consumption in 2020, the outer limit for ARRA spending, will be 104.67 quadrillion BTUs (quads), EIA now predicts. That's 0.54 quads higher than in the no-stimulus case—up in all categories except natural gas and nuclear.

ARRA lifts total US energy production by 0.49 quads to 81.88 quads in 2020 from the no-stimulus level, with increases confined to coal, biomass, and other renewables—the big beneficiaries of spending under the stimulus bill. The measure pushes up the combined contribution to 2020 energy supply of those sources by 1.91 quads. If half the federal energy spending under ARRA relates to supply, the US will have spent $17/MMbtu to achieve an annual boost from favored energy forms representing 2.3% of total domestic production. For perspective, natural gas is now worth about $3.30/MMbtu crude oil about $8.60/MMbtu. The total supply increment for coal, biomass, and other renewable energy is only fractionally greater in 2030 against the no-stimulus assumption than it is in 2020.

US import dependency declines over the course of the study period in all cases, but differences between the no-stimulus case and new projection are negligible. In 2030, the US still relies on foreign sources for 22-23% of its energy in the EIA forecast. This is not energy independence, a prominent goal of energy policy-making.

Oil as a share of total consumption also falls slightly—from 40% in 2007 to 37% in 2020 and 36-37% in 2030. Again, differences in specific years with and without ARRA are slight. So the new law advances the US very little toward the goal enunciated by Obama in February to "begin to end the tyranny of oil in our time." The decline was going to happen anyway.

Emission changes

Differences are bigger for energy-related emissions of carbon dioxide, another driver of energy policy. They're 1.3% lower with ARRA than without it in 2013 and 0.6% lower in 2030. But those differences are inconsequential to global average temperature.

The ARRA commits Americans to major expenditure on energy behavior that few would choose for themselves. It does so in service to energy goals—supply independence, greatly diminished reliance on oil, moderation of observed warming—that it will not attain.

Major spending on minor achievements is a poor deal in any system of economics. Some might call it senseless. ✦

Oil linked to US move toward thaw with Cuba

A proposal to allow work by US oil and gas companies off Cuba appears in a broad set of recommendations made before President Barack Obama on Apr. 13 eased travel and financial restrictions on the island nation.

A group of former ambassadors, foreign policy specialists, and professors working in a Brookings Institution project on Feb. 26 published 33 steps toward renewal of relations between the two countries in Miami, Fla., home to many Cuban-Americans and the center of opposition to restoration of relations.

A step allowing licenses for US companies to develop offshore oil, gas, and renewable energy is one of 10 "medium-term initiatives" recommended by the 19-member group in its Roadmap for Critical and Constructive Engagement (see table, opposite page). The group's project is called US Policy toward a Cuba in Transition.

Obama's move represents a tentative loosening of the trade embargo that the US imposed in 1962 after breaking diplomatic relations with Cuba a year earlier. The US took those steps in response to Fidel Castro's revolutionary assumption of power in 1959 and alignment with the old Soviet Union.

The US president's measured overture partly reflects concerns in the US about the power void that will develop when 78-year-old Raul Castro, who succeeded his brother as the Cuban president in February 2008, becomes unable to govern.

Foreign policy officials fear that Cuba without either Castro brother in firm command will become an unstable prize sought by Venezuela's anti-US President Hugo Chavez, slide back into the orbit of Russian influence, or degenerate into lawlessness subject to exploitation by terrorists and drug cartels (see Comment).

Reliance on Venezuela

Heavy reliance on Venezuela for oil is an evident source of concern in Cuba.

A member of Petrocaribe, the alliance of Caribbean countries that buy oil from Venezuela under preferential terms, Cuba receives 94,000-96,000 b/d from the South American exporter. That's more than all the other 17 members combined.

Cuba consumes about 150,000 b/d of oil and produces 54,000 b/d of crude oil and natural gas liquids. Gas production is 20,000-22,000 boed.

According to Jorge Pinon, energy fellow at the Center for Hemispheric Policy at the University of Miami and author of the Comment on p. 32, Cuba hasn't paid for the Venezuelan oil since 2003. The Chavez regime thus holds great leverage over the Cuban government not only as a principal supplier of oil but as a creditor as well.

Pinon points out that worry about Venezuelan influence explains Raul Castro's recent visits to capitals of other major oil exporters.

Cuba has offered onshore and offshore exploration and production rights to international operators in recent years under production-sharing contracts. Some of the blocks cover deep water of the southeastern Gulf of Mexico (see map, OGJ, Dec. 11, 2000, p. 42).

Repsol YPF in 2004 drilled a deepwater well, the Yamagua-1, in 1,660 m of water that was reported to have indicated oil generation in the basin. Norsk Hydro and ONGC Videsh of India later acquired interests in the block.

Cuba's existing production comes from onshore and near-shore fields. The oil is heavy—10-15° gravity—and high in sulfur.

Sherritt International, Toronto, is the major non-Cuban producer, accounting for about 30,000 b/d of gross production.

Refining a question

A question for Cuba is what to do with any increase that develops in crude oil production. Its domestic refining capacity is limited, and US sanctions block access to most refineries in the Caribbean.

Cuba's three refineries have name-

PROPOSALS IN BROOKINGS INSTITUTION REPORT ON US-CUBAN RELATIONS*

Short-term initiatives

- Remove all restrictions on family and humanitarian travel to Cuba.
- Permit and expand specific licenses for people-to-people travel for educational, cultural, and humanitarian purposes—all travel permitted under law.
- Reinstate remittances for individuals and independent civil society in Cuba.
- Allow all Cubans who meet requirements of US immigration law to travel to the US.
- Promote normal diplomatic activities on a reciprocal basis, including in-country travel, official meetings, exchange of attaches, and sponsorship of cultural and educational exchanges.
- Open a dialogue between the US and Cuba, particularly on issues of mutual concern, including migration, counternarcotics, environment, health, and security.
- Develop agreements and assistance with the government of Cuba for disaster relief and environmental stewardship.
- Conduct a review of the purpose, content, and implementation capacity of the new contracts awarded to private companies and nongovernmental organizations during the last months of the Bush administration.
- Establish an assistance program for civil society and license the transfer of funds for activities that focus on human rights, rule of law, microenterprise, and professional training.
- Provide licensing for providers of US government and private assistance in order to advance the goals of US policy identified in this report.
- Modify current licensing regulations so that tradable medicines developed in Cuba are only subject to Food and Drug Administration approval without separate Office of Foreign Assets Control (OFAC) authorization.
- Permit the free exchange of ideas, including the creation of art, cinema, and music by amending OFAC regulations to allow the Free Trade in Ideas Act (the "Berman Amendment") to reflect its original intention of permitting the creation and free flow of informational materials and ideas.
- Modify regulations to permit the donation and sale of communications equipment under a general license, and license the provision of telecommunications services as provided in the Cuban Democracy Act.
- License Cuban state and nonstate entities to access satellite and broadband communications networks.
- Do not object to an Organization of American States (OAS) dialogue with Cuba on the status of its membership. Permit Cuba to participate in OAS specialized and technical agencies and in knowledge-building seminars at multilateral institutions.
- Review the evidence to determine if Cuba should continue to be listed as a state sponsor of terrorism.

Medium-term initiatives

- Encourage and fund a wide variety of educational exchanges and scholarships that promote understanding and provide training in diverse fields such as arts, economics, and journalism.
- Permit commercial credit terms without government guarantees for the sale of communications equipment.
- Allow licenses for US companies to participate in the development of Cuban offshore oil, gas, and renewable energy resources.
- Encourage and participate in multilateral organizations that further human rights and the growth of civil society in Cuba.
- Do not object to Cuba's reinstatement in the OAS if the General Assembly consents.
- Seek to recover executive authority to permit Cuba's participation in international financial institutions.
- Work with Congress to restore Executive Branch authority over travel to Cuba.
- Upgrade US diplomatic relations.
- Open bilateral discussions for the resolution of the claims of US citizens relating to expropriated property.
- Open bilateral discussions for a framework to satisfy mutual concerns over Guantanamo Bay Naval Base.

Long-term initiatives

- Open reciprocal diplomatic and consular offices in major cities in the US and Cuba.
- Provide general licenses for the exportation of additional categories of goods and services such as products that enhance the environment, conserve energy, and provide improved quality of life.
- Permit importation of additional categories of Cuban goods.
- Support Cuban efforts to promote the reconciliation of the Cuban nation.
- Reach mutually acceptable settlement on claims for expropriated property.
- Reach mutually acceptable solution for restoring Cuban sovereignty over the territory of Guantanamo Bay.
- Achieve full diplomatic relations between the US and Cuba.

*Roadmap for Critical and Constructive Engagement, part of project entitled US Policy Toward a Cuba in Transition.

plate capacity totaling 288,000 b/d. But they don't achieve operating rates anywhere near nameplate levels.

The Havana refinery, formerly Shell-Esso, has capacity of 121,000 b/d but operates at only about 20,000 b/d and probably will be closed. The refinery formerly owned by Texaco at Santiago de Cuba has capacity of 101,000 b/d but operates at about 22,000 b/d.

The 66,000-b/d Cienfuegos refinery has been operating at 53,000 b/d. It has 8,000 b/d of hydrotreating, 8,000 b/d of catalytic reforming, and 10,0000 b/d of light ends fractionation capacities.

According to Oil & Gas Journal's Worldwide Refining survey, the Havana facility is the only one of the three refineries with significant conversion capacity—14,700 b/d of catalytic cracking.

Venezuela has asserted plans to invest $10 billion in downstream projects in Cuba by 2015 through a unit of state-owned Petroleos de Venezuela SA working with its Cuban counterpart, Cubapetroleo SA (Cupet). With oil prices low, however, there are questions whether all or any of the projects will be funded (see map).

At Cienfuegos, the Venezuelan government proposes to spend $3.7 billion to expand crude oil distillation capacity to 150,000 b/d and add a delayed coker. The completion target is 2012.

Also at Cienfuegos, Venezuela proposes to build an LNG terminal with two 1 million-tonne/year trains at an estimated cost of $440 million. The terminal would start up in 2013.

It plans to expand the Santiago de Cuba refinery to 50,000 b/d of crude capacity and add heavy bottoms conversion capacity by 2013.

Venezuela proposes to build a 150,000 b/d refinery at Matanzas with 75,000 b/d of upgrading capacity for heavy Cuban crudes. The refinery, estimated to cost $4.3 billion, would start up in 2015.

Other proposals include improvements to the Matanzas and Cienfuegos harbors, reactivation of a crude oil pipeline between the cities, and new crude and products storage. Those

Oil work can be part of US-Cuban rapprochement

Jorge R. Pinon
Center for Hemispheric Policy
University of Miami

COMMENT

Two thirds of Cuba's petroleum demand currently relies on imports, and Venezuela is the single source of these imports under heavily subsidized payment terms.

This petroleum dependency, valued at over $3 billion in 2008, could be used by Venezuela as a tool to influence a future Cuban government in maintaining a politically antagonistic and belligerent position toward the US.

Cuba has learned from experiences and is very much aware of the political and economic risks and consequences of depending on a single source for imported oil. The collapse of the Soviet Union and the 2003 Venezuelan oil strike taught Cuba very expensive lessons.

President Raul Castro understands the risks; his recent visits to major oil exporters such as Brazil, Russia, Angola, and Algeria underscore his concerns. A relationship with Brazil would provide a balance to Cuba's current dependency, while others could bring with it corrupt and unsavory business practices.

Only when Cuba diversifies suppliers and develops its offshore resources, estimated by the US Geological Survey to be at 5.5 billion bbl of oil and 9.8 tcf of natural gas undiscovered reserves, will it have the economic independence needed to consider a political and economic evolution.

US restrictions

Although Cuban authorities have invited US oil companies to participate in developing their offshore oil and natural gas resources, US law does not allow it.

American oil and oil equipment and service companies have the capital, technology, and operational know-how to explore, produce, and refine in a safe and responsible manner Cuba's potential oil and natural gas reserves. Yet they remain on the sidelines because of the almost 5-decade-old unilateral political and economic embargo.

The president can end this impasse by licensing American companies to participate in developing Cuba's offshore oil and gas. Embargo regulations specifically give the secretary of the treasury the authority to license prohibited activities. The Helms-Burton law codified the embargo regulations as well as the secretary's power, embedded in the codified regulations, to rescind, modify, or amend them. The proof of this is that several years after the Helms-Burton law was enacted, former President Bill Clinton expanded travel and money transfers to the Cuban people and civil society.

Cuba's future

By seizing the initiative on Cuba policy, the president could claim an early and relatively easy policy success. Critically, he would position the US to play a role in Cuba's future, thereby giving Cubans a better chance for a stable and democratic future.

A future Cuban government influenced by its energy benefactors would most likely result in a continuation of the current political and economic model. If Cuba's new leaders are unable to fill the power vacuum left by the departure of the old cadre, they could become pawns of illicit business activities and drug cartels, and the US could face a mass illegal immigration by hundreds of thousands of Cubans.

If US companies were allowed to contribute in developing Cuba's hydrocarbon reserves, as well as renewable energy such as solar, wind, and sugarcane ethanol, the change would reduce the influence of autocratic and corrupt governments. Most importantly, it would provide the US and other democratic countries with a better chance of working with Cuba's future leaders to carry out reforms that would lead to a more open and representative society.

The author
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projects, estimated to cost $1.6 billion, would be completed by 2012.

Obama's move

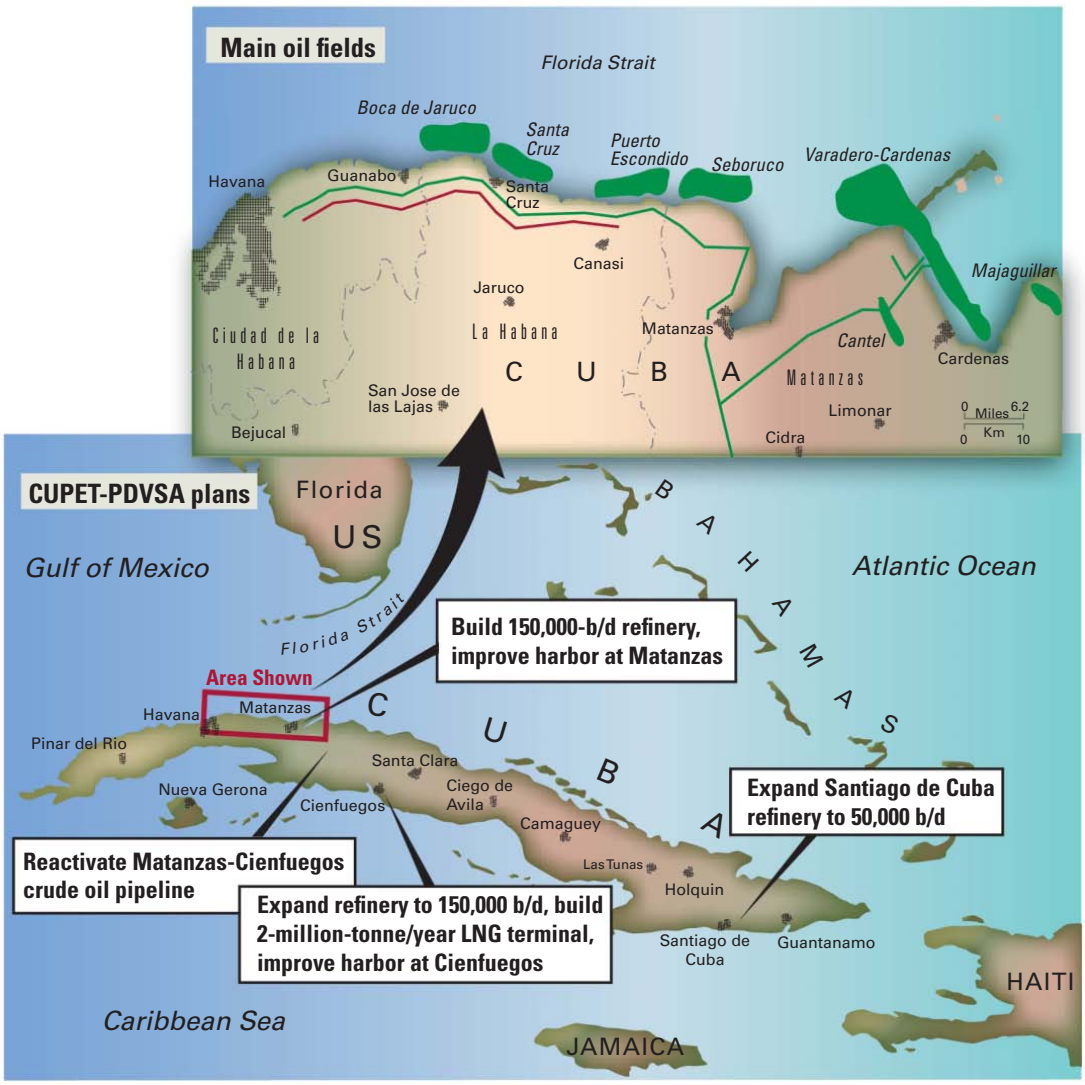
The US president's initiative on Apr. 13 included nothing directly related to oil and gas.

While criticized by observers who want no warming of US relations at all with Cuba, the move implemented only a handful of the recommendations put forward by the Brookings project.

Here are elements of Obama's latest initiative:

- Lift all restrictions on transactions related to the travel of family members to Cuba.
- Remove restrictions on remittances to family members in Cuba.
- Authorize US telecommunications network providers to enter into agreements to establish fiber-optic cable and satellite telecommunications facilities linking the US and Cuba.
- License US telecommunications service providers to enter into roaming service agreements with Cuba's telecommunications service providers.
- License US satellite radio and

CUBA'S OIL FIELDS; CUPET-PDVSA PLANS



satellite television service providers to engage in transactions necessary to provide services to customers in Cuba.

• License persons subject to US jurisdiction to activate and pay US and third-country service providers for telecommunications, satellite radio, and satellite television services provided to individuals in Cuba.

• Authorize the donation of certain consumer telecommunication devices without a license.

• Add certain humanitarian items to the list of items eligible for export through licensing exceptions.

Obama's only other public step concerning Cuba so far has been his January executive order on closure within 1 year of detention facilities at Guantanamo Bay Naval Base and disposition of 300 suspected terrorists held there as enemy combatants.

That move didn't specify whether the base itself would be closed or in other ways address sovereignty issues central to the Brookings Institution recommendations. ✦

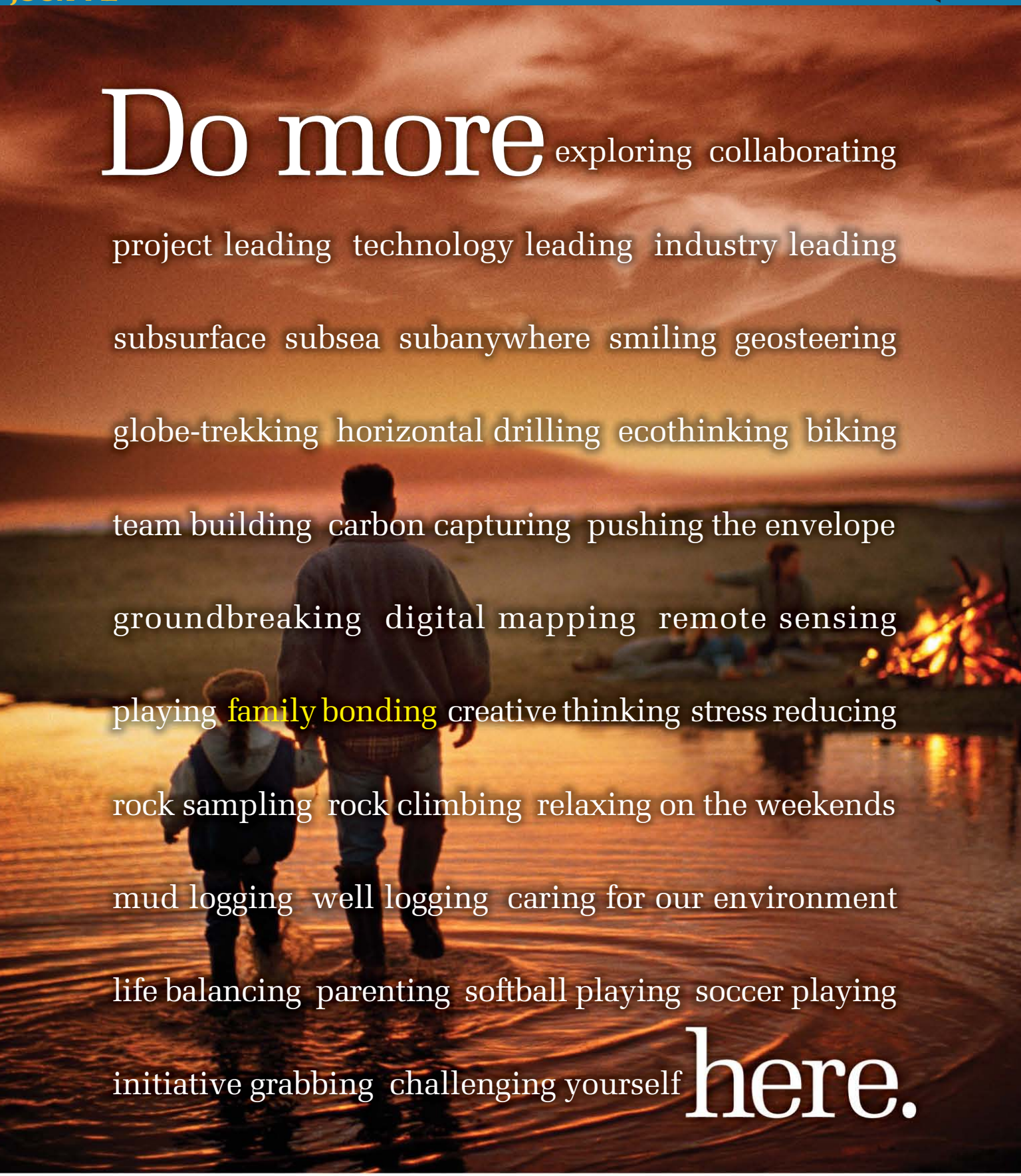
Cavaney: Cap-and-trade proposal would hit refiners hard

Nick Snow
Washington Editor

Refiners will be hit harder than other US manufacturers under proposed cap-and-trade legislation, a ConocoPhillips official told the US House Energy and Commerce Committee.

Red Cavaney, the company's senior vice president for government, public affairs, and communications, said the estimated $68 billion the US Energy Information Administration estimated refiners would pay annually under a $25/ton carbon tax includes collections of end-users' carbon taxes in addition to levies on refiners' greenhouse gases under the measure.

"Unlike other manufacturers, we would not be able to pass this on," he told the committee Apr. 22 during the first full day of hearings on the bill which Reps. Henry A. Waxman (D-Calif.), the committee's chairman, and Ed-



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StatoilHydro

ward J. Markey (D-Mass.), the chairman of its Energy and Environment Subcommittee, introduced on Mar. 31.

Cavaney said when the hearing recessed that the measure also doesn't consider the impacts of the federal Renewable Fuel Standard, changing blends, growing overseas competition and falling demand on US refiners. The bill also doesn't recognize contributions from renewable fuels actions that have already occurred or domestic refiners processing heavier grades of crude than their non-US competitors.

"It is vital that the mechanisms for allowance allocation to trade-exposed energy-intensive industries are applied fairly and in a way that comprehends the fundamentals of how these markets work. We are deeply concerned about our ability to fully pass on these costs of compliance and the potential implications that even a small percentage of unrecoverable costs could have on what is historically a low-margin business," he testified.

Adjustments needed

Oil-state committee members echoed his concern. "Adjustments will be necessary if we're going to hold refiners responsible for consumer compliance. We need to find a way to make sure the US gets as close to energy independence as it can. Climate issues are important, but so are economic strength and energy security," said Rep. Charlie Melancon (D-La.).

Reps. Gene Green (D-Tex.) and John Sullivan (R-Okla.) each asked Cavaney if refiners should be eligible for rebates for energy-intensive industries under the proposed program. Cavaney responded that they should. "We're the second most energy-intensive industry in America, but it's not clear if we qualify. There are some 6.5 million bbl a day of refining capacity under construction outside our borders, which receive government help. We need to be able to compete with them," he said.

Cavaney was part of a panel of witnesses who testified on behalf of the US Climate Action Program (USCAP), a coalition of businesses, consumers, and environmentalists that produced legislative recommendations for controlling greenhouse gases which the House Energy and Commerce Committee used as it was prepared the current bill.

Cavaney testified that ConocoPhillips believes that a mandatory US national climate protection program linked to other national and international programs offers the best approach for achieving meaningful global greenhouse gas emissions reductions.

"First, we believe that a well-designed federal climate protection program, as opposed to multiple state/regional initiatives and other alternatives, would result in a more efficient and less costly approach. Second, industry needs a consistent and enduring climate change program to provide the regulatory certainty necessary to make informed, long-term investment decisions," he said.

Business case

ConocoPhillips also claims there is a firm business case for this position, according to Cavaney. "For example, we believe US climate policy should be designed to optimize the use of natural gas as a transition fuel to a low-carbon economy. In addition, well-designed climate policy will create new opportunities in areas such as deployment of carbon capture and storage (CCS), and development of new energy technologies," he said.

He and other witnesses from USCAP members suggested that allowances will be needed in addition to auctions to mitigate climate policy impacts on consumers, businesses, and the overall economy.

"The potential for significant dislocation and value destruction, both to individual companies and regions of the United States, is real but can be effectively addressed with a sensitive balance between auctioned allowances and allowances allocated on an interim basis, and with complementary measures for clean coal and other core technologies, including advance nuclear projects," said David Crane, chief executive of NRG Energy Inc., an electricity wholesaler, in his written statement.

The group said that the period before the proposed cap-and-trade program took effect in 2012 would be critical. "One of the areas to watch is the price of natural gas. US industries would be placed at a further disadvantage to overseas competitors if it goes too high," said Chad Holliday, who retired from DuPont Co. Jan. 1 after 10 years as its chairman.

Duke Energy Corp. Chief Executive James R. Rogers said the proposed legislation recommends an economy-wide cap-and-trade program, which falls within the recommendations of USCAP's Blueprint for Legislative Action. "It also proposes a greenhouse gas registry and acknowledges the need for significant cost-containment mechanisms, including allowance banking and borrowing, multiyear compliance and the use of offsets as a low-cost carbon emissions reduction strategy," he noted.

'Good foundation'

The bill also allows for a periodic assessment of the science behind it and has provisions to implement a strategic reserve pool while accelerating development, deployment, and commercialization of carbon capture and storage and other zero- and low-carbon technologies, Rogers continued. "There is a good foundation here to build upon and the draft's 648 pages present enough material to start lively conversations about a proposal that isn't just about climate change but, in fact, proposes a fundamental shift in US energy policy," he said.

"Then there is the case of the missing pages. These are the ones that contain the critical decision on how allowances will be distributed. Those pages, for Duke Energy and its customers, are the key to that third tenet of sound climate policy: protecting customers from prices that increase so rapidly that they disrupt their livelihoods. Ensuring that electric consumers are treated fairly and

not burdened with unnecessary cost increases is a mission from which I will not retreat," Rogers said.

Meg McDonald, global issues director at Alcoa Inc., said, "During the evolution toward a comprehensive global emissions trading regime, transitional arrangements for energy-intensive, trade-exposed sectors will be necessary to protect our competitiveness. This will be essential to protect the employment and contribution to the US economy that industries such as aluminum, steel, chemicals, glass and paper represent."

When he testified as part of another panel later in the day, Paul N. Cicio, president of the Industrial Energy Consumers of America, warned that reducing US GHG emissions from about 7 billion to 5 billion tons in a relatively short period without a readily available supply of low-cost and low-carbon energy would raise energy prices significantly.

"Energy efficiency and renewable energy will help, but will not close the gap. CCS and nuclear will not be contributors over the next 10 years, which means the power sector will be dependent on natural gas for power generation. Expansion of renewable energy means electric utilities will be required to build gas-fired back-up plants," Cicio said.

'Significant implications'

Cicio observed: "It is extremely important to note that gas-fired power generation sets the marginal price for electricity. The implications are significant. As demand for gas goes up, prices will go up, which will also increase the price of electricity across the country, a double-hit to consumers. Gas demand by the power sector has grown by 28% since 2000 while domestic gas production has increased only 7%."

Others agreed that gas prices during the transition need to be considered more carefully. "US chemical makers and other manufacturers simply cannot compete effectively in a global market with such high and volatile costs for a key input. Congress can level the global manufacturing playing field by adopting demand and supply side policies that ensure US companies have access to competitively priced gas," American Chemistry Council President Cal Dooley said in an Apr. 22 letter to Waxman.

The bill also needs a feedstock credit, Dooley maintained. "Slightly more than half the energy we buy is used as a feedstock, and those purchases account for 70% of industry spending on energy inputs. When used as a feedstock, most of these fossil fuels are converted into products and do not emit greenhouse gases," he said.

Three prominent Obama administration officials applauded the committee's efforts to develop cap-and-trade legislation in the hearing's first panel. "While we are still reviewing the details, it is clear that Chairman Waxman's legislation would advance the president's goals of launching a new sector of clean energy jobs, making our economy more competitive, and weaning the nation from its dependence on oil," US Energy Secretary Steven Chu said.

US Transportation Secretary Ray LaHood also commended the committee for its work, adding that DOT has been and will continue to be a partner in Congress and the administration's efforts. "This is essential because transportation sources are a significant [GHG] contributor in the US and must be part of the solution. I look forward to working with you as we develop policies to address the transportation system in this climate change bill," LaHood said.

'A good start'

"Achieving energy independence and reducing carbon emissions are not easy challenges. But this committee has dealt with difficult challenges before," said US Environmental Protection Agency Administrator Lisa P. Jackson. She said that when Waxman and his predecessor as chairman, John D. Dingell (D-Mich.), worked with other committee members to pass the 1990 Clean Air Act amendments, they found consensus despite dealing with acid rain, smog, hazardous air pollutants, the threat to the ozone layer, and other controversial issues. "I believe the committee can make history again this year, and this draft bill is a good start," she testified.

"Now, the 'no, we can't' crowd will spin out doomsday scenarios about runaway costs. We do not claim to be able to do something for nothing. But EPA's available economic modeling indicates that the investment Americans would make to implement the cap-and-trade program [under this bill] would be very modest compared to the benefits that science and plain common sense tell us a comprehensive energy and climate policy will deliver," Jackson maintained.

EPA distributed a preliminary analysis of the bill as she testified. It said that the legislation would cost the average US household an additional $98-140/year before appliance efficiency, weatherization, and other cost-saving measures are taken. Its model projected allowance prices of $13-17 in 2015 and $17-22 in 2020, adding that these prices "would be over 96% higher if the discussion draft did not allow substantial use of cost-saving offsets."

Committee Republicans who had expressed concern that the bill before them contained no cost estimates pressed her for details. Jackson conceded that EPA's analysis of costs involved only part of the programs in the bill. She said that the agency could provide more comprehensive estimates with additional study.

GOP committee members primarily objected to the missing cost estimates. "This draft has a big, gaping hole because it doesn't address this question. We're going to hold our colleagues on the other side of the aisle accountable, especially if they're from fossil fuel-producing areas," said Rep. John Shimkus (Ill.).

'The worst time'

Rep. Roy Blunt (R-Mo.) said, "Every credible study I've seen tells me that a cap-and-trade program will increase the cost of energy and hurt businesses and consumers throughout the US. I doubt

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Gingrich is a late, eloquent addition

He was not originally scheduled to testify. Then the US House Energy and Commerce Committee announced former Speaker Newt Gingrich (R-Ga.) would follow former Vice-President Al Gore (D) and former US Sen. John W. Warner (R-Va.) during the third full day of hearings Apr. 24 on proposed climate change legislation.

A Republican committee source told me negotiations began more than a week earlier to bring more balance to the hearings led by committee chairman Henry A. Waxman (D-Calif.) and Edward J. Markey (D-Mass), who chairs the committee's Energy and Environment Subcommittee.

"It was especially obvious with the Gore-Warner panel. So the majority agreed to invite Gingrich," she told me Apr. 27. The source didn't say it, but the majority made the former speaker a solo witness instead of having him testify with Gore and Warner.

Gingrich delivered. He did more than simply reiterate his call to develop more domestic energy resources. He said that the proposal before the committee would not improve national security and address economic decline, but simply increase the power of government.

Cleaning up messes

"Have we learned nothing during the past 6 months? Consider: The US government failed to regulate Wall Street correctly, and the result has been trillions of dollars of taxpayer money to clean up the mess that politicians and bureaucrats created," he said.

Fannie Mae and Freddie Mac were supposed to manage mortgages, yet the US housing market collapsed in 2008, Gingrich continued. Washington politicians responded by making US taxpayers foot the bill.

"Now the bill before you would create a multi-billion dollar artificial market for carbon, regulated and managed by the US government, paid for by taxing every American who uses energy," Gingrich told committee members.

"With $2 trillion up for grabs, the environmental pieties begin to be a little difficult to take seriously. Lobbyists have not been hired for good citizenship and idealism. Lobbyists have been hired to ensure their clients get rich off this new government-managed flow of cash," he observed.

The Waxman-Markey draft got a few things right, he conceded. It restricts the US Environmental Protection Agency from regulating carbon. It supports technologies to use more coal in ways less damaging to the environment. And it promotes development of a smart electrical grid.

'Intellectually dishonest'

But the bill provides more carbon reduction punishments than incentives, he continued. "This is simply an intellectually dishonest bill. It promises what it cannot deliver and then punishes what currently exists," Gingrich declared.

That same day, committee Republicans asserted House rules to request an additional hearing so the minority could call more witnesses. A few from groups such as the Heritage Foundation had testified already. Ranking Minority Member Joe Barton (R-Tex.) said that 14 Republicans testified with 54 Democrats.

The GOP committee source said that was a modest improvement. Originally, only seven Republicans were scheduled, she told me. ✦

there's ever a good time to burden American consumers with extra costs, but I believe that now is probably the worst time to implement an energy program that will pass the costs directly to the consumer every time we flip on a light switch, turn up the thermostat, fill up our [gasoline] tank, or purchase an American-made product.

But the committee's Democratic leaders said that it was time to move ahead on global climate change legislation. "We have reached a crossroads where inaction is simply not an option," said Markey, the chairman of the committee's Energy and Environment Subcommittee. He said, "Our economy cannot continue to depend heavily on foreign oil. We cannot continue energy policies that look to last century's energy sources while other nations race ahead to take the lead in developing and marketing clean energy technologies and green jobs."

Waxman said committee members from both parties and their staffs have made a major commitment of their time, which has been crucially important.

"I also want to warn you that as hard as we have been working, the pace is going to accelerate over the next 4 weeks. There are many issues that we need to discuss and resolve between now and Memorial Day. We will be working hard because the goals are so important. The energy legislation we are considering will create millions of jobs, revive our economy, and secure our energy independence. It will also protect our environment," he said in his opening statement.

NPRA's stance

A law to address climate change, according to National Petrochemical & Refiners Association Pres. Charles T. Drevna, should set a realistic carbon reduction target without political preconceptions or punitive provisions. Speaking Apr. 24 before the House Energy and Commerce Committee, Drevna said such a law also should protect affected US industries and the jobs of their

employees from foreign competition in countries whose governments do not constrain carbon dioxide emissions; not mandate contradictory or redundant policies; not establish a single federal program that supersedes other federal, state, and local programs and statutes; and not give any form of energy an advantage over others with respect to carbon constraints, Drevna testified during the third full day of hearings on proposed cap-and-trade legislation.

"A rather rudimentary description of the petroleum refining process, but one that must be achieved in order to facilitate technological and commercial success, is the rearrangement of the links between and among hydrocarbon molecules.... There are more consequential links, as well: the link between energy and economic strength for the entire nation, and the link between energy and American security," Drevna said.

He said the essential question is whether the Waxman-Markey proposal will strengthen those links or create adverse impacts not just for refiners but the general economy.

'One chance'

"The answer to this question must be fully investigated, understood, and documented before enactment of any legislation. Most likely, we have but one chance to get it right. The nation simply cannot afford anything short of complete understanding," Drevna told committee members.

International participation also is critical to ensure that any US carbon reduction program actually reduces global emissions while protecting the domestic economy's competitiveness, Drevna said.

"One ton of carbon dioxide emitted in Columbus, Ohio, is indistinguishable from one ton emitted in Beijing, Mumbai, or Moscow. Any legislation enacted must contain robust provisions to prevent leakages of both jobs and emissions. Without international participation, any US carbon control measures would have little or no impact on global greenhouse gas emissions," Drevna said.

Another witness said the Alliance of Automobile Manufacturers, which represents 11 car and light-truck producers accounting for 80% of annual US vehicle sales, was still analyzing the Waxman-Markey legislative draft. But Dave McCurdy, the group's chief executive, said it lays out a basic framework to address climate change which aligns with the alliance's core principles for such a program.

"The long-term viability of any program will depend on a technologically and economically sustainable transition to cleaner sources of energy and utilize market-based measures to the greatest extent possible. Such a program should [provide incentives for] rapid development and deployment of advanced technologies while delineating appropriate roles for federal, state, and local governments," he said in his written statement.

Comprehensive approach

McCurdy said the Waxman-Markey draft takes a comprehensive GHG emissions reduction approach that includes transportation, utilities, energy suppliers, utilities, and consumers. "Importantly, the draft caps emissions upstream at the fuel source, which allows for the broadest possible coverage and also will result in clear price signals that encourage conservation and [provide incentives for] businesses and consumers alike to invest in clean energy technologies," he said.

"Making carbon dioxide the common denominator for future competition between completely different fuel options and power-train technologies stimulates innovation as it provides transparency to the consumer, who in turn can choose the appropriate technology for his or her individual mobility needs," McCurdy added.

He said the proposed transition from some free allowances to a full auction addresses political issues associated with the move to a carbon-capped world while establishing a clear path to a system where incremental carbon costs are passed through. The transparency of these costs is particularly important in transportation, where manufacturers expect energy providers to pass through the market price of carbon, he said.

McCurdy said while scheduled reductions in the emissions cap are very challenging during the early years in the proposed legislation, its provision for offsets and a strategic allowance reserve provides a mechanism to contain costs. Automotive manufacturers are concerned about whether these mechanisms will be enough to ensure the program's long-term economic and political viability, he said.

"It is also critical to avoid excessive energy price volatility. Rapid increases and decreases in energy prices make introducing new low-carbon technologies and fuels exponentially more difficult and risky, particularly in our industry where long lead times are required. We would encourage Congress to ensure that a final bill include robust provisions to address price volatility, including self-implementing triggers to avoid inflation due to higher-than-expected energy prices," McCurdy told the committee. ✦

Changes likely as cap-and-trade legislation moves through US House

Nick Snow
Washington Editor

US House Energy and Commerce Committee Chairman Henry A. Waxman (D-Calif.) planned to mark up cap-and-trade legislation the week of May 11 when he and Rep. Edward J. Markey (D-Mass), the chairman of the committee's Energy and Environment Subcommittee, introduced their draft proposal on Mar. 31.

By the time the committee completed 3½ days of hearings on their climate-change proposal Apr. 24, however, it was obvious that changes would need to be made. Opposition from committee Republicans was no surprise. But some Democrats also expressed reservations about several provisions and their potential impacts.

The hearings also revealed basic climate change strategy disagreements that could hamper Waxman's plan to have a bill ready to send to the House floor by Memorial Day.

US Energy Secretary Steven Chu, Transportation Secretary Ray LaHood, and Environmental Protection Agency Administrator Lisa P. Jackson expressed the Obama administration's support for the working draft. It does not appear likely that the White House's desire for a cap-and-trade program free of offsets will last long once lawmakers start marking up the bill, however.

Jackson also had to contend with committee members who said EPA's proposed finding that greenhouse gases pose a danger to public health and the environment is a tactic to pressure Congress to act. It actually was a response to a US Supreme Court order that Congress authorized when it passed the 1990 Clean Air Act amendments, she said in response to a committee member's question.

'The best way'

EPA spent months researching the GHG issue, as that law requires, before issuing its proposed finding, Jackson continued. A 60-day public comment period is under way and the agency has begun to develop regulations for its implementation if it becomes final, she said. Earlier in the hearing, however, she said: "I believe new legislation is the best way to address global warming and greenhouse gases."

US President Barack H. Obama would prefer that a cap-and-trade program be a simple auction, Jackson continued. "He also is interested in finding ways to mitigate impacts this would have on the economy and looks forward to working with the committee on this," she said.

EPA's release of preliminary cost estimates for the Waxman-Markey working draft during the Apr. 22 hearing caused a mild stir. Republican committee members had complained that the proposal said nothing about costs. Rep. John M. Shimkus (R-Ill.) called the omission "a big, gaping hole." They said the committee's Democratic leaders were moving it through so quickly that the Congressional Budget Office, which provides nonpartisan objective economic analyses for federal lawmakers, had not had time to fully examine the draft.

Jackson emphasized that EPA's estimates were preliminary. They did not consider the massive economic recovery bill, with billions of dollars in renewable energy and energy efficiency investments, which Congress passed and Obama signed earlier this year. They also did not include significant provisions of the Waxman-Markey working draft such as the renewable electricity standard and the energy efficiency standards.

The estimates found that costs under the working draft would be low for the average US household (27-38¢/day or $98-140/year before appliance efficiency, weatherization, and other cost-saving measures were applied). Allowance prices would be $13-17 in 2015 and $17-22 in 2020. These would be 96% higher if substantial use of cost-saving offsets was not allowed, according to an EPA handout distributed in the hearing room as Jackson testified.

Robust growth

It also said the US gross domestic product would grow robustly under the Waxman-Markey proposal (to $15-16 trillion in 2015 and $22-23 trillion in 2030) as clean energy technology was deployed and GHG emissions were reduced. Consumption, which measures a household's purchase potential, would grow by 9-10% from 2010 to 2015, 18-19% by 2020, and 36-40% by 2030, it indicated.

Republicans were skeptical. Several called the proposed legislation "cap-and-tax" instead. "We thought the American public was angry over a dollar or two increase in [gasoline] prices last summer. Just wait until they get their hands on their utility bills under cap-and-tax," said Rep. Fred Upton (Mich.), the Energy and Environment Subcommittee's ranking minority member.

Approximately 21% of all US utility accounts were overdue in 2008 as end-users carried past-due balances averaging $160 for electricity and $360 for gas, he added. "Times are tough, yet this proposal puts a bull's-eye on the back of working families who are struggling to feed their families and keep the lights on," Upton said.

Some Democrats' questions were specific. When Rep. Diana DeGette (Colo.) asked Jackson more about ways the program in the discussion draft could relieve cost impacts on families, the EPA administrator replied: "One opportunity is deciding what happens to money a cap-and-trade system would generate. We assumed that 40% would be returned to American families."

Rep. Gene Green (Tex.), whose Houston district includes several refineries, asked Jackson and Chu if impacts of the national Renewable Fuel Standard's second phase on carbon emissions during motor fuel production had been fully analyzed. Jackson responded that she would work with the US Department of Energy on the matter. Chu said that he would ask the US Energy Information Administration to look into it.

Republicans continued to question the US government's ability to efficiently operate a carbon cap-and-trade program, contending that one in Europe has failed. Jackson responded in her testimony that the Acid Rain Trading Program, which became law in 1990, delivered an estimated $120 billion of annual economic benefits while costing only $3 billion yearly. "Our economy grew by 64% even as the program cut acid rain pollution by more than 50%. And past auto emissions standards sparked key technological innovations," she said. ✦

EPA asked to set new drillsite discharge standards

Eric Watkins
Oil Diplomacy Editor

Activist organizations are urging the US Environmental Protection Agency to expand regulation of wastewater discharges from the oil and gas drilling industry to cover a host of exploration, stimulation, and extraction activities, according to Water Policy Report.

Arguing that expanded development and increased use of chemicals during extraction are raising new concerns for water quality, the activists say emerging water pollution problems associated with these activities, especially horizontal hydraulic fracturing for natural gas, have revealed significant shortcomings in EPA's effluent limitations guidelines (ELGs) for the oil and gas extraction sector.

However, industry sources told WPR—a Washington publication covering EPA's water quality and drinking water programs—that new standards would be unnecessary and ineffective. New national standards are unsuitable because wastewater varies greatly depending on regional geology, and permit writers would have to revert to their current case-by-case analysis anyway, one industry source said.

New standards wanted

Earthjustice, a nonprofit public interest law firm specializing in proenvironmental litigation, and a host of environmental groups, including the Natural Resources Defense Council and Waterkeeper Alliance, are urging the EPA to set new wastewater discharge standards for oil and gas development, according to early April comments on the agency's final 2008 ELG program plan.

EPA is considering creation of a new ELG for wastewater from coalbed methane extraction and is collecting information on so-called produced water discharges and treatment technologies.

However, environmentalists argue the agency should create more expansive wastewater discharge standards "rather than focusing the ELGs narrowly on the regulation of wastewater discharges from coalbed methane extraction."

The activists recommend:

- Setting a pretreatment standard banning wastewater discharges to publicly owned treatment works (POTWs).
- Creating a new subcategory in the centralized wastewater treatment plant ELG to address oil or gas-related wastewaters with a zero discharge limit for the subcategory.
- Regulating the storage of effluents kept near the wellhead.

Environmentalists say new standards are necessary because oil and gas development is expanding rapidly and because the sector is developing previously uneconomic resources, which may require more aggressive extraction practices.

The groups are especially concerned about the practice of hydraulic fracturing, where water and chemicals are forced into the ground to crack shale formations and release natural gas so it can be extracted.

The environmentalists say banning wastewater discharges to POTWs is necessary because the treatment plants simply dilute the wastewater, rather than treat for the salts, minerals, and fracturing chemicals that may be in the wastewater.

As an example, the groups cite contamination of the Monongahela River in Pennsylvania in late 2008. The river was impaired by total dissolved solids such as chlorides and sulfates, and activists say the state environment department blamed the contamination on the discharge of oil and gas wastewater to POTWs.

Activists are urging EPA to gather and publish information about the chemicals used in fracturing fluid and provide toxicological, epidemiological, and fate and transport data for the chemicals. The groups also seek an ELG to set enforceable best management practices for storage of wastewater near the wellhead.

New standards necessary?

But industry sources say new standards are not necessary and would not be effective. ELGs are technology-based and are best suited to water treatment systems where the contamination is predictable, one industry source said.

Produced water from oil and gas development, however, varies widely depending on regional geology, the source told WPR. So permit writers would likely have to depart from the ELG technology requirements and use their best professional judgment, which is the standard that permit-writers currently use, the source said.

There is also no need to ban discharges to POTWs, the industry source said. Instead, water treatment plants should determine whether their treatment is adequate to deal with oil and gas wastewater and meet their standards.

A local industry source also raised concerns with the environmentalists' comments, WPR said.

Of the more than 7,000 drilling permits issued by Pennsylvania in 2008, fewer than 300 use hydraulic fracturing, the source said. And the water quality incident in Pennsylvania, which activists say proves POTW treatment is inadequate for drilling wastewater, was actually caused by runoff from abandoned coal mines, the source said.

Hydraulic fracturing has been used since the 1950s, and new ELGs are not necessary because oil and gas wastewater has been handled very well under the current water permitting program, the source said.

Because states like Pennsylvania have been effective in dealing with unique contents of wastewater from the region, the source said, "We don't believe EPA needs to get involved at that level."

DOE shale gas report

Meanwhile, the Department of Energy in April released a report examining the scope of regulatory oversight for shale gas. It commissioned the report from the Ground Water Protection Council, a group representing state regulators of underground injection wells and oil and gas interests.

The report, Modern Shale Gas Development in the United States: A Primer, downplays the potential for environmental harm from increased use of hydraulic fracturing, as well as from extensive horizontal drilling. The report said the latter "has not introduced any new environmental concerns."

Hydraulic fracturing, the report argues, is a "key technology" for the nation's energy supply. There are some challenges for water availability and management, but "innovative regional solutions are emerging that allow shale gas development…while ensuring that the water needs of other users are not affected and that surface and ground water quality is protected," it said.

Rather than encourage new regulation or retraction of the exemptions for hydraulic fracturing under the Safe Drinking Water Act, the report deems the current regulatory structure overseeing the environmental safety of natural gas drilling to be largely safe.

The report notes repeatedly that states, local governments, and tribes may in many instances create more stringent regulations than those federally mandated and examines requirements under the Clean Water Act, the Clean Air Act, Resource Conservation and Recovery Act, the Endangered Species Act, and the Comprehensive Environmental Response, Compensation and Liability Act.

Further, the report said, "Natural gas will continue to play a significant role in the US energy picture for some time to come," providing around 22% of the nation's energy over the next 20 years. ✦

LNG supply, fuel competition pose major concerns in US

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

How US markets will accommodate the impending flood of LNG continues to puzzle industry observers. It was a question hanging over several speakers and discussions on Apr. 28 at CWC's LNG Summit New Orleans 2009.

In addition, speakers and panelists addressed the extent to which other fuels, especially coal, might put natural gas, and therefore LNG, at a competitive disadvantage.

Distressed prices

Much of the focus for the past year or more among LNG analysts has been on where new spot supplies from liquefaction projects coming online 2009-11 will go, given weak demand in the major European and Asian markets. It has been the sentiment that LNG will default to the US as a market of last resort, price notwithstanding.

Unlike Asia and Europe, this analysis has run, the US historically had much greater flexibility of supply. This is fostered by its extensive natural gas exploration, pipeline infrastructure, and connections with its North American neighbors.

But the US scene has been complicated in the last 2-3 years by the advent of prolific gas supplies from unconventional sources, especially shale plays in Texas and the Rocky Mountains. Discovery and development of massive shale reserves in Louisiana, Arkansas, New York, and Pennsylvania have only added to the overhang of supply potential.

John Fahy, managing director for Eras Consulting Ltd., addressed the conventional wisdom of the US as a dumping ground for spot LNG supplies seeking markets: He just doesn't accept the argument.

Fahy believes spot LNG will come to the US "only at distressed [price] levels," near what we are seeing today. "US [natural gas] storage is full," he said. Storage and firm supply contracts for Spain and Japan similarly discourage spot cargoes.

As part of his analysis, Fahy also disputed the widespread notion that US shale gas, whose activity has been rapidly contracting under depressed prices, must bring about $7/MMbtu to break even. A more likely breakeven price is nearer $4/MMbtu, "maybe $4.50," he said.

Excelerate Energy's Andree Stracke,

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Argentina, UK eye Falklands oil

The Falkland Islands are in the news again, a matter of interest to the oil and gas industry given the reserves under the region's waters, estimated at 18 billion bbl.

Last week, the Argentine foreign ministry presented the UN with 40 volumes of documentation staking the country's claim to 1.7 million sq km of seabed, including the UK overseas territories of the Falklands, South Georgia, and South Sandwich Islands, and a largish chunk of Antarctica.

Argentina's claim, submitted under Article 76 of the 1994 UN Convention on the Law of the Sea, aims to expand its maritime territory by 35% to 370 nautical miles from the shore on the basis of a claimed extension of the Argentine continental shelf.

According to Buenos Aires, the submission represents the culmination of 11 years of research and 12 maritime expeditions. But a skeptical UK Foreign Office said it will present a counter-claim by the UN's May 13 deadline.

On the attack

Meanwhile, members of the British press are doing their level best to scotch the Argentinean claims.

"Sneaky Argentina is trying to grab the Falklands back from Britain to steal the oil-rich seabed around the islands," writes a columnist for the UK's Express Newspapers.

"The Argies are begging the UN to help them in their political bid," he said, adding that "Argentina were sent packing from the British islands in 1982 after first invading South Georgia."

The jingoism is apparent when we are reminded "Prime Minister Maggie Thatcher's Task Force defeated their forces and kicked them out."

The columnist has no problem dismissing new claims by the Argentinean government, which says "12 years of research proves their continental shelf in Antarctica goes 150 miles beyond the 200-mile limit."

The writer also has no trouble summing up the evident greed of the Argentine government saying its demands "would increase the area of South Atlantic they own by up to three times the size of France—taking all 778 islands."

Argentina dismissed

Worse, he says, "the Argies want Britain's South Georgia and South Sandwich Islands—an area of ocean rich with oil." Still, the Latin American country is probably not going to prevail as "British Embassy authorities in Buenos Aires vowed to block any moves by Argentina."

The column even cited a British Embassy spokesman who said: "We do not accept that there is any basis for the Argentine submission."

Of course the British don't accept the Argentinean claim. After all, that's why they will submit a counter-claim by May 13.

And what will that do?

Well, under UN laws, submission of the counter-claim would prevent either nation from exploiting the contested seabed until a diplomatic agreement is reached.

Given the drawn-out nature of the UN's territorial resolutions, the UK's counter-claim would spell the end of any drilling activity in the area for the foreseeable future.

Game, set, and match. ✦

however, offered a somewhat contrarian viewpoint. Price is not the key issue, he said. In summer 2008, when US prices were $8-13/MMbtu, no LNG cargoes arrived at US terminals. In 2009, with US prices near $3.50/MMbtu, "lots of cargoes" are arriving or en route to the US.

Competition

A panel discussion of fuel alternatives to natural gas and LNG not surprisingly found formidable problems with major renewables—wind and solar—as well as with coal and nuclear.

This discussion was conducted with repeated reference to the policies of US President Barack Obama's administration and likely climate change legislation currently being debated in the US Congress. All panelists agreed that whatever legislation made it into law would favor renewables.

Repsol Energy North America's Pres. Phil Ribbeck reminded attendees that natural gas should be viewed as complementary to renewables, not in competition, as the nation moves away from a carbon-intensive economy.

Addressing the major fuel with which natural gas completes—coal—Ribbeck said current prices in the East have already forced the equivalent of 1.7 bcfd of coal out of markets there. "The breakeven price for coal is above $4/MMbtu," he said.

Poten & Partners' Fisoye Delano, who chaired the discussion, was skeptical about the reputed benefits of nuclear power, noting its huge costs not only to build but also to operate. ✦

Afghanistan blocks offer unproduced discoveries

Afghanistan's Ministry of Mines is launching a bid round of three blocks in the lightly explored Afghan-Tajik and Amu Darya basins.

Each of the three blocks contains oil and-or gas discoveries, most of which have never been produced.

Any successful bidder will need the stomach to operate in a landlocked country with sparse infrastructure and undergoing wartime conditions. Oil and gas marketing options are uncertain.

Bids are due June 15, and bidders are to be notified of the outcome by July 1, 2009.

Blocks and fields

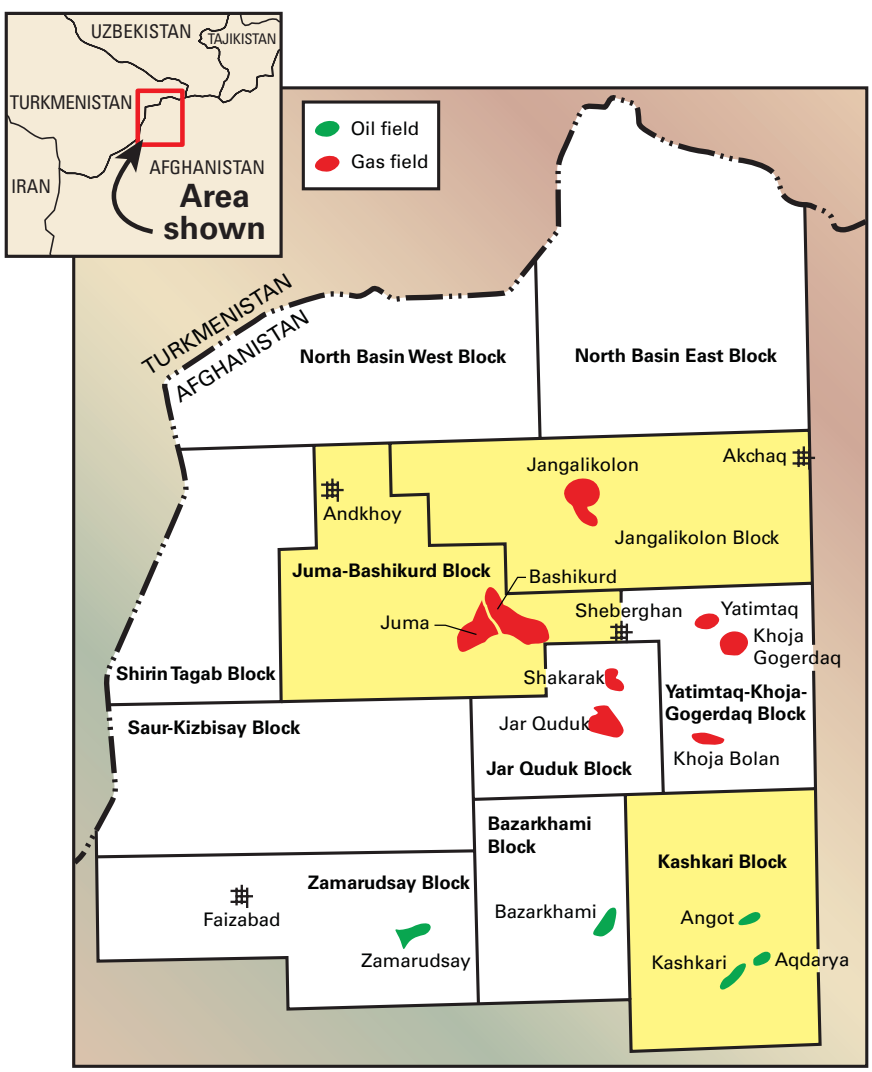
Detail is sparse on previous Soviet exploration in the Afghan oil and gas fields.

The Jangalikolon block is the largest at 493,952 acres, Juma-Bashikurd covers 459,853 acres, and Kashkari is 425,753 acres.

The ministry estimated that Jangalikolon has 671 bcf of recoverable gas, Juma-Bashikurd 1.2 tcf, and Kashkari 64.4 million bbl of oil. It also estimated 143.8 million bbl of possible reserves in Kashkari.

AFGHANISTAN LICENSE BLOCKS

Fig. 1



Source: Afghanistan Ministry of Mines

Most of Afghanistan's producing reservoirs are of Cretaceous and Jurassic age, and the bulk of the gas is sour and resides in the Jurassic.

The ministry said the Soviets drilled four wells and started but did not complete another five wells at Jangalikolon, 35 km north of Sheberghan. Well No. 4 went to TD 4,222 m in Upper Jurassic sandstone and tested 35 MMcfd of sour gas at 600 atm bottomhole pressure from a 20-m perforated interval. The gas was 0.035% hydrogen sulfide.

Field size is 7 by 13 km.

The ministry said Juma-Bashikurd field, 25 km northwest of Sheberghan, covers 36 sq km and has seven wells.

The ministry said Angot field, 12 km south of Sari Pol, has produced from four of 10 wells drilled. The field produced an unknown volume for about 6 months in 1988-89, and the produced oil was trucked to Kabul and used to heat water. The reservoir is a Hauterivian limestone at 1,800-1,950 m, and the block contains several smaller oil fields.

Angot field, the only Afghan field to have been on sustained production, was discovered in 1967. Soviets found most of the other fields in the 1970s.

Other information

A road show for the licensing round is in progress, with stops in Dubai, London, Calgary, and Houston, and ending in Singapore on May 15 (OGJ Online, Mar. 19, 2009).

The US Geological Survey, after completing a multiyear study in 2006, estimated Afghanistan's mean undiscovered resources at 15.7 tcf of gas, 1.6 billion bbl of oil, and 562 million bbl of natural gas liquids (OGJ Online, Mar. 27, 2006).

USGS said much of Afghanistan's petroleum resource potential and all the known oil and gas reserves are in the north. It said most of the undiscovered oil is in the Afghan-Tajik basin to the east, while most of the undiscovered gas is in the Amu Darya basin that extends into Turkmenistan. ✦

Eagle Ford viewed among top US shale gas plays

Formation characteristics from two of its first five wells indicate that the Cretaceous Eagle Ford shale in LaSalle and McMullen counties of South Texas "is one of the highest quality shale reservoirs discovered in the US," said Petrohawk Energy Corp., Houston.

Petrohawk raised its internally estimated ultimate recovery assumption for wells in the play to a midpoint of 5.5 bcfe/well, with a range of 4-7 bcfe/well, based on gas in place data derived from the core analysis from the two wells and performance of wells completed to date.

Petrohawk cited encouraging parameters from the two wells 30 miles apart: the Dora Martin-1H in LaSalle County and the Donnell-1H in McMullen County.

Core analysis from the two wells indicates 180-210 bcf/sq mile of free gas in place, 83-85% gas saturation, 9.4-10.7% porosity, 1,110-1,280 nanodarcies of permeability, and 4.4-4.7% total organic carbon.

Petrohawk recognizes a trend across the field from southwest to northeast of increasing condensate yield, from no condensate production from the Dora Martin-1H to a yield of 110 bbl/MMcf of gas from the Donnell-1H.

The Eagle Ford shale has been encountered in all five wells from 11,000 ft to 11,700 ft true vertical depth. Petrohawk has leased 160,000 contiguous net acres prospective for the formation in LaSalle and McMullen counties. The Texas Railroad Commission has named the area Hawkville field.

Petrohawk operated one horizontal rig in the play in the quarter ended Mar. 31 and has added a second rig.

Three wells were drilled and two were completed in the quarter. The Donnell-1H was completed on Feb. 20 at 3.6 MMcfd and 395 b/d of condensate on a 19/64-in. choke with 3,585 psi flowing casing pressure. The Brown Trust-1H was completed on Mar. 26 at a rate of 8.1 MMcfd and 200 b/d of condensate on a 24/64 in. choke with 4,210 psi flowing casing pressure.

"Production data from the four wells completed to date indicates lower initial annual decline rates, and a flatter hyperbolic decline, than those observed in other shale plays," Petrohawk said.

The company's first three wells, which had pilot holes, averaged 53 days from spud to rig release. The fourth had intermediate casing but no pilot hole and took 32 days. The fifth well was drilled in 22 days without intermediate pipe or a pilot hole.

Drilling and completion costs range from $4.5 million to $5.5 million/well. ✦

Peru inks 13 exploration agreements with IOCs

Peru's state-owned Perupetro, recovering from earlier scandals connected with the awarding of exploration licenses, has signed 13 new contracts valued at $650 million with international oil companies.

"With these 13 contracts we now have in effect a total of 92 oil contracts," a situation that shows "the confidence" that investors have in the country, said Peru's President Alan Garcia during the signing ceremony at Government Palace in Lima.

Recently appointed Energy and Mines Minister Pedro Sanchez expressed optimism over the awards, saying they would help transform the country's oil and gas industry. "For many years, Peru has been a net importer," he said. "We [now] will become net exporters."

The awards went to Faulkner Suits Exploration Inc., Block 27; Cepsa, Block 130; Golden Oil Corp., Block 132A/132B; Petrolifera Petroleum Ltd., Block 133; KEI Pty., Block 144; Olympic Peru Inc., Block 145; and Emerald Energy PLC, Block 163.

Other awards went to Grupo Pe-

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trolero Suramericano SAC, Block 156; PVEP Peru, Block 162; Talisman Energy Inc. and Colombian Ecopetrol SA, Block 158; Cia. Consultora de Petroleo SA and South Korea's Kedcom Co. Ltd., Block 160; and Pan Andean Resources PLC, Block 161.

A four-company consortium comprised of Pluspetrol, Peru's state oil company Petroperu, India's Reliance Exploration & Production DMCC, and Chinese-owned Sapet Development Peru Inc. (Sapet Peru) was awarded Block 155.

Under terms of the new contracts, the companies will drill 35 wells during the exploration phase. If commercial volumes of hydrocarbons are discovered, the average royalty rate to be paid to the government will be more than 30%.

Meanwhile, Peruvian officials said an auction for an additional 12 lots for oil and gas will be held in July.

"I'd like to take this opportunity...to announce the start of the 2009 selection process, which will officially begin in July and include 12 or 13 lots that may contain petroleum," said Perupetro Pres. Daniel Saba.

The auction will be Peru's first since last year, when several top government officials were fired or forced to resign after being accused of steering concessions to favored bidders.

At the time, Peru's former mines and energy minister, Juan Valdivia, resigned, while Perupetro board member Alberto Quimper and Perupetro Pres. Cesar Gutierrez were fired.

The scandal was exposed when an audio tape surfaced on an investigative television news show that included a conversation between Quimper and Romulo Leon, a prominent member of President Garcia's APRA party, in which they apparently agreed to favor Discover Petroleum of Norway in a round of energy auctions.

The Norwegian company, which partnered with Petroperu, was later awarded five blocks: four of them off the country's central Pacific coast and the fifth onshore near Peru's borders with Brazil and Bolivia.

Peru's justice ministry said it would investigate the banking records of the Peruvian executives and suspend the contracts awarded to Discover. ✦

Australia

Blue Energy Ltd., Brisbane, agreed to pay for two successful exploration wells that tested the potential of the Cretaceous Burrum coal measures on ATP 613P in Australia's Maryborough basin.

Blue Energy will become operator and conduct further exploration to earn a 75% interest from Magellan Petroleum (Eastern) Pty. Ltd. in a farmout on ATPs 613P, 674P, and 733P, which cover the basin's entire coal area along Hervey Bay in eastern Queensland.

Gas in place on the three tenements is estimated at 372 bcf.

Papua New Guinea

Oil Search (PNG) Ltd. took a farmout from Eaglewood Energy Inc. to earn an interest in PPL 260 in the Papuan basin fold belt in Papua New Guinea.

Oil Search will pay Eaglewood $1.5 million and complete the required seismic program at its sole cost by June 30, 2009, to earn a 10% interest in the license. Oil Search and Eaglewood will shoot $1.6 million in further seismic at a cost of $800,000 to Eaglewood.

After all seismic is completed, Oil Search will have 3 months to elect to earn a further 60% interest by paying 90% of the cost to drill an exploration well on trend with giant Hides and Juha gas-condensate fields.

New Mexico

Carbon dioxide response at a pilot in Milnesand field in New Mexico is close to proving the applicability of tertiary oil recovery to the entire 6,800-acre field, said Enhanced Oil Resources Inc., Houston. The company has injected 80 MMcf of the gas since Sept. 1, 2008, and pilot production attributed to the technique is 33-38 b/d of oil from the Permian San Andres formation.

Injection is to switch to water-alternating-gas around July 1.

Consulting engineers estimated that the company could recover as much as 53 million bbl of oil from Milnesand and nearby Chaveroo fields in Roosevelt and Chaves counties. Milnesand is the first field to be flooded in New Mexico, whereas several San Andres floods are operating on the Texas side of the Permian basin.

Oklahoma

Newfield Exploration Co., Houston, has been slowing its pace of Woodford shale completions in Oklahoma due to low gas prices.

Gross production is 240 MMcfd of gas, and the company is operating 11 rigs in the field, six of which roll off term contract in 2009.

"The timing of rig contract expirations and the fact that more than 90% of the company's 165,000 net acres now held by production provide Newfield with operational flexibility in the second half of 2009," Newfield said.

Laterals Newfield drills in the play are expected to average more than 5,000 ft in 2009.

Utah

Oil sales from Monument Butte field in the Uinta basin are averaging 19,000 b/d, up from 17,000 b/d at the end of 2008, said Newfield Exploration Co., Houston.

The increased sales reflect improved demand for black wax crude, the company said. Differentials have narrowed to about $12/bbl below West Texas Intermediate crude, including transportation expense.

Newfield continues to run three rigs in the area, which covers 180,000 gross acres. Substantially all of the acreage is held by production.

OFFSHORE ASSETS – HSE PERFORMANCE MANAGEMENT

CULTURE – THE KEY TO SUSTAINABLE PERFORMANCE

WHAT IS CULTURE?

Some companies wonder why they keep experiencing the same process safety problems. Others wonder why they seem to have plateaued in health, safety and environmental (HSE) performance.

Culture is KEY. It is the individual and organizational "DNA" that represents our tendency to want to do (1) the right thing in (2) the right way at (3) the right time, (4) ALL the time – even when if no one is looking.

The HSE culture that exists on an offshore asset or in a company is the result of all the actions - and inactions - in institutional/workforce memory.

Many facilities use management systems to help control risks of hazardous processes. These management systems are operated by people – people whose inherent attitudes about safety can affect the choices they make in operating these systems and, thus, the overall safety performance of the facility.

ESSENTIAL FEATURES OF A GOOD CULTURE

Industry has established attributes of a good process safety culture. Focusing on these features allows a company to evaluate existing safety culture and determine how best to improve it.

1. Establish HSE as a core value
2. Provide strong leadership
3. Establish and enforce high standards of performance
4. Formalize the HSE culture approach
5. Maintain a sense of vulnerability
6. Empower individuals to successfully fulfill their HSE responsibilities
7. Defer to expertise
8. Ensure open and effective communications
9. Establish a questioning/learning environment
10. Foster mutual trust
11. Provide timely response to HSE issues and concerns
12. Provide continuous monitoring of performance

These essential features can be used to both evaluate HSE culture and used as a point of comparison for HSE performance outcomes.

HOW TO EVALUATE CULTURE

Process safety and HSE are hard to measure and more difficult to change. There are few direct indicators of process safety and HSE culture, and because of its nature, it cannot be evaluated very frequently.

Typical ways to get a handle on process safety and HSE culture are:

- Employee surveys
- Interviews
- Work observations
- HSE leading indicator metrics

Based on lessons from conducting the Baker Panel evaluation, we have devised a formal approach for connecting process safety and HSE performance outcomes to culture. This performance assurance review (PAR) approach consists of the following steps at a facility:

- Developing a current "HSE performance picture" and assessing the "historical performance movie"
- Understanding employee opinions about safety culture issues
- Mapping these results to the 12 culture features
- Addressing technical, management system and underlying cultural issues to create sustainable, improved process safety performance

Companies can perform a PAR at a single facility, but the results will be more robust if the evaluation is done at multiple representative facilities, business divisions, and corporate offices.

In 2007, the Center for Chemical Process Safety (CCPS) published its next generation process safety management (PSM) system called Risk Based Process Safety (RBPS). The RBPS framework has 20 elements grouped into four accident prevention pillars and is being applied to HSE for offshore assets.

Commit to Process Safety
- Process Safety Culture
- Standards, Codes, Regulations, and Laws
- Process Safety Competency
- Workforce Involvement
- Stakeholder Outreach

Understand Hazards and Evaluate Risk
- Process Knowledge Management
- Hazard Identification and Risk Analysis

Manage Risk
- Operating Procedures
- Safe Work Practices
- Asset Integrity and Reliability
- Contractor Management
- Training and Performance Assurance
- Management of Change
- Operational Readiness
- Conduct of Operations
- Emergency Management

Learn from Experience
- Incident Investigation
- Measurement and Metrics
- Auditing
- Management Review and Continuous Improvement

Learning from all process safety sources of experience is vital for sustainable process safety performance and continuous improvement. Plus, we need to expand our sources of learning to those available outside our plant, company, and even industry because we cannot "afford" to learn only learn from our own mistakes. We cannot learn quickly enough using only our own mistakes and incidents.

PATH FORWARD

Some predict that future major incidents will all have poor HSE culture as a contributing factor. Culture will be the "root cause" of the next decade. Industry must do more to equip itself to learn and do something about the underlying organizational and culture causes of major accident situations – BEFORE they happen.

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ASSET OPTIMIZATION—1

Real-time data, models optimize complex production off Trinidad

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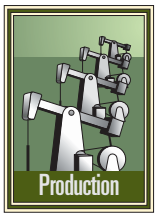
BP Trinidad & Tobago (BPTT) has leveraged real-time data with engineering models to manage a complex gas offshore production scheme.

The optimization system:

- Turns real-time data into actionable information.
- Encourages cross-discipline communication by integrating subsea, offshore, and onshore facilities.
- Provides an understanding of the impact of field and process constraints together in production potentials and capacity utilization, including available separation and transportation capacity, pipeline backpressure effects, well operational limitations, and onshore treatment constraints. Treatment constraints include rvp and water content, as well as the capacity of installed stabilization units.
- Helps in meeting contractual obligations in the most profitable way, such as by producing the nominated gas quantities in a way that maximizes the condensate's revenue stream.
- Allows fast reacts to system upsets and planned equipment outages.
- Provides an in depth understanding of potential new field developments and of required changes in the operating philosophies to maximize investment value.

This first of two articles describes the components of the optimization system; the concluding part will provide examples of how BPTT uses the system.



Operations optimization

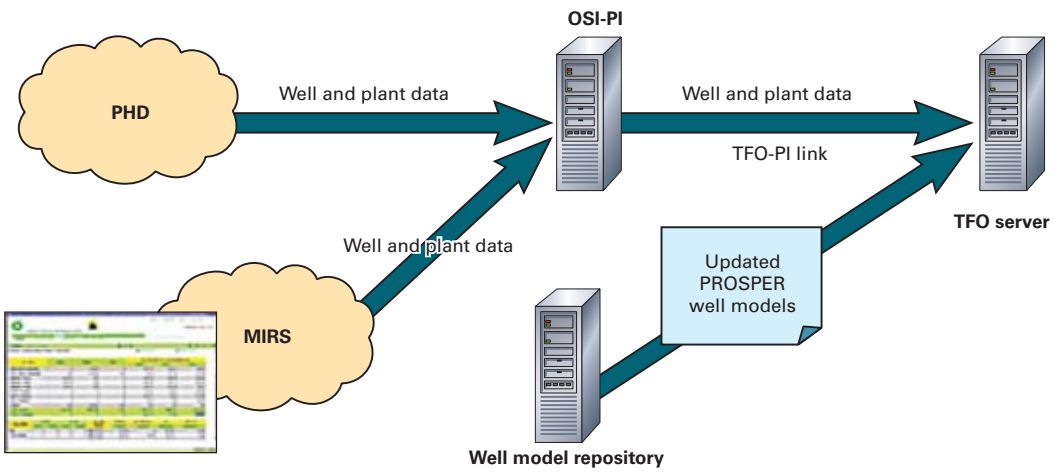
Exploration and production operations require the combined expertise of process and control engineers, petroleum engineers, and geologists. These disciplines frequently address problems from different perspectives and often use different modeling tools for helping to make day-to-day decisions.

Unified decision frameworks that consolidate and encompass larger scopes and broader data sources help align otherwise conflicting objectives and allow operations to tackle issues such as:

- Process surveillance monitoring for providing a comparison of actual reservoir performance with simulated expected performance for fault diagnosis or degradation monitoring.

TFO NETWORK ARCHITECTURE

Fig. 1



• Production optimization for maximizing gas production with available onshore and offshore equipment; changing operating philosophy or conditions such as pressures, routing, gas lift, water injection, and gas injection, as well as the best use of available equipment capabilities.

• Capacity planning for assessing spare plant capacity and available production potential.

• Maintenance planning for determining the effect of equipment outages on production capacity.

• Contract renegotiation for obtaining the maximum gas nominations and best utilization of spot gas markets.

• Debottlenecking through identification of process bottlenecks and planning of additional investments or redefinition of operating strategies.

To confront these issues BPTT implemented the Trinidad field optimizer (TFO).

The optimizer is an off-line advisory system that links to real-time data sources as well as to modeling and simulation packages (Aspen HYSYS and PROSPER) to provide an overall representation of BPTT's gas production and conditioning facilities.

BPTT has embedded the tool into its operational decision-making processes, and its hydrocarbon value assurance team will employ it to analyze various real operating value realization scenarios.

The main advantages of such a system are for:

• Reacting in a timely manner to changes in system conditions.

• Managing gas and associated liquids production more efficiently.

• Maximizing revenue.

BPTT operations

BP Trinidad & Tobago holds exploration and production licenses for operating off Trinidad's east coast; the unit represents about 10% of BP Global's business.

Currently 11 offshore production platforms feed into 3 offshore processing hubs: Cassia Bravo, Amherstia, and Mahogany Bravo. The hubs have a combined capacity to process 3.75 bscfd of gas and associated liquids.

Four gas pipelines and one liquid pipeline link the offshore platform network to Trinidad's east coast. The gas pipelines have a combined gas export capability of more than 3.5-bscfd.

Currently, market demand does not constrain the associated crude and condensate production; therefore, these products have an unconstrained revenue value.

BPTT has contracts for supplying natural gas at specific pressures to the domestic market through the National Gas Co. of Trinidad & Tobago (NGC) and to the Liquefied Natural Gas Co. (Atlantic LNG).

These midstream markets represent about 2.7 bscfd in combined demand requirement.

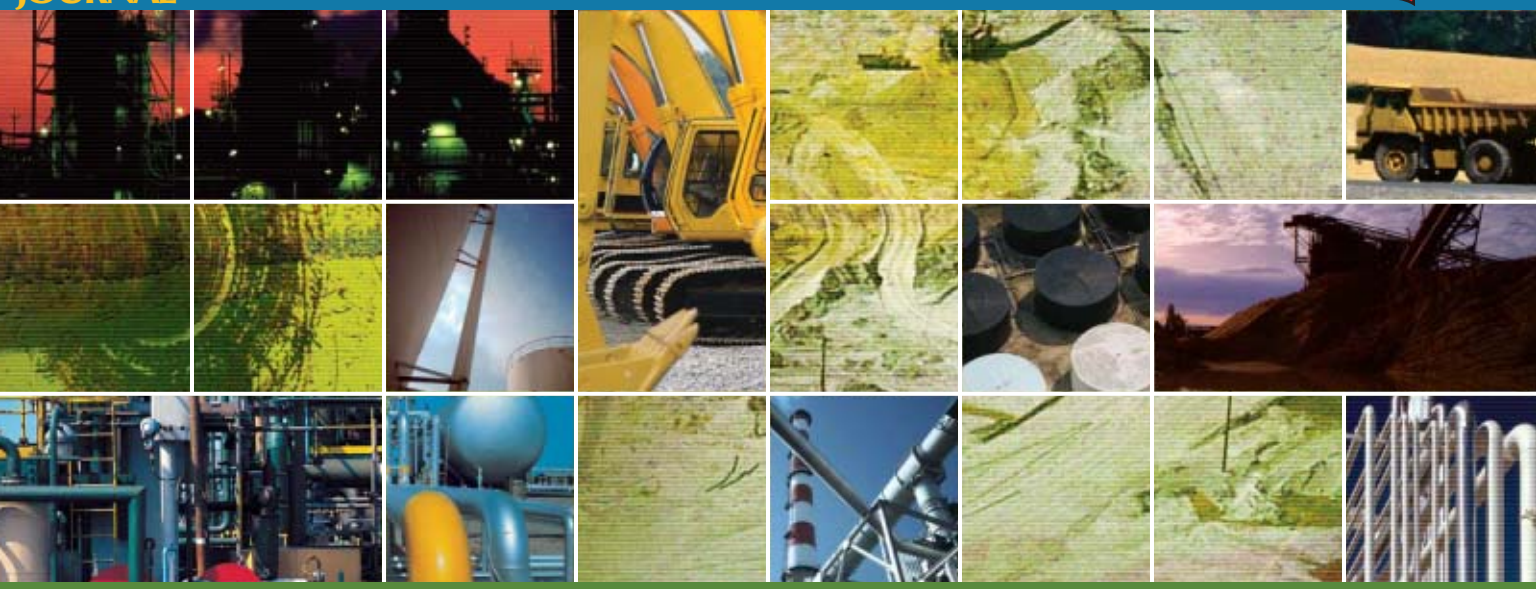
Adopting technologies

Well documented is the importance of addressing the issues of people, process, and technology through the successful adoption of new solutions.[1,2] Taking a simplistic approach and focusing on only one or two of the three areas is one of the single most important reasons identified for failed technology adoption initiatives.

In the case of oil and gas producing assets, this is even more important because the industry is under pressure to keep assets producing at full capacity or agreed-upon rates. This leads to most operators being risk-averse.

At BPTT, a team of gas dispatchers ensures that market demand is met 24 hr/day all year. Their operating process includes calling the respective markets to understand the demand profile throughout the day and to ensure that the gas supply meets required operating pressures. They normally manage this process hourly and the work often is time consuming and redundant.

Adoption of the new technology will improve productivity by allowing the gas dispatchers to eliminate guesswork with respect to daily optimization, add additional revenue to the saturated gas business by operating more efficiently in maximizing liquid hydrocarbon production while meeting gas nominations, and reduce the time to react to



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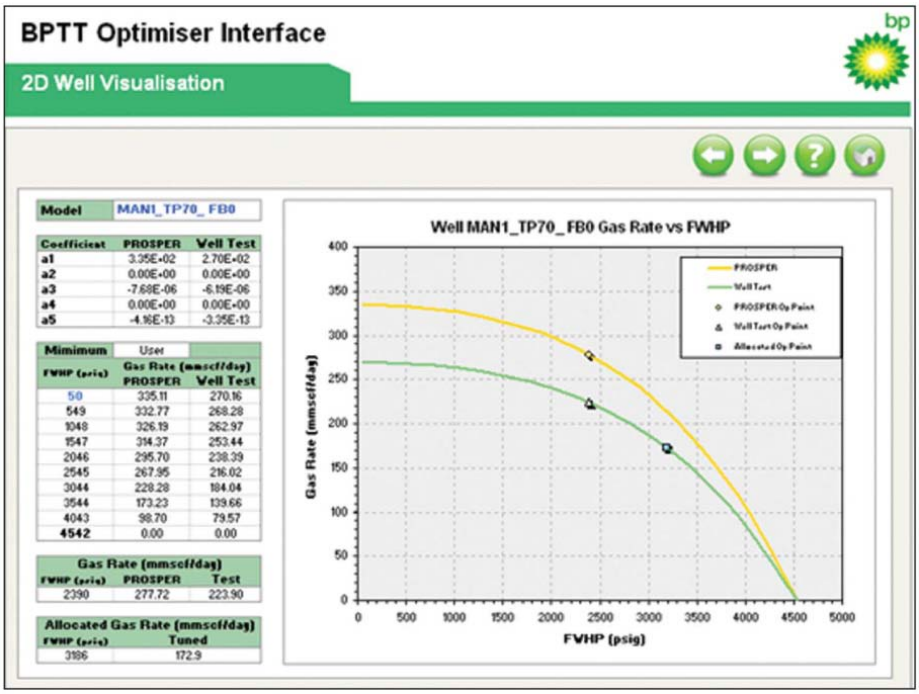


This screen shows the type of information available from the BPTT optimizer interface (TFOI) that acts as the human interface between the optimizer end users and the linked simulation model and databases (Fig. 2).

changes that affect normal operating conditions.

BPTT formed a production optimization team (POT) 3 years ago primarily to manage daily optimization. The team requests inputs from petroleum engineers from each processing hub, gas dispatch team, and market representatives in a daily forum.

The inputs include installed platform capacity (IPC) data, schedules for planned downtimes for both offshore, market activities, and production adding opportunities. By carefully analyzing the data inputs, the team reschedules events affecting production to ensure that BPTT met market demand for any specific day.

BPTT emphasizes maximizing revenues by producing wells with greater condensate to gas ratios. From this, BPTT developed a well priority shut-in list to manage all wells. This list advises operators on which wells to open and close to maintain integrity and maximize crude and condensate production.

The petroleum engineers update the list monthly. Once the personnel reach agreement on the new work schedule and supply profiles, the gas dispatch team works with the well priority shut-in list as a guide to supply demand.

The tedious work flow between the POT, asset engineers, and gas dispatchers requires constant communication to develop a solution to different scenarios. The implementation of the TFO tool simplifies the process for certain issues.

It was equally important to integrate the needs of the shareholders to ensure that the tool is robust so that it satisfies the scenario requests with respect to system optimization.

BPTT's implementation of the TFO tool required the collaboration of the following technologies:[3,4]

- Fast running modeling and simulation tools.
- Fast running optimization tools.
- Digitally enabled metering systems.
- Communication systems.
- Real-time databases, process historians.
- User interface infrastructure.
- Work-flow-handling tools.

TFO description

The TFO is a model-based off-line advisory system that uses historical process data and an ad-hoc HYSYS steady-state model to find the values of key process variables that render an optimum production situation that typically leads to meeting a certain gas nomination while maximizing the condensate recovery.

TFO has the following software components (Fig. 1):

- Library of well models—PROSPER from Petroleum Experts Ltd.
- Steady-state field model and optimizer—Aspen HYSYS from Aspen Technology Inc. (TFO model—TFOM).
- Excel executive work-flow managing application (TFO interface—TFOI).
- Data historian—PI from OSI Software Inc.
- MIRS production database—BPTT proprietary implementation.

TFOI acts as the human interface between the optimizer end users and the linked simulation model and databases (Fig. 2). It handles the data traffic between the various system components and, among others, performs the following actions:

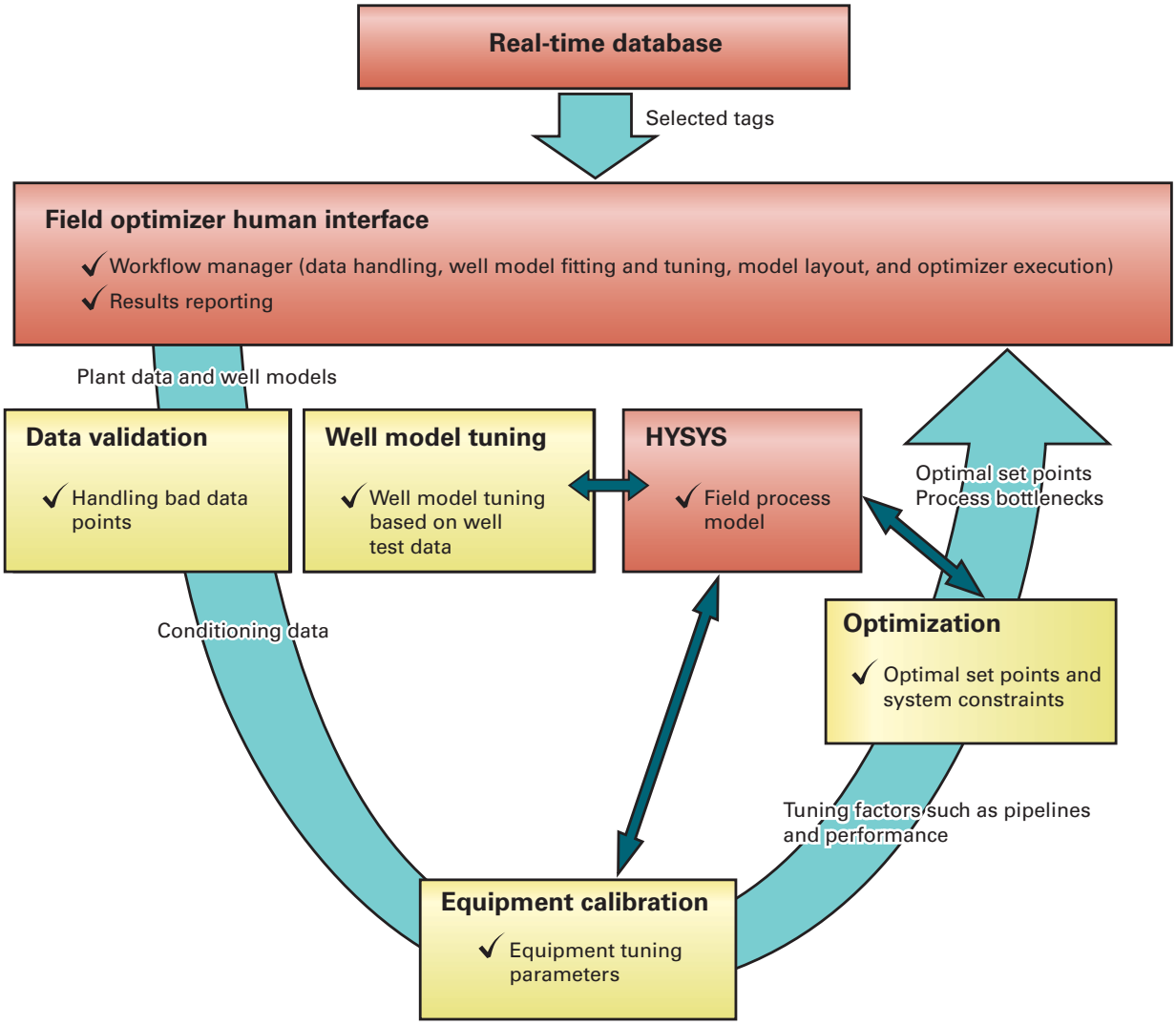
- Sensitivity analysis of the individual well models to generate a parametric characterization of the wellhead pressure-flow behavior.
- Retrieval and validation of field data
- Field-model validation against field data including comparison of snapshot model predictions with historic process data.
- Field-model calibration to match actual process conditions.
- Configuration of specific optimization scenarios.
- Presentation of results in terms of potential extra revenues and required actions to achieve them.

TFO design

The essential principles that drove

TFO APPLICATION WORKFLOW

Fig. 3



the implementation of the TFO were (Fig. 3):

- Connectivity—The optimizer will have built-in field data retrieval, validation, and visualization mechanisms.
- Flexibility—The optimizer will be dynamically reconfigurable to represent the actual state of asset equipment at all times.
- Fidelity—The optimizer will allow validation against key plant data and be easily tuned when necessary.
- Robustness—The optimizer will run without failure for all possible asset production situations, such as wells, platforms, pipelines, separation trains on or off.
- Usability—The user interface will be friendly and intuitive, providing simple mechanisms to display and visualize model results in a way that effectively communicates among team members.

TFOM

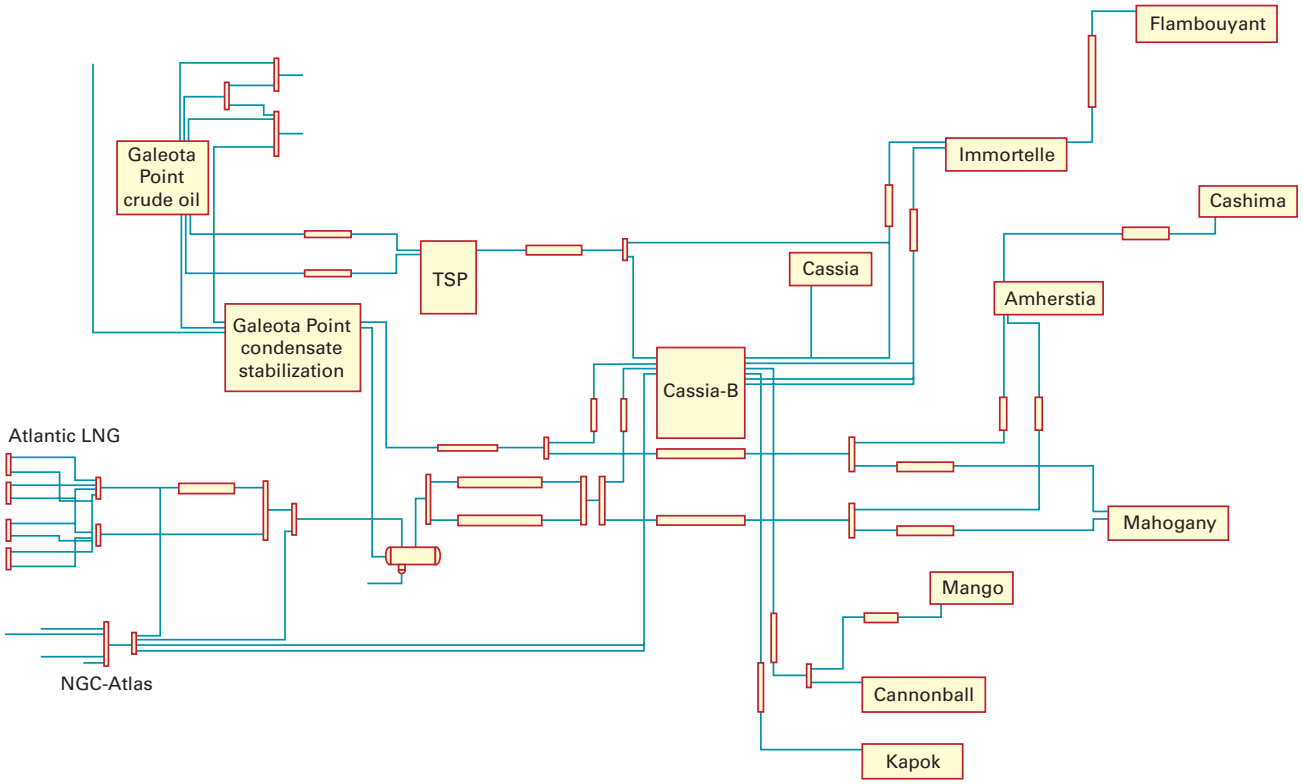
The engine of TFO is a HYSYS model (TFOM) that combines first engineering principles with ad hoc empirical characterizations of critical pieces of equipment, developed from long-term historic process data. This dual modeling approach increases the fidelity of the model without losing any of its predictive capabilities, which are required for meaningful optimization runs.

The TFOM is provided with built-in autocalibration mechanisms that allow its operation in the same field model that eliminate the need of additional parameter estimation models. This one model approach is better than other approaches in that it minimizes optimizer maintenance costs and simplifies application workflow.

An additional advantage is that the same model used for optimization also can serve for what-if analysis and other

TFO MODEL ORGANIZATION

Fig. 4



off-line studies because it is calibrated already against field data.

A key element of the design of field optimizers such as TFO is the ability automatically to activate and deactivate blocks and subsystems. A gas asset such as BPTT is a continuous moving target (Fig. 4). Wells and platforms are shut down and brought on line regularly for such reasons as controlling and adjusting gas productions to demand, performing well tests, and fixing flow-assurance problems.

An optimizer that is unable automatically to detect and react to this dynamic nature of the asset has little value.

The TFOM:

- Allows switching from a validation-calibration mode to optimization mode with a simple flag change.
- Allows activating-deactivating wells, platforms, pipelines, and separation trains through on-off status indicators, with some of them directly retrieved from data historians.

The model has a robustness considerably higher than a standard process simulation typically requires. The model must protect individual pieces of equipment against unfeasible operating regions or provide extrapolation mechanisms to avoid model failures during optimization.

The small inefficiencies and short cuts that will never manifest in a standard simulation model tend to pop up quickly when the optimization engine controls the model.

Some areas that need special attention during construction of the model include:

- Avoiding recycle loops whenever possible. These loops solved in an iterative manner in sequential modular flow sheets are a sink of simulation time and a source of noise.
- Allowing the configuration of certain unit operation blocks in different ways. The preference is for direct calculations instead of iterative loops inside individual units. These loops are converged as part of the optimizer problem configuration.

TFOI

The Excel-based executive TFO application (TFOI) handles the connectivity of the model with the required data sources and with the library of validated PROSPER well models, which production and allocation engineers typically update. TFO uses a centralized OSI PI server that receives real-time data from the various Honeywell Uniformance PHD servers installed in each platform or terminal.

The PI server also receives cumulative production data from the BPTT proprietary MIRS production database.

TFOI performs the following functions:

- Data retrieval from the PI server. This includes well data such as well status, wellhead pressure, and choke opening. Also included are plant data such as platform separator pressures, gas and condensate pipeline pressures

and flow rates, platform daily productions, redelivery points flow rates (at Altantic, NGC, Atlas, Picton, etc.). Other gas and crude oil plant process variables retrieved include separator pressures and temperatures, and stabilization columns flow rates.

- Gross error detection of bad PI readings and option for the users to validate and correct individual data pieces.
- Sensitivity analysis of PROSPER well models including generation of wellhead parametric models, supplied to the HYSYS field model as a way of characterizing well behavior, such as flow rate, as a function of wellhead pressure. In addition, it compares the latest well test data with PROSPER model predictions and tunes the PROSPER models to best match well test data.
- Model validation and calibration for comparing field data with model predictions and reporting deviations as a means of deciding the need for model calibration. Execution of TFOM in parameter estimation mode minimizes the differences between model predictions and the corresponding field data. The scope of the parameter estimation mode includes gas and liquid pipelines pressure drops, platform productions, gas calorific values in gas delivery points, condensate quality indicators (rvp, and water content), separator temperature differences, and overall asset gas balance (gas produced vs. gas sold).
- Configuration of the optimization problem includes selecting decision variables and their minimum and maximum bounds, including swing and fixed wells. The process also allows editing maximum and minimum bounds of system constraints such as separator gas rates and allowed platform productions. In addition, one can specify the commercial targets that typically consist of a certain gas nomination value for the day as well as the gas and condensate prices for the various revenue streams.

The process also requires specifying the optimization problem to solve by selecting among a list of possible business situations such as meeting gas nominations and maximizing condensates production, operation revenue, and capacity utilization.

- Reporting optimization results that are in the form of detailed optimizer output sheets including decision variable values, constraints status, and objective function value; and optimizer executive summary sheets that highlight well ranking (before and after optimization), gas and condensate productions (before and after optimization). ✦

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Su Tu Vang project overcomes tough construction environment

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Cuu Long Joint Operating Co.
Ho Chi Minh City

The successful Su Tu Vang (Golden Lion) project off Vietnam demonstrates that even during periods of tough industry conditions companies can bring on stream well planned and properly scoped projects safely and efficiently.

Su Tu Vang is the second field development in Block 15-1 off Vietnam.

Cuu Long Joint Operating Co. (CLJOC) began producing Su Tu Vang field on Oct. 14, 2008, 14 days ahead of schedule and under budget. Field start-up coincided with the 10-year anniversary month of CLJOC's establishment.

CLJOC, established on Oct. 28, 1998, operates Block 15-1. Its coventurers include PetroVietnam Exploration Production Corp. Ltd., 50.00%; ConocoPhillips (UK) Cuu Long Ltd., 23.25%; Korea National Oil Corp., 14.25%; SK Energy Co. Ltd., 9.00%; and Geopetrol Vietnam SA, 3.50%.

Block 15-1 is at the north end of the Cuu Long basin, about 180 km east-southeast of Ho Chi Minh City. Water depths in the block are 35-60 m. Production from Block 15-1 began on Oct. 29, 2003, when CLJOC brought Su Tu Den (Black Lion) field on stream (OGJ, Oct. 20, 2008, p. 41). Cumulative Block 15-1 production was about 123 million bbl of oil at yearend 2008.

Exploration, appraisal

Su Tu Vang field is about 7 km south of the Su Tu Den structure.

CLJOC completed the SV-1X discovery well in the fractured granite basement on Oct. 23, 2001. The next well, SV-2X completed on Sept. 12, 2002, appraised the northeast area of the structure. A third well, SV-3X, drilled in February 2004 near the southwest end of the structure, failed to encounter commercial hydrocarbons.

CLJOC declared Su Tu Vang field commercial on May 7, 2004, with the successful completion of the fourth well, SV-4X.

Concept selection study

CLJOC's concept selection study in 2004 determined the optimum field development plan.

The study investigated multiple options, including:

- Expanding the existing floating production, storage, offloading (FPSO) vessel, as originally planned during the Su Tu Den Southwest development.
- Supplementing or replacing the existing FPSO with additional or larger floating systems.
- Using a combination of fixed facilities with a floating storage and offloading (FSO) vessel.
- Using a concrete gravity-based structure (GBS) to meet oil storage requirements.

CLJOC ruled out the FPSO expansion because new field production would likely exceed the expanded FPSO capacity, and the FPSO expansion would require a 90-day field-wide shutdown for heavy lifts and module integration.

The venture also ruled out replacing or supplementing the existing FPSO with additional or larger floating production systems because of the lack of worldwide shipyard capacity.

The GBS concept was dismissed because it could not economically provide the minimum oil storage capacity needed for the relatively shallow water depth in Block 15-1.

The preferred concept was a 12 slot, 18-well central processing platform (CPP) and a SuezMax class FSO. The concept included a float-over deck configuration to mitigate schedule risk and minimize offshore installation and hookup and commissioning (HUC) requirements.

CLJOC sized the facility to support Su Tu Vang field and the future Su Tu Den Northeast development. The design set the facility's capacity at 100,000 bo/d, 160 MMscfd of lift and export gas, 225,000 b/d of injection water, and 130,000 b/d of produced water.

The design provided system flexibility by reconfiguring the pipeline network to allow diversion of production from Wellhead Platform A (WHP-A) to the CPP and for routing stabilized oil from the CPP to either the new FSO or the existing FPSO (Fig. 1).

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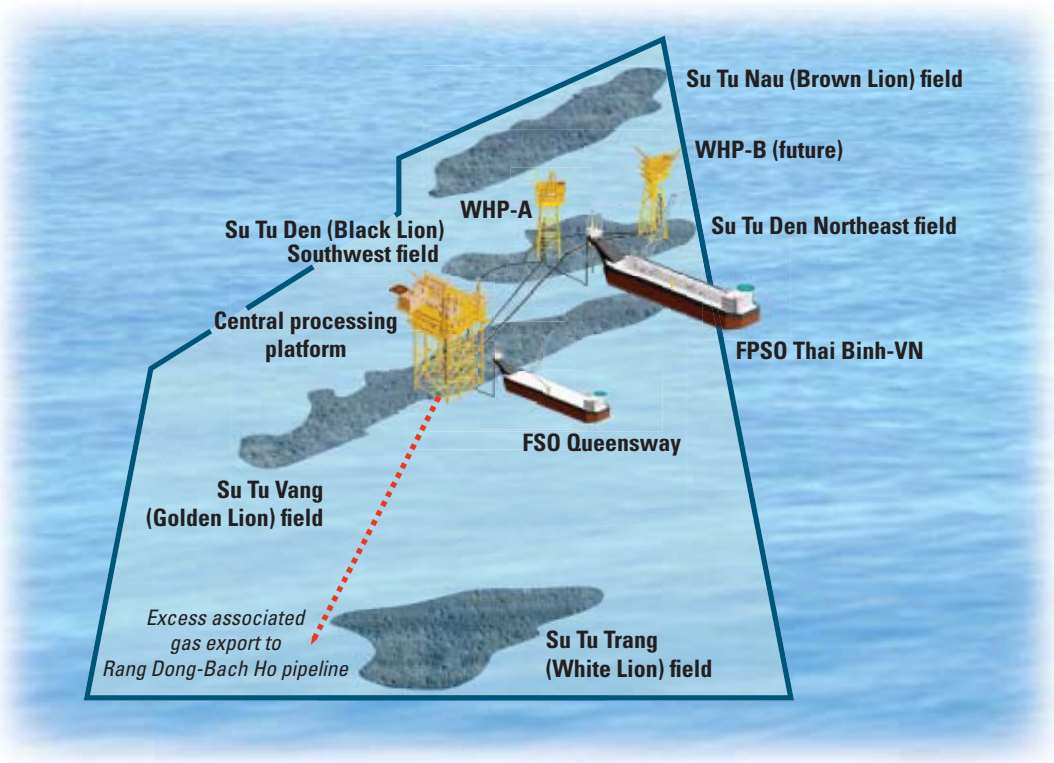
BLOCK 15-1 INFRASTRUCTURE

Fig. 1



to PetroVietnam Gas through a new spur line to the Rang Dong-Bach Ho pipeline system.

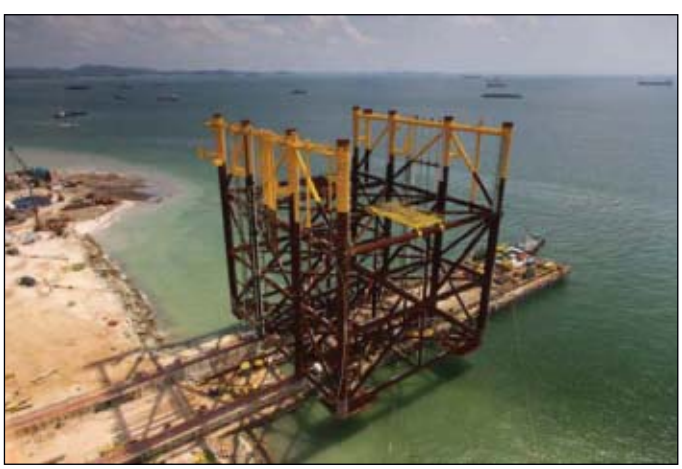
Preliminary engineering

CLJOC began preliminary engineering on Jan. 24, 2005, and an integrated team of company and contractor staff completed the work in August 2005.

The team developed the typical preliminary engineering deliverables but also dedicated significant effort to identify long-lead equipment and primary structural steel requirements. This helped mitigate schedule downside by preplanning critical activities requiring immediate action at the start of detailed engineering.

Following preliminary engineering, CLJOC developed and issued the engineering, procurement, construction, and installation (EPCI) bid packages for the CPP and pipelines. Three qualified bidders participated in the process.

After an extended bid period and subsequent clarification meetings, CLJOC selected and recommended a single bidder to the Block 15-1 coventurers.



Load out from the Batam, Indonesia yard of the 3,945-tonne, 8-pile central processing platform took place during July 2008 (Fig. 2).

Contract strategy

CLJOC's general philosophy is to develop fit-for-purpose strategies for each major contract, with the objective of assigning risk to the party best positioned to manage that risk.

For the CPP/pipelines EPCI contract, the project used a virtual integrated team with J. Ray McDermott Asia Pacific (JRMAP) staff holding the lead positions and CLJOC discipline engineers participating on the team.

For the FSO, CLJOC structured the contract as a turnkey arrangement that covered tanker modifications, turret, risers, and vessel transportation and installation. Vessel operation is under a time-charter party agreement. CLJOC monitored the design and fabrication progress with a small oversight team during work in the shipyard.

Project execution

The Block 15-1 management committee approved CLJOC's bid award recommendation and awarded the CPP/pipelines EPCI contract to JRMAP on Mar. 9, 2006. The CLJOC management team charged the project team with the following goals:

- Execute the project with zero lost workday cases (LWCs) and a target total recordable injury rate (TRIR) of less than 0.50.
- Achieve first oil by Oct.

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28, 2008.

- Complete the project within 10% of the authorized budget.
- Design the facility to ramp up to full capacity within 90 days of first oil.
- Achieve a long-term direct operating efficiency of at least 92%.

The CLJOC project team mobilized in early March 2006 to JRMAP's Singapore office to commence detailed engineering and procurement activities.

Deck and jacket fabrication began on Sept. 15, 2006, at JRMAP's Batam, Indonesia, yard. The yard installed a new skidway for the Su Tu Vang deck fabrication.

JRMAP subcontracted fabrication of the 12-slot template and CPP flare boom to Petroleum Technical Services Co. (PTSC) of Vung Tau, Vietnam.

The construction contractor completed all deck fabrication and precommissioning activities on the 15,150-tonne CPP deck before its sail-away from Batam in August 2008 (Fig. 3).

The project team's greatest challenge involved the living quarters and central control room-switchgear building contract. The work scope was not completed by the original subcontractor and CLJOC moved the work to the Batam yard, where JRMAP and CLJOC successfully completed the work without affecting the project schedule.

Tow-out of the 3,945 tonne, 8-pile jacket was on July 27, 2008 (Fig. 2), with jacket installation finishing on Sept. 3, 2008.

The 15,150-tonne CPP deck sailed from Batam on Aug. 25, 2008 (Fig. 3). All deck fabrication and precommissioning activities were complete at sail-away, minimizing the cost and time associated with the offshore HUC.

The deck float-over took place on Sept. 5, and deck installation finished on Sept. 18, 2008 (Fig. 4).

At peak activity, the offshore installation, hookup, and commissioning work involved more than 25 vessels and 1,100 personnel.

A float-over operation in September 2008 placed the CPP deck on top of the jacket (Fig. 4).

CLJOC awarded the FSO as a turnkey contract to Tanker Pacific Management (Singapore) Pte. Ltd. on Nov. 8, 2006. Engineering and procurement activities continued into July 2007.

Vessel conversion began in January 2008 and finished in September 2008. The FSO Queensway sailed from the Singapore Jurong Shipyard on Sept. 10, 2008, and installation work finished on Nov. 25, 2008.

Project safety

The Su Tu Vang project achieved a LWC rate of 0.11 and a TRIR of 0.20 incidents/200,000 man-hr on a total

exposure of more than 11 million manhr, exceeding the TRIR target of 0.50.

Project personnel completed 2006 and 2007 with no LWCs but incurred six LWCs in 2008. JRMAP and its subcontractors suffered three incidents during fabrication. Tanker Pacific and its subcontractors had two incidents in the Jurong shipyard during vessel conversion and a third during offshore installation.

CLJOC established both a proactive safety monitoring program and a safety incentive program at the start of the project, and yard oversight and supervision increased after the first incident in early 2008.

Initial operations

First oil flowed from the Su Tu Vang CPP on Oct. 14, 2008, 14 days ahead of the sanction schedule. The final project cost is forecast to be about 1.8% under the authorized budget. Production ramped up to facility capacity 44 days after first oil. Facility direct operating efficiency progressively improved after start-up and exceeded 98% in January and February 2009.

The project successfully achieved the schedule, budget, start-up, and reliability goals set by the CLJOC management team.

Best practices

The CLJOC project team successfully executed the Su Tu Vang project during a period of unprecedented cost escalation and resource constraints. This period had steel costs nearly doubling, fabrication facilities heavily booked, substantial shortages of qualified manpower, and significant backlogs among industry equipment suppliers.

The following five best practices were key elements for successfully completing the Su Tu Vang project:

1. *Fit-for-purpose contract strategy.* CLJOC's contract strategy attempted to place risk with the party best able to manage that risk. This contributed to lower costs, reduced schedule slippage, improved facility reliability, and enhanced alignment of interests between contractor and owner.

2. *Deck float-over concept.* CLJOC performed a decision and risk analysis exercise to determine the best deck design concept. The analysis considered such factors as well accessibility, simultaneous operations downtime, rapid ramp-up of production, and a balance between onshore and offshore HUC activities.

The ability to shift costly offshore work to the lower cost onshore fabrication site was a key driver in the decision to use a float-over system. This allowed for completing fully the entire deck before its departure from the fabrication yard.

3. *Subsea template with predrilled wells.* CLJOC removed the existing 4-slot template installed during field appraisal and replaced it with a larger 18-well template. The 18 well-12 slot design allowed for the reuse of two appraisal wells as development wells, thereby, reducing costs. Four additional wells, predrilled and mud line suspended during facilities fabrication, provided six wells available for tieback immediately after deck installation. This allowed rapid production ramp-up soon after facility commissioning.

4. *FSO lease structure.* CLJOC determined the FSO size and commercial structure by balancing lease costs against production constraints caused by storage limitations during the monsoon season. The Block 15-1 production plateau duration was a key factor in this analysis. Consequently, CLJOC structured the FSO lease with an initial 5-year term and five optional 1-year lease extensions, preserving the flexibility to capitalize on potential future production upside.

5. *Operations staff integration into the project team.* CLJOC seconded its operations personnel into the project team from the start of preliminary engineering. They provided key input from design development through commissioning and hand-over. The mechanical completion and commissioning process served as a training and familiarization period for many of the operations personnel.

Acknowledgments

The authors thank the management of Cuu Long Joint Operating Co., PetroVietnam, PetroVietnam Exploration & Production, ConocoPhillips (UK) Cuu Long Ltd., Korea National Oil Corp., SK Energy, and Geopetrol SA for their support and permission to publish this article. ✦

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FOURTH QUARTER 2008
FIRST QUARTER 2009

Economic turmoil pushes propane supply to season-ending surplus

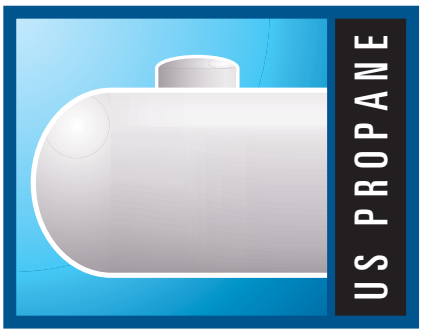
Dan Lippe
Petral Worldwide Inc.
Houston

Weather is always an important influence on propane supply-demand trends during the winter heating season, but the financial crisis and ensuing economic recession had substantial and overriding impact on supply-demand trends during winter 2008-09.

Late last year, we highlighted the impact of Gustav and Ike on gas plants, refineries, and petrochemical plants (OGJ, Nov. 3, 2008, p. 54). We did not know in fall 2008 that the financial crisis would dwarf Gustav and Ike as the most important influence on supply-demand trends for the winter heating season 2008-09. Furthermore, the financial crisis pushed a normal crude oil price correction in July into hyper-collapse during the fourth quarter.

This collapse prompted OPEC producers (Saudi Arabia in particular) to make major cuts in crude production. Production cuts in Saudi Arabia reduced associated-gas production and gas plant propane-butane recovery volumes. As the international propane supply-demand balance tightened, waterborne imports into the US became much more expensive.

At the end of September, the US had a propane inventory deficit of more than 10 million bbl relative to 2006. Despite this deficit and strong retail demand, inventory levels ended the winter heating season with a year-to-year gain of about 8 million bbl. The sharp decline in feedstock demand was the major factor that catalyzed the swing of 18 million bbl in inventory levels relative to 2006.



Feedstock demand

During fourth-quarter 2008, feedstock demand for propane declined by 118,000 b/d vs. consumption during third-quarter 2008 and averaged only 194,000 b/d. While a decline in feedstock demand in the fourth quarter is consistent with seasonal patterns, the decline in 2008 was double the typical decline of 50,000-70,000 b/d. Feedstock demand during fourth-quarter 2008 was 9.7 million bbl less than during fourth-quarter 2007. Propane's share of fresh feed averaged 14.9% during fourth-quarter 2008 vs. 21.9% during third-quarter 2008 and 17.8% during fourth-quarter 2007.

From a low point of 130,000 b/d in December 2008, feedstock demand for propane rebounded in first-quarter 2009. Demand averaged 165,000-175,000 b/d in January and 225,000-235,000 b/d in February. For full first-quarter 2009, we estimate that demand

Propane feedstock demand is an important balancing element for the overall propane market in North America. When colder weather pushes sales and consumption in the retail markets steadily higher, ethylene producers in the Gulf Coast have substantial capability to reduce their consumption and effectively offset some or all of the impact of a colder than normal winter. Historically most of the seasonal decline in ethylene feedstock demand has occurred during fourth quarter. Frequently, feedstock demand for propane rebounds during first quarter.

ETHYLENE FEEDSTOCK DEMAND FOR PROPANE Table 1

Month	Feedstock consumption, 1,000 b/d	Portion of fresh feed, %
October 2008	246.8	17.0
November	203.3	15.2
December	130.5	12.5
January 2009	172.7	14.5
February	228.4	18.1
March*	220.0	20.0

*Forecast.
Source: Petral Worldwide Olefin Plant Survey

averaged 210,000-220,000 b/d, or 8.0-8.5 million bbl less than during first-quarter 2008. The cumulative year-to-year decline in feedstock demand was about 16-17 million bbl during the winter heating season. The decline in feedstock demand helped offset low propane inventories and strong demand in retail heating markets.

Table 1 shows trends in ethylene feedstock demand for propane. The deepening economic recession depressed on housing starts during fourth-quarter 2008 and pushed consumer confidence sharply lower. The downturn in housing and consumer spending, in turn, reduced demand for ethylene during fourth-quarter 2008 and first-quarter 2009.

Enterprise Products Partners LP in March 2009 began operations at its Meeker II natural gas processing plant in Colorado's Piceance basin. The Meeker II expansion doubles processing capacity at the complex to 1.5 bcfd with the capability to extract as much as 70,000 b/d of NGL. Inlet volumes at Meeker at start-up were 750 MMcfd, with 38,000 b/d of NGL being extracted. The company predicted gas volumes to reach 1.1 bcfd by yearend 2009, when NGL production would reach 60,000 b/d. Photo from Enterprise Products.

Ethylene producers operated at 67% of capacity in fourth-quarter 2008 and first-quarter 2009. Ethylene producers will operate at 65-75% of capacity during second and third quarters 2009. On this basis, total demand for fresh feed will average 1.25-1.40 million b/d.

Feedstock demand for propane will reach 310,000-330,000 b/d during second and third quarters 2009 and propane's share of fresh feed will average 21.5-23%. Fig. 1 shows historic trends in ethylene feedstock demand for propane.

Retail demand

Temperatures during fourth-quarter 2008 were colder than in the previous winter for all eastern regional markets. For example, total heating degree-days in the Northeast and mid-Atlantic region were 4.3% and 11.7%, respectively, higher than in 2008. In the upper Midwest during fourth-quarter 2008, heating degree days averaged 9.6% higher than in 2008. Heating degree-days in fourth-quarter 2007 were themselves higher than in fourth-quarter 2006.

We estimate that total retail propane sales averaged 835,000-850,000 b/d in fourth-quarter 2008 or 15,000-35,000 b/d higher than in fourth-quarter 2007. We estimate that total retail propane sales increased to 1.10-1.15 million b/d in first-quarter 2009 or equal to first-quarter 2008.

Based on actual demand data for 2007, conservation effects partially offset the impact of colder weather. We accounted for continued conservation efforts in making estimates for retail during for winter 2008-09. On this basis, retail demand during the winter heating season totaled 175-180 million bbl, or about 5 million bbl more than during the previous winter.

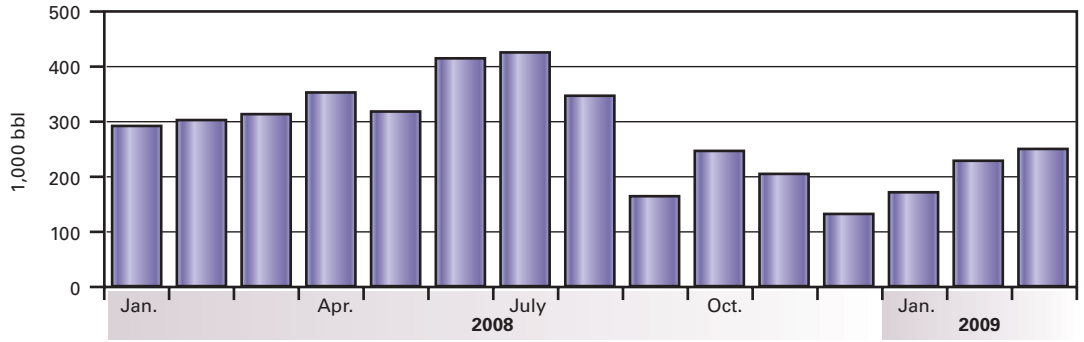
Propane supply

Propane prices fell sharply in concert with the collapse in crude oil prices. Natural gas prices also declined during fourth-quarter 2008 but not as sharply as propane prices. Consequently, profit margins for propane recovery from gas processing plants were sharply lower in fourth-quarter 2008 and first-quarter

Propane's use as a space heating fuel in residential and commercial markets reaches its seasonal peak each year during fourth and first quarters. Residential and commercial propane demand begins to increase during September and October and usually reaches peak demand during December and January.

US ETHYLENE FEEDSTOCK DEMAND FOR PROPANE

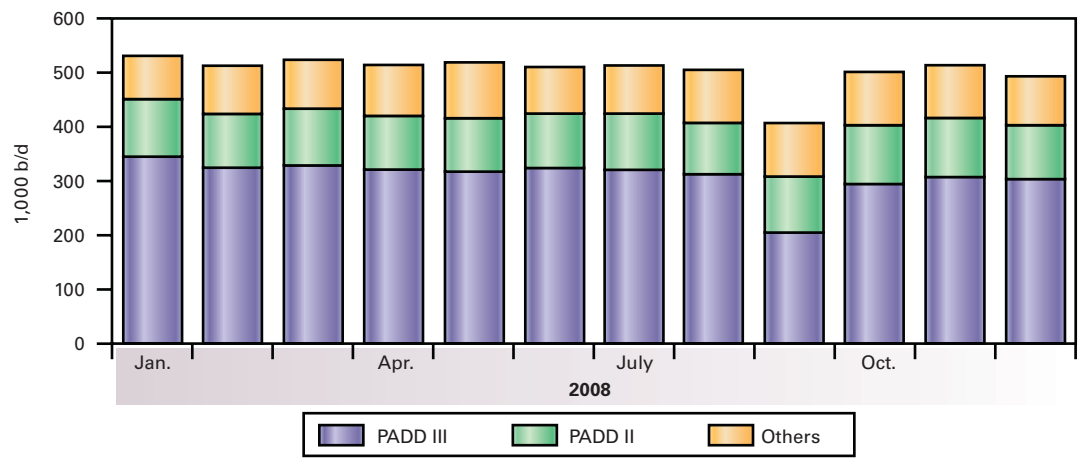
Fig. 1



Source: Petral Worldwide Inc., Houston

US GAS-PLANT PROPANE PRODUCTION

Fig. 2



Source: US Energy Information Administration

2009 compared with those for third-quarter 2008. Propane recovery, however, remained very profitable. In most regions, propane recovery margins were double the prevailing levels of 2003-05.

For refineries, economic incentives to move propane into the merchant market also remained strong. Propane prices averaged $8.00-8.75/MMbtu, or $3-5/MMbtu higher than natural gas prices during fourth-quarter 2008. Refineries had no incentive to burn propane instead of natural gas during the winter heating season. Refineries in the upper Texas Coast, however, did not fully recover from hurricane-related downtime until late in fourth-quarter 2008. This factor limited refinery propane supply.

Data published by the US Energy Information Administration indicate that total domestic production from gas plants and net propane production from refineries averaged 803,000 b/d, or 48,000 b/d (4.5 million bbl) lower than year earlier production volumes. We expect domestic production averaged 865,000-875,000 b/d during first and second quarters 2008. These volumes compare favorably with 857,000 b/d of total domestic production during second-quarter 2008.

For the winter 2008-09, domestic propane production totaled about 152 million bbl, or 1 million bbl less than during the previous winter heating season.

Gas plants

EIA statistics indicate that gas plant propane production averaged 499,000 b/d for fourth-quarter 2008 and was 21,000 b/d lower than year earlier volumes. Hurricane-related natural gas curtailments in the Gulf of Mexico and ethane rejection reduced gas plant propane production in Louisiana by 25,000 b/d vs. year earlier volumes.

Similarly, gas plant production in Texas and New Mexico was 10,000 b/d lower than in fourth-quarter 2007—primarily due to extensive ethane rejection and associated propane production losses during November and December. Production in the Rocky Mountains during fourth-quarter 2008, however, posted a year-to-year increase of 10,000 b/d.

We expect gas plant production to average 530,000-550,000 b/d in first and second quarters 2009. Fig. 2 shows trends in propane production from gas plants.

Refineries

In fourth-quarter 2008, propane production from refineries (net of propylene for propylene chemicals markets) averaged 304,000 b/d—an increase of 5,000 b/d from net refinery supply in third-quarter 2008 but a decline of 27,000 b/d vs. year earlier volumes, according to EIA statistics.

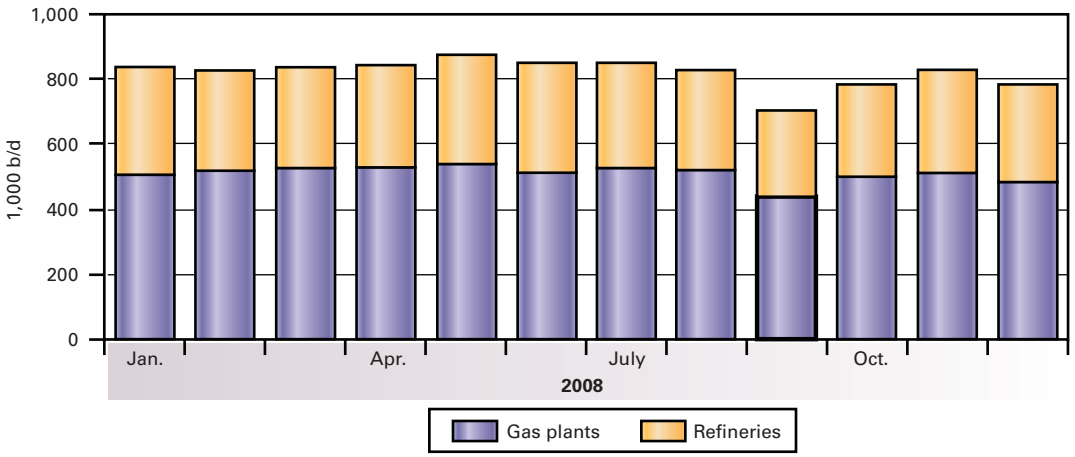
Consistent with hurricane-related outages, net refinery propane pro-

duction during fourth-quarter 2008 was at its lowest level in October 2008 and averaged only 290,000 b/d. Production was higher in November and December 2008, but remained below second-quarter 2008 average of 327,000 b/d.

We expect propane supply from refineries to average 325,000-335,000 b/d in first and second quarters 2009. Fig. 3 shows trends in total propane production (gas plants and refineries).

TOTAL US PROPANE PRODUCTION

Fig. 3



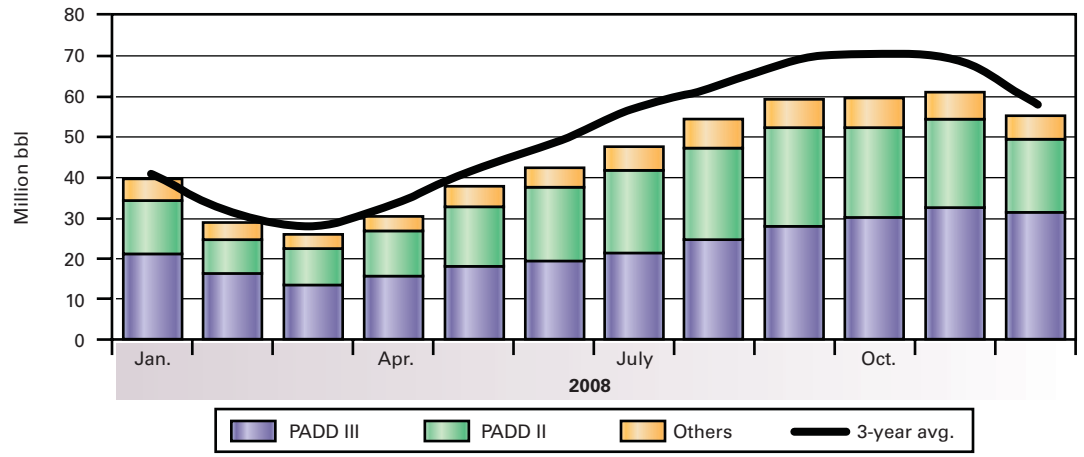
Source: US Energy Information Administration

Imports

Data from the Census Bureau-Foreign Trade Division show that propane imports from Canada increased in fourth-quarter 2008 and averaged 134,000 b/d in fourth-quarter 2008, or 5,000 b/d lower than year earlier volumes and 38,000 b/d below the

US PROPANE INVENTORY

Fig. 4



Source: US Energy Information Administration

average for 2000-05. We estimate that propane imports from Canada increased to 170,000-180,000 b/d in first-quarter 2008.

Consistent with seasonal supply trends, international imports declined during fourth-quarter 2008, as reported by the Census Bureau-Foreign Trade Division, and averaged only 39,000 b/d. International imports were 20,000 b/d fewer than year earlier volumes during fourth-quarter 2008. Prices in the Northeast US, however, increased sharply in January and February 2009.

The jump in prices attracted a surge in waterborne shipments into East Coast import terminals. We estimate that waterborne imports alone averaged 50,000-60,000 b/d in first-quarter 2009.

US PROPANE INVENTORIES

Table 2

Month	PADD 2	PADD 3	Other regions	Total
	Million bbl			
July 2008	21.3	20.5	5.78	47.5
August	24.6	22.6	7.05	54.2
September	27.8	24.5	6.88	59.2
October	29.9	22.7	6.91	59.5
November	32.6	21.6	6.56	60.7
December	31.3	18.4	5.66	55.4
January 2009	26.4	13.6	4.59	44.6
February*	21.0	9.2	3.94	34.2
March*	16.8	8.4	3.80	29.0

*Based on weekly survey estimates.

Inventory trends

Nov. 1 normally marks the beginning of the inventory liquidation season for the US. Occasionally, however, propane inventories reach their seasonal peak in mid to late November. In fourth-quarter 2008, propane inventory in primary storage reached its seasonal peak of 57 million bbl (excluding non-fuel propylene) during the second week of November.

For North America overall, inventories reached a seasonal peak of 70.7 million bbl at the end of September, or 2.9 million bbl lower than the inventory peak in 2007. Even though hurricane-related problems reduced total domestic production by 4.5 million bbl in fourth-quarter 2008 and by 2.5 million bbl during December alone, inventories of purity propane totaled 51.8 million bbl, or 1.77 million bbl more than year earlier volumes. The weakness in ethylene feedstock demand during fourth-quarter 2008 was enough to offset lower domestic production.

During a typical winter, propane markets pull 40-44 million bbl of inventory from primary storage. Weekly inventory reports from the EIA showed that inventories of purity propane declined by only 25 million bbl during first-quarter 2009 and by 33 million bbl for the full winter heating season.

The weakness in ethylene feedstock demand was enough to offset lower domestic production during fourth-quarter 2008. The surge in waterborne imports into East Coast terminals during first quarter helped to minimize the impact of colder than average temperatures and strong retail heating demand.

Purity propane in primary inventory in Canada totaled only 8.9 million bbl on Sept. 1, 2008, or 1.2 million bbl fewer than year earlier volumes and 1.6 million bbl fewer than the 5-year average. Statistics from Canada's National Energy Board showed that Canadian companies withdrew 7.6-8.0 million bbl of propane from primary storage

Consistent with the seasonal increase in retail propane sales, propane imports from Canada typically increase to peak seasonal volumes of 150,000-175,000 b/d during fourth quarter and 170,000-190,000 b/d during first quarter. Additionally, propane imports from international sources (outside North America) usually decline sharply during fourth quarter. Imports from international sources typically remain at seasonally minimum levels during first quarter.

during the winter heating season.

Inventories of purity propane fell to a seasonal low of 1.1-1.3 million bbl at the end of March 2008. Purity propane inventories in Canada were 2.0 million bbl lower than the 5-year average and 1.2 million bbl lower than year earlier levels at the end of March.

Fig. 4 presents trends in propane inventory.

Regional inventory trends

Propane inventory in primary storage in US Petroleum Administration for Defense District (PADD) II peaked during the second week of October 2008 and totaled 25.3 million bbl, or 1.7 million bbl more than peak inventory in 2007 and 1.3 million bbl higher than the average for 2002-06. By the end of February 2009, inventory in primary storage in PADD II declined to 12.5 million bbl and was 3.3 million bbl lower than the 5-year average.

During March 2009, however, EIA's weekly reports indicate that inventories in PADD II increased by 300,000-500,000 bbl and ended the winter heating season at about 13.0 million bbl, or about 2 million bbl higher than the 5-year average.

Propane inventory in primary storage in PADD III (excluding nonfuel propylene) reached its peak during the first week of December 2008 (about 2 months later than in PADD II) and totaled 29.7 million bbl, or 1 million bbl more than the peak inventory level of 2008. The record high inventory for PADD III for the first week of December was 36.6 million bbl (December 2005).

By the end of January 2009, inventory in primary storage in PADD III declined to 24.1 million bbl, or 7 million bbl higher than in 2008. Withdrawals of inventory remained at typical levels during February and March, and inventories fell to a seasonal low of 17.0-17.5 million bbl at the end of March 2009—a year-to-year increase of 5.0-5.5 million bbl.

Pricing, economics

Although the hypercollapse in crude oil prices was the dominant influence on propane price trends, ethylene feedstock parity values and unusually weak feedstock demand were the dominant influence on propane price relationships vs. other NGLs during fourth-quarter 2008.

At the beginning of the heating season, propane prices in Mont Belvieu averaged 103.5¢/gal in October 2008 and were 37% lower than the August average of 165.2¢/gal. During the period of falling spot prices, propane's ratio vs. West Texas Intermediate declined to 56.8% in October 2008 and 54.0% in November 2008 vs. 62.1% in September 2008.

For third-quarter 2008, propane prices averaged 168¢/gal and feedstock parity values vs. light naphthas averaged 181.6¢/gal. In fourth-quarter 2008, propane prices averaged 79.4¢/gal and feedstock parity values vs. light naphthas averaged 77.7¢/gal. These comparisons indicate that the impact of the economic recession on ethylene feedstock demand reinforced the generally bearish impact of the collapse in West Texas Intermediate prices on propane prices as well as prices for other ethylene feedstocks during third and fourth quarters 2008.

The decline in WTI prices accelerated during November and December 2008. Propane prices fell more sharply than did WTI prices during November and continued to decline during December 2008. Propane prices, however, were equal to 61.7% of WTI in December 2008, or 14% stronger than in November 2008. The shift to colder than average temperatures and the surge in propane transfers from Mont Belvieu to the northeastern retail markets were strong bullish influences and counterbalanced the bearish of very weak feedstock demand.

As the frenzied scramble for propane supply in northeastern retail markets reached its peak in January 2009, spot prices in Mont Belvieu increased to 72.6¢/gal and were equal to 73.0% of

PADD: US Petroleum Administration for Defense Districts*

PAD District I (East Coast) consists of three subdistricts:

- Subdistrict IA (New England): Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont.
- Subdistrict IB (central Atlantic): Delaware, District of Columbia, Maryland, New Jersey, New York, Pennsylvania.
- Subdistrict IC (lower Atlantic): Florida, Georgia, North Carolina, South Carolina, Virginia, West Virginia.

PAD District II (Midwest): Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, South Dakota, Ohio, Oklahoma, Tennessee, Wisconsin.

PAD District III (Gulf Coast): Alabama, Arkansas, Louisiana, Mississippi, New Mexico, Texas.

PAD District IV (Rocky Mountain): Colorado, Idaho, Montana, Utah, Wyoming.

PAD District V (West Coast): Alaska, Arizona, California, Hawaii, Nevada, Oregon, Washington.

*PADDs were delineated during World War II to facilitate oil allocation.
Source: US Energy Information Administration, Washington, DC

WTI. Average postings in the Northeast, however, jumped to 87-88¢/gal in January. In view of the 8¢/gal pipeline tariff from Mont Belvieu to Selkirk, NY, prices in Mont Belvieu could have been even higher in January, but weak feedstock demand counterbalanced strong demand in the Northeast retail heating market.

In February 2008, supply concerns in the Northeast retail markets began to abate. As a result, spot prices in Mont Belvieu declined by 7.2¢/gal and the propane-WTI price ratio declined to 70.2%. An overdue rally in WTI prices began in late February and extended through the end of March. Despite the rally in crude oil prices, spot propane prices in Mont Belvieu averaged only 65¢/gal in March and were equal to 57.8% of WTI.

Spring, summer prices

We view the crude oil price rally during February-March 2009 to be an overdue correction. As a result, WTI prices will average $45-55/bbl during second and third quarters 2009. Spot ethane prices, however, are likely to remain relatively weak and will continue to undermine propane's value in at least 40% of the ethylene feedstock market.

Spot propane prices in Mont Belvieu will weaken during second quarter and will average 62-64¢/gal. Prices will remain in this range during third-quarter 2009. Feedstock parity values vs. ethane will decline to 52-55¢/gal during second and third quarters 2009. Feedstock parity values vs. light naphthas will average 65-75¢/gal during second and third quarters 2009.

The economic incentive to crack propane rather than light naphthas will average 4-8¢/gal. The disincentive to crack propane relative to ethane, however, will average 8-10¢/gal. The propane-WTI ratio will average 56-60% during second and third quarters 2009. ✦

The author

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NELSON-FARRAR COST INDEXES

Refinery construction (1946 Basis)
(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2006	2007	2008	Jan. 2008	Dec. 2008	Jan. 2009
Pumps, compressors, etc.	222.5	777.3	1,758.2	1,844.4	1,949.8	1,893.7	1,997.7	2,010.9
Electrical machinery	189.5	394.7	520.2	517.3	515.6	510.9	515.0	517.3
Internal-comb. engines	183.4	512.6	959.7	974.6	990.9	985.3	1,006.7	1,018.7
Instruments	214.8	587.3	1,166.0	1,267.9	1,342.1	1,299.2	1,372.2	1,375.5
Heat exchangers	183.6	618.7	1,162.7	1,342.2	1,354.6	1,374.7	1,253.8	1,253.8
Misc. equip. average	198.8	578.1	1,113.3	1,189.3	1,230.6	1,212.8	1,229.1	1,235.2
Materials component	205.9	629.2	1,273.5	1,364.8	1,572.0	1,405.0	1,364.8	1,357.2
Labor component	258.8	951.9	2,497.8	2,601.4	2,704.3	2,662.0	2,783.8	2,785.5
Refinery (Inflation) Index	237.6	822.8	2,008.1	2,106.7	2,251.4	2,159.2	2,216.2	2,214.2

Refinery operating (1956 Basis)
(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2006	2007	2008	Jan. 2008	Dec. 2008	Jan. 2009
Fuel cost	100.9	810.5	1,569.0	1,530.7	1,951.3	1,671.4	1,233.2	1,156.2
Labor cost	93.9	200.5	204.2	215.8	237.9	214.4	249.9	265.6
Wages	123.9	439.9	1,015.4	1,042.8	1,092.2	1,023.0	1,124.3	1,175.3
Productivity	131.8	226.3	497.5	483.4	460.8	477.2	449.9	442.6
Invest., maint., etc.	121.7	324.8	743.7	777.4	830.8	796.7	817.8	811.0
Chemical costs	96.7	229.2	365.4	385.9	472.5	423.7	406.8	399.4
Operating indexes								
Refinery	103.7	312.7	579.0	596.5	674.1	620.6	602.4	597.8
*Process units**	103.6	457.5	870.7	872.6	1,045.1	928.1	792.8	768.2

**Add separate index(es) for chemicals, if any are used. See current Quarterly Costimating, first issue, months of January, April, July, and October.*

These indexes are published in the first issue of each month. They are compiled by Gary Farrar, OGJ Contributing Editor.

Indexes of selected individual items of equipment and materials are also published on the Costimating page in the first issue of the months of January, April, July, and October.

One-call system addresses offshore damage prevention

Ken Palmer
Bill Byrd
RCP Inc.
Houston

Jack Garrett
GulfSafe LLC
Dallas

A new Gulf of Mexico offshore damage prevention and notification "one-call" system, operating in conjunction with existing onshore systems, offers a cost-effective means of preventing damage to offshore infrastructure. The system is entirely web based, with all incoming locate requests addressed on line. It services four of the US Minerals Management Service planning areas for the US Outer Continental Shelf.

Background

All states have some form of one-call system excavators and the operators of buried facilities can use to avoid excavation damage. These systems provide a centralized communications platform connecting excavators with the operators of buried facilities in the planned excavation area. State and federal laws and regulations codify the requirements governing these systems. While these systems have proven their worth in preventing excavation damage and incidents, until recently a notification system addressing offshore excavation activities has not been available.

In February 2009 GulfSafe LLC, Dallas, a wholly owned subsidiary of Texas Excavation Safety System Inc. (TESS), started a web site addressing offshore damage prevention and notification with the goal of eliminating preventable damage to subsurface infrastructure in the Gulf of Mexico and Straits of Florida. TESS operates one of the largest one-call centers in the US, processing more than 2 million incoming notifications/year, and has more than 20 years of notification system experience.

RCP Inc., Houston, provided appropriate GIS datasets for development of the Gulf of Mexico one-call notification system. This article discusses how the databases were acquired and prepared for implementation into GulfSafe's system and describes how the system functions.

Increasingly crowded

America's critical infrastructure, including energy and communication systems, is expanding offshore, with the Gulf of Mexico one of the most active locations. Innovative technology is required to address the potential threats from this rapid development. Protection of this crucial energy source is a matter of economic and national security.

The roughly 43 million leased OCS acres in the Gulf of Mexico account for about 15% of US domestic natural gas production and 27% of domestic oil production.[1] More than 33,000 miles of pipelines crisscross the bottom of the gulf, connecting more than 4,000 platforms to the coast.[2] These production platforms range in size from single well caissons in 10-ft water depths to large complex facilities in water depths greater than 7,000 ft.[3]

Leases for wind farms and wind-produced electrical energy are under development in the shallow waters of the gulf. The first wind farm agreement in the GOM with the Texas General Land Office and wind developer Galveston-Offshore Wind LLC to construct a wind farm about 7 miles off Galveston Island was signed in October 2005.[4] Leases will likely expand into deeper waters.

StatoilHydro recently allocated 400 million NOK ($78 million) to floating a Siemens turbine in more than 200 m water in the North Sea about 10 km off Karmoy, on Norway's southwestern tip. The installation took place atop a con-

DATA PARAMETERS, FILE TYPES

Area	Data providers	Boundaries	Pipelines	Platforms	Wells	Fairways	Military warning areas	Obstructions	Archeological sites	Environmentally sensitive areas
OCS	6	eOO, .pdf	eOO, ASCII	eOO, ASCII	.pdf, ASCII	eOO	Shapefile, .pdf	.pdf, Excel	.pdf	Shapefile, .pdf, eOO
Texas	9	Shapefile, .pdf	Shapefile, .pdf	—	Shapefile, Excel	Shapefile	—	Shapfile, Excel	—	Shapefile
Louisiana	10	Shapefile	Shapefile	Shapefile	Shapefile	Shapefile	—	Excel	—	Shapefile
Mississippi	4	Shapefile	Shapefile	—	Excel	—	—	Excel, .pdf	—	Shapefile, Excel
Alabama	3	Shapefile, .pdf, Excel	Proprietary	Shapefile	Shapefile, Excel	Shapefile	—	Excel	—	.pdf, Shapefile
Florida	3	.pdf	Shapefile	—	—	—	—	Excel	—	.pdf, Shapefile

ventional oil and gas platform in water about 10 times deeper than conventional offshore wind-turbine foundations.[5]

Tentacles of electrical wire from turbine locations will eventually abound on the ocean floor, joining the thousands of miles of telecommunications cables already traversing the ocean bottom. Three communications cables affecting web and telephone services were severed recently, affecting much of the Middle East. A ship's anchor cut one of the cables. Repairs require pulling cable ends to the surface and can take several days.[6] Several government agencies have jurisdiction over areas of the Gulf of Mexico, with some overlapping. No one agency or organization, however, is available with a centralized, automated method to coordinate new developments.

Offshore one-call

Unlike a traditional one-call operation, the offshore notification process is completely web-based. All notifications travel through www.gulfsafe.com and all member or facility operator notifications are made on line. Technical and user support occurs online or by phone.

Use of the service to request notifications of activity is free. Member companies pay the costs to help prevent damage to their structures. The service shares notification requests with all five traditional one-call centers on the Gulf Coast, ensuring continuity between onshore and offshore operations. The new system services four of the MMS OCS planning areas: the Western Gulf of Mexico (Texas); Central Gulf of Mexico (Louisiana, Mississippi, and Alabama); Eastern Gulf of Mexico (Florida), and Straits of Florida (Florida Keys).

The offshore notification system uses GeoCall software for its web-based service. The software manages member information, incoming tickets, and transmitting tickets to members. The platform has been expanded to operate in a maritime environment and integrate with Gulf of Mexico land-based one-call systems.

Data acquisition

Acquired data sets filled the following categories:

- Boundaries.
- Blocks, tracts.
- Pipelines.
- Wells, platforms.
- Biological areas, including fisheries and wildlife.
- Artificial reefs.
- Wrecks, obstructions; e.g., Fisherman's Gear Compensation Fund obstructions, marine debris.
- Ordinance disposal areas.
- Military warning areas.
- Archeological sites.
- Fairways, designated anchoring areas.
- Telecommunications systems.

State or federal agencies provided most data and a hard copy manual documented the paper trail for both future updating and reference purposes. The accompanying table provides a summary of file types available for the five Gulf of Mexico areas and the number of providers.

Key federal agencies contacted included US Army Corps of Engineers (ACOE), US Fish and Wildlife Service (USFWS), National Marine Sanctuaries Program (NMSP), National Oceanic and Atmospheric Administration (NOAA), National Marine Fisheries Service (NMFS), and the MMS. The MMS website was a key source for OCS information.

Downloading databases in each format occurred during the data collection phase. Using a .pdf format allowed easy access and review of the information. Potential terrorist activities have prompted the National Pipeline Mapping System (NPMS) not to release pipeline information to the general public, raising the importance of its inclusion in this restricted system.

Key state agencies included:

- *Texas:* Texas Land Office, Texas Parks and Wildlife Department, Railroad Commission of Texas (TRRC).
- *Louisiana:* Louisiana Geographic Information Center, Louisiana Digital GIS Map, Louisiana Oil Spill Coordinator's Office, Louisiana Department of Wildlife and Fisheries, Louisiana Department of Natural Resources Coastal Management.
- *Mississippi:* Mississippi Department of Environmental Quality, Mississippi Department of Marine Resources, Mississippi Fish and Wildlife Service, Mississippi State Oil and Gas Board (MSOGB).
- *Alabama:* Alabama State Oil and Gas Board (ASOGB), Alabama Department of Conservation and Natural Resources.
- *Florida:* Florida Fish and Wildlife Conservation Commission, Florida Department of Environmental Protection, Florida State Oil and Gas Board.

A direct correlation existed between oil and gas activity in a state and availability of searched data. Texas and Louisiana had an abundance of information.

Texas has 16 gulf-front counties, and a plethora of information was available from the TRRC and Texas Land Office for building the databases. Louisiana accounts for about 90% of the nation's offshore oil and gas production and has land and water interstate gas and liquid pipelines totaling 32,514 miles and intrastate pipelines totaling 11,267 miles.[7]

Mississippi has three counties, Hancock, Harrison, and Jackson, bordering the gulf. The state's oil and gas board has stated no oil and gas production or pipelines requiring permitting are allowed in near-shore waters, but several OCS pipelines come ashore in Mississippi. The state has since delegated oil and gas activity to the Mississippi Development Authority.

Alabama has two counties, Mobile and Baldwin, bordering the gulf. NPMS says ExxonMobil, Shell, Legacy, and others own the offshore assets that include 9,424 miles of onshore and offshore hazardous liquid, gas transmission, and gas gathering pipelines. Alabama's oil and gas board said these pipeline data were proprietary.

Florida has 13 counties adjacent to the Gulf of Mexico with only one offshore pipeline so far entering the state landing in Manatee County. Owned by Gulfstream Natural Gas System LLC, the line connects south Alabama to Tampa Bay, Fla., covering 419 offshore miles. No oil and gas wells exist in Florida's state waters and all oil and gas leases have been purchased by the state.

Standardizing data

Checking acquired data ensured consistency and accuracy. Sources often provided data in multiple tables that were combined into one. Importing the resulting files into Environmental Systems Research Institute Inc's. (ESRI) ArcInfo as coverage files and converting them into shape files, allowed them to be viewed and checked in GIS.

Tables with X and Y coordinates were standardized and screened for corrupt data. Data with errors that could not be corrected were eliminated. Converting X and Y coordinates into decimal degrees and storing them in numeric fields with Y data (longitude) changed to negative values allowed importing the data into GIS as an event layer on a map. Viewing finished data projected and defined in the proper geographic coordinate system on the map provided additional quality control.

Placing all data into a geodatabase format created a base map of the Gulf of Mexico with layers designed to be easily turned on and off in the table of contents. Layers linked the path to the data within the geodatabase and provided labeling and symbology information.

A contracted commercial source provided pipeline, platform, and interconnect information for the system, updated every 6 months. When database information was client-privileged or re-

stricted, GulfSafe agreed to acquire the data directly from participating clients.

Updating the various databases on a regular basis is key to the proper functioning of the one-call system. The MMS database information on pipelines, platforms, blocks, well completions, and company information is available monthly. The potential for updating other databases varies. ✦

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3. "MMS: 52 production platforms, 3 jackups, 1 platform drilling rig destroyed by Ike," http://www.drillingcontractor.org., Sept. 29, 2008.
4. Texas General Land Office, Oct. 24, 2005.
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6. Fort Worth Star Telegram, Dec. 22, 2008.
7. "Improving the Safety of Marine Pipelines," Committee on the Safety of Marine Pipelines, Marine Board, National Research Council, The National Academies Press, 1994.

The authors

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Equipment/Software/Literature

Flowmeter comes in high temperature version

The Steel-Trak Model 640S immersible thermal mass flowmeter now comes in a special high-temperature option capable of trouble-free operation in process temperatures as high as 750° F.

Suited for uses in petrochemical plant operations and constructed of heavy-duty 316 stainless steel wetted materials, this high-temperature version includes remote-mounted electronics and mineral-insulated cabling.

The maker says the instrument promises accuracy, easy installation, and low maintenance in an explosionproof package.

Featuring direct gas mass flow measurement, units use the firm's patented Dry-Sense technology for drift-free performance. The meter also features the Smart Interface package for field programming and meter validation and diagnostics.

All meters are calibrated to customer specifications at this company's calibration laboratories and are directly traceable to NIST and compliant to ANSI/NCSL Z540 and MIL-STD-45662A and certified to ISO 9001 standards.

The company's Steel-Mass Model 640S is hazardous area approved by CSA and CRN (Canada), FM (US), ATEX, CE and PED (EU), IEC Ex (Australia), and Chinese Pattern Approval (China). Meter accuracy is ±1% of reading plus ±0.5% of full scale with repeatability of ±0.2% of full scale.

The ¾ in. diameter sensor probe inserts easily into ducts and pipes up to 72 in. in size and is offered with a range of process connections (including hot tap). Probes may easily be removed for cleaning or the optional built-in purge cleaning system (using external high pressure air) may be used.

Source: **Sierra Instruments Inc.,** 5 Harris Court, Bldg. L, Monterey, CA 93940.

New chemical cost performance program

Newly launched SafeSpend is an oil field production chemical cost performance program.

It gives operators the option to work with the source shown below to review and personalize their account for maximum cost effectiveness.

SafeSpend reflects the commitment to flexible pricing incentives that can include tiered discounts, rebates, early pay discounts, and price protection indexing to customize each chemical program.

SafeSpend is also designed to help operators maintain more predictable operating costs by approaching chemicals in terms of the cost per barrel of production instead of the cost per gallon of chemical and by adapting chemical programs to changes in production needs.

Source: **Multi-Chem,** 2905 Southwest Blvd., San Angelo, TX 76904.

Services/Suppliers

Schkoda

Shrode

Burman

ENERTAG Inc.,

a subsidiary of ENERTAG SAS, Meudon La Foret, France, has expanded its operations by opening an office in Houston. Oleg-Serguei Schkoda, CEO of both entities, hired Catherine Shrode as CFO and Charlene Burman as director of business development and marketing. Previously, Schkoda held managerial and technical/engineering positions with GE Energy, Schlumberger, WesternGeco, and Baker Hughes INTEQ. Shrode's prior work was as a financial consultant for Constellation Energy, Chesapeake Energy, York International, and Duke Field Services. Burman previously worked in business development, sales, and marketing for PennWell Corp. and Halliburton and in engineering for Schlumberger Offshore.

Founded in 2004, ENERTAG provides smart radio frequency identification applications for oil and gas offshore, marine, and subsea operations that include inspection, repair and maintenance, asset management and inventory, pipelines, construction, facilities, and underwater operations.

GlobaLogix,

Houston, has appointed Robert Burkhardt CFO. He has been with GlobaLogix since 2007, previously serving as controller. Prior to that, Burkhardt was controller/CFO with a metals distribution firm and CFO of a manufacturing group specializing in alloy pipe fittings. He is a CPA and US Air Force veteran and has a BBA in accountancy from Memphis State University.

Burkhardt

GlobaLogix offers a broad spectrum of oil field services, specializing in capturing operational field data and converting it into usable, actionable information for oil and gas companies.

Imports of crude and products

	Districts 1-4		District 5		Total US		
	4-17 2009	4-10 2009	4-17 2009	4-10 2009	4-17 2009	4-10 2009	*4-18 2008
	1,000 b/d						
Total motor gasoline	1,106	1,014	11	60	1,117	1,074	1,006
Mo. gas. blending comp.	953	706	11	11	964	717	609
Distillate	192	144	0	0	192	144	261
Residual	291	437	92	9	383	446	608
Jet fuel-kerosine	97	26	18	50	115	76	178
Propane-propylene	63	108	6	4	69	112	232
Other	(11)	188	111	113	100	301	726
Total products	**2,691**	**2,623**	**249**	**247**	**2,940**	**2,870**	**3,620**
Total crude	**8,468**	**8,425**	**1,387**	**966**	**9,855**	**9,391**	**10,041**
Total imports	**11,159**	**11,048**	**1,636**	**1,213**	**12,795**	**12,261**	**13,661**

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

Purvin & Gertz LNG netbacks—Apr. 24, 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	8.14	6.23	7.40	6.13	6.75	7.33
Everett	2.81	1.18	2.52	1.29	1.60	3.05
Isle of Grain	2.64	1.02	2.19	0.94	1.43	2.20
Lake Charles	1.36	-0.09	1.20	0.05	0.18	1.83
Sodegaura	3.65	5.92	3.91	5.66	5.06	3.15
Zeebrugge	5.16	2.58	4.37	2.49	3.27	4.44

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

Crude and product stocks

District	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane–propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	14,595	56,836	39,530	10,148	52,996	14,659	2,746
PADD 2	85,235	52,632	21,975	6,884	34,331	1,135	13,993
PADD 3	195,214	73,350	42,239	12,733	40,258	15,579	24,127
PADD 4	16,854	5,617	1,994	580	2,686	217	[1]725
PADD 5	58,702	28,872	23,253	9,359	12,040	4,742	—
Apr. 17, 2009	**370,600**	**217,307**	**128,991**	**39,704**	**142,311**	**36,332**	**41,591**
Apr. 10, 2009	**366,743**	**216,505**	**127,906**	**39,338**	**139,629**	**36,170**	**40,826**
Apr. 18, 2009[2]	**316,081**	**212,572**	**105,173**	**38,283**	**104,702**	**39,415**	**27,562**

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

Refinery report—Apr. 17, 2009

District	Refinery operations		Refinery output				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane–propylene
	1,000 b/d						
PADD 1	1,161	1,214	2,211	86	359	99	43
PADD 2	3,164	3,148	2,294	225	924	37	247
PADD 3	7,377	7,228	2,786	716	2,226	209	664
PADD 4	472	470	288	25	146	12	[1]59
PADD 5	2,574	2,456	1,509	373	481	147	—
Apr. 17, 2009	**14,748**	**14,516**	**9,088**	**1,425**	**4,136**	**504**	**1,013**
Apr. 10, 2009	**14,205**	**13,987**	**8,913**	**1,400**	**3,951**	**479**	**988**
Apr. 18, 2008[2]	**15,058**	**14,827**	**8,867**	**1,429**	**4,116**	**771**	**1,048**
	17,675 Operable capacity		**83.4% utilization rate**				

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

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

OIL&GAS JOURNAL online research center

OGJ crack spread

	*4-24-09	*4-25-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	56.85	129.07	–72.22	–56.0
Brent crude	48.83	115.04	–66.21	–57.6
Crack spread	8.02	14.04	–6.01	–42.9
FUTURES MARKET PRICES				
One month				
Product value	58.05	131.69	–73.64	–55.9
Light sweet crude	48.48	117.95	–69.47	–58.9
Crack spread	9.56	13.74	–4.18	–30.4
Six month				
Product value	58.88	126.64	–67.76	–53.5
Light sweet crude	55.42	114.34	–58.92	–51.5
Crack spread	3.46	12.31	–8.84	–71.8

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

Statistics

OGJ GASOLINE PRICES

	Price ex tax 4-22-09	Pump price* 4-22-09	Pump price 4-23-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	156.7	203.2	356.5
Baltimore	157.6	199.5	343.4
Boston	155.6	197.5	338.4
Buffalo	143.4	204.3	360.2
Miami	148.9	200.5	365.6
Newark	242.6	275.2	329.2
New York	128.3	189.2	344.9
Norfolk	153.3	191.7	330.5
Philadelphia	155.0	205.7	347.6
Pittsburgh	159.2	209.9	345.0
Wash., DC	176.3	214.7	353.3
PAD I avg	161.5	208.3	346.8
Chicago	156.5	220.9	384.9
Cleveland	158.4	204.8	342.7
Des Moines	160.4	200.8	340.0
Detroit	147.4	206.8	350.5
Indianapolis	140.4	199.8	349.5
Kansas City	158.8	194.8	333.5
Louisville	159.9	200.8	359.2
Memphis	159.0	198.8	338.9
Milwaukee	153.5	204.8	360.1
Minn.-St. Paul	159.8	203.8	339.5
Oklahoma City	154.4	189.8	334.4
Omaha	152.6	197.9	342.5
St. Louis	154.8	190.8	343.8
Tulsa	154.4	189.8	329.9
Wichita	152.4	195.8	333.7
PAD II avg	154.9	200.0	345.5
Albuquerque	161.4	197.8	338.7
Birmingham	156.5	195.8	344.8
Dallas-Fort Worth	154.4	192.8	344.2
Houston	154.3	192.7	341.7
Little Rock	155.6	195.8	342.8
New Orleans	153.4	191.8	340.7
San Antonio	152.4	190.8	333.5
PAD III avg	155.4	193.9	340.9
Cheyenne	160.6	193.0	330.8
Denver	156.5	196.9	356.5
Salt Lake City	149.0	191.9	341.8
PAD IV avg	155.3	193.9	343.0
Los Angeles	144.8	211.9	382.3
Phoenix	163.4	200.8	333.6
Portland	178.5	221.9	362.9
San Diego	163.3	230.4	391.5
San Francisco	168.3	235.4	400.2
Seattle	166.0	221.9	371.7
PAD V avg	164.0	220.4	373.7
Week's avg.	**158.0**	**203.6**	**348.9**
Mar. avg.	**147.6**	**193.2**	**319.7**
Feb. avg.	**144.0**	**189.6**	**303.1**
2009 to date	**144.8**	**190.4**	—
2008 to date	**271.5**	**315.0**	—

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

REFINED PRODUCT PRICES

	4-17-09 ¢/gal		4-17-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	146.32	New York Harbor	140.60
Gulf Coast	140.94	Gulf Coast	138.60
Los Angeles	149.94	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	142.35	ARA	144.89
Singapore	152.31	Singapore	143.74
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	147.44	New York Harbor	109.24
Gulf Coast	145.44	Gulf Coast	115.19
Los Angeles	161.94	Los Angeles	114.96
		ARA	105.74
		Singapore	110.47

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

BAKER HUGHES RIG COUNT

	4-24-09	4-25-08
Alabama	4	6
Alaska	8	7
Arkansas	45	42
California	18	37
Land	16	35
Offshore	2	2
Colorado	50	125
Florida	0	0
Illinois	1	0
Indiana	0	2
Kansas	18	11
Kentucky	9	9
Louisiana	132	152
N. Land	73	53
S. Inland waters	5	24
S. Land	11	20
Offshore	43	55
Maryland	0	1
Michigan	0	0
Mississippi	10	11
Montana	1	10
Nebraska	0	0
New Mexico	30	81
New York	1	7
North Dakota	38	62
Ohio	7	12
Oklahoma	90	214
Pennsylvania	30	20
South Dakota	1	2
Texas	378	883
Offshore	4	9
Inland waters	0	1
Dist. 1	11	25
Dist. 2	14	36
Dist. 3	26	58
Dist. 4	40	91
Dist. 5	96	189
Dist. 6	62	115
Dist. 7B	9	30
Dist. 7C	13	68
Dist. 8	36	131
Dist. 8A	11	25
Dist. 9	22	35
Dist. 10	34	70
Utah	16	42
West Virginia	21	24
Wyoming	34	66
Others—NV-5; TN-3; VA-4; WA-1	13	16
Total US	**955**	**1,842**
Total Canada	**65**	**88**
Grand total	**1,020**	**1,930**
US Oil rigs	202	360
US Gas rigs	742	1,473
Total US offshore	51	67
Total US cum. avg. YTD	**1,262**	**1,784**

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

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

SMITH RIG COUNT

Proposed depth, ft	Rig count	4-24-09 Percent footage*	Rig count	4-25-08 Percent footage*
0-2,500	46	8.6	70	5.7
2,501-5,000	63	60.3	111	48.6
5,001-7,500	111	18.0	213	17.3
7,501-10,000	212	3.3	420	3.0
10,001-12,500	182	3.8	472	4.0
12,501-15,000	192	—	279	—
15,001-17,500	119	—	127	—
17,501-20,000	53	—	72	—
20,001-over	38	—	35	—
Total	**1,016**	**7.4**	**1,799**	**7.0**
INLAND	9		30	
LAND	961		1,714	
OFFSHORE	46		55	

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

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

OGJ PRODUCTION REPORT

	[1]4-24-09	[2]4-25-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	22	21
Alaska	733	701
California	657	654
Colorado	65	65
Florida	5	6
Illinois	28	27
Kansas	105	106
Louisiana	1,472	1,294
Michigan	16	16
Mississippi	63	58
Montana	92	87
New Mexico	165	159
North Dakota	200	151
Oklahoma	177	170
Texas	1,370	1,338
Utah	60	57
Wyoming	151	149
All others	68	72
Total	**5,449**	**5,131**

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

US CRUDE PRICES

	4-24-09 $/bbl*
Alaska-North Slope 27°	39.60
South Louisiana Sweet	52.00
California-Kern River 13°	44.05
Lost Hills 30°	52.30
Wyoming Sweet	40.05
East Texas Sweet	47.50
West Texas Sour 34°	42.00
West Texas Intermediate	48.00
Oklahoma Sweet	48.00
Texas Upper Gulf Coast	41.00
Michigan Sour	40.00
Kansas Common	47.00
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 OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	4-17-09
United Kingdom-Brent 38°	51.70
Russia-Urals 32°	49.75
Saudi Light 34°	50.22
Dubai Fateh 32°	51.75
Algeria Saharan 44°	51.88
Nigeria-Bonny Light 37°	52.65
Indonesia-Minas 34°	55.81
Venezuela-Tia Juana Light 31°	51.72
Mexico-Isthmus 33°	51.61
OPEC basket	51.64
Total OPEC[2]	51.10
Total non-OPEC[2]	50.13
Total world[2]	50.68
US imports[3]	49.06

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.

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

US NATURAL GAS STORAGE[1]

	4-17-09	4-10-09	4-17-08	Change, %
	bcf			
Producing region	779	756	506	54.0
Consuming region east	668	651	596	12.1
Consuming region west	294	288	180	63.3
Total US	**1,741**	**1,695**	**1,282**	**35.8**
	Jan. 09	**Jan. 08**	**Change, %**	
Total US[2]	**2,141**	**2,055**	**4.2**	

[1]Working gas. [2]At end of period.
Source: Energy Information Administration
Data available in OGJ Online Research Center.

PACE REFINING MARGINS

	Feb. 2009	Mar. 2009	Apr. 2009	Apr. 2008	2009 vs. 2008 Change	2009 vs. 2008 Change, %
			$/bbl			
US Gulf Coast						
West Texas Sour	9.41	3.80	6.29	14.92	–8.63	–57.8
Composite US Gulf Refinery	7.64	2.43	4.13	14.65	–10.52	–71.8
Arabian Light	9.39	0.19	1.85	11.23	–9.38	–83.5
Bonny Light	0.55	0.26	2.85	6.88	–4.03	–58.5
US PADD II						
Chicago (WTI)	8.41	3.40	7.03	12.68	–5.65	–44.6
US East Coast						
NY Harbor (Arab Med)	14.82	2.89	2.25	11.43	–9.18	–80.3
East Coast Comp-RFG	11.33	5.22	7.08	11.57	–4.49	–38.8
US West Coast						
Los Angeles (ANS)	10.49	3.73	9.33	12.94	–3.61	–27.9
NW Europe						
Rotterdam (Brent)	4.31	1.79	2.55	3.97	–1.42	–35.6
Mediterranean						
Italy (Urals)	2.38	0.58	1.88	8.52	–6.65	–78.0
Far East						
Singapore (Dubai)	2.22	–0.64	1.05	6.98	–5.94	–85.0

Source: Jacobs Consultancy Inc.
Data available in OGJ Online Research Center.

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	Jan. 2009	Dec. 2008	Jan. 2008	Dec. 2009-2008 change	Total YTD 2009	Total YTD 2008	YTD 2009-2008 change
				bcf			
DEMAND							
Consumption	2,702	2,389	2,722	–20	2,702	2,722	–20
Addition to storage	79	110	68	11	79	68	11
Exports	95	111	111	–16	95	111	–16
Canada	64	79	68	–4	64	68	–4
Mexico	28	28	40	–12	28	40	–12
LNG	3	4	3	0	3	3	0
Total demand	**2,876**	**2,610**	**2,901**	**–25**	**2,876**	**2,901**	**–25**
SUPPLY							
Production (dry gas)	1,781	1,796	1,711	70	1,781	1,711	70
Supplemental gas	6	6	2	4	6	2	4
Storage withdrawal	778	615	892	–114	778	892	–114
Imports	346	365	385	–39	346	385	–39
Canada	314	327	356	–42	314	356	–42
Mexico	5	7	1	4	5	1	4
LNG	27	31	28	–1	27	28	–1
Total supply	**2,911**	**2,782**	**2,990**	**–79**	**2,911**	**2,990**	**–79**

NATURAL GAS IN UNDERGROUND STORAGE

	Jan. 2009	Dec. 2008	Nov. 2008	Jan. 2008	Change
			bcf		
Base gas	4,236	4,229	4,231	4,232	4
Working gas	2,141	2,840	3,346	2,055	86
Total gas	**6,377**	**7,069**	**7,577**	**6,287**	**90**

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

WORLDWIDE NGL PRODUCTION

	Jan. 2009	Dec. 2008	1 month average production 2009	1 month average production 2008	Change vs. previous year Volume	Change vs. previous year %
			1,000 b/d			
Brazil	84	82	84	89	–6	–6.5
Canada	646	550	646	699	–53	–7.6
Mexico	366	364	366	366	—	—
United States	1,721	1,604	1,721	1,783	–62	–3.5
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	202	200	202	199	3	1.5
Western Hemisphere	**3,218**	**3,000**	**3,218**	**3,336**	**–118**	**–3.5**
Norway	266	273	266	302	–36	–11.9
United Kingdom	156	164	156	182	–26	–14.5
Other Western Europe	10	10	10	10	—	–1.9
Western Europe	**432**	**447**	**432**	**494**	**–63**	**–12.7**
Russia	405	420	405	421	–16	–3.8
Other FSU	150	150	150	150	—	—
Other Eastern Europe	15	16	15	16	—	–2.2
Eastern Europe	**570**	**586**	**570**	**587**	**–16**	**–2.8**
Algeria	350	350	350	350	—	—
Egypt	70	70	70	70	—	—
Libya	80	80	80	80	—	—
Other Africa	131	120	131	135	–4	–2.9
Africa	**631**	**620**	**631**	**635**	**–4**	**–0.6**
Saudi Arabia	1,305	1,353	1,305	1,440	–135	–9.4
United Arab Emirates	250	250	250	250	—	—
Other Middle East	835	835	835	870	–35	–4.0
Middle East	**2,390**	**2,438**	**2,390**	**2,560**	**–170**	**–6.6**
Australia	61	62	61	57	5	8.3
China	650	650	650	620	30	4.8
India	—	—	—	—	—	—
Other Asia-Pacific	169	169	169	181	–12	–6.7
Asia-Pacific	**880**	**881**	**880**	**858**	**23**	**2.6**
TOTAL WORLD	**8,121**	**7,971**	**8,121**	**8,470**	**–348**	**–4.1**

Totals may not add due to rounding.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

OXYGENATES

	Jan. 2009	Dec. 2008	Change	YTD 2009	YTD 2008	Change
			1,000 bbl			
Fuel ethanol						
Production	19,545	20,054	–509	19,545	15,818	3,727
Stocks	14,243	15,227	–984	14,243	10,674	3,569
MTBE						
Production	1,394	1,236	158	1,394	1,731	–337
Stocks	1,560	649	911	1,560	1,342	218

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

US HEATING DEGREE-DAYS

	Feb. 2009	Feb. 2008	Normal	2009 % change from normal	Total degree-days July 1 through Feb. 28 2009	Total degree-days July 1 through Feb. 28 2008	Total degree-days July 1 through Feb. 28 Normal	% change from normal
New England	1,029	1,019	1,060	–2.9	4,927	4,523	4,768	3.3
Middle Atlantic	931	940	983	–5.3	4,390	3,905	4,332	1.3
East North Central	1,021	1,153	1,061	–3.8	5,062	4,630	4,835	4.7
West North Central	1,028	1,225	1,078	–4.6	5,246	5,123	5,163	1.6
South Atlantic	503	439	507	–0.8	2,277	1,943	2,233	2.0
East South Central	586	586	523	12.0	2,858	2,577	2,853	0.2
West South Central	297	362	414	–28.3	1,711	1,727	1,912	–10.5
Mountain	699	770	737	–5.2	3,467	3,708	3,835	–9.6
Pacific	480	474	439	9.3	2,051	2,322	2,256	–9.1
US average*	**701**	**736**	**732**	**–4.2**	**3,377**	**3,190**	**3,388**	–0.3

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center. **NOTE: No new data at press time.**

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Shock in Canada: Alberta not worst on environment

In Canada, calling Alberta green—even brownish green—can cause a ruckus.

As home to the huge and important oil sands industry, Alberta faces big environmental problems: requirements for water and energy, emissions of air pollution and greenhouse gases, surface disturbance, and the need to handle wastewater and other byproducts, to name a few.

Alberta also is Canada's third largest provincial economy and its leader in revenue per person. It thus contributes mightily to a Canadian program for interprovincial wealth-sharing.

As production of bitumen from Alberta's oil sands has grown, so has criticism—mostly from other provinces—about the environmental consequences. Many Albertans find the scorn ungrateful.

Into this bubbling stew on Apr. 22 plopped a report ranking Alberta well above bottom in provincial greenitude.

Corporate Knights, a quarterly magazine published in Toronto, assigned Alberta sixth position among 13 provinces and territories in an environmental assessment. British Columbia came in first, followed by Ontario and sparsely populated Northwest Territories, Yukon Territory, and Nunavut.

A Globe and Mail (Toronto) article about the report drew contentious online response.

"Pure malarky [sic]," declared one of 154 comments posted as of Apr. 24. Another: "Ontario would definitely have come in first had it not been polluted by the presence of Corporate Knights."

Albertans had their say, too. "So Alberta isn't so bad after all," wrote one. "Time for all you bigots to apologize. While you're at it, you can also thank Alberta for all the transfer payments that pay your welfare checks."

Corporate Knights came in for grave suspicion for daring to suggest Alberta isn't Canada's worst environmental nightmare. The magazine in fact claims as part of its mission "to humanize the marketplace" and as a goal "to jumpstart Canada to become the world leader in responsible commerce."

That doesn't sound sympathetic to whatever impulses may lurk in Canadian industry to bulldoze first and ask why later.

Indeed, if the Globe and Mail comments accurately reflect the Canadian mood, a stronger proclivity where Alberta is concerned may be to bite the hand that not only feeds but also invents solutions to environmental problems.

(Online Apr. 24, 2009; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

Tax hike sends wrong signal

The push by consumer nations for lower oil prices to help spark an economic recovery may be undermined when crude-producing nations see those governments take advantage of oil price reductions to ratchet up taxes on refined products, particularly in Europe.

Changes in the UK's taxation policy indicate the producers have grounds for such suspicions, said Paul Horsnell, a managing director and head of commodities research at Barclays Capital in London. "Last November, the duty on gasoline in the UK stood at 50.35 pence/l. Changes in December and earlier this month brought it up to 54.19 pence/l. as of [Apr. 19], which at current exchange rates is the equivalent of $125/bbl [of gasoline] or $153/bbl including the indirect tax element of retail prices."

Prior to the latest increase, he said, "Taxation already made up 73% of the average UK retail gasoline price, which is the equivalent of $4.80/gal."

Moreover, the UK budget statement on Apr. 22 announced "a further increase of 2 pence/l. to be made in September, plus an additional penny per liter above inflation in April for the next 4 years," Horsnell reported. "In just 10 months starting last November, the UK will have increased fuel duty by 5.84 pence/l., the equivalent of $13.50/bbl, with changes in indirect taxation bringing the overall increase in the tax take to at least $11/bbl."

Horsnell said, "Given that this rapid ramping up of the direct tax element (by 11.6% in just 10 months) had previously been stalled by high prices, producers might be forgiven for seeing this as an extra $10/bbl or so that has gone into consumer tax revenue simply because prices are lower. With European governments signaling that retail prices will be kept high regardless of the level of crude prices, it also gives producers an impetus to want to get $20/bbl or so back on the upstream price relatively quickly, before that amount is expropriated instead by European governments through downstream taxation." Overall, he said, "It appears to us that producer-consumer relations are deteriorating again, with some old wounds being reopened. Through opportunistic taxation policies, in our view, European governments in particular are pushing producers into a more hawkish stand on prices."

On Apr. 23 in London, the June IPE contract for North Sea Brent crude gained 30¢ to $50.11/bbl, selling at a premium over the June contract for benchmark US light, sweet crudes that closed at $49.62/bbl on the New York Mercantile Exchange.

Flu affects energy market

After climbing more than 12% in a 4-day rally through Apr. 24 in the New York market, crude prices were down in early trading Apr. 27 amid concerns that the swine flu outbreak will further reduce air travel.

In Houston, however, analysts in the Houston office of Raymond James & Associates Inc. reported, "The US has already declared a public health emergency, and the European Union's health commissioner recently advised against any nonessential travel to the US and Mexico. Regardless of a potential decrease in air travel, crude stockpiles are at their highest level since 1990, and speculators are net-short oil for the first time in 6 weeks."

'Coal floor' slips

With the supply cost curve falling and inventories increasing, the coal price "floor" for natural gas may not provide much protection for gas producers, said Adam Sieminski, chief energy economist, Deutsche Bank, Washington, DC.

The switch to gas from coal among customers able to do so has been concentrated on the US East Coast, "where coal prices are substantially higher than in the West and gas prices are more marginally so," Sieminski said.

Citing a recent report by Wood Mackenzie Ltd., a former Deutsche Bank subsidiary, Sieminski said, "While break-even costs on these gas plays are high, cash costs are very low—less than $1/MMbtu in almost every play." With coal mining costs running much higher, he said, "Coal shut-ins are much more likely, meaning those costs will set both base case coal and gas prices." Sustained gas prices of $3.50-4/MMbtu will cause a drop in North American gas drilling "beyond what we have seen to date," Sieminski said. "But rig lay-downs do not filter through to production declines for 3-6 months, so they do not provide short-term price support."

According to the WoodMac study, there is some risk that the entire coal supply curve could fall as materials costs decline due to weaker worldwide demand. "There may be a coal floor," Sieminski said, "but in our view, it is too low to do gas producers much good."

(Online Apr. 27, 2009; author's e-mail: samf@ogjonline.com)

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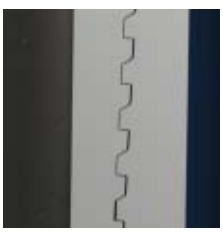

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