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International Petroleum News and Technology / www.ogjonline.com

Asian Processing Review

Aboveground constraints may limit Mexico's oil production
Elusive Alabama shales need more work, Energen says
Sequential, simultaneous Barnett fracturing compared
Method helps avoid pipeline condensation, black powder

OIL&GAS JOURNAL®

Dec. 15, 2008
Volume 106.47

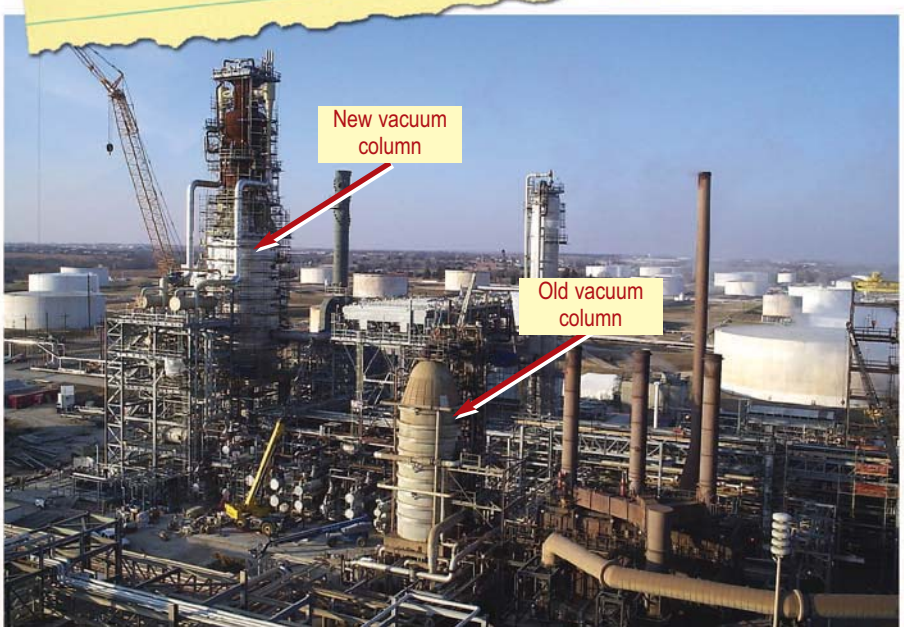
ASIAN PROCESSING REVIEW

REGULAR FEATURES

COVER

This 600,000-tonne/year ethylene production plant in Nanjing, China, is one of the major petchem start-ups in Asia in the past few years. Plant operator BASF-YPC Co. Ltd., established in 2000, is a 50-50 joint venture of BASF AG and Sinopec. This week's special report, Asian Processing Review, discusses the rapid expansion of the processing industry in Asia, led by India and China. The first article, starting on p. 44, discusses the growth of the Asian petrochemical industry and how it will increase demand for naphtha in the region. The second article, p. 52, covers refining capacity trends in Asia. Photo from BASF.

Process Notes



Why Produce Diesel from the Vacuum Unit?

Look ahead five years. The economy is likely to keep tightening and the rush to control pollution will inevitably be accompanied by demands for greater energy conservation. Consequence? A growing market for diesel which yields more energy per unit volume. Yet many continue to believe that producing diesel from the vacuum unit is poor design—that it should be produced only from the atmospheric column. Hence many refiners feed 20-30% diesel boiling range material to their FCCs or hydrocrackers. But where most motor fuel is diesel, refiners have long known that producing vacuum unit diesel can increase production up to 5 volume percent on whole crude.

Maximum diesel production is simply not possible in the atmospheric column because flash zone temperature would need to be 760°F or higher. Moreover, the inherent reflux rate below the diesel draw results in molar L/V ratio less than 0.15. But in vacuum columns it can be 0.4 or higher. And distillation is driven by L/V!

Also: eliminating diesel from vacuum unit feed cuts vacuum gas oil (VGO) yield because it is more difficult to vaporize the feed in the vacuum column flash zone. If atmospheric diesel recovery is very high, VGO yield is low. As crudes get heavier it is essential to leave some diesel in the vacuum column feed to achieve reasonable VGO cutpoints.

Lastly, if you process Canadian oils sands Dilbit and Synbit, you can't run the atmospheric heater hotter than 680°F resulting in very high diesel boiling range material in the vacuum feed. To obtain reasonable diesel recovery from the whole crude you *must* produce it in the vacuum unit.

For a more involved discussion please request Technical Papers #255 and 261.

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General Interest

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Processing

Transportation

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KBC holds a long-term working relationship with a client, which operates a medium-complexity refinery along the coast of Romania. In an effort to improve the performance and profitability of its operations, the refiner decided to undertake an Energy Efficiency Improvement Initiative. The work consisted of:

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OGJ Newsletter

Dec. 15, 2008

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General Interest — Quick Takes

Study: Tapping off-limit US resources beneficial

Development of US oil and gas resources that Congress has kept off-limits for decades could generate more than $1.7 trillion in government revenues, create thousands of new jobs, and enhance the nation's energy security by significantly boosting domestic energy production, a new study suggested.

The study by ICF International, which the American Petroleum Institute commissioned, concluded that developing offshore areas covered by congressional moratoriums until recently, along with resources in the Arctic National Wildlife Refuge and a small portion of currently unavailable land in the Rocky Mountains, could increase US crude oil production by as much as 2 million b/d by 2030, offsetting nearly a fifth of the nation's crude imports.

Natural gas production could increase by 5.34 bcfd, or the equivalent of 61% of the expected gas imports in 2030, the study added. It also estimated that development of all US oil and gas resources on federal lands could exceed $4 trillion over the life of the resources.

US crude production would rise by 36% and natural gas production would increase by 10% if development is permitted in the studied areas of the US Outer Continental Shelf, ANWR, and the Rockies, according to the ICF study. About 160,000 jobs would be created in the process, it indicated.

API Pres. Jack N. Gerard said the study underscores how the oil and gas industry could enhance US energy security and help solve domestic economic problems by increasing US oil and gas production.

"The US oil and gas industry supports more than 6 million jobs, and more drilling for oil and gas will mean more energy for America, more well-paying jobs, and trillions of dollars of much-needed revenues that will help federal, state, and local governments pay for critical services," he said.

NPRA sees flaws in regulating GHGs under CAA

Attempts to regulate greenhouse gases (GHG) under the Clean Air Act (CAA) would have numerous potentially harmful consequences, the National Petrochemical & Refiners Association told the US Environmental Protection Agency.

"The regulation of GHG under the CAA would constitute EPA's single largest and potentially most complex assertion of authority over the [US] economy and Americans' lifestyles," the trade association warned in a Nov. 25 response to EPA's July 30 Advanced Notice of Proposed Rulemaking.

"Regulation of GHG under the act would have enormous consequences for every facet of the economy, for industry large and small, as well as for the general population. Indeed, the potential impact on the country to regulate GHG cannot be overstated and makes all prior EPA regulatory efforts pale by comparison," it maintained.

It said EPA still has much work to do before making a final decision on whether GHG emissions from automobiles cause or contribute to US public health or welfare endangerment. EPA's analysis "draws most heavily on reports prepared by only a handful of entities, particularly the Intergovernmental Panel on Climate Change, and especially with respect to its analysis of human health and welfare effects," NPRA said in its filing.

"The agency has an obligation, however, to consider all relevant science on climate change, impacts, and effects on health and welfare. It may not disregard data without justification," the association said.

NPRA does not believe EPA should proceed with an endangerment finding at this time nor begin a process of subjecting various entities to various CAA provisions in an effort to begin GHG emissions, NPRA Pres. Charles T. Drevna said on Dec. 2.

"The act was not designed to address a global pollutant like [carbon dioxide] and, thus, cannot be used to meaningfully alter its atmospheric concentration. Indeed, EPA's suggested approaches for applying the CAA's provisions to GHG sources would impose severe costs on domestic industry, reduce our domestic energy security, and damage the national economy as businesses shift activities overseas to areas where they will not be subject to futile regulation," he said.

"Discussion of these issues in the ANPR is woefully inadequate, and the public should be given the opportunity to consider them before EPA makes any further decisions under the CAA," Drevna said.

EU, Egypt sign energy cooperation agreement

The European Commission and Egypt's Foreign Affairs Minister Ahmed Aboul Gheit, signed a memorandum of understanding Dec. 2 to enhance energy cooperation between Egypt and the European Union. The pact would reinforce energy security for both.

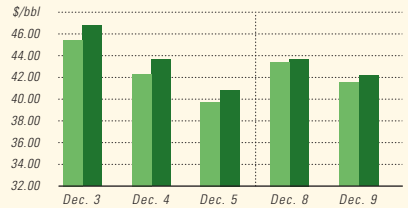
Among five priorities are the establishment of a work program to gradually converge Egypt's energy markets with the EU's and the development of energy networks such as the Arab Gas Pipeline, which could transport Egyptian and possibly Iraqi natural gas to European countries.

Other areas covered include market reforms, promotion of renewable energy and energy efficiency, and technological and industry cooperation.

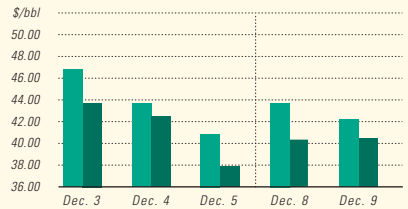
"Egypt is the EU's sixth largest natural gas supplier and a key transit country between the Middle East, Africa, and the EU," said EC Commissioner Benita Ferrero-Waldner. "Egypt's commitment to energy reforms is crucial for the creation of a Euro-Mediterranean energy market." ✦

Industry Scoreboard

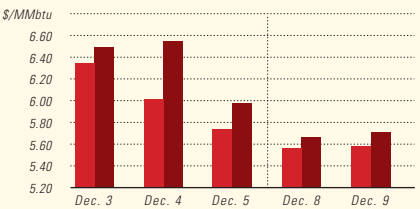
IPE BRENT / NYMEX LIGHT SWEET CRUDE



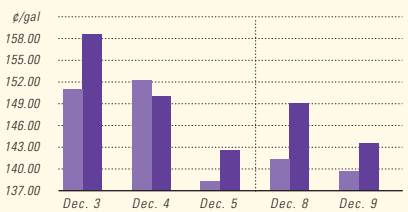
WTI CUSHING / BRENT SPOT



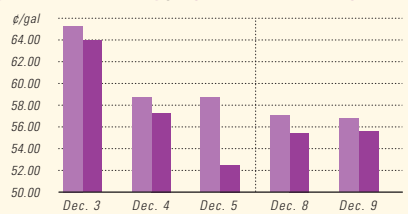
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



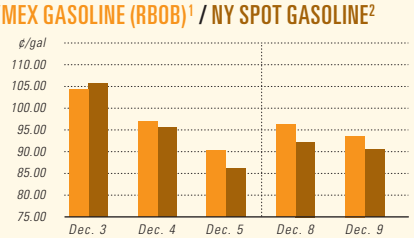
IPE GAS OIL / NYMEX HEATING OIL



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.

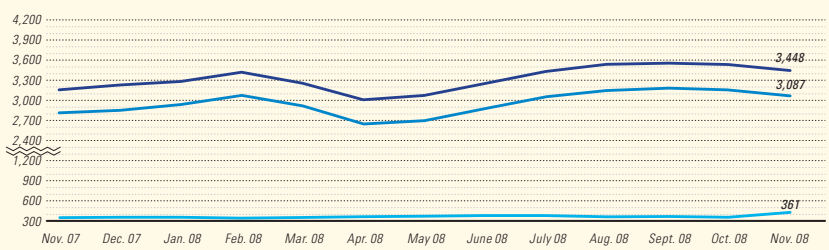
US INDUSTRY SCOREBOARD — 12/15

Latest week 11/28	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	8,935	9,229	–3.2	9,006	9,289	–3.0
Distillate	3,990	4,079	–2.2	3,955	4,197	–5.8
Jet fuel	1,333	1,601	–16.7	1,521	1,624	–6.3
Residual	583	763	–23.6	594	728	–18.4
Other products	4,425	4,861	–9.0	4,620	4,818	–4.1
TOTAL DEMAND	19,266	20,533	–6.2	19,513	20,678	–5.6
Supply, 1,000 b/d						
Crude production	4,988	5,018	–0.6	4,951	5,065	–2.3
NGL production[2]	2,394	2,661	–10.0	2,270	2,405	–5.6
Crude imports	9,959	9,976	–0.2	9,810	10,042	–2.3
Product imports	2,851	3,185	–10.5	3,143	3,477	–9.6
Other supply[3]	1,267	857	47.8	1,360	1,023	32.9
TOTAL SUPPLY	21,459	21,697	–1.1	21,534	22,012	–2.2
Refining, 1,000 b/d						
Crude runs to stills	14,655	15,151	–3.3	14,655	15,152	–3.3
Input to crude stills	14,907	15,504	–3.9	14,907	15,441	–3.5
% utilization	84.9	88.9	—	84.9	88.5	—

Latest week 11/28	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	320,372	320,828	–456	305,240	15,132	5.0
Motor gasoline	198,942	200,476	–1,534	200,623	–1,681	–0.8
Distillate	124,973	126,694	–1,721	132,344	–7,371	–5.6
Jet fuel–kerosine	38,567	38,005	562	39,939	–1,372	–3.4
Residual	37,156	38,842	–1,686	38,033	–877	–2.3
Stock cover (days)[4]			Change, %		Change, %	
Crude	21.9	21.9	0.0	20.1	9.0	
Motor gasoline	22.3	22.3	0.0	21.7	2.8	
Distillate	31.3	31.5	–0.6	29.9	4.7	
Propane	49.2	48.5	1.4	47.5	3.6	
Futures prices[5] **12/5**			Change		Change	%
Light sweet crude ($/bbl)	45.50	53.54	–8.04	92.49	–46.99	–50.8
Natural gas, $/MMbtu	6.23	6.67	–0.44	7.45	–1.22	–16.4

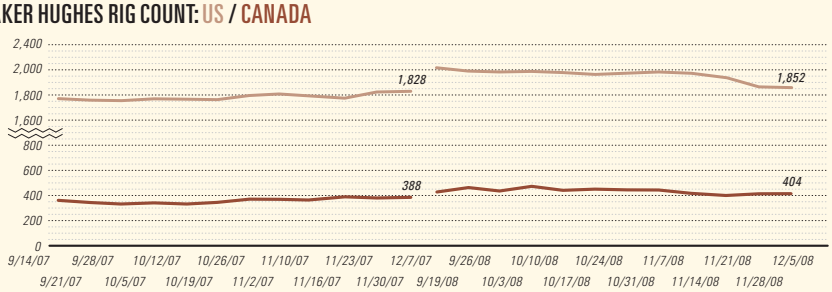
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average 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

Exploration & Development — *Quick Takes*

Pioneer drilling lateral in Eagle Ford shale

Pioneer Natural Resources Inc., Dallas, is drilling the horizontal leg in Cretaceous Eagle Ford shale in an exploratory well in DeWitt County, Tex.

This is about 90 miles east-northeast of where Petrohawk Energy Corp., Houston, gauged an Eagle Ford gas-condensate discovery in LaSalle County (OGJ Online, Oct. 21, 2008).

Petrohawk is completing its second well in LaSalle and is drilling in McMullen County, Pioneer said.

Pioneer has logs through Eagle Ford from the more than 150 wells it has drilled in the Cretaceous Edwards Trend along its 310,000-acre spread from LaSalle to Lavaca counties and chose to horizontally drill the Eagle Ford where it saw the best porosity. Permeability is the question, the company said Dec. 2.

Eagle Ford shale is the source rock for the Cretaceous Austin chalk and Edwards formations, Pioneer noted.

Meanwhile, the company's Edwards gas production is averaging 85 MMcfd.

Reindeer delays gas project off W. Australia

The Apache Australia-Santos Ltd. joint venture has postponed its Reindeer gas project off Western Australia, citing the poor global economic outlook that has impacted the project's main customer.

The project included an unmanned wellhead platform and an undersea natural gas pipeline to transport gas 100 km to shore. The proposed onshore plant, at Devil Creek, 65 km south of Karratha, included gas processing facilities for supplying the domestic market in Western Australia. The project was to have come on stream in 2010.

Deferral of Reindeer means that Apache and Santos will have to suspend or terminate engineering and construction contracts. The main contractor is Perth-based Clough Engineering.

However Santos said that work will continue on regulatory approvals to ensure that restarting the project can be timely once gas sales agreements supporting the development are concluded.

Reindeer, which contains an estimated 410-640 petajoules of gas, was found in 1997 on permit WA-209-P.

Apache has a 55% interest and is the operator. Santos holds the remaining 45% interest.

Cabot to hike Pennsylvania Marcellus program

Cabot Oil & Gas Corp., Houston, plans to boost production from Devonian Marcellus shale in northeastern Pennsylvania in the next few weeks from the current 13 MMcfd as it hooks up six vertical and three horizontal wells.

Meanwhile, the company expects to expand to eight rigs in 2009 from the five currently working.

Cabot's first horizontal Marcellus well came on line at 6.4 MMcfd after a six-stage frac in its 2,000-ft lateral. Measured total depth is 8,925 ft.

Marcellus drilling totals 18 wells, 4 of them horizontal. The 2009 program calls for 16 vertical and 7 horizontal wells. Four vertical and 3 horizontal wells remain to be drilled in 2008.

Typical costs are $1.3-1.5 million for a vertical well and $2.6-2.9 million for a horizontal well. Average footage is 7,200 vertically and 2,200 ft laterally.

The company has laid 10 miles of pipeline and started up one compressor with a second unit standing by as produced volumes warrant.

Haynesville gas flows as high as 28 MMcfd

Three operators reported new horizontal completions in Jurassic Haynesville shale at rates as high as 28.2 MMcfd of gas.

The three companies, Petrohawk Energy Corp. of Houston and Comstock Resources Inc. and EXCO Resources Inc. of the Dallas area, plan much more activity in the Haynesville in East Texas and Northwest Louisiana.

Petrohawk reported the 28.2 MMcfd rate at its Sample 9-1 in 9-14n-11w, Red River Parish, La., about 12 miles south of Elm Grove gas field. The rate came on a $^{30}/_{64}$-in. choke with 7,100 psi flowing casing pressure.

Petrohawk's Brown 17-4 in 17-16n-11w, Bossier Parish, gauged 23.4 MMcfd on a $^{26}/_{64}$-in. choke with 7,700 psi FCP. And its Goodwin 9-5 in 9-16n-11w, Bossier Parish, made 21.1 MMcfd on a $^{26}/_{64}$-in. choke with 6,750 psi FCP. The company plans to complete five more Haynesville shale wells by yearend 2009.

Initial flow rate is 9 MMcfd at Comstock's BSMC LA 7-1H well in Toledo Bend North field, De Soto Parish. The flow came from a 4,300-ft lateral at 11,750 ft true vertical depth after a 10-stage frac.

Comstock is running another 10-stage frac at its Collins LA 15-1H well in Logansport field, also in De Soto. It has a 4,200-ft leg at 11,350 ft. The company has a 22% interest in the Gamble 24-1H well at Logansport, drilled to 11,800 ft TVD with a 3,950-ft lateral.

Comstock has drilled the vertical portion of two other Haynesville wells. Bogue A-6H in Waskom field in Harrison County is to get a 4,000-ft lateral, and Green 13H in Blocker field in Harrison County is to get a 3,700-ft lateral. Comstock is drilling vertically at Headrick 1H and Hart 1H in Logansport and Moneyham 7H in Longwood field. Each is due a 4,000-ft leg.

EXCO said its first Haynesville horizontal well, Oden 30H6 in De Soto Parish, averaged 22.5 MMcfd on a $^{26}/_{64}$-in. choke with 7,800 psi FCP. It has a 4,481-ft lateral at 12,304 ft TVD.

EXCO has two operated horizontal wells, one vertical well, and two outside-operated horizontal wells in the play and plans to drill 25 or more horizontal Haynesville wells in 2009.

Busy 2009 seen in western Newfoundland

Vulcan Minerals Inc., St. John's, expects a busy year in several exploration plays in Newfoundland and Labrador in 2009.

Vulcan plans to drill a 3,600-m exploration well, Robinson-1, onshore in the Bay St. George basin that would be the basin's deepest well ever. It is on a seismically defined structure with several prospective reservoirs.

A drill pad is being built for the well, which is the culmination of several years of seismic work and shallow drilling. Vulcan's 50%

working interest is to be carried fully by Investcan Energy Corp.

Vulcan plans to drill two other onshore wells 1,500-2,500 m deep onshore in the basin and is reviewing the prospect for completing two 150-m core holes at Flat Bay to sample for natural fracture systems.

Leprechaun Resources Ltd., private Alberta company, has become operator of three onshore permits at Parsons Pond, western Newfoundland, in which Vulcan holds 7.39-18.57% interests. Leprechaun is raising funds. The Parsons Pond area covers 100,000 acres of Cambrian-Ordovician platformal rocks in an area of numerous oil seeps, and seismically defined drill targets occur as deep as 4,000 m, Vulcan noted.

Vulcan owns 19% of the stock of NWest Energy Inc., which holds 100% working interest in 1.6 million acres off western Newfoundland. The blocks cover a Cambrian-Ordovician-Silurian platform and foreland basin rocks with petroleum potential. NWest is shooting seismic and seeking partners for drilling.

Meanwhile, Vulcan and Investcan plan to explore 584,466-acre License 1107 off Labrador. The license offsets two undeveloped gas discoveries and has several seismic leads. Investcan's interest is 50%.

Shell farms into Sicilian offshore licenses

Northern Petroleum UK Ltd. has brought in as a partner Shell Italia Exploration & Production SPA for its licenses off Sicily under a farmout agreement.

Shell will acquire a 55% interest in GR17-NP, GR18-NP, GR19-NP, and a 70% stake in GR20-NP, GR21-NP, GR22-NP licenses.

Shell has agreed to pay €1.9 million for Northern Petroleum's back-costs and various seismic work. Northern will serve as operator during the initial seismic phase, and Shell will serve as operator once drilling starts.

The assets are estimated to hold unaudited, combined, and unrisked prospective resources of 1.9 billion bbl of recoverable oil.

Derek Musgrove, Northern Petroleum managing director, said, "Shell will bring to the project Italian thrust belt and production experience, in addition to its international major project and deepwater expertise. In 2003, we perceived the potential of the thrust belt play in the Sicily Channel ahead of the new climate of gas oil prices and have been progressing these licences for several years. The area under licence in the Sicily Channel is 4,367 sq km and if drilling is successful it could open up a new Western European hydrocarbon province." ✦

Drilling & Production — *Quick Takes*

Montana BLM okays Bowdoin gas field plan

A decision to drill new and replacement wells at a rate equal to the retirement of no longer productive wells will keep the Bowdoin natural gas field active for another 35-50 years, the US Bureau of Land Management said on Dec. 5.

BLM officials in Montana announced a finding of no significant impact as they approved a proposed alternative with additional mitigation for the project by Fidelity Exploration & Production Co. and five other producers who want to drill within one of Montana's oldest gas fields.

They said that the field, which has been active from the 1930s and has about 1,450 wells, generally straddles the line between Phillips and Valley counties south from the Canadian border to US Highway 2.

"Production from some wells that were drilled in the 1940s would be restored by drilling new replacement wells from the original drilling pads. In other instances, areas within the field that were previously passed over would be tapped to increase productivity," said Donato Judice, supervisor in BLM's Great Falls office.

Approved project components include up to 635 wells on individual sites; construction of new access roads and associated facilities, upgrading and use of existing roads; disposal of produced water with evaporation ponds at each well site; use of solar, wind, and gas-fired engines as external power sources, and installation of electric power lines on a site-specific, case-by-case basis, and use of remote electrical devices to measure temperature, pressure, and well flow at each wellsite, the decision said.

Fidelity E&P is a division of MDU Resources Group Inc. of Bismarck, ND, a holding company which also operates oil and gas pipelines and electric and gas utilities from Minnesota to Oregon and Washington.

StatoilHydro tables Canadian bitumen upgrader

Norway's StatoilHydro has dropped plans to develop a $16 billion (Can.) bitumen upgrader in Alberta because of soaring costs, poor global economic conditions, and a lack of legislative clarity.

The announcement joins a growing list of major energy infrastructure proposals that operators are delaying or canceling as economic conditions deteriorate and oil prices fall. Royal Dutch Shell PLC has postponed a planned expansion of the Athabasca Oil Sands Project and the 100,000 b/d Carmon Creek oil sands project, near Peace River in northwest Alberta. Petro-Canada also warned last month that it could cancel its proposed upgrader following a 50% leap in costs for its massive Fort Hills project that could exceed $28 billion (Can.).

In May, StatoilHydro's project was initially delayed for 2 years to 2016. The upgrader was going to process bitumen into synthetic crude from its 257,000 acres of oil sands leases that were bought last year for $2.2 billion (Can.) to diversify from mature North Sea assets. During the first phase the capacity would be 80,000 b/d and this was expected to cost $4 billion (Can.). Later expansion would boost capacity to to 243,000 b/d.

However, StatoilHydro said it would continue to monitor the cost and price environment and reassess downstream options. "This decision does not impact the upstream part of the company's oil sands venture. The production from the project will be marketed as unprocessed bitumen," the company added.

It will continue with its 10,000 b/d Leismer steam-assisted gravity drainage project that is slated to start up in late 2010. Flint Energy Services Ltd. has been contracted to construct the facility 160 km south of Fort McMurray, Alta., under a $41 million contract (OGJ Online, Nov. 19, 2008). ✦

Processing — *Quick Takes*

Sonangol lets contract for Lobito refinery

Sonangol EP has awarded an engineering, procurement, and construction management services-site development contract to KBR for the 200,000 b/d Lobito refinery in Angola, about 373 miles south of Luanda.

Financial details were not disclosed.

The EPC award follows KBR's front-end engineering and design contract granted in November. KBR will start its new assignment immediately on the grassroots refinery, which will process heavy crudes and reduce Angola's product imports.

KBR's EPC work also includes construction of a heavy haul road to transport materials and equipment to the refinery, as well as a marine facility that will be used to import and export both raw and finished hydrocarbon products.

PetroSA lets contract for South African refinery

PetroSA has let a feasibility and front-end engineering and design contract to KBR for its 400,000 b/d refinery in the Coega industrial development zone outside Port Elizabeth, South Africa. The value of the contract was not disclosed.

The award builds on the prefeasibility study that KBR carried out for Project Mthombo earlier this year (OGJ Online, Nov. 11, 2008).

KBR will start the work in December, and operations at the $11 billion refinery, which will be Africa's largest, are expected to start in 2014.

Feasibility studies will be completed in September 2009, and a final investment decision is scheduled for late 2010.

The refinery is of strategic importance to South Africa as national demand for refined fuels has outstripped the nation's refining capacity. Diesel consumption is forecast to grow at 6% and petrol at 2%/year during 2009-20.

Sipho Mkhize, PetroSA's president and chief executive, said that if there were no investment in refining capacity, South Africa would have to import 10 billion l. of fuel/year by 2015—equivalent to 20% of the national requirement.

"Importing this much refined fuel will have a negative impact on the country's foreign exchange reserves and makes national supply very vulnerable to external factors," Mkhize added.

KBR will work with PetroSA to outline a competitive supplier development program to stimulate economic growth, jobs, and skills development in the eastern Cape under the industry liquid fuels charter. ✦

Transportation — *Quick Takes*

Firms charged in Buncefield storage depot fire

Total UK Ltd., Hertfordshire Oil Storage Ltd. (HOSL), British Pipeline Agency Ltd. (BPA), TAV Engineering Ltd., and Motherwell Control Systems 2003 Ltd. will be criminally prosecuted for the December 2005 Buncefield oil storage depot fire in Hertfordshire, UK.

The companies must appear in court on Jan. 23, 2009.

The companies face the proceedings after the Health and Safety Executive and the Environment Agency investigated and published its reports.

The agencies are jointly responsible for regulating nonnuclear hazardous industrial sites in the UK.

During the incident there were a number of explosions, and 43 people were injured.

Total is being accused of failing to ensure the health, safety, and welfare of its employees, failing to protect persons not in its employment, and polluting groundwater near the plant.

Total said it had sought legal advice and would consider its position once all the relevant papers have been served.

HOSL is facing two charges: failing to prevent a major accident and limit its consequences to persons and the environment, and polluting groundwater.

Hundreds of businesses, insurance companies, and local residents are seeking a total of £700 million in damages from Total and HOSL in a separate civil lawsuit.

BPA was charged with failing to take all necessary measures to prevent major accidents, and pollution groundwater.

TAV Engineering and Motherwell are being prosecuted for failing to protect the health and safety of people not in their employment.

In 2006, investigators said 300 tons of gasoline had escaped from a tank, but they were unable to identify the reason behind the ignition at the depot, 40 km north of London.

The UK minister for health and safety said in response to the investigation's recommendations that planning for emergencies was improving as was the effectiveness of emergency responses at major hazard sites. There also has been careful planning to maintain the resilience of the UK's fuel supply.

Kirkuk-Ceyhan line resumes flow after repairs

Iraq resumed sending some 430,000 b/d of crude oil through its pipeline to Turkey on Dec. 4 after flow was shut down on Dec. 1 due to technical problems.

"Oil is flowing at around 18,000 bbl/hr," reported a shipping agent, following the 2-day halt said by Turkish officials to have been caused by an unidentified technical fault on a section of pipeline in Iraq.

The line had begun carrying oil earlier on Dec. 1 after the completion of repairs to damage caused by an explosion and fire on Nov. 21 in Turkey's southeastern province of Mardin.

The Kurdistan Workers Party (PKK) rebel group claimed responsibility for the Nov. 21 bomb attack, which triggered the large fire that stopped flow along the Kirkuk-Ceyhan line.

Turkish authorities confirmed that the blast appeared to be caused by sabotage, although they said an investigation was ongoing (OGJ Online, Dec. 1, 2008). ✦

Letters

Alarmed at legislation

Your editorial "A chance to play offense" is outstanding (OGJ, Nov. 24, 2008, p. 20).

I am an independent oil man, having been in the business over 50 years, and view with alarm impending legislation repeating past mistakes to the industry and the national economy.

I think there are some steps, although expensive, the US can take that will continue to preserve our world position as number one with the largest market, but also militarily, and keep our considerable influence in world affairs.

A start would be get on a war-time footing and build nuclear generating plants, upgrade the electrical grid, and free up more federal lands for drilling for oil and gas.

John L. Wright
Tulsa

Calendar

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

OIL&GAS JOURNAL online

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DECEMBER

Seatrade Middle East Maritime Conference & Exhibition, Dubai, +44 1206 545121, +44 1206 545190 (fax), e-mail: events@seatrade-global.com, website: www.seatrade-middleeast.com. 14-16.

2009

JANUARY

Petrotech International Oil & Gas Conference & Exhibition, New Delhi, +91 11 2436 4055, +91 11 2436 0872 (fax), e-mail: convenor_petrotech@iocl.co.in, website: www.petrotech2009.org/registration.aspx. 11-15.

Expandable Technology Oil & Gas Conference, Abu Dhabi, +44 (0) 1 483 598000, e-mail: sally.marriage@otmnet.com, website: www.expandableforum.com. 14.

Oil & Gas Maintenance Technology Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: attendingOGMT@pennwell.com, website: www.oilandgas-maintenance.com. 19-21.

Pipeline Rehabilitation & Maintenance Conference, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: attendingOGMT@pennwell.com, website: www.pipeline-rehab.com. 19-21.

SPE Hydraulic Fracturing Technology Conference, The Woodlands, Tex.,

(972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 19-21.

World Future Energy Summit, Abu Dhabi, +971 2 444 6011, +971 2 444 3987 (fax), e-mail: sales@turretme.com, website: www.worldfutureenergysummit.com. 19-21.

API Exploration & Production Winter Standards Meeting, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 19-23.

API/AGA Oil and Gas Pipeline Welding Practices Conference, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 21-23.

International Process Analytical Technology Forum (IFPAC), Baltimore, (847) 543-6800, (847) 548-1811 (fax), e-mail: info@ifpacnet.org, website: www.ifpac.com. 25-28.

Global E&P Summit, Madrid, +44 (0)20 7202 7500, +44 (0)20 7202 7600 (fax), e-mail: info@wtgevents.com, website: www.epsummit.com. 26-28.

Offshore West Africa Conference, Abuja, (918) 831-9160, (918) 831-9161 (fax), e-mail: attendOWA@pennwell.com, website: www.offshorewestafrica.com. 27-29.

The European Gas Conference, Vienna, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 27-29.

SIHGAZ International Hydrocarbon & Gas Fair, Hassi Messaoud, + 213 21 21 58 74, + 213 21 21 58 72/76 (fax), e-mail: contact@foirex.com, website: www.sihgaz2009.com. 28-31.

FEBRUARY

SPE Reservoir Simulation Symposium, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 2-4.

IADC Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 3-4.

Deep Offshore Technology International Conference & Exhibition (DOT), New Orleans, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.dotinternational.net. 3-5.

Global Petrochemicals Conference & Annual Meeting, Cologne, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 3-5.

Russia Offshore Annual Meeting, Moscow, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 4-6.

NAPE Expo, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 5-6.

Pipeline Pigging & Integrity Management Conference, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: clarion@clarion.org, website: www.clarion.org. 9-12.

CERA Week, Houston, (617) 966-5992, e-mail: info@cera.com, website: www.cera.com. 9-13.

SPE Unconventional Fields Conference, Margarita Island, Venezuela, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

Pipe Line Contractors Association Annual Conference (PLCA), Carlsbad, Calif., (214) 969-2700, e-mail: plca@plca.org, website: www.plca.org. 11-15.

IADC/SPE Managed Pressure Drilling & Underbalanced Operations Conference & Exhibition, San Antonio, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 12-13.

International Petrochemicals Technology Conference & Exhibition, London, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: enquiries@europetro.com, website: www.europetro.com. 16-17.

IP Week, London, +44 (0)20 8561 6030, +44 (0)20 8561-0131 (fax), e-mail: events@energyinst.org.uk, website: www.energyinst.org.uk. 16-19.

EnerCom's The Oil & Services Conference, San Francisco, (303) 296-8834, e-mail: kgrover@enercominc.com, website: www.theoilandservicesconference.com/index.html. 18-19.

International Downstream Technology & Catalyst Conference & Exhibition, London, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: enquiries@europetro.com, website: www.europetro.com. 18-19.

ASEG/PESA International Geophysical Conference & Exhibition, Adelaide, +61 8 8352 7099, +61 8 8352 7088 (fax), e-mail: ASEG2009@sapro.com.au, website: www.sapro.com.au/aseg.htm. 22-25.

Laurance Reid Gas Conditioning Conference, Norman, Okla., (405) 325-2248, (405) 325-7164 (fax), e-mail: bettyk@ou.edu, website: www.engr.outreach.ou.edu. 22-25.

Nitrogen + Syngas International Conference and Exhibition, Rome, +44 20 7903 2167, +44 20 7903 2432 (fax), e-mail: conferences@crugroup.com, website: http://crugroup.com. 22-25.

CERI Natural Gas Conference, Calgary, (403) 282-1231, (403) 284-4181 (fax), e-mail: conference@ceri.ca, website: www.ceri.ca. 23-24.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), e-mail: inquiry@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 23-26.

MARCH

EAGE North African/Mediterranean Petroleum and Geosciences Conference & Exhibition, Tunis, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 2-4.

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ARTC Annual Meeting, Kuala Lumpur, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 10-12.

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Turkish International Oil & Gas Conference & Showcase (TUROGE), Ankara, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 10-12.

Middle East Oil & Gas Show & Conference (MEOS), Manama, +973 17 550033, +973 17 553288 (fax), e-mail: aeminfo@batelco.com.bh, website: www.allworldexhibitions.com/oil. 15-18.

Purvin & Gertz Annual International LPG Seminar, The Woodlands, Tex., (281) 367-9797, website: www.purvingertz.com. 16-19.

Gas Asia, Kuala Lumpur, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 17-18.

SPE/IADC Drilling Conference & Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 17-19.

Latin American Meeting on Energy Economics, Santiago, 56 2 3541411, 56 2 5521608 (fax), e-mail: info@elaee.org, website: www.elaee.org. 22-24.

NPRA Annual Meeting, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 22-24.

ACS Spring National Meeting & Exposition, Salt Lake City, (202) 872-4600, e-mail: service@acs.org, website: www.acs.org. 22-26.

NACE Corrosion Conference & Expo, Atlanta, (281) 228-6200, (281) 228-6300 (fax), website: www.nace.org/c2009. 22-26.

PIRA Understanding Global Oil Markets Seminar, Dubai, 65 6581 4122, e-mail: jay@pira.com, website: www.pira.com. 23-24.

SPE Americas E&P Environmental and Safety Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 23-25.

API Spring Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 23-26.

Asian Biofuels Roundtable, Kuala Lumpur, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: a.ward@theenergyexchange.co.uk, website: www.wraconferences.com/FS1/AB1register.html. 24-25.

Journally Speaking

Technology, humanly applied

Steven Poruban
Senior Editor

Technology developed by the oil and gas industry to locate and extract oil and natural gas from below the earth's surface is now being adapted for humanitarian purposes.

The revamped application, in this instance, was fueled by a devastating natural event: the Asian Tsunami, or Boxing Day Tsunami, that followed the Indian Ocean earthquake in December 2004. The massive deadly wave struck the coastlines of Indonesia, Sri Lanka, India, and Thailand, as well as other more-distant locations, killing thousands of people and injuring and displacing thousands of others.

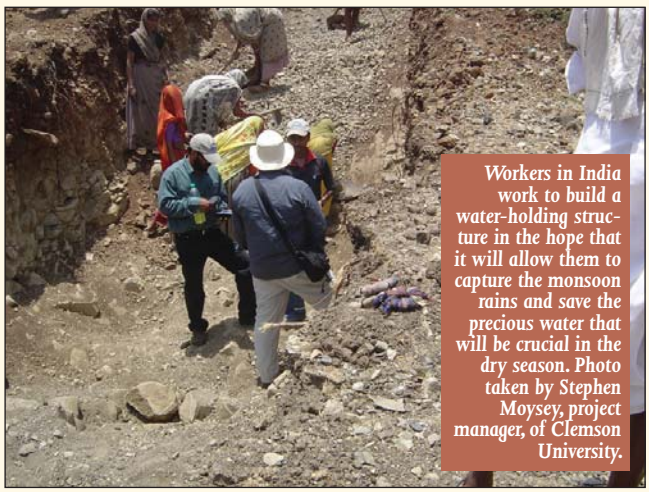
Shortly after the disaster, Craig Beasley, then-president of the Society of Exploration Geophysicists (SEG), summoned a call to action to SEG's membership, urging them to help, stating, "We have a significant contribution to make as geophysicists."

In early 2008, SEG Foundation, a trust formed by SEG to provide scholarships for students of geophysics, established a program called Geoscientists Without Borders (GWB). With a $1 million funding commitment from Schlumberger (and with further investment since provided by Australia's Santos Ltd.), the program's mission statement is straightforward: "Connect universities and industries with communities in need through projects using applied geophysics to benefit people and the environment around the world."

First projects announced

Last month, GWB revealed that India and Thailand would be the sites for the first two projects sponsored by the GWB program.

Hydrogeophysics will play a major role in both project sites, SEG reported, adding, "Joining universities and their students with communities in two foreign countries, the projects demonstrate the useful and often critical use of geophysics to assist communities with significant needs for such basic resources as fresh water."



Workers in India work to build a water-holding structure in the hope that it will allow them to capture the monsoon rains and save the precious water that will be crucial in the dry season. Photo taken by Stephen Moysey, project manager, of Clemson University.

One of the first projects will address the severe water crisis in rural India, SEG said. Clemson University will partner with the Foundation for Ecological Security (FES), an Indian nonprofit organization, to use electromagnetic induction to map soil moisture and shallow aquifers in the Salri watershed in India's Madhya Pradesh state.

"The scarcity of fresh water is a longstanding problem in central India that impacts the health, productivity, and quality of life for millions of people," project organizers said. Even though rainfall for the area is usually 45-60 in./year, they said, most of it falls in only 3 months of the year. "The goal of this project is to increase the water supply through water capture, storage, and usage management," they said.

Led by Stephen Moysey of Clemson University and Rangoori Ravindranath of FES, GWB will provide tools and knowledge that will assist villagers in making water management decisions that will favorably impact water supply throughout the year, SEG said.

Work in Thailand

In Chiang Mai, northern Thailand, SEG reported that three distinct humanitarian efforts under one project are planned that will "mitigate earthquake hazards, address water quality issues, and preserve cultural heritage through archaeological mapping."

GWB will use seismic, ground-penetrating radar, electrical, gravity, and magnetic methods to address geotechnical issues. Boise State University (BSU) will work in partnership with Chiang Mai University (CMU) to "advance humanitarian geophysics in Southeast Asia through a student-based approach, by teaching students geophysical skills that can be used in their home regions," SEG said.

"Undergraduate and graduate students, with the help of professionals and teachers, will gain hands-on experience with geophysical data acquisition, processing and interpretation, creating reports that address local environmental and engineering problems," SEG said.

Leading the effort are Lee Liberty and Kasper van Wijk of BSU, and Spencer Wood (retired from BSU), Fongsaward Singharajwarapan, and Siriporn Chaisri of CMU. ✦

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Editorial

Ranking high in bribery

On some rankings it's best to score near the bottom. So it is with assessments by Transparency International (TI), the anticorruption group, of the tendency of industries to pay bribes. On two new rankings related to TI's Bribe Payer's Index for 2008, the oil and gas business ranks near the top.

The survey evaluates 22 of the world's wealthiest exporting countries based on the likelihood that companies from them pay bribes abroad. It comes from observations of 2,742 senior business executives from companies in 26 countries, selected according to the size of their imports and inflows of foreign direct investment. This year the survey also produced two evaluations of the likelihood that companies from specific industries engage in illicit behavior.

Third place

In a list showing how likely companies in specific industries are to bribe public officials, the oil and gas industry ranks third. It scores 5.9 on a scale of 0-10 in which 0 means "bribes are almost always paid" and 10 means "bribes are never paid."

Industries more likely than oil and gas to practice bribery, according to the TI assessment, are real estate and property development, scoring 5.7, and public works contracts and construction, 5.2. Industries least likely to be involved in bribery are information technology, 7.0, and banking and finance and fisheries, 7.1 each.

The other TI industry ranking gauges the frequency of attempts to influence legislation, laws, and decision-making through private payments to public officials. On this list, based on the same 0-10 scale, the oil and gas industry holds second place with a score of 5.7. The public works contracts and construction industry holds the number-one position on this list, too, at 5.6. Third place belongs to mining, 5.8. The least frequent payers for influence are agriculture and fisheries, 7.1 each, and light manufacturing, 7.2.

TI's basic country survey also assigns scores of 0-10: the higher the score, the lower the likelihood that companies from the country pay bribes abroad. The countries least likely to export bribery are the Netherlands, 8.7, and Canada and Belgium, 8.8 each.

On the country list, unlike the industry rankings, the cleanest countries rank highest. At the bottom of the ranking are Mexico, 6.6, China, 6.5, and Russia, 5.9. Other countries with more than minor oil production and their scores are the UK, 8.6, Australia, 8.5, France and the US, 8.1 each, Brazil and Italy, 7.4 each, and India, 6.8.

The index, said Huguette Labelle, TI chair, shows "a number of companies from major exporting countries still use bribery to win business abroad." Labelle urged countries to commit to the provisions of the Organization for Economic Cooperation and Development Antibribery Convention, which the TI report calls "the foremost international legal instrument for tackling the supply side of international bribery."

Surveyed executives don't think governments are answering the call. The TI report said, "two thirds of senior business executives believed that governments are ineffective in the fight against corruption." But the executives themselves seemed less than savvy about anticorruption efforts. The report said three fourths of them "revealed that they were not at all familiar" with the OECD convention.

TI's survey reflects perceptions about bribe-paying—the countries from which it emanates and the industries that practice it. Perceptions can be wrong. They do influence behavior, however. The public's behavior toward the oil and gas industry, transmitted inevitably through politics, cannot improve after the TI report.

How to react

The oil and gas industry has several ways to react to TI's findings. It can agree with them and either do nothing or resolve to improve. It might also disagree with the findings and either do nothing or actively defend itself. Companies and their trade associations will have to decide how to proceed.

What they must not do is shrug off the TI findings as not relevant to their work or, worse, evidence of ingrained practice about which nothing can be done. Bribes are tools of corruption, and corruption hurts people, usually poor people. Work by oil and gas companies that hurts people is work that shouldn't be done. ✦




Held under the Patronage of H.E. Dr Abdul Hussain Bin Ali Mirza,
Minister of Oil & Gas Affairs, Chairman-National Oil & Gas Authority, Kingdom of Bahrain

The Gulf International Convention & Exhibition Centre
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Aboveground constraints may limit Mexico's oil production

Jude Clemente
San Diego State University
San Diego

The irreversible decline of Mexico's Cantarell field has been the subject of steady discussion in the industry. The broad consensus is that Mexican oil production levels are at serious risk, with concomitant implications for international oil markets. For the most part, however, analysts have focused on what a drop-off would mean for the US, 16% of the crude imports of which come from its southern neighbor.

But what does Cantarell's decline means for Mexico itself, currently the world's sixth largest oil producer? Consider these issues:

- Oil export revenues form the primary pillar of Mexico's drive toward modernization and economic growth. Funds from the state-owned oil company, Petroleos Mexicanos (Pemex), represent over 40% of the federal budget.
- Cantarell's production has declined to 1.12 million b/d in 2008 from about 2.1 million b/d in 2006 (OGJ, Dec. 11, 2006, p. 29, and OGJ Online, Sept. 26, 2008). Pemex officials believe Cantarell production will decline at about 14%/year in the coming years.
- Cantarell has accounted for more than 50% of Mexico's production since 2000, and the nation exported most of its oil during that time, with more than 80% going to the US.

The socioeconomic consequences of a decrease in oil production, then, would be profound for Mexico, leaving the country with what one analyst called a "nightmarish budget crisis."

New direction needed

As the erosion of Cantarell's output proceeds after several years of enhancement from nitrogen injection, pressure intensifies on Mexico's oil industry to offset the decline. Thus, the search is on to find and develop new fields that not only replace losses from Cantarell but ultimately allow Mexican production rebound. It is increasingly clear, however, that a difficult—and different—path lies ahead.

Two leading experts on Mexico's oil situation have stressed that "business as usual" will not enable the country to meet its oil production goals, and they suggested actions more likely to succeed:

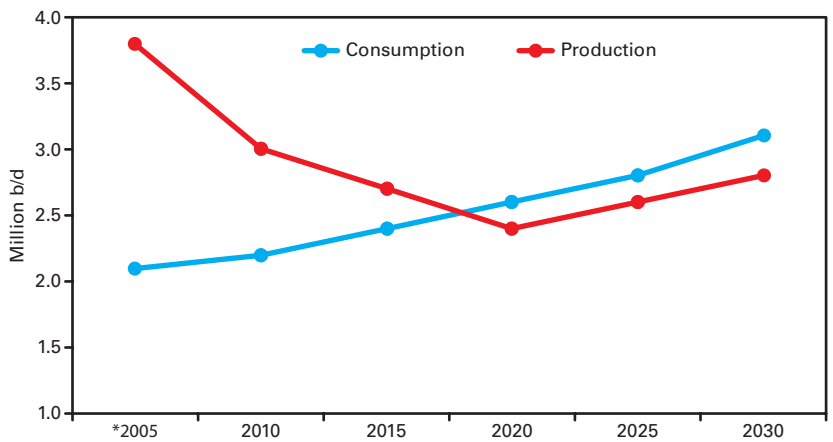
- Pemex must be permitted to develop strategic alliances with technologically sophisticated international oil companies, says George Baker, publisher of Mexico Energy Intelligence.
- Pemex must pay more attention to exploration to balance its emphasis on production if the country hopes to meet its long-term goals, insists David Shields, an independent oil analyst and author of several books on Pemex.
- The company also needs to systematically refurbish and expand its facilities along the entire energy supply chain, Shields says.

These changes will require major adaptation by the country's leaders. The 2008 energy reform bill, which passed through Congress in October, does not offer the sweeping changes the oil industry needs.

Pemex officials express confidence that two other oil systems will be able to compensate for Cantarell's terminal decline. The onshore Chicontepec basin and offshore Ku Maloob Zaap (KMZ) together are estimated to hold 53% of Mexico's reserves and 72% of

MEXICO'S OIL PRODUCTION VS. DOMESTIC CONSUMPTION

Fig. 1



*In 2005, Mexico had 1.7 million b/d to export.
Source: EIA International Energy Outlook 2008

non-Cantarell reserves.[1]

While these regions will require extensive capital expenditures, sophisticated technology, and time to develop, they appear to be Mexico's greatest opportunities over the next decade to compensate for Cantarell's decline.

Unfortunately, there is a growing likelihood that even if the key technical challenges are tractable, aboveground issues in Mexico will constrain production and limit exports. Cambridge Energy Research Associates (CERA) contends that the greatest threats to global production increases are not belowground but rather from the human conditions of politics, economics, regulation, and a hesitancy to proceed.

Resource nationalism

In 1938, Mexico became the first major producer to expel international oil companies (IOCs)—mostly American and British—and created Pemex. This event remains a symbol of sovereignty and a source of national pride.

Numerous politicians have played on this emotion and railed against any "theft of the oil industry" by outsiders. Mexico's leading leftist political figure, Andres Obrador, has steadfastly opposed private investment in the oil sector. "The country's oil belongs to the people, even the most humble. We must defend this historic conquest," he said.[2]

Mexico's oil industry, therefore, has little opportunity to partner with foreign companies to improve production, despite the expertise and technology such firms could provide. The Mexican people distrust IOCs, especially those from the US, and proposals for private investment generate mass protests throughout the country. A recent poll showed that 62% of the population opposes partnering with IOCs.[3]

However, the administration of President Felipe Calderon, a former energy minister, realizes that Mexico must seek help in developing its energy resources. In a February interview, Energy Minister Georgina Kessel said. "We are looking for (Pemex) to have the flexibility to form associations like all the companies in the world."[4] Calderon was even more explicit in a televised national address. "We must act now. Time and our oil are running out," he said.[5]

But Calderon's April initiative, pushing for outside investment in deepwater oil exploration and production (E&P), remains unpopular. "We are in complete disagreement with the [Calderon] government," said Manlio Beltrones, a senator from the Institutional Revolutionary Party (PRI), in a radio interview.[6]

Ordinary Mexicans are understandably skeptical when private investors access state enterprises. Mexican businessman Carlos Slim was ranked as the richest man in the world in 2007, mostly by making billions from the privatization of Mexico's national telephone company, Telmex.

Aging infrastructure

Pemex's financial troubles—exemplified by a staggering increase in debt to more than $110 billion in 2008 from $43 billion in 2000—have led to a patchwork oil infrastructure.[7 8]

The company lacks funds to modernize because Pemex pays such a high percentage of its revenues to the government. In 2006, for example, of $97 billion in Pemex sales, $79 billion (81%) went to federal coffers.[9] As the government's need for revenue escalates, funds to improve energy infrastructure decline. In 1997, Pemex had a budget of $2.7 billion for maintenance. In 2007, the budget was only $1 billion.[10]

A deteriorating pipeline system highlights Mexico's infrastructure problems. Over the past decade, maintenance expenditures have been only one third of what is required, and more than half of the pipelines are operating beyond their 30-year lifespan.[11] In an effort to maintain production, equipment is pushed to the limit, and ruptures regularly occur from excessive pressure. Pemex has consistently been forced to close pipelines because of a lack of maintenance, and it now needs over $3 billion for urgent pipeline repairs.

Recognizing these problems, Calderon has outlined a "National Infrastructure Program," which includes investments of $75 billion in E&P and $27 billion in refining by 2012.[8] Unfortunately, the urgency of maintaining the production system is the squeaky wheel that demands the grease. Over 80% of Pemex's E&P budget is funneled into production rather than exploration (OGJ Online, Apr. 22, 2008).

Even according to relatively optimistic Pemex data, proved reserves have fallen 41% since 2000 to about 14.7 billion bbl.[12] The US Energy Information Administration (EIA) indicates reserves have declined 75% since 1997 and now stand at 12.4 billion bbl. Shields's March 2008 report for the University of California at Berkeley presents an even more cautious view, estimating Mexican reserves at 11.8 billion bbl."[8]

Burgeoning demand

Mexico's population, like that of many other energy-producing nations, is growing rapidly and consuming more energy, reducing exports.

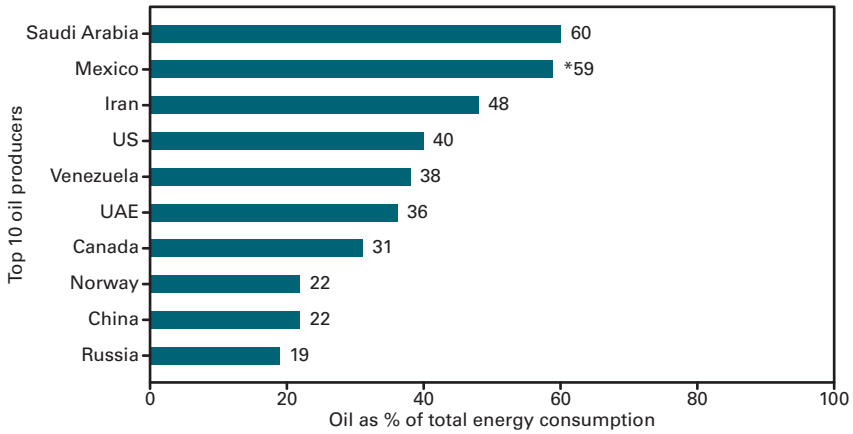
Its population will increase to 140 million in 2030 from 109 million in 2008—an increase of over 25% in less than a generation.[13]

Economic growth is changing the face of Mexico. The gross domestic product will increase to $2.9 trillion in 2030 from about $1.4 trillion in 2007—an annual growth of 3.3%.[13] This increase is the foundation of the rise of an energy-consuming middle class.

Automobile sales are up, and there is firm evidence that "gas guzzlers" from the US are finding their way to Mexico, raising fuel consumption.[14] More importantly, forecasted growth in the number of vehicles in the next 20 years is staggering. J. Dargay, D. Gately, and M. Sommer, in a 2007 report, projected that Mexico's vehicle fleet will increase to 66 million in 2030 from 17 million in 2002, an astounding quadrupling of vehicles in less than 3 decades.[15] The group's study found that the average

OIL USE AS A DOMESTIC FUEL, 2005

Fig. 2



*During 2003-08, Mexico rose from 13th to 10th highest oil consuming country.
Sources: EIA 2008 web site, US Central Intelligence Agency

annual growth rate for the number of vehicles in Mexico is nearly double that of the US and Canada combined.

This energy demand growth has huge implications. EIA, in its International Energy Outlook 2008, projected that during 2005-20 Mexico's oil consumption will increase by about 24%. Mexico will need 2.6 million b/d of oil in 2020—about 500,000 b/d more than in 2005. Mexico's oil production, however, will have fallen to 2.4 million b/d from 3.8 million b/d during the same time. By 2020, Mexico's oil consumption will have outstripped production by 200,000 b/d (Fig. 1).

By 2030, Mexico's oil consumption will have increased from today's by 48%. By then, Mexico will need 300,000 b/d more than it can produce. Interestingly, EIA is forecasting that Mexico's oil production will increase to 2.8 million b/d in 2030 from 2.4 million b/d in 2020. It remains unclear what will ignite the 2020's resurgence because EIA recognized that Cantarell is declining at 14%/year, and Pemex officials have admitted that KMZ and the Chicontepec basin will peak in 2010 and 2016, respectively (OGJ Online, Feb. 25, 2008).

Even if EIA's optimistic forecast is correct, Mexico would still need to import 300,000 b/d to satisfy domestic consumption by 2030. But the country might need even more. What would make oil production increase 17% in 2020-30? Where will this oil come from?

Mexico's shift—from US oil supplier to its competitor for oil imports—could happen very quickly.

In addition, burgeoning transportation demand has led to a drastic rise in gasoline imports since 2000. Mexico now imports about 40% of its gasoline.[16] This growth is expected to increase by 58%—to a total of 489,000 b/d by 2015 (OGJ Online, Apr. 22, 2008). This demand is driven by the rising middle class, an increasing percentage of young people, and rapid urbanization that was not adequately planned.

Gasoline is wasted in the standstill traffic jams that are part of everyday life in the country's large cities. Further, the current pipeline-storage systems are insufficient to handle increasing gasoline imports, and Mexico faces shortages. Virtually all gasoline imports come through the Atlantic port of Tuxpan, where facilities are outdated and capacity is constrained. Mexico's northern states often face gasoline shortages.

As Fig. 2 demonstrates, Mexico is more reliant on oil as an energy source than most major producers. Accordingly, socioeconomic dislocations from inadequate supply colliding with increasing demand will be severe.

Oil exports are at immediate risk. In fact, Mexico's waning ability to export oil is already apparent. According to Pemex's official June "Monthly Petroleum Statistics," total exports fell to 1.7 million b/d in 2007 from about 1.8 million b/d in 2006—a 6% reduction and a decline that is expected to accelerate. In May, Pemex's exports to the US dropped to 1.2 million b/d, a 21% decrease in just 1 year.[17]

Not only is Mexico exporting less oil, it is exporting heavier oil. Pemex's June statistics indicated that 89% of crude exports this year has been of the Maya variety, which averages about 22° gravity. Last year, 87% of crude exports was Maya, up from 83% in 2006. Mexico is now being forced to keep the lighter oil that it produces—Isthmus (34°) and Olmeca (39°)—for domestic consumption.

Production costs rising

The financial status of Pemex is particularly vexing given the rapidly escalating costs of energy production. CERA, for example, recently reported that Pemex's global Upstream Capital Cost Index has doubled since 2005.[18] To make matters worse for Mexico, CERA added: "Specialized deepwater equipment…showed the largest increase."

More than half of Mexico's prospective reserves lie in deep water. Chris Salden, British Petroleum's vice-president of E&P in Mexico, reported that Pemex would need an investment of $200 billion during the next decade for deepwater work.[19]

Downstream costs are rising steadily as well. The Nelson-Farrar index of refining costs, reported in OGJ since 1946, has shown steady escalation across the board—labor, materials, and equipment. Escalating refining costs are an especially important issue given Mexico's "need to build a refinery every 3-4 years over the next 2 decades" (OGJ Online, May 5, 2008).

While costs are rising worldwide, Mexico's situation is exacerbated by the dramatic change in the source and quality of future oil supply. As the focus now shifts to other fields, it is becom-

ing more apparent that Cantarell was the epitome of "low hanging fruit."

Cantarell needed just 200 wells.[20] The water at Cantarell is calm. Due to its shallow pay, straightforward geology, and high oil concentration, Cantarell has been relatively easy to exploit since its discovery in 1971.

Contrast this to the characteristics of the two fields Pemex views as being able to offset Cantarell's decline in the next decade (see table).

The development of the Chicontepec basin will require an average of 1,000 wells/year for 15 years.[21] This is more than Pemex currently drills in the entire country. The channel system has low permeability and mostly heavy oil in thin pay. This complex geology limits primary oil recovery rates to the 5-7% range and is the main reason development has been limited since oil was discovered there over 80 years ago.[22] The heavy oil at KMZ also indicates production costs are destined to rise in Mexico.

Competing social needs

The emerging middle class and the country's increasing dedication to social programs are requiring substantial expenditure, with much of the funding coming directly from Pemex. Energy revenues are siphoned off to pay for schools, roads, and medical, antipoverty, and other human welfare programs. The government has created a major recycling program and is building orphanages and affordable housing, while making low-interest loans available for business start-ups. It also has toughened emission standards.

In addition, Mexico has begun an historic struggle against the drug cartel activity that has paralyzed the nation. This effort will require even more resources that ideally would be used to help solve the problems of its oil industry. High oil prices are the main reason Mexico has the money to fight crime and poverty. In his attempt to persuade the US Congress to help fund Mexico's drug battle, US President George W. Bush recently claimed Mexico has spent $3 billion to fight the drug war.[24]

Given these swelling social programs, reinvestment in oil exploration and development has become an afterthought, whereas E&P investment could discover more oil to support social programs.

In September 2007, Calderon called for "an urgent reduction in public spending to reduce the enormous dependence on oil revenue."[25]

MEXICO'S MOST IMPORTANT OIL REGIONS

Characteristic	Cantarell	KMZ	Chicontepec basin
Area size, sq miles	70	47	2,400
Average depth, m	50	100	Varies
Production costs, $/bbl	5+	9+	12+
Peak year	2004	2010	2016
Peak amount, million b/d	2.11	0.8	0.5
Average crude density, °	22 heavy	13 very heavy	18-45 heavy to light*
2007-12 required investment, $ billion	14.5	9	14.5

*Majority of reserves are heavy, in 20s° gravity range, but some lighter pockets exist.
Sources: Rigzone.com, Bloomberg.com, OGJ, Shields 2008, Broderick 2007

Institutional barriers

Private investment in Mexico's oil industry is not permitted under the nation's constitution. Mexican law limits Pemex to offer outside companies only multiple service contracts whereby Pemex pays a fixed cost for services on oil projects. The contractor does not receive any part of the earnings that Pemex may realize. Outside companies are not involved in E&P, and risk contracts are forbidden.

Pemex pays over 60% of its annual earnings in taxes and royalties, and Mexico's Congress must approve its budget each year. These factors limit E&P investment. When Pemex generates above-average revenues, the government takes a larger amount of earnings through higher taxes. Conversely, when Pemex produces below-average revenues, the company's budget is reduced to offset the deficits created in other sectors of the government.

Baker says that unless upstream regulatory changes occur, Mexican oil production probably has peaked.

Intellectual isolation

Despite the crucial role of deep water in Mexico's energy portfolio, Pemex is sometimes absent from advanced technology meetings such as the Offshore Technology Conference (OTC) held annually in Houston.[26]

Modernizing into deepwater operations might be especially difficult because Pemex has little access to necessary educational infrastructure. Only two Mexican universities offer doctorates in deepwater geology, and the number of PhDs at Pemex from English-speaking universities is on the decline. Critics claim that Pemex managers are appointed on the basis of party loyalty rather than experience or knowledge. Such patronage is an important constraint because Pemex officials are replaced with each presidential administration, a new one being elected every 6 years.

Calderon recently engaged television and radio advertisements pushing for the public to be more open to

The author

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reform. Baker believes internal reform is only part of the solution: "To improve Pemex, you need to have a view that...looks beyond Pemex," and "Any particular effort to reform Pemex, as an effort itself, will not succeed."[27]

Shields asserts there is no vision behind Calderon's bill. "It is a proposal that tries to give something to everybody, and it does not seem to get very far in anything,"[28] he said. ✦

References

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FERC issues final EIS for LNG project near Baltimore

Nick Snow
Washington Editor

The US Federal Energy Regulatory Commission identified additional adverse environmental impacts as it issued a final environmental impact statement (EIS) on Dec. 5 for a proposed LNG project outside Baltimore.

However the staff said such impacts would be "mostly limited" from the LNG import terminal and associated pipeline. The conclusion in the final EIS was similar to one reached in its draft EIS of the project Apr. 25, which noted that AES Corp. plans to build the terminal within an industrial port setting at Sparrows Point. The facility would be capable of storing up to 480,000 cu m of LNG with a base-load send-out rate of 1.5 bcfd of revaporized natural gas, FERC said.

Maryland state and local government officials have expressed opposition to the project, saying it would bring LNG tankers up Chesapeake Bay and potentially disrupt Baltimore Harbor vessel traffic. Two members of the state's congressional delegation said Dec. 5 that they were not satisfied with FERC's final EIS.

US Sen. Barbara A. Mikulski (D-Md.) said on Dec. 5 that the number of recommended mitigation measures grew to 179 in the latest document from 151 in the draft EIS. "I remain firmly opposed to a new LNG facility at Sparrows Point. For over 2 years, I have repeatedly raised my safety, security and environmental concerns about this LNG facility and pipeline. I am deeply disappointed that FERC continues to rubber stamp a project that our state is adamantly opposed to," she declared.

Rep. Dutch Ruppersberger said, "This is a tough setback, but I will not give up the fight to stop the proposed LNG facility from coming to eastern Baltimore County. I have said from the very beginning this proposed liquefied natural gas plant is absolutely inappropriate for this residential area." The final EIS "ignores the safety of nearby residents who would live in the shadow of the facility," he charged.

More mitigation action

FERC's staff said in the final EIS that the US Coast Guard's waterway suitability report for the project has "preliminarily determined" that additional recommended mitigation measures would be needed to make the Patapsco River, Chesapeake Bay, and territorial seas suitable for LNG marine traffic to the proposed terminal site and responsibly manage marine and safety risks.

"Along the marine transit route, potential impacts, thought short-term, could be significant to boaters and fishermen by interfering with their normal and accustomed practices of using the Chesapeake Bay and Patapsco River," it conceded.

AES would need to coordinate with the Port of Baltimore and with special boating interest groups to minimize disruption of scheduled annual maritime events, the final EIS suggested. "Coordination with the Coast Guard's Marine Event Permit Office would be necessary since events may require LNG vessels to adjust their transit . . . We have also recommended that AES work with the Coast Guard and Patuxent River Naval Air Station during development of its transit management plan," it said.

FERC's final EIS also said the proposed project's construction would have a temporary impact on about 1,801 acres of land. There are no existing residences within a mile of the planned terminal, but the proposed pipeline would cross within 50 ft of 179 residences and 56 other buildings, it indicated.

Mid-Atlantic Express LLC, the AES division that proposes to lay an 88-mile pipeline from the LNG terminal to Eagle, Pa., has filed site-specific plans for residences within 25 ft of construction, the final EIS said. But FERC's staff found that the plans lacked detail and sufficient mitigation measures, it added. "Pipeline construction could also affect wells and septic systems; therefore, we have recommended that Mid-Atlantic Express file site-specific plans for residences within 50 ft of the pipeline construction work space as well as measures for mitigating impacts to wells, septic systems, and other utilities," it said.

Camps, parks, trails

The pipeline's construction also could have adverse impacts on several camps, parks, and trails, it continued. "Many of the construction impacts would be temporary; however some scenic watersheds would be permanently impacted," it said.

AES would be required to develop and implement an emergency response plan, which would involve state and local agencies and municipalities, including a cost-sharing plan and a transit management plan, according to the final EIS. The company also would have to meet requirements of FERC, the Coast Guard and other federal agencies.

Ruppersberger said the Coast Guard issued a report earlier this year which

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WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Early responses to falling demand

The US Energy Information Administration's latest Short-Term Energy Outlook said it all on Dec. 9: "The current global economic slowdown is now projected to be more severe and longer than in last month's Outlook, leading to further reductions of global energy demand and additional declines in crude oil and other energy prices."

While record prices earlier in the year led EIA to forecast an average West Texas Intermediate crude price of $100/bbl for 2008, it now expects WTI prices to average $51/bbl next year, under current economic assumptions and assuming no major supply disruptions. A month earlier, EIA projected a 2009 WTI average price of $63.50/bbl.

"The US economic recession is also contributing to lower natural gas wellhead prices. The Henry Hub spot price is projected to decline from an average of $9.17/Mcf in 2008 to $6.25/ Mcf in 2009," it added.

Companies are reacting cautiously, industry observers told me. "We're seeing a gradual, rather than a dramatic, response so far," said Frederick Lawrence, vice-president of economics and international affairs at the Independent Petroleum Association of America.

Uncertain time frame

"We're definitely starting to see some of the bigger companies cut back their capital expenditures for next year. Everyone is...unsure about the time frame right now, but it looks as if demand might be weaker next year. It's not certain whether it will last far into 2010," he said.

Service and supply companies are making contingency plans, said Gary C. Flaherty, Baker Hughes Inc.'s investor relations director. The Houston company already is seeing a reaction in drilling statistics, he said. "We peaked at 2,031 rigs in the US at the end of September. Looking at the credit crisis and the price of oil and gas, we think we're on pace to exit the year at 1,840."

He said Baker Hughes has noticed that conventional gas drilling in the Mid-Continent and Rocky Mountains has fallen, while unconventional gas drilling from the Haynesville and Marcellus shales has remained constant.

'High-grading prospects'

"We're seeing operators high-grading their prospects that have the biggest impacts on cash flow. They may be more expensive, but they also have the initial production that provides a positive contribution," Flaherty told me. Service and supply companies have set up contingencies, he continued. "We're doing a lot of planning right now."

"Everyone knows how important workforce retention is. I think companies will hesitate to let crews go because they've put in such a big effort to build them. They may reduce the number of hours, but we're not hearing about layoffs," Lawrence said.

IPAA expects a better indication early next year from both a private capital conference it is sponsoring and the North American Prospect Expo. "So far, I've heard that the numbers for NAPE are high, particularly for the international side," he said. ✦

found that AES does not appear to take security seriously and assumes that the Coast Guard will handle all security at taxpayer expense. "In addition, the company…wants Maryland taxpayers to foot much of the bill for any security changes that may need to be implemented. This is unfair because the natural gas will be pumped out of state," he said.

FERC's final EIS said the Coast Guard's Feb. 25 Waterway Suitability Report identifies specific risk mitigation measures that would be needed to responsibly manage maritime safety and security risks. "Accordingly, we have recommended that the proposed facility comply with all requirements set forth by the Coast Guard," it said.

FERC noted that since the draft EIS was issued in late April, US Commerce Secretary Carlos Gutierrez issued a finding that the project, if approved, would be consistent with the Coastal Zone Management Act, as necessary for the establishment of safety and security zones for LNG traffic in Maryland and Virginia waters.

FERC said commissioners would consider the staff's recommendations in the final EIS when they make a final decision on the proposed project. ✦

MMS chief hopes Obama, Congress won't reinstate OCS bans

Nick Snow
Washington Editor

Acknowledging that he will have no direct influence after Jan. 20, US Minerals Management Service Director Randall B. Luthi said he hopes the Obama administration and Congress seriously consider expanded opportunities on the US Outer Continental Shelf.

"We have given the new administration a head-start with this new 5-year OCS leasing program," which US

Interior Secretary Dirk A. Kempthorne announced on July 30, Luthi told members of MMS's OCS Policy Committee Dec. 9 as it met in Herndon, Va., outside Washington. "I would ask the incoming president and Congress not to rush to reimpose moratoriums. Once they are in place, they are very hard to remove," he added.

Luthi said he hopes to have a draft proposed OCS plan for the 2010-15 period completed by early January but emphasized it would be at least 2 more years before it became final. This will give coastal states and communities, energy producers and consumers, environmental organizations, and other groups ample time to supply input, he explained.

The new plan also will consider energy production beyond oil and gas but recognizes that traditional fuels will be needed as alternatives are developed, Luthi said. "We could provide a bridge to renewables with traditional resources. When we release the draft proposed plan in January, it will ask questions about buffer zones, environmental sensitivities and other issues," he suggested.

Luthi said he also hopes MMS can complete a revenue-sharing plan with Gulf Coast states required under the 2006 Gulf of Mexico Energy Security Act by Mar. 31, 2009, and a GOMESA-mandated plan for sharing revenue from existing federal offshore leases starting in 2017 by September.

'A real deadline'

"You've all read in your newspapers about so-called midnight regulations from outgoing presidential administrations. That's probably true to some extent. But it's also true that no one is as efficient as when they face a deadline, and Jan. 20 is a real deadline. There are people in MMS who would like to finish what they've been working on," Luthi said.

OCS Policy Committee Chairman Victor G. Carillo said the group was meeting under very different circumstances from its previous session in March. Crude oil prices hit $145/bbl in early July, gasoline cost more than $4/gal, and there were calls for both more conservation and efficiency and more production of domestic energy resources, he said.

US President George W. Bush withdrew presidential OCS leasing bans on July 14 and Congress allowed other remaining moratoriums to expire on Sept. 30, he continued. "We then experienced a remarkable stock and financial market meltdown and growing recession. We also have seen a significant drop in oil and gas prices. Finally, we witnessed a historic presidential election in November and are waiting to see where the US Department of the Interior heads under the Obama administration," said Carillo, who also is director of the Texas Railroad Commission's oil and gas division.

A 2-day workshop a week earlier in Williamsburg, Va., gave MMS an opportunity to hear from stakeholders about a possible lease sale off that state's coast in 2011, Luthi told reporters following his address. "If you're going to make this work, it's all about partnerships with the states, the industry, and environmental and tourism groups," he maintained.

Federal policymakers also should not overlook the fact that MMS and the US Bureau of Land Management, DOI's primary federal resource management agencies, generate federal revenue second only to the US Internal Revenue Service, Luthi continued. "It takes years to plan a sale. They should give the 5-year planning process a chance to work and not be in a rush to reimpose moratoriums until the revenue potential has been considered," he said. ✦

EA report outlines issues with Iraqi energy security, fragile systems

Eric Watkins
Oil Diplomacy Editor

While Iraq's oil industry will continue to face problems with security in 2009, the country's crumbling production and pipeline systems are more likely to disrupt crude exports, according to a report by London-based Exclusive Analysis (EA).

"Notwithstanding an overall improvement in security, the situation in the country is still extremely fragile, and progress over the next 12 months is at significant risk of being reversed by a variety of factors," the report said.

In general, progress is at risk from "residual sectarianism, fueled by unresolved issues like the status of Kirkuk, by rogue Shia militants' violent opposition to the continuing Coalition presence, and by the potential fragmentation of Prime Minister's Al-Maliki's United Iraqi Alliance."

Security risks in Basra province and to the offshore oil platforms are being reduced, the analyst said.

However, it noted that the building of Iraqi Navy capability has encountered delays, including slippage in the delivery dates of Malaysian and Italian patrol vessels.

Protecting ports

At the start of 2008, some of Iraq's ports had been infiltrated by rival militias vying for control of Basra province and oil smuggling operations.

Fighting between the groups led to routine blockages of access to oil fields and ports.

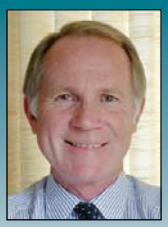
Crucially, the perimeter of Umm Qasr, Iraq's only bluewater port and the entry point for 80% of its imports, was secured when Iraqi government military forces removed the Mehdi Army militiamen who had assumed control.

Key port administrators were

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com



White Nile raises the white flag

Oil-gas explorer White Nile Ltd. recently raised the white flag in Sudan, saying it plans a change of mission and will now invest in African agriculture.

White Nile said that's happening because the current economic environment and political situation in southern Sudan are not conducive to funding nonproducing early stage oil and gas exploration.

By contrast, it said, the agricultural and associated civil engineering industries in Africa are resilient enough to generate returns on investment even in the current economic environment.

That's hard to figure until you add in the fact that White Nile—soon to be called Agriterra—could not begin its operations in southern Sudan until January 2011 when the region holds a referendum on total independence.

White Nile, chaired by former England cricketer Phil Edmonds, said violence in southern Sudan has prevented its clarifying its exploration rights on Block Ba.

No guarantees

In fact, the firm doesn't think it will be able to clarify its rights any time soon, and certainly not before the planned referendum on independence for southern Sudan.

White Nile would have no guarantee that the planned referendum—assuming it were held—would give them the desired result. Independence could be turned down, and there would go White Nile's deal.

Even if independence were approved, White Nile would still have no guarantees that its agreement would be honored by the government of southern Sudan. Too many other things could happen by then.

So, White Nile said it will quit the oil and gas business in order to invest in and develop projects with an already proven business model, and in areas that attract foreign investment....

As for political stability in Sudan, things don't look promising. Events in the region suggest that White Nile had seen the writing on the wall insofar as its investment was concerned.

The Army digs in

The Sudanese army recently reinforced its presence in South Kordofan, a region bordering Darfur, in what the Khartoum government says is a preventive measure against the rebel group of the Justice and Equality Movement (JEM).

Ominously, an army spokesman last week said military forces began moving into the oil-rich region but did not disclose if JEM posed a direct threat.

The announcement came days after southern Sudan officials accused the north of building up a large force in South Kordofan, saying the deployment violated the terms of the 2005 peace deal that ended 2 decades of north-south civil war.

That won't end Sudan's oil business, as indicated by PetroChina, which has just completed a crude oil import terminal at Qinzhou.

The terminal feeds PetroChina's 10-million-ton-capacity refinery at Qinzhou, which is designed to process crude oil from parent China National Petroleum Corp.'s overseas oil projects—among them, Sudan. ✦

dismissed, and Iraqi marines were deployed as part of the security crackdown. The capability of the Iraq Navy, which operates from Umm Qasr port, was bolstered by the delivery of US patrol boats.

However, a projected increase in the capabilities of the Iraqi Navy, including the delivery of new patrol vessels from Italy and Malaysia, has been delayed, in part due to arguments over the cost of the vessels and mechanics of transferring money, which is likely to extend into 2009. The new vessels will enable the Iraqi Navy to carry out more patrols, which have already increased by almost 100% since the start of the year.

Protecting terminals

In April, the Iraqi Navy assumed responsibility for protection of the Khawr al-Amaya oil terminal (KAOT) and the al-Zubayr port. Currently one Iraqi Navy marine battalion defends the two oil terminals.

"However it is the al-Basrah oil terminal (ABOT) that is most vulnerable, given that it is the only functioning oil platform," EA said, noting that the terminal is still at risk to attacks by small boats operated by insurgents or Iranian Revolutionary Guards, despite the Coalition naval presence.

Although security issues remain a concern, they are being replaced by infrastructural limitations as the primary risks facing Iraq's six commercial and oil transit ports on the Persian Gulf, EA said.

Underinvestment issues

"As security risks decline, it is clear that the years of underinvestment in infrastructure and a severe lack of modern equipment, such as container cranes, are undermining the stability of supply chains," it said.

While the Iraqi Navy will take over responsibility for guarding the two offshore oil terminals at Basrah and Khor al-Amaya, repair and upgrade work is essential to expand (or even maintain) export capacity, particularly with respect of the terminals' connection to the

mainland ports.

In October, a study commissioned by the US Congress warned that the two 50-km subsea oil pipelines that transport the crude to the terminals were at imminent risk of failing due to "severe corrosion and vulnerability to rupture, thus reducing their ability to withstand attempted interdiction or sabotage."

Failure would cause a lengthy suspension in over 1.5 million b/d of exports, EA said, noting that it was also reported in October that Basra port loading rates declined to 1.32 million b/d, due to a power generation failure.

"Addressing these issues will require significant investments in dredging, port construction, and offshore terminal works, as well as several years to implement projects," EA said.

Meanwhile, Iraq's exports risk suffering severe bottlenecks.

Still, British military sources in Iraq are nevertheless optimistic and confirmed that port facilities are improving and that navigational access is getting better. ✦

Petrobras delays strategic plan; receives investment offers

Eric Watkins
Oil Diplomacy Editor

Brazil's Petroleo Brasilerio SA (Petrobras) continues to review its 2009-13 strategic plan, with no deliberation taking place yet at the board level, according to an official report.

Even as the company firms up its plan, however, government officials claim to have no concern over funding, especially as substantial offers of finance are coming in from other nations such as China and the UAE.

"The company is finalizing the review of its strategic plan," Petrobras said in a filing with stock regulators. "Until now, there has not been any deliberation by either executive directors or the board of the company about the plan."

Mines and Energy Minister Edison Lobao told the state news agency that the plan was still due to be released by yearend—changing earlier dates announced by Petrobras downstream director Paulo Roberto Costa, who said the board would meet by Dec. 19 or 20 to discuss and finalize the document.

In October, Petrobras delayed the release of its 2009-13 strategic plan, which is to include the company's first investments in the subsalt region, due to worsening global market conditions.

However, in this week's filing with the regulators, Petrobras said current market conditions would not greatly affect the company's investment plans.

The company's current strategic plan, released in 2007, envisioned investments of $112 billion during 2008-12.

"Throughout its long history, Petrobras has confronted various adverse conditions that did not create obstacles for development of its long-term growth strategies," Petrobras said.

"In spite of the international financial crisis, the company was capable of raising $7.5 billion throughout 2008 to finance its investments," Petrobras said.

Upbeat mood prevails

The firm's upbeat mood this week echoed remarks on Dec. 5 by Petrobras Chief Executive Officer Jose Sergio Gabrielli, who said that new strategic planning—"to be announced at the end of the year"—will be for investment above current plans of $19.5 billion/year.

"The next plan will probably have investment at over $20 billion annually," Gabrielli told delegates at the Annual Chemical Industry Meeting held by the Brazilian Chemical Industry Association (Abiquim).

Gabrielli said the company's 2008 investment is expected to come in at over $50 billion reais, a figure that should be surpassed in 2009.

The Petrobras announcement this week coincided with statements by Lobao that China and the UAE have offered Brazil resources to fund production from its potentially huge offshore oil fields.

"China is offering Petrobras $10 billion initially," Lobao said in an interview published Dec. 8 by the daily Folha de Sao Paulo. "We also received a representative of a prince in the [UAE], which also wants to invest in Petrobras."

China made its offer in talks with Petrobras attended by Energy Ministry representatives, said Lobao, who added that the funds would be destined for the company's investment plans and development of the presalt layer.

Responding to questions about the Brazilian company's plans amid the global credit crisis, Lobao said that Brazil has "several other alternatives" to fund Petrobras's investment plan and pay for production from the presalt layer.

Among the alternatives, Lobao named domestic loans, foreign loans, the government budget, and the "possibility of using part of the country's foreign exchange reserves," which are estimated at around $207 billion.

Meanwhile, Gabrielli said that Petrobras will start to test oil exploration in the presalt areas of the Santos basin beginning in March 2009. The testing period will last 18 months, he said, and initially will aim to produce 15,000-30,000 b/d.

Last month, Brazilian officials issued conflicting statements concerning the potential impact of the current global financial crisis—as well as other issues—on the exploration and development of the country's subsalt layer (OGJ Online, Nov. 24, 2008). ✦

Italian pipeline developers undeterred by credit crunch

Uchenna Izundu
International Editor

The Galsi and Interconnector-Greece-Italy (IGI) pipeline partners do not expect the credit crisis to negatively impact their plans, as they have very strong balance sheets, according to a senior company official.

However Elio Ruggeri, project leader at the department of hydrocarbons at Edison SPA, told OGJ at the European Autumn Gas Conference (EAGC) at Lake Como, Italy, that securing gas supplies from Shah Deniz for the IGI line was difficult due to limited available volumes and intense competition from different markets. "Russia and Turkey will also have a share of this gas," he said. No contracts have been signed to fill the IGI pipeline.

Enhancing security

Edison is a partner in both projects, which are expected to enhance Italy's gas supply security. Gas demand in Italy should grow to 96-104 billion cu m/year in 2015 from 85 billion cu m/year in 2007, according to Ruggeri. Gas imports are expected to increase to 26 billion cu m/year by 2015, up from 18, and the incremental need for import capacity is expected to rise to 41 billion cu m/year by 2015, up from 32.

Currently, the Italian gas market is tight. But demand destruction in natural gas has already begun, warned Davide Cornaggia, supply and sales director at mid-size operator Gas Plus Italiana SPA. "Customers are consuming less, and gas use for power generation has decreased in the last 2 months by a substantial amount. I understand that this has also happened elsewhere." The nation faces a dilemma where there is a risk of a gas bubble in the summer of 2009, Cornaggia added. With these projects, along with Italian LNG import terminals, there could be an oversupply of gas in the medium term.

Ruggeri said Italy could become a gas transit country for France and Germany provided the pipeline system becomes integrated in Europe.

The Galsi partners, including Sonatrach, Enel SPA, Sfirs (Sardinia Reg), and Hera SPA, plan to make a final investment decision next year. The front end engineering design (FEED) work is to be finished by yearend 2008. Tenders for the engineering, procurement, and construction contract are being prepared along with the financial structure for the project.

Sonatrach leading way

Sonatrach is leading the proposed 840–km Galsi pipeline, which will have a capacity of 8 billion cu m/year and in 2,800 m of water will be one of the world's deepest offshore pipeline ever laid. It will deliver Algerian gas via Sardinia into Italy starting in 2012. The definition of the transportation contracts between Galsi and its shippers are being drawn up.

This pipeline would connect Sardinia for the first time to Italy's national grid and improve its environmental footprint. According to a memorandum of understanding signed in September by Galsi and Snam Rete Gas (SRG), Galsi will be responsible for the FEED and securing permits with SRG's help during the development phase. Galsi will build, own, and operate the international section while SRG will concentrate on the national section.

The IGI line is an 800-km pipeline that would deliver 9 billion cu m/year of gas from the Caspian to Italy and western Europe via Turkey and Greece in 2012. However, to meet this deadline, gas supply agreements and gas transit agreements must be finalized within the next year to make the final investment decisions in 2009.

Edison will take 6.4 billion cu m/year, and its Greek partner Depa will have 1.6 billion cu m of capacity in IGI, which has been exempted from third party access under European Union rules. Ruggeri said 1 billion cu m/year of gas has been set aside for third parties and there has been 17 nonbinding expressions of interest (EOI) from Italian and other companies under the open season held in June.

"We don't know how much capacity had been applied for as we didn't ask for this figure under the EOI," Ruggeri said. "There were two lots of 100 million cu m each that were offered, and I suspect that people would have bid for the entire capacity."

During the next phase, the IGI consortium will ask interested shippers to submit binding offers to reserve transportation capacity, which will be followed by an allocation stage. ✦

IEA: Energy security to come from mitigating climate change

Paula Dittrick
Senior Staff Writer

The global economic slowdown cannot distract policymakers worldwide from progressing on climate change mitigation efforts through international accords and related national energy policies, said Richard J. Jones, deputy executive director of the Paris-based International Energy Agency.

"Mitigating climate change will substantially improve energy security," Jones told a Dec. 9 energy forum at Rice University's James Baker Institute

for Public Policy. "I personally believe investment in energy is a sound way to create jobs and get out of economic crisis."

Referring to IEA's World Energy Outlook 2008 report (WEO2008), Jones said a new international climate agreement is the first step toward a sustainable energy system. Effective implementation of such a system is crucial, he said.

Governments will have to provide financial incentives and regulatory frameworks that support both energy security and climate policy goals in an integrated way, said Jones, a former US ambassador to Israel, Kuwait, Kazakhstan, and Lebanon. He became IEA deputy executive director on Oct. 1.

Massive investments in energy are needed, he said, citing an IEA reference scenario that calls for cumulative investment of more than $26 trillion (in 2007 dollars) during 2007-30. That investment is $4 trillion higher than IEA calculated in its WEO2007 report, largely because of increased costs in the oil and gas industry.

Energy investments needed

The WEO2008 report was released last month. Of the latest investment scenario, the power sector accounts for $13.6 trillion while most of the rest goes to oil and gas, mainly for exploration and development and mostly in countries outside the Organization for Economic Cooperation and Development.

The current financial crisis is not expected to affect long-term investment, but could delay bringing current projects to completion, IEA said. Just over half of projected global energy investment in 2007-30 goes simply to maintain the current level of supply capacity.

"Much of the world's current infrastructure for supplying oil, gas, coal, and electricity will need to be replaced by 2030," Jones said. "We have to run faster just to keep in place."

Future investments in energy infrastructure hinge upon successful negotiations of an international agreement on combating climate change, he said, noting that on current trends, energy-related emissions of carbon dioxide and other greenhouse gases will rise inexorably, pushing average global temperature by as much as 6° C. in the long term, he said.

Jones said the 15th Conference of the Parties (COP), scheduled in November 2009 in Copenhagen, provides an opportunity for policymakers to negotiate a new global climate change policy regime going beyond 2012, which is the final year of coverage of the Kyoto Protocol's first commitment period.

The COP needs to establish a framework for long-term cooperative action toward a clear global goal for stabilizing the volumes of GHG emissions being released into the atmosphere, he said.

The energy industry must play the central role in curbing GHG emissions—through major improvements in efficiency and rapid switching to renewables and other low-carbon technologies, including carbon capture and storage, he said. "Carbon capture and storage will require creation of a huge infrastructure," Jones said, adding that this effort will create jobs while cutting GHG emissions. ✦

Booz & Co.: Strategic growth remains possible despite recession

Paula Dittrick
Senior Staff Writer

Falling energy consumption and the credit crisis have slashed liquidity in the capital markets, yet Booz & Co.'s energy consultants advise oil companies to remember that strategic growth remains possible.

"The industry's initial response has been to retrench, restructure, and 'live within one's means.' Companies have reduced their capital spending budgets," Booz partners said in letter to oil and gas clients.

Reminding clients that long-term energy fundamentals are strong despite currently depressed valuations, Booz suggests that now could be a good time to invest in core businesses.

"Indeed, the long-term fundamentals do support a robust outlook for the industry: The International Energy Agency forecasts that the global economy needs 64 million b/d of incremental crude supply, the equivalent of almost six times Saudi Arabia's current capacity, by 2030," the partners said.

A recession also represents an excellent time to gain ground in the competition for talented employees, said the Booz letter signed by R. Andrew Clyde and Andrew Steinhubl, both partners, along with Eric Spiegel, senior partner.

E&P spending forecasts

A recent report by IHS Herold suggests 2009 exploration and production spending in Canada and the US will decline at least 10% from 2008 levels. Major projects, especially oil sands projects, have been delayed or canceled.

However, Booz partners question whether the sky is falling. Instead, they say an "often-ignored part of weathering a recession successfully is about strategic growth." They advise energy companies to contemplate strategic opportunities.

"While it is prudent to reconsider capital spending in light of reduced liquidity, companies shouldn't miss the opportunity to fund or even accelerate projects that capitalize on future industry trends," Booz said.

For example, service companies could invest to expand in regions, such as the Middle East, that are expected to

see above-average growth.

"We realize that capital budgets will remain under pressure in the near term, given the high degree of uncertainty and the need for companies to live within their cash flow," Booz said. "But don't overlook the fact that as activity decreases, we are likely to see a reduction in the cost of services and raw materials, which will improve the economics of project investments."

A recent Booz analysis identified a 12-month lag between crude prices and declines in the IHS cost inflation index.

"This suggests that now might be the right time to begin planning and negotiating with your suppliers, making key procurement decisions in anticipation of the economy's eventual recovery," the Booz letter said. ✦

Analyst forecasts 'major risks' ahead in Iraq

Eric Watkins
Oil Diplomacy Editor

Iraq has ambitious targets, aiming for 500,000 b/d annual oil output expansion and a long-term goal of 6 million b/d, according to a recent report by analyst BMI.

"However, there are major risks involving attacks on oil installations, Iraq's OPEC entitlement, and the success of new energy policy in stimulating IOC [international oil company] investment," BMI said.

IOCs in 2008-09 are expected to enter production-sharing agreements with the state, which should help accelerate the growth in oil output.

Based on the efforts of existing contractors and national oil industry bodies, BMI is forecasting average oil production of 2.3 million b/d for 2008. Production in May was 2.5 million b/d, with 2 million b/d exported.

Further field reactivation work and the initial IOC efforts point to output of an estimated 3.15 million b/d in 2012.

BMI is forecasting an increase of 86.5% in Iraqi oil production during 2007-18, with crude volumes rising steadily to 4 million b/d by yearend 2018.

Iraqi oil consumption

BMI forecasts that Iraq's real gross domestic product will grow at 10.6% for 2008, following 5.4% in 2007. "We are assuming 7.4% growth in 2009, followed by 9.4% in 2010, 10.1% in 2011, and 5.5% in 2012," the analysts reported.

Oil consumption during 2007-18 is set to increase by 111%, with growth slowing to an assumed 5%/year towards the end of the period.

"We expect oil demand of 620,000 b/d in 2007 to rise to 975,000 b/d in 2012, depending on investment in infrastructure and the development of domestic production," BMI said. The analysts expect demand of 1.31 million b/d by 2018.

As percentage of region

Iraq will account for 10.89% of Middle East regional oil supply by 2012, while creating 8.25% of its demand, BMI reported.

Regional oil production, which stood at 22.87 million b/d in 2001, averaged 25.42 million b/d in 2007 and is set to rise to 28.94 million b/d by 2012.

Regional oil use of 8.24 million b/d in 2001 rose to 10.61 million b/d in 2007. It should average 10.86 million b/d in 2008 and then rise to around 11.81 million b/d by 2012.

Natural gas comparisons

Iraqi gas production is expected to climb to 35 billion cu m by the end of the 2007-18 period.

During this time, gas demand will grow 166%, and export potential will rise to 24.4 billion cu m by 2018.

Iraq in 2007 consumed 1.08% of the Middle East's gas, with its market share forecast at 1.11% by 2012. It contributed 1.1% to 2007 regional gas production and by 2012 could account for 2.61% of supply.

The entire Middle East in 2007 consumed 370 billion cu m, with demand of 541 billion cu m expected for 2012, representing a 46% growth.

Middle East production of 363 billion cu m in 2007 should reach 575 billion cu m in 2012, which implies net exports rising to 34 billion cu m by the end of the period.

OPEC 2008 prices

BMI also released figures for the Organization of Petroleum Exporting Countries' basket prices, revising its projections for 2008 upwards from the last quarterly report.

"We are now assuming an OPEC basket price average of $106[/bbl] for 2008, compared with the $81 estimate provided by our last quarterly report," the analyst said.

Based on recent price differentials, Brent would average $109.71/bbl for 2008; WTI, $110.64/bbl; and Urals, $106.88/bbl.

In second-quarter 2008, BMI estimates that OPEC's basket price averaged just under $115/bbl, up 24% from the first quarter.

The basket price had exceeded $127/bbl on May 22, slipping back towards $121/bbl later in the month. In June, BMI assumed an average $120/bbl to deliver a quarterly estimate of $114.98/bbl.

By comparison, the estimated second-quarter 2008 average prices for the main marker blends are $118.63/bbl for Brent, $119.61/bbl for West Texas Intermediate, and $115.89/bbl for Russian Urals (via Mediterranean delivery). ✦

Elusive Alabama shales need more work, Energen says

Alan Petzet
Chief Editor-Exploration

Energen Corp., Birmingham, Ala., plans further exploratory tests in 2009 of Conasauga and Chattanooga gas shales in Alabama without partner Chesapeake Energy Corp., Oklahoma City.

A three-well test program this year "generated neither positive nor conclusive results," said Energen (OGJ Online, Dec. 1, 2008). The 2009 tests may involve drilling more wells, testing alternative completion techniques, and-or completing other zones.

Energen doesn't believe the three wells have condemned the entire acreage play, said John Richardson, president and chief operating officer of Energen Resources Corp.

Chesapeake chose not to stay in due to financial considerations, opportunities presented by other known shale plays, and the lack of positive results, but Energen has the financial capacity to pursue the plays on its own and will proceed in a low-risk manner, said James McManus, president and chief executive officer of Energen Corp.

"In fact, all of our costs in this program to date, including approximately $42 million in capitalized unproved leasehold, are less than the $55 million pre-tax gain generated by the sale of one half of our then-200,000-acre lease position to Chesapeake in October 2006," McManus said.

Energen, with a 330,000-acre net lease position in the acreage plays, faces little lease expiration pressure in 2009. The two companies also hold 14,000 acres outside the three areas.

The Energen-Chesapeake agreement permanently excludes Chesapeake from 9 surrounding sq miles if it elects not to participate in a well proposed by Energen. Chesapeake could participate in other wells and could farm out its 50% interest in the acreage to Energen or others, Richardson noted.

Finding costs of less than $3/Mcf would be needed to make the shales economic, he estimated.

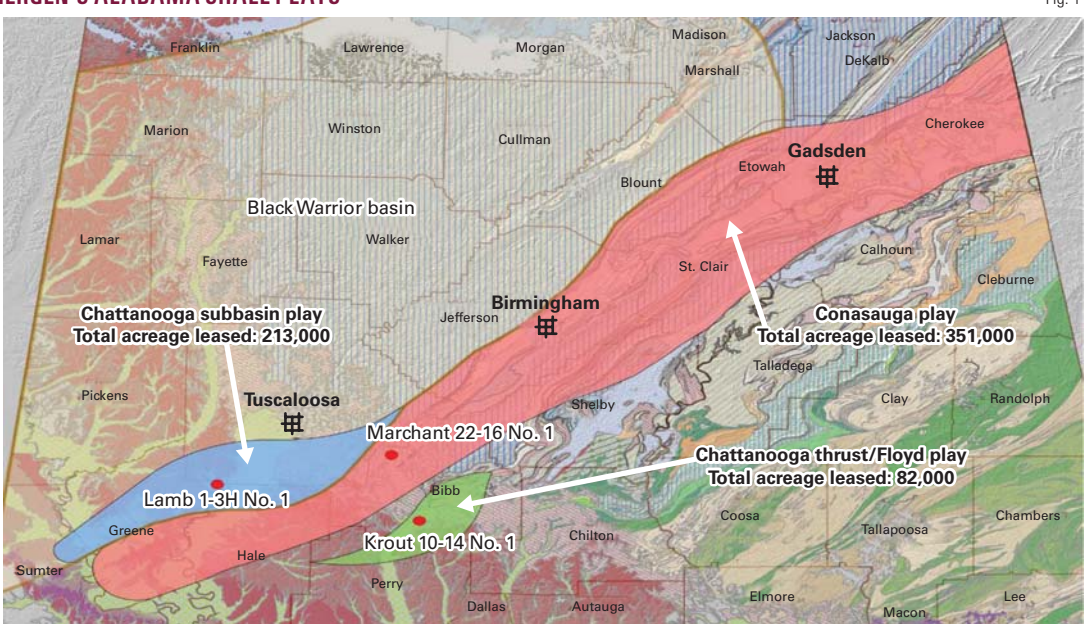
Conasauga shale

The companies leased 351,000 acres south of the Appalachian thrust to pursue gas in the Conasauga shale.

Energen and Chesapeake spud the Marchant well, in 22-22s-7w, Bibb

ENERGEN'S ALABAMA SHALE PLAYS

Fig. 1



Source: After Energen Corp.

County, on Apr. 15, 2008, and drilled to TD 12,400 ft.

The well, which topped the Conasauga at 2,500 ft and topped a mushwad zone at 4,000 ft, was drilled with little deviation or sticking, problems that have plagued the wells at Big Canoe Creek field 75 miles to the northeast in northern St. Clair County (OGJ, Feb. 19, 2007, p. 37).

Mushwad is an acronym for malleable unctuous shale, weak-layer accretion in a ductile duplex. After the ductal Conasauga shale was deposited in Cambrian time, Richardson explained, it "acted as a lubricant that allowed the overlying strata to break and thrust upward as they glide on top of the shale. The shale is piled up against basement ramps and becomes thousands of feet thick."

Energen acquired and reprocessed more than 1,000 miles of 2D seismic to enhance the mushwad signature and gained enough comfort to drill some distance from Big Canoe Creek field.

Marchant 22-16 had eight strong shows at 6,500-12,400 ft, and the companies attempted to complete the deepest and most notable, at 11,525-730 ft.

The Conasauga is a carbonate-dominated sequence of interbedded shales and carbonates alternating every few inches to every few feet, Richardson said.

"There is nothing like the Conasauga anywhere in the country; it is a different kind of formation," he said.

A Sept. 15 frac at 11,558-723 ft contained 165,000 gal of crosslinked gel and 220,000 lb of sand and resulted in a disappointing flow of less than 50 Mcfd despite strong mud log shows.

This suggested that the completion technique didn't work but could be the result of the geologic complexity of the mushwad, Richardson said.

"Our theory is that hydraulic fracturing may not be effective in forming a conduit to enhance the production from a zone that is so broken and deformed. If so, the question is, does this apply to all of the mushwad or is it a localized occurrence?

"Our thought is to hydraulically stimulate one or more of the additional zones of interest in this well. If they do not yield satisfactory results, we may consider lateral drillouts in order to contact more of the gas-bearing rock," Richardson said.

From 3,000 to 4,000 ft the same well encountered a zone "that was not waded, had very low dip rates, and had slightly higher shale content than the lower strata that was ultimately completed.

"This very thick zone at a shallow depth may offer some potential in the future in a more traditional geologic setting," Richardson said.

Chattanooga shale

The Chattanooga shale has long been of interest in Alabama because it appeared rich in organics but was usually only 25-40 ft thick.

Energen and Chesapeake recognized the existence of a subbasin along the Appalachian thrust with the potential for encountering intervals of the Devonian age Chattanooga shale that were 100 ft thick or more, Richardson said.

The Lamb 1-3H No. 1, in 1-23n-3e, Greene County, was spud June 2 and drilled with mud. It cut 93 gross and 91 net ft in Chattanooga at 9,150 ft. The 91 net ft refers to that portion of the gross interval that had a gamma ray of 150 or more API units.

"We also encountered Floyd shale at 8,954 ft and several Pennsylvanian aged sands from 6,000-8,000 ft," he said.

Circulation was lost in several formations at 4,500-5,500 ft, making detailed analysis of most of these zones difficult.

"We were unable to obtain a complete logging suite or a full core." The incomplete core implied encouraging values of porosity at less than 4% and permeability a bit above 200 nanodarcies, Richardson said.

The companies gained enough encouragement to proceed with a horizontal leg, but it encountered a fault. They kicked off at 9,150 ft and drilled a 2,035-ft lateral in the Chattanooga shale and ran a four-stage frac totaling 2 million gal of slick water and 2 million lb of sand starting Oct. 30.

After recovering 50% of the frac fluids, no significant gas flow was recorded.

"We expected to see significant gas flows much earlier in the process. That we did not calls into question the completion design or the productivity of the shale itself," Richardson said.

"Our assessment at this point is that we will likely drill and complete an additional well in a different geographic setting. Hopefully this will encounter fewer lost circulation problems and be in a better position to evaluate the Chattanooga and Pennsylvanian sands potential.

"We also anticipate testing different completion and stimulation designs. For example, after analyzing data gathered to date, we think that using an energized fluid such as nitrogen in our stimulation may be less reactive with the shale than slick water and could yield a positive result."

Chattanooga thrust/Floyd

The original concept with the Krout well was a mushwad-type formation to the south and east of the main Conasauga play. The Krout 10-14 No. 1, in 10-22n-9e, Bibb County, was spud on Jan. 26.

"We found instead a thrust system that repeated the Chattanooga and Floyd sections," Richardson said. "This formation gave the appearance of a mushwad on seismic due to the tectonic activity. It is very structurally complex, overturned, and thrusted with highly dipping formations."

Mud logs from the Krout and Goodson wells 1 mile apart depict greatly different geologic conditions.

The Krout mud log shows five Chattanooga sections and an abnormally thick Floyd section.

"It appears that the Floyd section has been overturned on itself and has a gross thickness of more than 400 ft with a net thickness of 158 ft as measured by gamma ray of more than 150 API units."

The companies attempted completion in the Lower Chattanooga at 8,210-50 ft and 8,300-90 ft. This zone had 130 ft of net Chattanooga shale.

A hydraulic frac on Oct. 8 with 200,000 gal of cross-linked gel and slick water and 150,000 lb of sand yielded a disappointing flow of less than 50 Mcfd.

"Therefore," Richardson said, "we have no plans for future Chattanooga shale completions in this play, but we do plan to evaluate the abnormally thick Floyd that we encountered." ✦

Kazakhstan

Arawak Energy Ltd., Jersey, Channel Islands, UK, reduced oil production at Akzhar, Besbolek, Karataikyz, and Alimbai fields in Kazakhstan Dec. 5 in connection with high taxes and export duties and the drop in oil prices.

After authorities imposed a customs export duty, Arawak and other small producers began offering oil for sale locally and those prices fell to below the cost of production.

Arawak cut output to the minimum levels needed to maintain processing facilities. Production from the nonoperated Saigak field, governed by a production sharing agreement, is not affected.

Arawak expected net production to drop to less than 2,000 b/d from 13,700 b/d in mid-November after a five-rig development drilling program in Akzhar and Besbolek fields.

Kyrgyzstan

Santos International Holding Pty. Ltd. has committed to Phase 2 of its five-block exploration program in Kyrgyzstan as a farmee of Manas Petroleum Corp., Baar, Switzerland.

Santos completed the first phase, spending $10 million for geological studies and reprocessing and shooting seismic surveys. It will drill three exploration and three appraisal wells in phase two, spending up to $7 million/well.

Morocco

Circle Oil PLC said its CGD-9 exploration well on the 296 sq km Sebou Permit in Morocco's Rharb basin northeast of Rabat sustained 8.86 MMcfd of gas from the Lower Guebbas formation. The discovery will undergo an extended well test, and the company plans to further assess the resource. The rig has moved to the KSR-8 well, third of a planned six-well program. Circle has 75% working interest, and Morocco's ONHYM has 25%.

Meanwhile, on the Ouled N'Zala concession the ONZ-6 discovery that sustained 3.32 MMcfd is likely to be commercial, and ONZ-4 is on continuous production at 1.5 MMcfd.

Alberta

Richards Oil & Gas Ltd., Calgary, is starting up a 75% owned processing plant and compressor to handle gas at Thorsby, Alta., southwest of Edmonton.

Nine standing wells are to be connected. The company has drilled 18 wells to date, including five in the quarter ended Sept. 30 targeting Horseshoe Canyon coals and Edmonton sands. Initial flow rates at the five were 200 Mcfd to more than 800 Mcfd/well. The plant is designed for low inlet pressure to maximize CBM production. Regulatory approval to commingle is being sought.

The company, which owns 88% working interest in more than 23 sections, believes the property has net production potential of 9-12 MMcfd.

Gulf of Mexico

Callon Petroleum Co., Natchez, Miss., suspended development of its 50% owned Entrada field in 4,650 ft of water on Garden Banks Block 782 in the deepwater Gulf of Mexico.

The company cited costs much higher than expected to date and commodity prices that have fallen to less than half their levels when development began in mid-2008.

Callon said the No. 3 well, drilled to 21,100 ft, needs to be sidetracked toward the No. 2 discovery well. It said it does not anticipate returning to the project under current economic conditions. Callon had expected Entrada to go on production in mid-2009.

CIECO Energy (US) Ltd., a subsidiary of Tokyo-based ITOCHU Corp., owns the other 50% interest in Entrada.

California

Royale Energy Inc., San Diego, plans to acquire 75% interest in more than 1,000 acres in what is believed to be a southern extension of North Tejon oil and gas field in the San Joaquin basin.

Royale will operate and fund the future development of the field in 35 and 36-11n-20w, Kern County, Calif.

It will attempt to recomplete the Windgap 42-36 well in Oligocene Vedder sandstone. Drilled in 2006, it cut two potential pay zones, the lower of which had virgin pressure and strong oil and gas shows, and flared gas while testing.

Royale Energy and Laris Oil & Gas LLC, Littleton, Colo., believe a freshwater mud system damaged the reservoir. Oil based drilling fluid was used to develop the rest of the field. Royale will drill short laterals. Then the companies plan continuous drilling on the 1,000 acres held by Laris.

Texas

East

Meridian Resource Corp., Houston, said its latest completion in the East Texas Austin chalk flowed at the rate of 18.6 MMcfd of gas and 2,800 b/d of oil with 1,300 psi flowing tubing pressure while still cleaning up.

The Sutton A-574 No. 1 in Polk County went to vertical TD of 12,200 ft and has 5,200-ft and 6,500-ft laterals in the chalk. The company's working interest is 63%.

The rig has moved to drill the dual lateral BSM A-278 No. 1 well, and the dual lateral BSM 507 No. 2 is being completed.

Williams compares sequential, simultaneous Barnett fracturing

P.N. Mutalik
Robert W. Gibson
Williams Exploration and Production
Tulsa

Williams Production Gulf Coast Co. is simultaneously fracturing wells in North Texas to improve production rates.

Since 2005, Williams has drilled more than 100 horizontal wells in the Barnett shale, an unconventional gas reservoir that underlies a 19-county area in the Fort Worth basin. Slickwater fracturing is the primary technique used to hydraulically fracture the wells.

Recently, Williams and several other operators tried fracturing two or more adjacent wells simultaneously with the goal of exposing the shale to more pressure and produce a more complex web of fractures, thereby improving the initial rates and reserves. Simultaneous fracturing or "simo-frac" technique is expensive and requires much more planning, coordination, and logistics as well as a larger surface location than single frac jobs.

This article discusses the case history of sequential and simultaneous fracturing of four similarly drilled and completed horizontal azimuth wells in eastern Parker County, Tex. All four wells were stimulated with near identical fracture treatments. Three wells with sequential and simultaneous fracturing had initial production (IP) of 3.3-3.5 MMscfd with 30-day averages ranging from 2.1-2.9 MMscfd. The fourth well was a single offset, horizontal well drilled with effective lateral length of 2,400 ft, located less than a quarter mile north of the first three wells. But Well D had significantly lower IP of 2.3 MMscfd and 30-day average production of 1.2 MMscfd.

The initial comparative test results are very encouraging and indicate that the sequential and simultaneous fracturing creates a more complex fracture network, which results in significantly improved well production.

Williams continues to evaluate the benefit of simultaneous fracturing and has done more simo-frac jobs in other counties with good results. Due to surface and lease constraints, many of the simo-frac jobs are performed in wells that are drilled from the same dual pad and have well spacing on the order of 500-700 ft. We provide an analysis of the simultaneous fracturing jobs completed to date in Parker and Johnson counties.

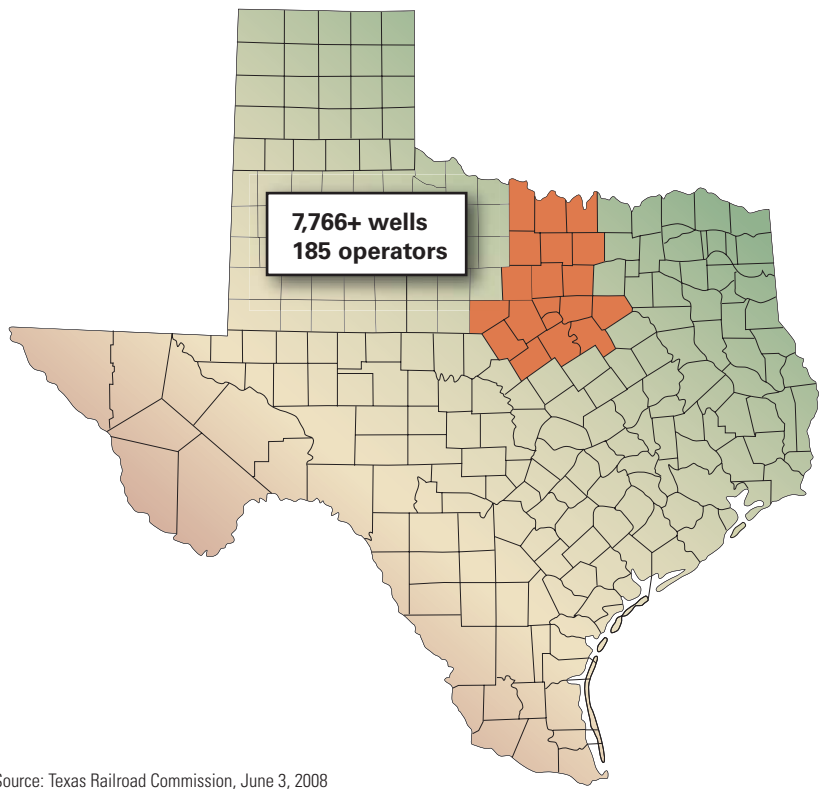
Based on a presentation to the SPE Annual Technical Conference and Exhibition, Denver, Sept. 21-24, 2008.

Barnett activity

The Barnett shale has evolved into the preeminent shale-gas resource plays in the US and is now considered by many as the largest onshore natural gas field in the US. The estimated productive part of the formation covers 5,000 sq miles, encompassing 19 counties (Fig. 1).[1]

BARNETT SHALE WELLS IN 19 TEXAS COUNTIES

Fig. 1



Source: Texas Railroad Commission, June 3, 2008

According to the latest figures published by the Texas Railroad Commission (RRC) in June 2008, there are more than 7,700 producing wells and 185 active operators in the Barnett shale, holding permits for more than 4,500 additional wells.

Production from Barnett shale currently exceeds 3.7 bcfd, accounting for more than 15% of Texas gas production. The Barnett shale has produced more than 3.8 tcf natural gas since 2000.[2]

'Simo-fracs'

Simultaneous fracturing of paired, offset wells is one of the recent trends in Barnett fracturing and is being increasingly used by many operators. In this technique, two or more adjacent wells that are roughly parallel to each other are fractured simultaneously. The goal is to expose the shale to more pressure and produce a more complex, three-dimensional web of fractures, increasing the density and surface area of the hydraulic fracture network. The drainage area of each of the wells is enhanced as the frac fluid is pushed into the space between the two wells that would not have been fractured if the operator had stimulated only well.[3 4]

Simo-fracs are expensive and require more coordination, logistical work, and a larger footprint than a single frac job. At the same time, they are cost-effective because the frac equipment is utilized more efficiently; two wells are completed in 1 week instead of 2 weeks.

Initially, simultaneous fracturing in the Barnett involved dual fracs, involving two horizontal wells close to each other. Today, operators are experimenting with triple simultaneous fracs or even quad-fracs.

Case history

Williams used three horizontal wells in eastern Parker County to experiment with sequential and simultaneous fracturing.

Fig. 2 shows the well layout of the wells. Well A, with a 2,200-ft long lateral, was drilled from a separate pad. Two other wells, Well B and Well C, with lateral lengths 1,900-2,000 ft, were drilled from a single pad. Wells A and C are spaced 900-ft apart at the heel and about 500 ft at the toe.

Williams drilled a fourth, stand-alone horizontal well, Well D, with an effective lateral length of 2,400 ft, less than half mile to the north. Due to lease constraints, only one well could be drilled from the Well D pad.

Stimulating Wells A, B, and C involved both sequential and simultaneous fracturing. Hydraulic fracturing of Well A was completed in five stages during the first week, followed by simultaneous fracturing of Wells B and C the following week.

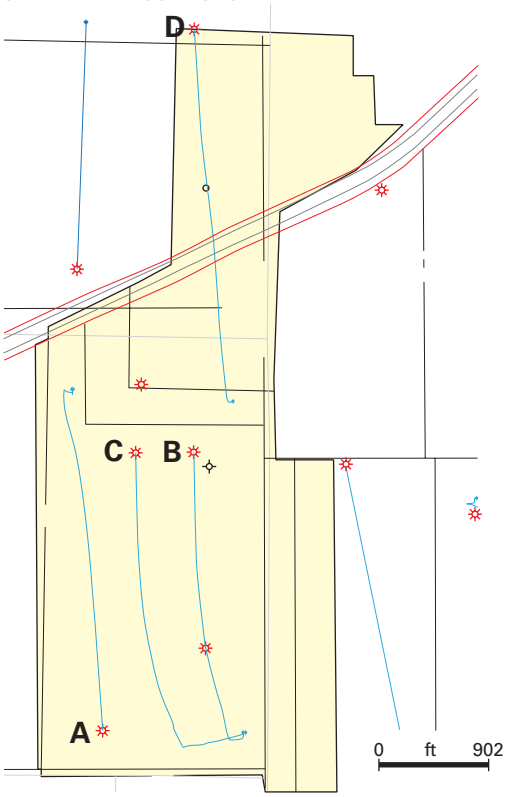
Fig. 3 shows the production performance of the four wells over the first 6 months of their production lives. The three simo- sequentially fraced wells had IP rates of 3.3-3.5 MMscfd and the first month averages ranged 2.1-2.9 MMscfd.

The stand-alone Well D well to the north had significantly lower IP of 2.3 MMscfd and the first-month average production was lower, at 1.2 MMscfd.

The initial results for the simo- sequentially fraced wells are encourag-

Barnett shale well locations

Fig. 2



Initial production (IP) following stimulation

Table 1

Well	Actual lateral, ft	30-day average act., Mcfd	IP/lateral length, Mcfd/ft	Current rate, Mcfd
Well A (sequential frac)	2,195	2,576	1.17	885
Well B (simo-frac)	1,955	2,864	1.46	890
Well C (simo frac, infill well)	1,889	2,087	1.11	655
Average	2,013	2,512	1.25	810
Well D (stand-alone well)	2,413	615	0.25	467

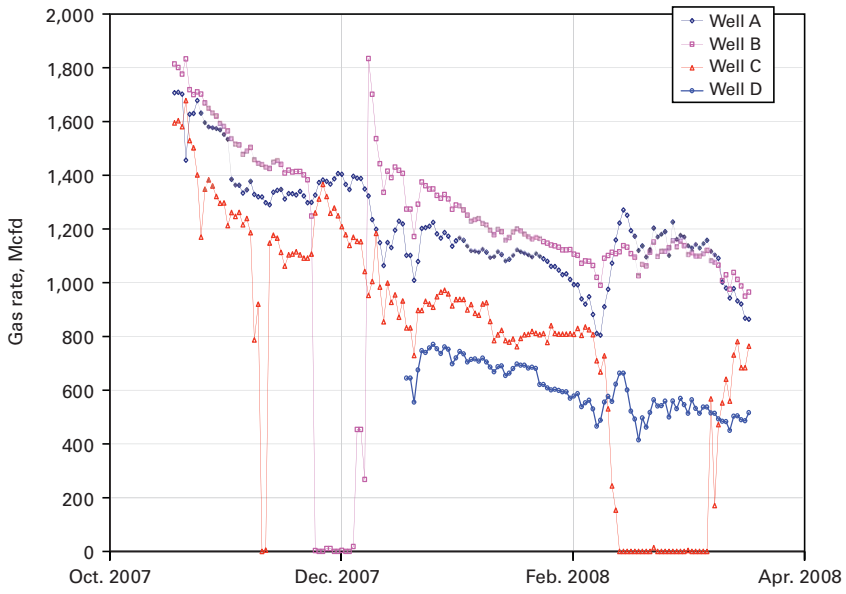
EUR, recovery factor calculations

Table 2

Well	Actual lateral, ft	EUR, bcf	EUR/lateral length, MMcf/ft	Recovery factor, %
Well A (sequential frac)	2,195	2.06	0.94	
Well B (simo-frac)	1,955	2.22	1.14	
Well C (simo frac, infill well)	1,889	1.18	0.62	
Average	2,013	5.46	0.90	25.9
Well D (stand-alone well)	2,413	0.89	0.37	6.4

WELL PRODUCTION HISTORY*

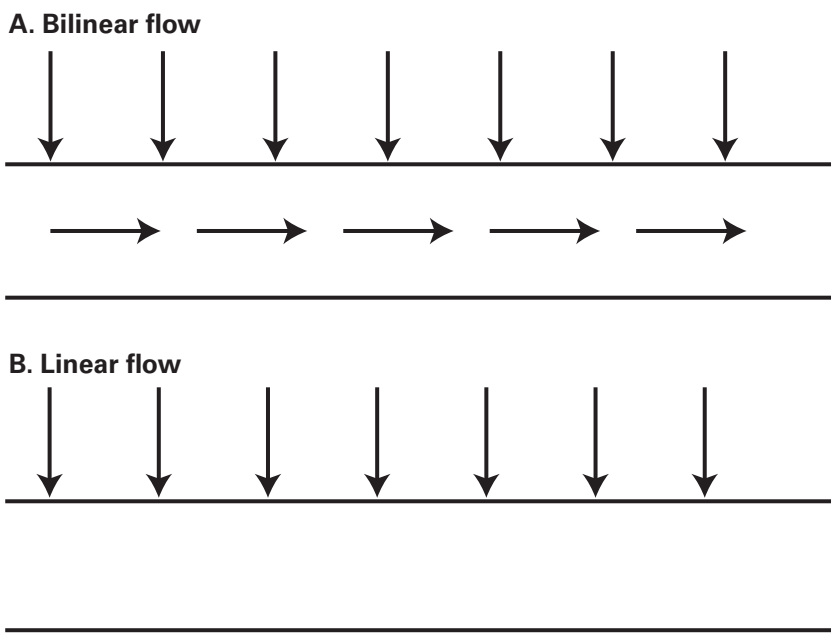
Fig. 3



*Comparing the simo-fraced and sequentially fraced wells A, B, and C with stand-alone Well D.

FLOW REGIMES

Fig. 4



ing and indicate that a more complex fracture network was created near the simultaneously fractured wells, contributing to significantly improved well performance.

The graph in Fig. 3 shows that the average 5-month production of the three sequentially fraced, simo-fraced wells was almost double that of stand-alone Well D. Well D was completed and had first sales about a month later than the three sequentially-fraced, simo-fraced wells. Well B has the best production among the three wells; it may be draining a larger area to the east. The Well A fracture network was likely enhanced due the subsequent simo-fracing of Wells B and C, resulting in enhanced production. Well C has the lowest production among the three wells, which may be attributed to interference effects from the two offset wells.

Successive stimulations using a multistage treatment often show a significant influence of the previous stage, including potential charging of the reservoir. The fluid from the previous stage remains at a somewhat elevated pressure, pushing subsequent stages away due to increased stress generated by the volume of pressurized fluid.[5]

In general, reactivation of existing fracture networks is thought to be less beneficial than creating new fracture networks.[6] The production data from the three wells appear to indicate that simo-fracing results in more enhanced fracture network and production gains, compared to sequential fracturing. This aspect needs to be further studied; more data are needed to validate this inference.

Table 1 compares the IPs of the simo, sequentially fraced wells with the stand-alone Well D. The average IP during the first 30 days shows a fourfold improvement due to sequential and simo-fracing. Based on IP/linear ft of lateral drilled, the simo-fraced wells showed a fivefold improvement.

Table 2 shows a summary of the estimated ultimate recovery (EUR) and recovery factor calculations. We based EUR estimates on decline-curve analysis and estimated gas-in-place assuming a drainage radius of 500 ft from the toe and the heel of the horizontal wells.

We calculated the combined drainage area for the three wells (A, B, and C) at 130 acres and the drainage area for Well D at 85 acres. Based on a gross reservoir thickness of 335 ft, a reservoir porosity of 3%, the calculated corresponding gas-in-place (GIP) was 21.1 bcf and 13.8 bcf, respectively. The adsorbed gas GIP is based on a gas content

of 96 scf/ton.

The analysis indicates a four-fold increase in recovery factor, to about 26% for the simo-fraced wells, from 6.4% for the stand-alone Well D. The average EUR per lateral length also showed a 2.5-fold increase and was 0.9 MMcf/ft of lateral for the simo-fraced wells vs. 0.37 MMcf/ft of lateral for the stand-alone well.

This case shows a significant enhancement in IPs, EURs, and recovery factors because of simultaneously fracturing the wells compared with individually fracturing a stand-alone well.

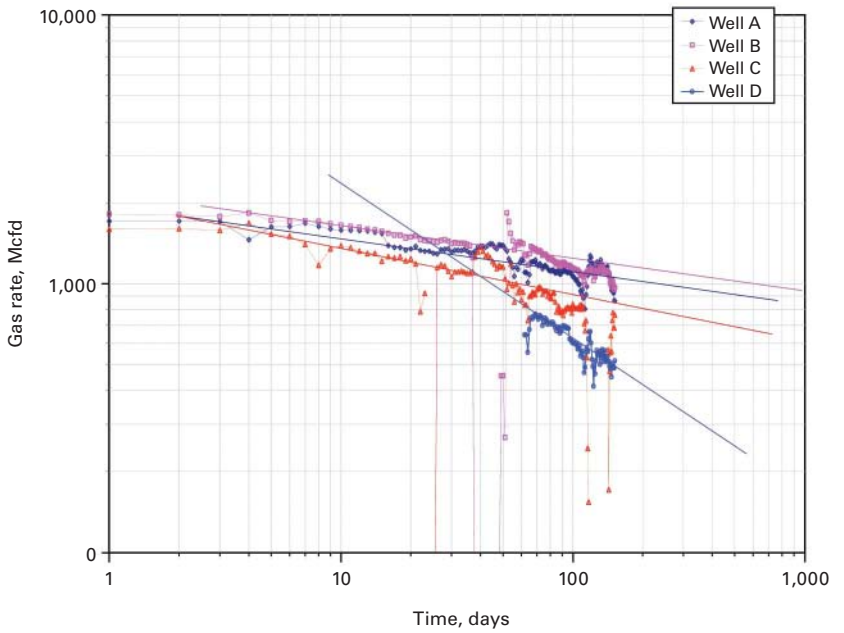
Production data analysis

Conventional graphical-interpretation techniques in hydraulically fractured tight-gas wells are typically based on analyses of flow-regimes, such as linear, bilinear, or pseudoradial flow. For low-permeability wells, the time required to reach radial flow can be impractically long; most of the production data in Barnett wells are either bilinear or linear flow.

In bilinear flow, the flow occurs both inside the fracture and outside the fracture, perpendicular to the fracture (Fig. 4). If the fracture has low permeability, bilinear flow will occur over a longer period. On the other hand, in linear flow, the flow occurs only perpendicular to the fracture. If the fracture has sufficient permeability, bilinear flow will last for a short period before linear flow begins.

Fig. 5 shows production data from the four wells on a log-log diagnostic plot of production over several months. Well D production data occur closer to bilinear flow (slope = 0.25) compared to the other three wells, which can be represented by linear flow (slope = 0.5). This implies that the quality of fracture is not as good in Well D as in the other three wells, which may be due to the types of fracture created. Since the three southern wells were simultaneously fractured, it is likely that better fractures were created in these three wells as compared to Well D.

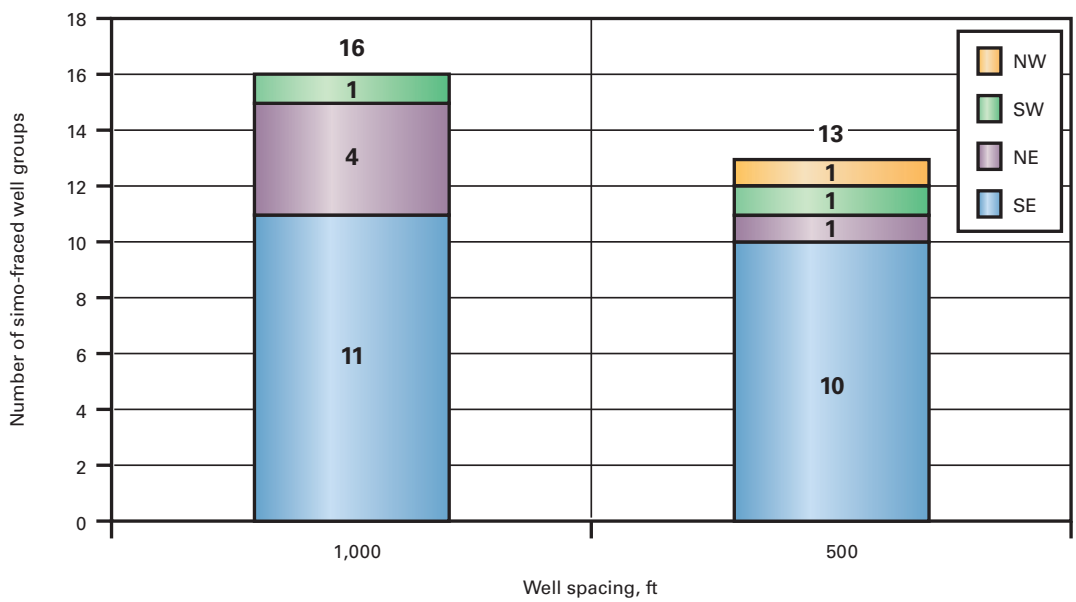
BARNETT WELL PRODUCTION Fig. 5



Frac data analysis

We reviewed the data from the fracturing jobs to evaluate possible rea-

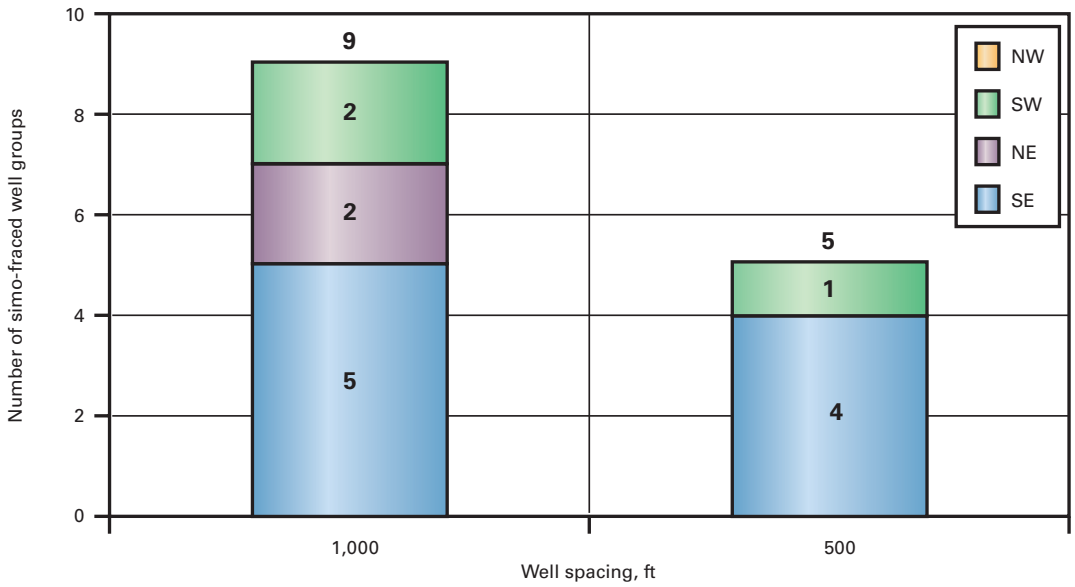
SIMO-FRACED WELL GROUP DISTRIBUTION BY SPACING, QUADRANT* Fig. 6



*Distribution of simo-fraced well groups in Parker County, Tex., distinguished by well spacing and quadrant.

SIMO-FRACED WELL GROUP DISTRIBUTION BY SPACING, QUADRANT*

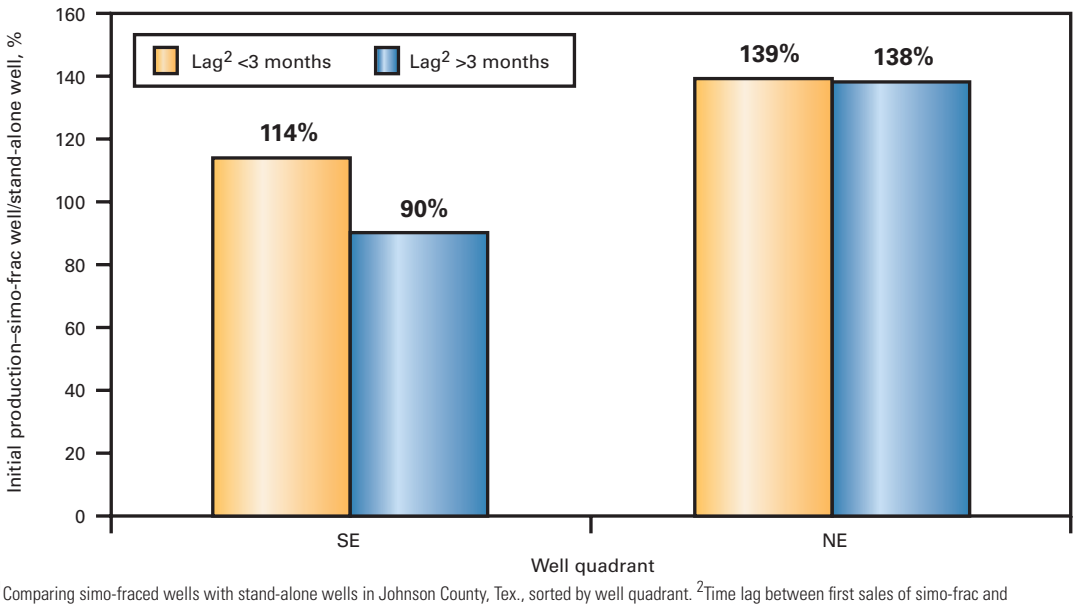
Fig. 7



*Distribution of simo-fraced well groups in Parker County, Tex., with less than 3-month lag between first sales of simo-fraced and stand-alone wells, sorted by well spacing and quadrant.

AVERAGE IP ENHANCEMENT-WELL QUADRANT[1]

Fig. 8



[1]Comparing simo-fraced wells with stand-alone wells in Johnson County, Tex., sorted by well quadrant. [2]Time lag between first sales of simo-frac and stand-alone well production.

sons behind benefits from simultaneous, sequential fracturing. It has been suggested that interaction of the fluid from the different fractures might provide additional energy to enhance the intensity of fracturing, either through higher net pressures or forced diversion of the fluids as they contact other fluid-filled fractures.[5]

Table 3 summarizes frac fluid recoveries and net pressures for the four wells. The results indicate better production performance from Wells A and B, which had higher net pressures, 1,000-1,600 psi, compared to the other two wells.

The percent-fluid recovery also appears to correlate with well production performance. Warpinski et al. suggested that rapid fluid cleanup with a high percentage of load recovery (>50%) may actually indicate that significant fracture network was not generated and only a simple fracture was created that acts like a "balloon" and quickly deflates back into the wellbore.[7]

The data are not consistent with the above observation and further analysis is needed. In the first 100 hr of flowback, Wells A and B had higher fluid recoveries, 20.8% and 10.5%, respectively, whereas the other two wells had fluid recoveries of 3-4%. Well C, despite being a better well compared to stand-alone Well D, had relatively poor fluid recovery. It is likely that due to the simo-frac and the more complex fracture network created near Well C, part of the flowback fluid was recovered in the offset wells, A and B.

Parker County simo-frac

To quantify the benefit from simultaneous fracturing further, we performed a comprehensive study, evaluating public data of simo-fraced

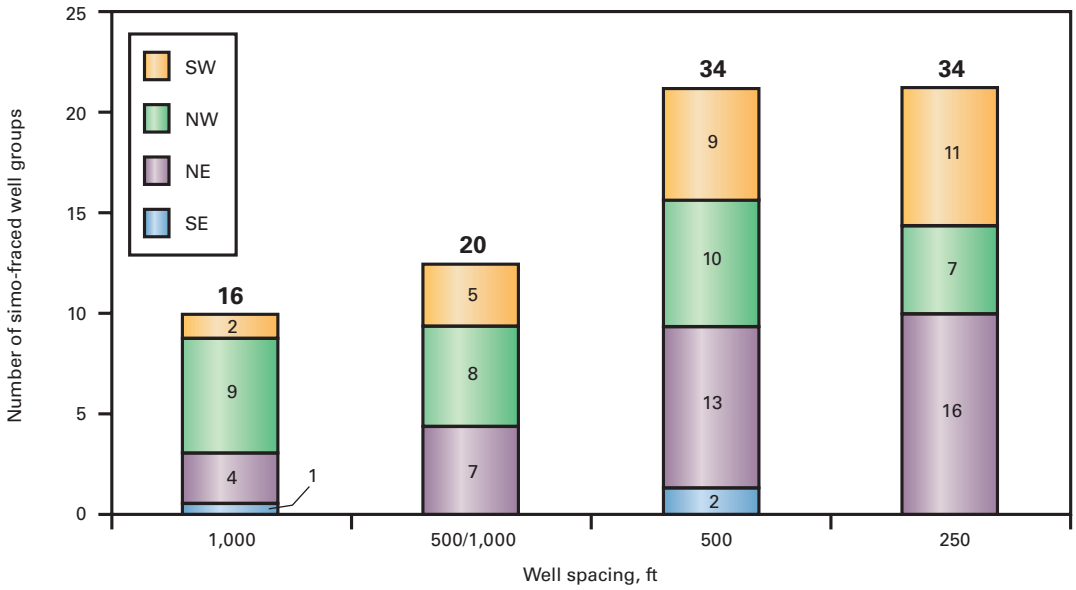
wells in Parker County.

We identified 29 groups of simo-fraced wells, based on first date of production in the same month or within 1 month of each other. We compared the production performance of these wells with that of stand-alone wells drilled within 1-1.5 miles from the simo-fraced wells. Thus, each group consisted of three wells: two simo-fraced wells and one stand-alone well.

For about 75% of the cases, the simo-fraced wells and the stand-alone wells were drilled by the same operator. Our analysis is based on production performance alone, provides general guidelines, and does not consider the influence of other parameters, such as local geology, frac design, frac injection rates, number of stages, etc., all of which can impact production performance.

WELL GROUP DISTRIBUTION BY SPACING, QUADRANT*

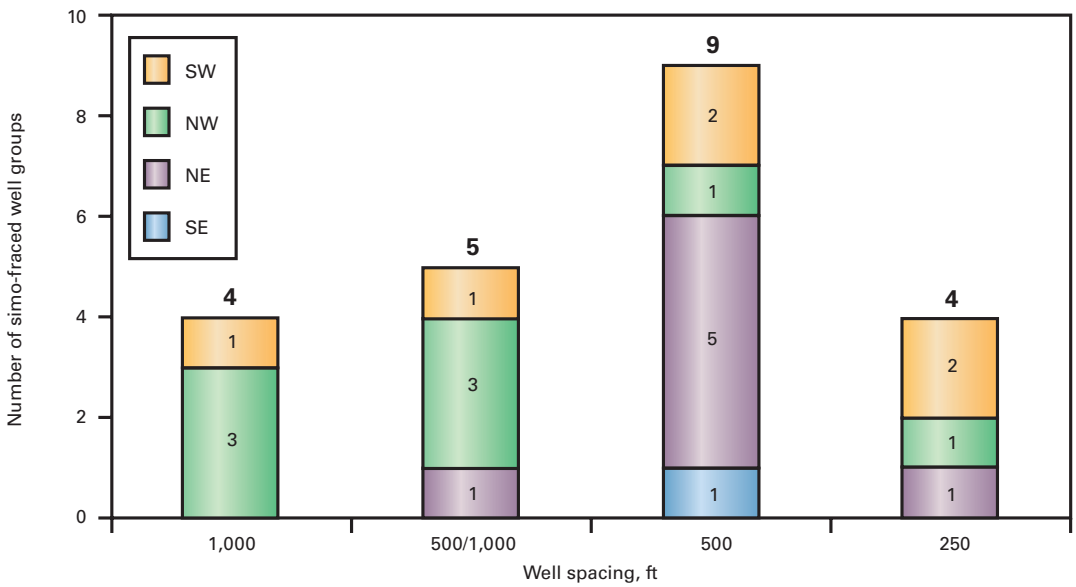
Fig. 9



*Distribution of all simo-fraced well groups in Johnson County, Tex., sorted by well spacing and quadrant.

WELL GROUP DISTRIBUTION BY SPACING, QUADRANT, <3-MONTH LAG*

Fig. 10



*Distribution of simo-fraced well groups in Johnson County, Tex., with less than 3-month lag between first sales of simo-fraced and stand-alone wells, sorted by well spacing and quadrant.

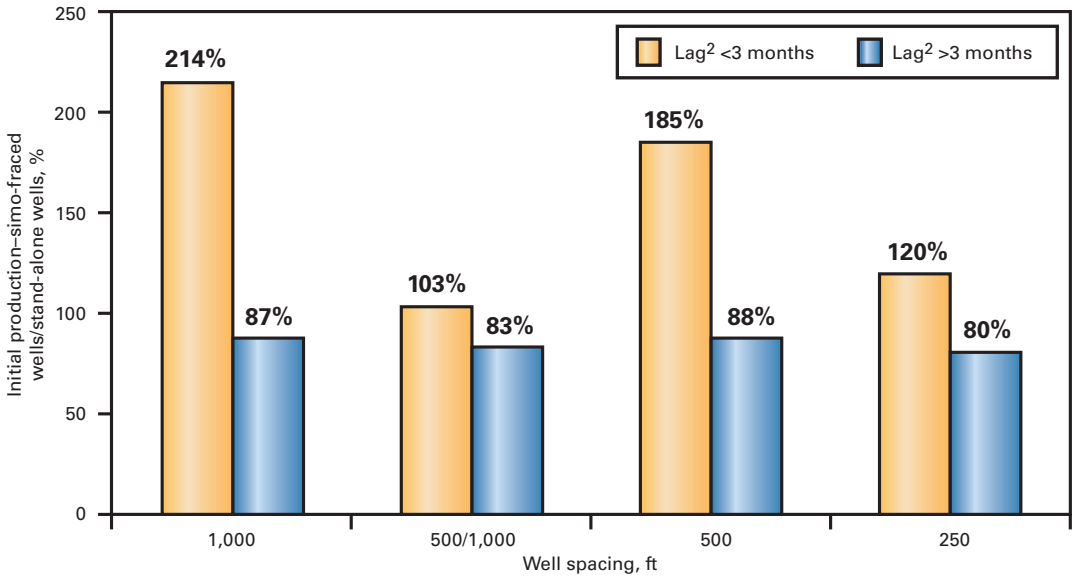
Fig. 6 provides a distribution of the simo-fraced wells by well spacing and quadrant. Of the 29 groups, about 55% (16 groups) included wells spaced 1,000 ft or greater and the rest were spaced about 500 ft. Most of the drilling activity in Parker County has been in the eastern half where the reservoir thickness is relatively higher. Thus, in terms of the location of the wells, almost 72% (21 groups) were in southeast quadrant and 90% (26 groups) were in eastern half of Parker County.

Using Parker County production data for simo-fraced wells, we evaluated the time lag between first sales of simo-fraced and stand-alone wells as a possible factor in the success of the simo-frac over stand-alone wells.

Fig. 7 provides a distribution of simo-fraced well groups with less than

AVERAGE IP ENHANCEMENT-WELL SPACING[1]

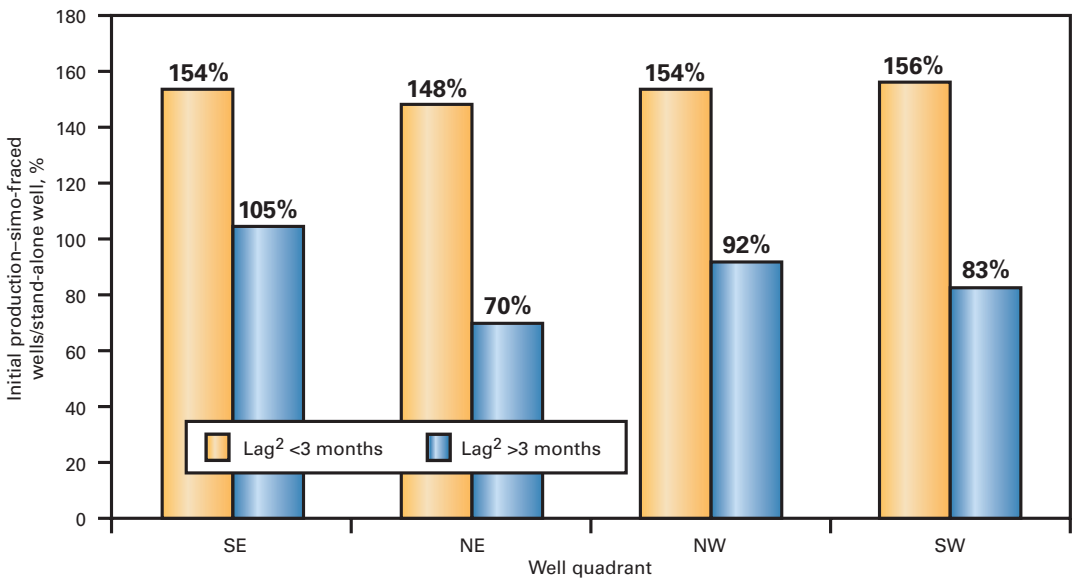
Fig. 11



[1]Comparing simo-fraced wells with stand-alone wells in Johnson County, Tex., sorted by well quadrant. [2]Time lag between first sales of simo-frac and stand-alone well production.

AVERAGE IP ENHANCEMENT-WELL QUADRANT[1]

Fig. 12



[1]Comparing simo-fraced wells with stand-alone wells in Johnson County, Tex., sorted by well quadrant. [2]Time lag between first sales of simo-frac and stand-alone well production.

3-month lag between first sales of simo-fraced and stand-alone wells, sorted by well spacing and quadrant in Parker County. About 50% of the well groups fell in this category, with many of the wells drilled on 1,000-ft spacing.

Fig. 8 provides a summary of the production enhancement seen in each of the quadrants of Parker County. We compared peak monthly production, which for most of the cases, is in the first or second month of well life.

The analysis of wells in the southeast quadrant, representing more than 70% of well groups, suggests that wells that had less than 3-months' lag between the simo-fraced wells and the stand-alone wells had the best success rate to see incremental production and reserves due to simo-fracing.

In the northeast quadrant, the simo-fraced wells outperformed the stand-alone wells, regardless of when the wells were completed. This could be attributed to factors such as variations in frac design or injection rates, as well as regional geology.

Johnson County simo-frac

Johnson County has seen a significant increase in drilling activity in recent years; operators have drilled some of the best-producing Barnett shale wells in this county.

To date, more wells have been simo-fraced in Johnson County than in Parker County. A total of 104 groups of simo-fraced wells was identified in Johnson County based on first date of production in the same month or within 1 month.

Fig. 9 provides a distribution of the simo-fraced wells by well spacing and

quadrant. Of the 104 groups, about 33% (34 groups) had wells drilled on 500-ft spacing. Due to shale thickness and the presence of the Viola limestone in the eastern part of Johnson County, some of the operators began experimenting with 250-ft spacing. About 33% (34 groups) included wells drilled on 250-ft spacing. About 40% (40 well groups) were in northeast quadrant and another 33% (34 groups) were in the northwest quadrant of Johnson County.

The analysis of the Johnson County production data for simo-fraced wells indicated that time lag between first sales of simo-fraced and stand-alone wells was a key factor in the success of the simo-frac compared with stand-alone well performance. The data suggest that wells that had less than 3 months' time lag between the simo-fraced wells and the stand-alone wells had the best success rate to see incremental production and reserves due to simo-fracing.

Fig. 10 provides a distribution of the simo-fraced wells with fewer than 3 months of time lag between first production from simo-fraced wells and stand-alone wells, sorted by well spacing and quadrant. Comparing Figs. 9 and 10 reveals that only 20-30% of the well groups fell in this category while the majority of the simo-fraced wells (70-80%) were drilled from 4 months to 3 or more years after the stand-alone well was drilled. We identified a few instances where the stand-alone well was drilled later after the simo-fraced wells by a different operator on an offset lease. In such instances, the simo-fraced wells did better than the stand-alone well.

Fig. 11 provides a summary of the production enhancement of simo-fraced wells over stand-alone wells sorted by well spacing. We compared peak monthly production, which for most of the cases, is in the first or second month of well life. The average production enhancement was 56% for simo-fraced wells over offset, nonsimo-fraced wells.

NET PRESSURES, FRAC FLUID RECOVERIES

Table 3

Well	Lateral length, ft	Net pressure, psi	Fluid recovery 100 hr bbl	100 hr %	300 hr bbl	300 hr %
Well A (sequentional frac)	2,195	1,000-1,400	10,738	20.8	22,292	43.3
Well B (simo-frac)	1,955	1,500-1,600	4,749	10.5	11,197	24.7
Well C (simo-frac, infill well)	1,889	400-900	1,421	3	1,457	Max bbl
Well D (stand-alone well)	2,413	200-300	3,073	4	6,359	Max bbl

As expected, the greater the well spacing, the lower the interference and depletion effects. Thus, wells with 1,000-ft spacing had greater incremental gain compared with wells with 500-ft spacing, which did better in turn than wells with 250-ft spacing.

Where the simo-frac wells were drilled more than 3 months after the stand-alone well, the production performance fell significantly and the average IP of simo-fraced wells was less than that of the stand-alone well (about 85% of the stand-alone well). We attribute this to possible interference and depletion effects, which might change the stress profile near the wellbore. Again, wells on 250-ft spacing were most affected by interference and depletion effects and had the lowest IPs compared to stand-alone wells at 80%.

Fig. 12 provides a summary of the production enhancement seen sorted by quadrant for Johnson County. The results indicate an average production enhancement of 53% in simo-fraced wells compared with offset, nonsimo-fraced wells. If a simo-frac well was drilled more than 3 months later, the average IP of the simo-fraced well was 87% of the stand-alone well.

Surprisingly, the lowest IPs of simo-fraced wells compared with stand-alone wells (70% factor) were in the northeast quadrant in Johnson County, which has generally had prolific producing wells. This may be because the presence of the Voila barrier in most of the northeast quadrant has resulted in operators fracturing with high injection rates and there have been excellent stand-alone wells in the area, even without simo-fracing.

Moreover, in some instances, the stand-alone and the simo-fraced wells (which were identified from maps) may not have been completed by the same operator. Again, the contrasting results could be due to differences in frac design, injection rates, number of stages, completion design, etc.

Observations

Simultaneous fracturing produces a more complex web of fractures, increases the surface area created by the frac, and thereby enhances initial production rates and ultimate recovery.

Simultaneous and sequential fracturing in southeast Parker County doubled production rates, on average, compared to a stand-alone well producing from the same leasing unit. The data appear to indicate that simo-fracing results in more enhanced fracture network and production gains compared to sequential fracturing.

The analysis of the data from simo-fraced wells in Parker and Johnson counties showed an enhancement in average peak IP rates of 21% to 55% over stand-alone wells, for wells that had less than a 3-month lag between first sales from simo-fraced wells and stand-alone wells.

On the other hand, if the time lag between first sales from simo-fraced wells and stand-alone wells was longer than 3 months, the simo-fraced wells showed lower average IP rates compared to stand-alone wells. Any material production from the same reservoir sink from interference and depletion effects causes changes in stress profile near the wellbore, which affects the production performance of

the simo-fraced wells.

Overall, the analysis suggests simultaneous fracturing is a viable technique for application in the Barnett shale reservoir. For the best chance of success, simultaneous fracturing should be planned in the initial wells that are drilled to develop a new lease.

Acknowledgments

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Wytch Farm wireless wellhead monitoring network self-organizes

The smart, self-organizing, wireless transmitters installed recently in Wytch Farm field provide for continuous monitoring of wellhead pressures, thereby eliminating the need for operations personnel to read manually wellhead pressure gauges.

Continuous monitoring eliminates these daily visits to the wellheads and enables operators to identify earlier unusual readings and take action to investigate and rectify faults before they develop into serious problems, according to Emerson Process Management, the company that furnished and installed the network.

BP PLC operates the field from onshore facilities (see photo) that produce from three separate reservoirs that extend offshore under Poole Harbour and Poole Bay, Dorset County, England.

Pumping units in Wytch Farm field have close spacing that may interfere with line-of-sight communications. Photo from BP.

Wireless network

As part of a drive to improve operations, BP says that it wanted to increase the available information, improve worker efficiency, and remove the need for operator rounds.

"Manual reading of pressure gauges on the wellhead was identified as one area we could improve, but we found that wired transmitters were simply too expensive due to the wiring infrastructure needed, so wireless is the perfect technology for this application," explained Chris Geen, BP manager,

The smart wireless network installed on one wellsite at Wytch Farm includes 40 wireless Emerson's Rosemount pressure transmitters.

Mounted on each wellhead are two transmitters. A single smart wireless gateway, mounted outside the process area, connects the transmitters to the control system.

BP collects the data in a PI historian database from which the collected data provide information for regular maintenance activity and safety reports.

Emerson says installation was quick and easy. The work involved isolating the manifold; removing the old dial gauge, and screwing in the wireless transmitter into an existing connector.

The company notes that despite short access periods to the site, it took less than 8 hr, spread over 2 days, to complete installation at the site, including a three-point manual calibration check on every device. It put all devices online within 30 min. Emerson described the wellhead area as open on one side but with cable trays, dense pipe work, and other metal obstructions on the other side that shielded some transmitters from the gateway location.

Self-organizing

Despite obstructions, Emerson says each transmitter when powered up found the gateway with each device quickly and easily joining the self-organizing network. Each wireless device in the self-organizing technology acts as a router for other nearby devices, passing messages along until they reach their destination. If there is an obstruction, the devices reroute the transmissions along the network until they find a clear path to the smart wireless gateway.

As conditions change or BP adds new obstacles—such as temporary scaffolding, new equipment, or a parked construction trailer—to the facilities, these wireless networks reorganize and find a way to get their signals through, Emerson explains.

It adds, "All of this happens automatically, without any involvement by the user, providing redundant communication paths and better reliability than direct, line-of-sight communications between individual devices and a receiver." ✦

Asia petchem expansions to 2015 increase demand for naphtha

Kevin McConnachie
FACTS Global Energy
Singapore

A wave of ethylene investment will take place in Asia during 2009-11 with distinct peaks in early and late 2009. A wave of aromatics investments will take place in 2008-09.

The scale of new petrochemical capacity will support pricing for Asian naphtha through at least 2011 because new ethylene capacity is predominantly naphtha based.

Both production and investments in the petrochemical industry have grown significantly in recent years. Investment is taking place predominantly in China, despite easier access to feedstocks, such as natural gas and naphtha, giving Middle East producers a significant competitive edge. Much of this Middle East capacity is furthermore targeting China. By 2015, China will have as much ethylene capacity as Japan, South Korea, and Taiwan combined.

Asian petrochemicals

The petrochemical sector in Asia is undergoing fundamental change due to three key forces.

The first is the massive expansion of Asian petrochemicals currently under way. The second is the rapid emergence of China as the largest petrochemical producer in Asia. The third is the sharp rise in production capacity in the Middle East.

China Petroleum & Chemical Corp. (Sinopec) and PetroChina are the largest producers in Asia. They both have an ambitious program of ethylene and aromatics investments. Joint ventures have been formed in China to further develop the industry.

Sinopec is not only entering into petrochemical ventures with foreign partners, it is also building integrated refining-petrochemical complexes in partnership with ExxonMobil and Saudi Aramco in Fujian and with Kuwait Petroleum Corp. (KPC) in Nansha, Guangzhou. In fact, joint-venture petrochemical investments in Asia are predominantly in China.

Condensate splitters will provide a new increment of Asian naphtha supply. The massive growth in Asian petrochemicals will support future naphtha markets in Asia as petrochemicals depend more on naphtha supplies from outside the region, primarily from the Middle East. The naphtha market will be strong despite competition for petrochemicals in Asian markets from low cost, gas-based Middle East production.

Asian ethylene

Already a significant region in the global ethylene sector, Asia is adding capacity at an unprecedented rate. Asia has 40 million tonnes/year (tpy) of ethylene capacity currently and is adding 24 million tpy during 2008-15 (Table 1).

This is equivalent to adding more than 50% of base capacity during an 8-year period. A wave of addition takes place during 2009-11 with strong peaks in first and fourth-quarters 2009.

Figs. 1 and 2 show Asia-Pacific ethylene capacity additions by country and year, respectively.

China will add most of the new ethylene production capacity. In 2005,

China for the first time passed Japan to rank second in the world in terms of ethylene production capacity, behind the US. China's gap with the US is narrowing.

China already has 10 million tpy of capacity, now the most in Asia, and is adding 14 million tpy of ethylene capacity during 2008-15. Much of the addition takes place in 2009 (4.95 million tpy) and 2011 (3.8 million tpy).

China, furthermore, could add another 5.5 million tpy of ethylene capacity with projects that are not currently considered firm. The scale of the Chinese industry will then dwarf that of the traditional Asian leader, Japan, and of South Korea, which built a world-scale ethylene industry in the last 2 decades. By 2015, China could have as much capacity as Japan, South Korea, and Taiwan combined.

Fig. 3 shows that Sinopec owns the most ethylene production capacity in China with 4.855 million tpy (48%) and with a share in another 1.5 million tpy of joint-venture capacity (15%). Sinopec's current joint-venture partners are BP and BASF.

The capacity of PetroChina, by contrast, is much lower at 2.78 million tpy (27%). PetroChina has not participated in joint ventures.

Fig. 4 shows that Sinopec will add another 3.4 million tpy on its own and another 2.99 million tpy with joint-venture partners including ExxonMobil, Saudi Aramco, KPC, and SABIC.

PetroChina will build another 4.52 million tpy during 2008-15. PetroChina's new capacity exceeds its current capacity of 2.78 million tpy.

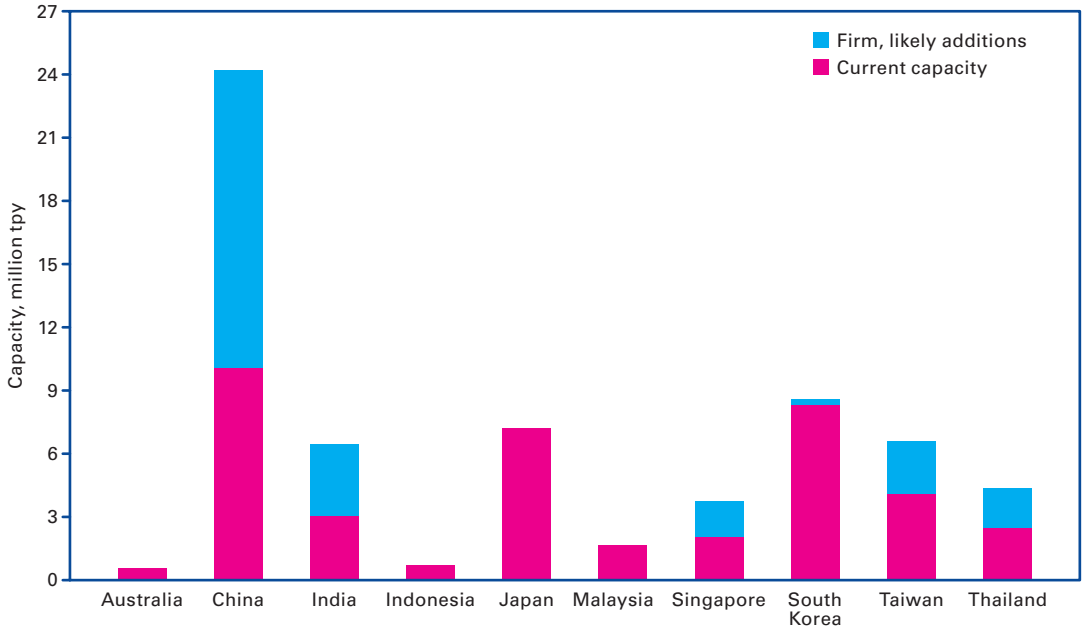
Formosa Plastics Corp. (FPC) had planned to build a 1.2 million tpy ethylene facility at Ningbo in 2014. This project is questionable because the private Taiwanese company may switch the project to Taiwan after the change of government in May 2008.

Many of the new facilities in China are world-scale projects with seven plants of more than 1 million tpy of capacity. China National Offshore Oil Corp. has a joint venture with Shell for an ethylene plant. Predominantly a crude producer, CNOOC built its ethylene and aromatics venture before it built its refinery, which is due to start up in fourth-quarter 2008.

China looks to emerge as the leader in Asian petrochemical production by 2015, with almost three times the capacity of South Korea, the next-largest

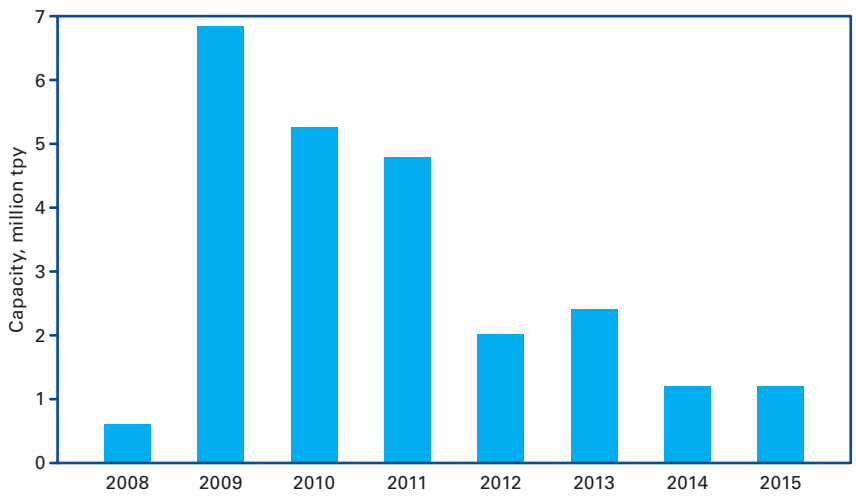
ETHYLENE PRODUCTION CAPACITY

Fig. 1



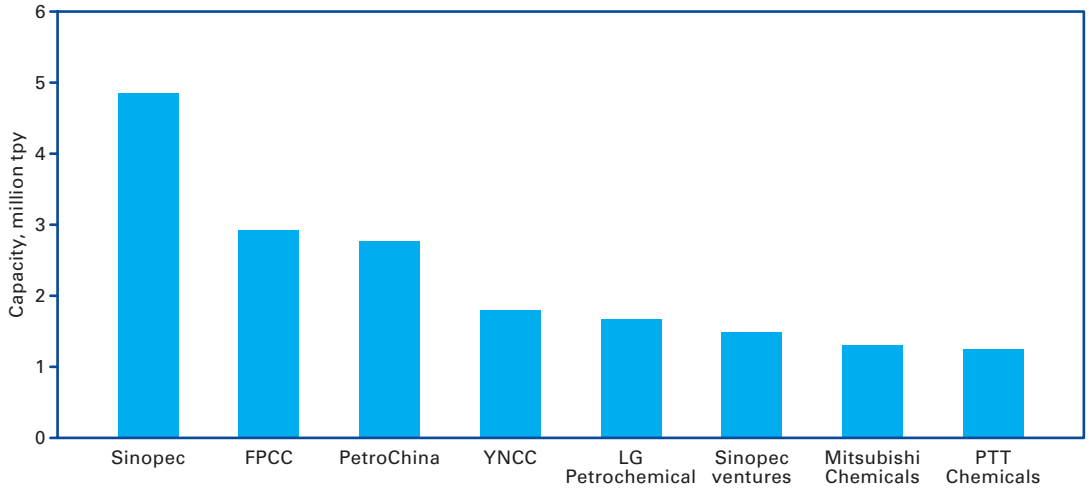
ETHYLENE CAPACITY ADDITIONS

Fig. 2



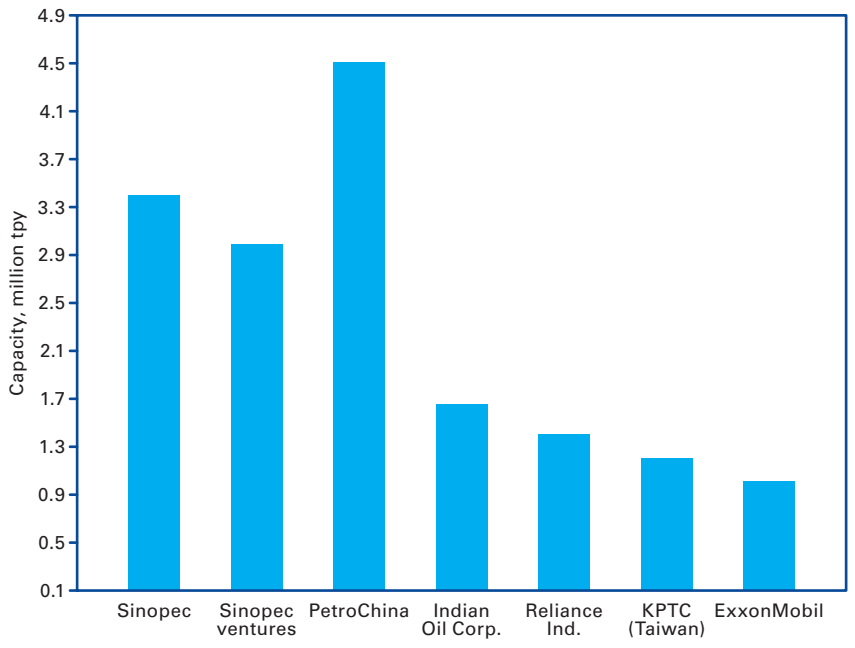
COMPANY ETHYLENE CAPACITY

Fig. 3



COMPANY ETHYLENE ADDITIONS

Fig. 4



country. China petrochemicals is growing much faster than China refining; therefore, China will emerge as a major naphtha importer.

India's ownership is much more dispersed as compared to China. Gas Authority of India Ltd. (GAIL), Haldia Petrochemicals Ltd., Indian Petrochemicals Corp. Ltd., and Reliance Industries Ltd. are all ethylene producers. India's planned expansions are predominantly the Reliance expansion of 1.4 million tpy in 2010, Indian Oil Corp.'s (IOC) expansions at Panipat, 857,000 tpy in 2010, and Paradeep, 800,000 tpy in 2013.

The Indian petrochemical industry is growing more slowly than the refining industry, which will remain a small but important supplier of naphtha exports. India, nevertheless, will still double petrochemical capacity.

Asia's ethylene industry continues to be naphtha based rather than gas based. Even though India, Indonesia, Australia, Malaysia, and Thailand are all able to establish a gas-based industry, nearly all of Asian petrochemicals are based on naphtha or LPG. Thailand's 1-million tpy PTT polyethylene project, however, is ethane based.

Singapore will double its capacity because Shell and ExxonMobil will commission crackers during 2009-11. These projects in Singapore are the only ethylene investments in Asia by the majors other than joint ventures in China with Sinopec.

Expansion of naphtha crackers means greater production of pyrolysis gasoline, most of which will find its way into aromatics production, while a portion will be blended into Asian gasoline.

Aromatics trends

Aromatics capacity growth is slower than ethylene capacity growth (Table 2). Asian aromatics capacity will nevertheless increase more than one-third vs. current levels. Most capacity additions will occur during 2008-09 (Fig. 5).

China will be responsible for half of the expansion in 2008 and nearly all the additions in 2009 (Fig. 6). In fact, China will almost double its capacity and will be responsible for more than half of all the capacity additions in Asia through 2015.

Japan is not expanding ethylene but is expanding aromatics through the Kashima condensate splitter-based project. The concept of the Mizushima condensate splitter project is different; it seeks to feed an existing aromatics complex more efficiently.

Petrochemical projects in Asia outside of Japan target the demand in growing markets. Projects in Japan have a different rationale. They aim to

tighten integration between refining and petrochemicals to meet declining fuel demand.

Singapore will double its capacity mainly through the Jurong Aromatics Corp. plant but also through the ExxonMobil expansion. Elsewhere in Asia, South Korea will add capacity at Hyundai-Cepsa and S-Oil. Taiwan will double its capacity through the KPTC project starting up in 2015; Thailand will increase its capacity by 60%.

Petchem investment trends

Asian refining is becoming increasingly integrated with petrochemicals. Refiners will try to diversify into petrochemicals to secure wider and higher-value markets for refinery products. Petrochemical producers will try to diversify into refining to secure a reliable source of feedstocks and markets for byproducts.

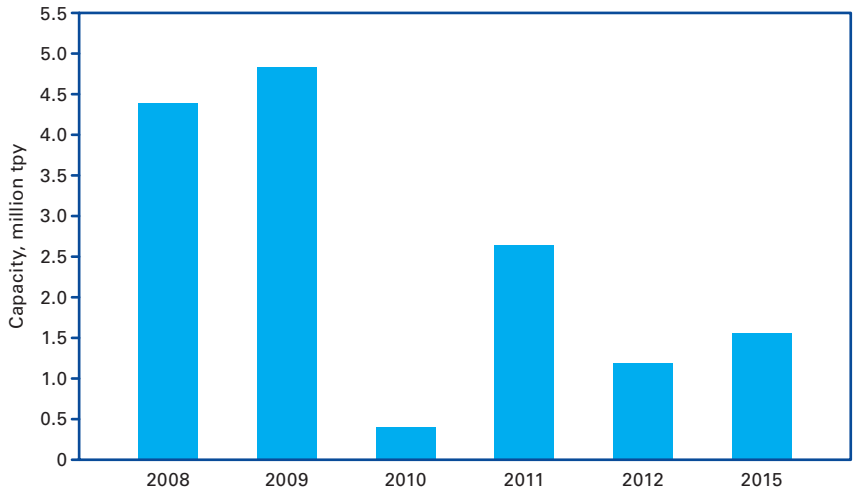
Dependence on the traded naphtha market for feedstocks exposes petrochemical producers to naphtha market volatility. Plants that feed mostly propylene will lean to catalytic cracking-based technologies and therefore look to increase propylene production from refinery catalytic crackers.

The major oil companies are investing directly, like the Shell 800,000-tpy and ExxonMobil 1 million tpy ethylene crackers in Singapore, and in the form of joint ventures with local partners, as in China. The Shell and ExxonMobil investments are integrated with existing refining and petrochemical operations.

Other than China, the majors are only investing in petrochemicals in Singapore, but they are not investing in primary distillation capacity. Investments by majors in Asian refining and petrochemicals are dwarfed by those of local and national oil companies. The majors prefer to invest in integrated refining and petrochemical developments and ethylene facilities on their own

AROMATICS CAPACITY ADDITIONS

Fig. 5



ASIA-PACIFIC ETHYLENE CAPACITY

Table 1

Country	Australia	China	India	Indonesia	Japan	Malaysia	Singapore	S. Korea	Taiwan	Thailand	Total
					Capacity, 1,000 tpy						
Jan. 1, 2008	500	10,115	3,009	700	7,346	1,670	1,980	8,305	4,100	2,436	40,161
Additions											
2008			247					350			597
2009		4,950					800			1,100	6,850
2010		1,120	2,477						770	900	5,267
2011		3,800					1,000				4,800
2012		2,000									2,000
2013		1,000	800						600		2,400
2014		1,200									1,200
2015									1,200		1,200
Total additions		14,070	3,524				1,800	350	2,570	2,000	24,314
Dec. 31, 2015	500	24,185	6,533	700	7,346	1,670	3,780	8,655	6,670	4,436	64,475

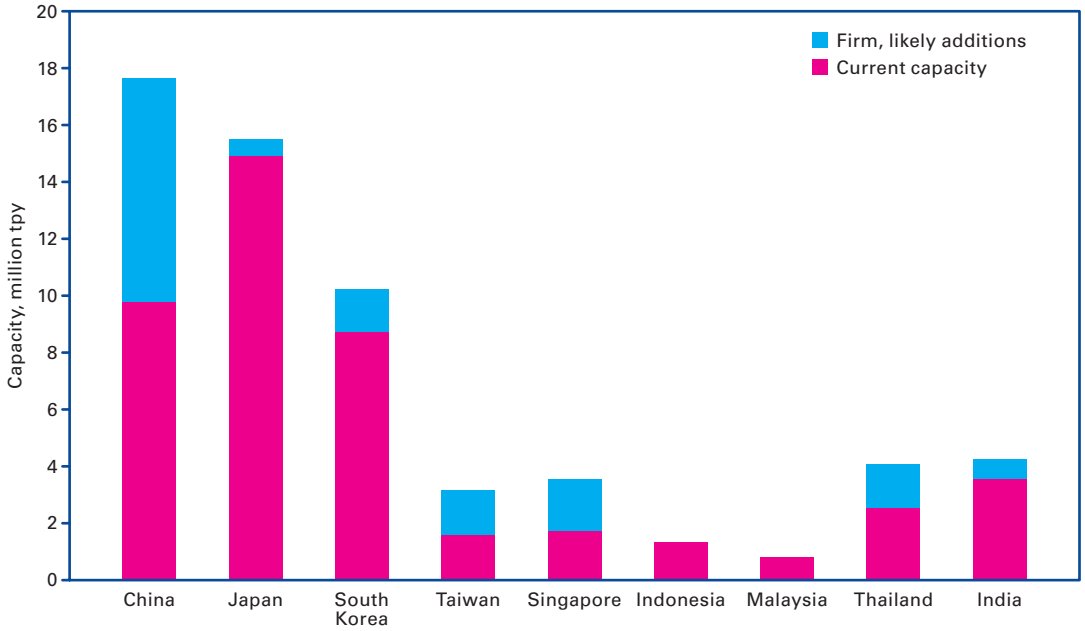
ASIA-PACIFIC AROMATICS CAPACITY

Table 2

Country	Australia	China	India	Indonesia	Japan	Malaysia	Singapore	S. Korea	Taiwan	Thailand	Total
					Capacity, 1,000 tpy						
Jan. 1, 2008		9,800	3,527	1,287	14,960	765	1,691	8,727	1,525	2,534	44,816
Additions											
2008		2,287			580					1,519	4,386
2009		4,391						350	90		4,831
2010		400									400
2011		800					1,840				2,640
2012								1,180			1,180
2013											
2014											
2015									1,550		1,550
Total additions		7,878	731		580		1,840	1,530	1,640	1,519	15,718
Dec. 31, 2015		17,679	4,258	1,287	15,540	765	3,531	10,257	3,165	4,053	60,535

AROMATICS PRODUCTION CAPACITY

Fig. 6



rather than in pure refining developments.

The major oil companies initially invested in China because the country's large deficit in petrochemicals represented a huge market. This investment was even more attractive after China entered into the World Trade Organization.

Early investments in the petrochemical sector included Sinopec-BP in the Shanghai Secco ethylene-aromatics facility, Sinopec and BASF in the Yangzi ethylene-aromatics facility, the GS Caltex-led aromatics venture, and CNOOC-Shell in the Huizhou ethylene-aromatics facility. The Chinese government favored foreign investment and advanced technologies to advance the ethylene development program.

There are two cases in which joint ventures are made for the first time in China in integrated refining-petrochemical complexes. The first is the Sinopec-ExxonMobil-Saudi Aramco Fujian venture, which includes an 800,000-tpy ethylene cracker being built along with the 160,000-b/d Fujian refinery expansion. The second is the Sinopec-KPC Nansha-Guangzhou venture, which includes a 1 million tpy ethylene cracker being built in association with a grassroots refinery.

Table 3 shows China's joint-venture partnerships, both existing and planned.

All of the Asian joint-venture petrochemical investments are in China. Besides the Fujian and Nansha refining-petrochemical investments, Sinopec and SABIC are building a 1 million tpy ethylene cracker in Tianjin.

Sinopec and BP are expanding the Secco Shanghai ethylene cracker by 190,000 tpy. This is in addition to the already-established CNOOC-Shell Huizhou venture, which will be linked into the CNOOC Huizhou refinery starting up in fourth-quarter 2008.

In addition to these joint-venture investments, Formosa is building a massive 1.2-million tpy ethylene cracker at Ningbo without a local partner.

There are four pure refining ventures with local partners. These ventures include the Sinopec-Saudi Aramco 200,000-b/d Qingdao refinery, the Chevron investment in Reliance, the International Petroleum Investment Co.-PakArab Refinery Ltd. 250,000-b/d refinery in Pakistan starting up in 2013, and the Idemitsu-KPC-Mitsui partnership with Petrovietnam in the 200,000-b/d Nghi Son refinery in Vietnam.

CHINA PETCHEM JOINT VENTURES

Table 3

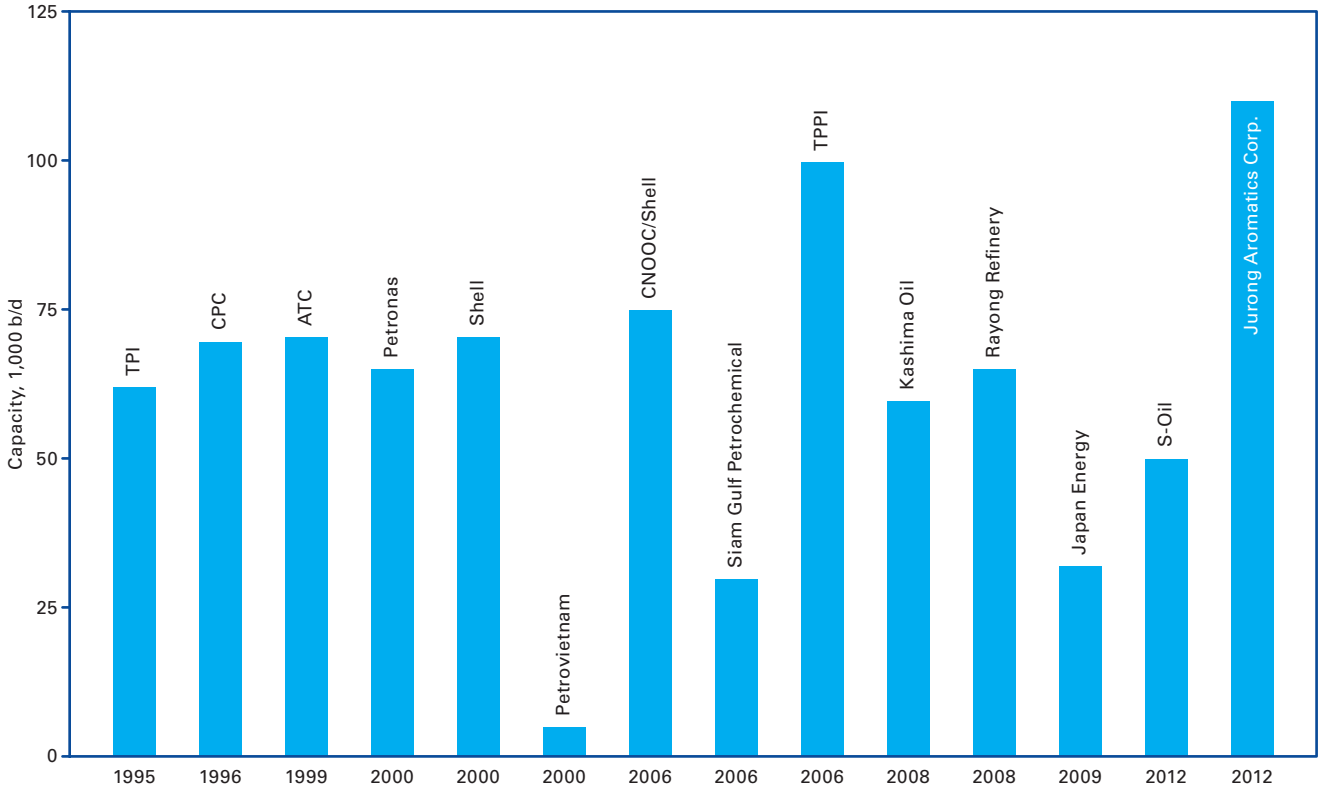
Plant	Companies	Province	Completion	Ethylene — Capacity,	Aromatics 1,000 tpy —
Shanghai	Secco (Sinopec, BP)	Shanghai	Existing	900	480
Yangzi	Sinopec, BP	Jiangsu	Existing	600	300
Huizhou	CNOOC, Shell		Existing	800	460
Qingdao Lidong	GS-led joint venture		Existing		340
Fujian	Sinopec, ExxonMobil, Saudi Aramco	Fujian	First-quarter 2009	800	700
Tianjin	Sinopec, SABIC	Tianjin	Third-quarter 2009	1,000	
Shanghai	Secco (Sinopec, BP)	Shanghai	Fourth-quarter 2009	190	
Nansha/Guanzhou	Sinopec, KPC	Guangdong	Fourth-quarter 2012	1,000	
Ningbo	FPC	Zhejiang	Second-quarter 2014	1,200	

Condensate splitters

Asia has a well-developed and growing condensate-splitting industry mostly serving the petrochemical sector. Condensate splitters are built in Asia to provide feedstock flexibility between condensate and naphtha to downstream ethylene crackers and aromatics complexes.

Asia condensate splitters

Fig. 7



Two Asian condensate splitters started up in 2006. Five more condensate splitters are scheduled to commission during 2008-12 (Fig. 7).

In China, the CNOOC-Shell consortium started up its $4.2-billion project in early 2006 at Daya Bay in Huizhou. It included a 75,000-b/d condensate splitter and condensate or naphtha cracker. The heart of the complex is a world-scale cracker producing 800,000 tpy of ethylene and 430,000 tpy of propylene.

It is designed to feed naphtha as well as condensate, the first of its kind in China. The project may be integrated with the CNOOC Huizhou refinery, starting up in fourth-quarter 2008. The refinery will process Bohai Bay crude, which could provide naphtha feedstock to the Shell-CNOOC complex.

In Indonesia, the Tuban condensate splitter, owned by Trans Pacific Petrochemical Industries, also started up in 2006. Construction started in the 1990s but was suspended at two thirds of completion due to the Asian financial crisis in 1998. The aromatics complex was completed after a consortium of Japanese banks granted financing.

Splitter output includes middle distillates, toluene, and xylenes. It does not have ethylene cracking and is not linked to a refinery.

In Thailand, the PTT-Aromatics (Thailand) Public Co. Ltd. (ATC) Rayong complex will be transformed into a world-class condensate splitting facility serving a downstream petrochemical complex. The complex will become the third-largest aromatics facility in Asia.

The ATC condensate splitter in Rayong, Thailand, was built in 1999 to supply downstream aromatics because the PTT refining system could not manufacture enough naphtha. Paraffinic naphtha is sold to other PTT ethylene crackers nearby.

A second condensate splitter is being constructed as part of a new arrangement that will integrate the PTT Rayong refinery with ATC. This integration also creates benefits for the refinery, as well as creating links between the new ATC condensate splitter and new downstream aromatics complex.

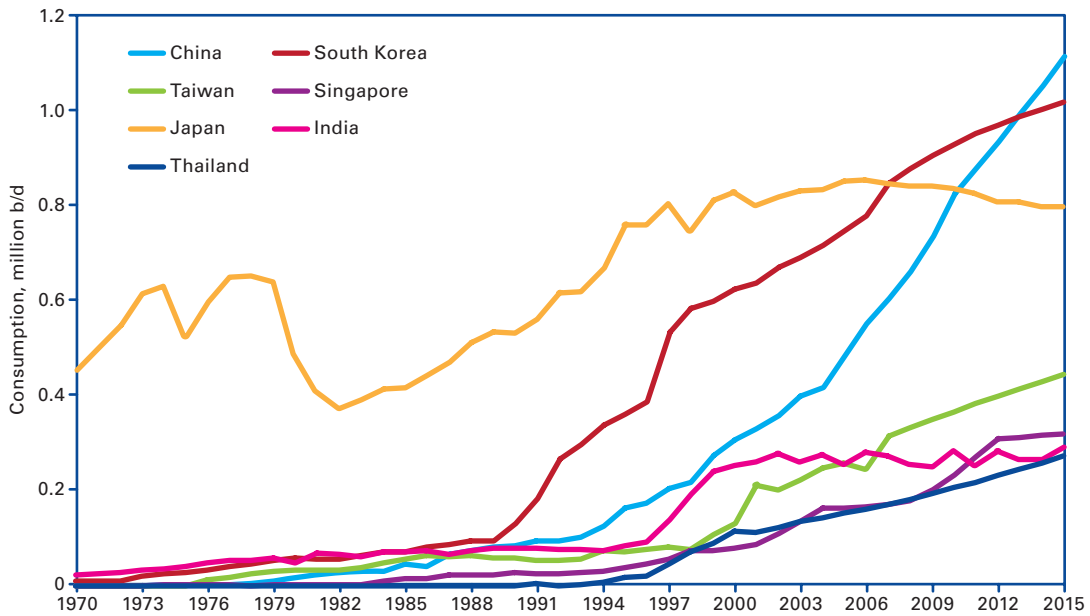
The project, scheduled to start up in third-quarter 2008, includes $387 million for a reforming complex, including the condensate splitter and a catalytic reformer to manufacture BTX for the new aromatics complex. This complex is a truly integrated refinery-petrochemical operation linking refining, condensate splitting, and aromatics, and providing feedstock for PTT ethylene crackers.

In Japan, a new 60,000-b/d condensate splitter was added to the Kashima refinery in 2008. Kashima Oil (a group company under Nippon Mining Holdings Inc., which is affiliated with Japan Energy) owns the splitter. The condensate splitter is part of the joint-venture project between Japan Energy Corp., Mitsubishi Chemical Corp., and Mitsubishi Corp.

Through the joint-venture com-

NAPHTHA CONSUMPTION

Fig. 8



pany, Kashima Aromatics Co., the three firms constructed a petrochemical complex, which consists of paraxylene production facilities (420,000 tpy), a 20,000-b/d catalytic reformer, and the condensate splitter. The Mizushima condensate splitter is part of the integration project with Nippon Oil. One of the key goals is to increase further the level of integration in the Mizushima region.

The start-up date for the 34,000-b/d Mizushima condensate splitter in the Okayama prefecture is second-quarter 2009. This is a venture with Mitsubishi Chemical Holdings Corp. and Asahi Kasei Corp. to produce naphtha.

In South Korea, S-Oil will spend $1.5 billion to build an aromatics complex, including a 50,000-b/d condensate splitter, scheduled for start-up in 2011-12. The aromatics complex will have 900,000 tpy of paraxylene capacity and 280,000 tpy of benzene capacity. This will be South Korea's first condensate splitter even though it is the largest consumer of condensate in Asia.

In Singapore, Jurong Aromatics Corp. (JAC) plans to build a $2 billion petrochemical complex on Jurong Island by 2012 that will include a 110,000-b/d condensate splitter. Partners in the JAC project include Jurong Energy Corp., Continental Chemical, Glenore, SK Energy, Noor Financial Investment Co., and Jiangsu Sanfang-Xiang Industrial Group Corp.

JAC has signed a $10 billion feedstock contract with BP that includes condensate supplies from the Middle East. This will be the second condensate splitter in Singapore.

Naphtha demand

The massive growth in Asian petrochemicals means that the region will depend even more on naphtha supplies from outside the region, principally from the Middle East. Despite enormous volumes, a handful of countries in North Asia dominate this demand.

China is the key growth market of this decade and the next. Japan is a large but slowly declining consumer. South Korea will overtake Japan in 2008 and China will overtake South Korea in 2011.

Naphtha consumption in South Korea climbed steeply after 1989 as the petrochemical sector developed, but is now leveling off. In 2001, naphtha consumption in Taiwan followed a similar pattern as South Korea but the growth rate was not as rapid.

One of the most enduring features in the region's demand has been the strength of naphtha. Even the financial crisis of 1997-98 did not affect naphtha demand.

Fig. 8 shows trends in Asia-Pacific naphtha consumption.

Total naphtha consumption in China was about 600,000 b/d in 2007, and it will increase to about 825,000 b/d by 2010 and exceed 1.1 million b/d by 2015. China intends to maximize chemical feedstocks from existing refineries, allowing more middle distillates to be used as petrochemical feedstocks. China will become the largest naphtha consumer in Asia by 2011. China was almost a net naphtha importer in 2007.

The developing South Korean petrochemical industry led Asian naphtha demand during the 1990s. Naphtha growth was strong during 2006-07 due to expansions in Yeocheon's Naphtha Cracking Centre, LG Petrochemical Co. Ltd., and LG Daesan Petrochemical.

Demand growth is now falling due to slowing petrochemical construction. Total naphtha consumption in South Korea was around 850,000 b/d in 2007 and will increase to 930,000 b/d by 2010, making South Korea temporarily the largest naphtha consumer in Asia. After 2010, naphtha consumption in South Korea will grow at about 2.0%/year, reaching about 1.02 million b/d by 2015.

Japan remains the largest consumer of naphtha in Asia-Pacific. Demand,

however, has grown only marginally in recent years. Total naphtha consumption in 2007 was about 850,000 b/d, and will decline to about 840,000 b/d by 2010 and 800,000 b/d by 2015

Asia-Pacific imports will increase to about 1.2 million b/d in 2010 and 1.38 million b/d in 2015 from 0.88 million b/d in 2007. India is the only significant naphtha exporter that still has a significant petrochemical industry, and is increasing exports as refining expansions outpace petrochemical expansions.

Asia will experience growth of about 4.0% in naphtha consumption during the next 5 years, mainly due to the expansion of ethylene capacity in China. Naphtha output in Asia will grow at about 2.8% during the same period.

China to a large extent, but particularly Japan, South Korea, and Taiwan, will always depend on naphtha feedstocks. They will feel the most pressure during periods of higher naphtha prices. Although naphtha prices will strengthen in the long run compared with current prices, there will be periods of weakness due to weaker gasoline and chemical prices and the availability of naphtha from west-of-Suez countries.

Producers in Australia, India, Indonesia, Thailand, and Malaysia may have easier access to large quantities of ethane recoverable from natural gas reserves. This will guarantee lower-cost ethylene production and sustainability as they switch feedstocks in future capacity expansions.

Malaysia and Thailand are already partly gas based. Thailand's expansions are either gas based or have gas-naphtha flexibility.

Asian petrochemicals is undergoing profound change led by massive growth in Chinese and Middle East capacity and the prospect of intense competition for Asian markets from these Middle East producers. The growth in Asian capacity lends sustained support to naphtha prices, and competition from the Middle East will place margins under pressure.

Low-cost exports from the Middle East may force the cancellation of projects in consuming countries due to expensive gas or naphtha. Although this theory may prove correct in the long run, consumer countries may retaliate by imposing tariffs and dumping regulations to protect their own industries. It is clear, however, that the demand for naphtha in Asia-Pacific will outpace output in the next few years. ✦

The author

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China, India lead growth in Asian refining capacity

John Vautrain
Purvin & Gertz
Singapore

Asian refining capacity continues to grow rapidly despite the effects of a suffering global economy. China and India especially are fast-growing economies that are leading demand growth for transportation fuels.

This article reviews the factors that influence refined-product demand growth in Asia and the future of refining projects in Asian countries.

Asian refining demand

East of Suez refining continues to increase even as Atlantic Basin refiners feel the effects of a global recession. For the past decade, most global petroleum demand growth has occurred East of Suez as Asian economies grow rapidly. Although economic signals are not certain, Asian petroleum demand and refining will continue to expand in the next 5 years.

Asia consists of many different economic and political systems. Some Asian economies continue to be heavily centrally planned and others are based on free markets. Politically, one-party systems continue in countries like China and Vietnam while turbulent and often multiparty democratic coalitions govern India.

In petroleum, national oil companies or other dominant state-run enterprises supply many countries such as China, India, Indonesia, and Vietnam. Alongside the state-run companies are innovative private-sector enterprises.

Four countries dominate Asian petroleum demand: China, Japan, India, and South Korea (Fig. 1).

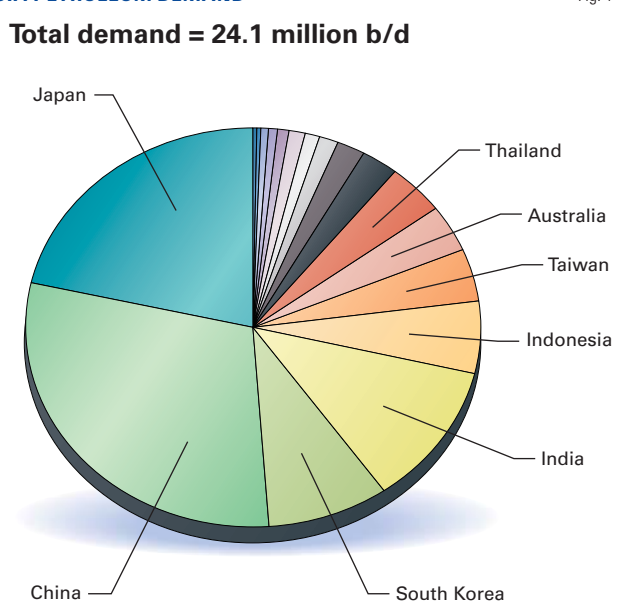
Economically, the Asian economies as a group are healthier than their Atlantic Basin counterparts.

Although 2008 was a relatively poor year by Asian standards, substantial positive GDP expansion will continue in key economies. Many Asian economies have healthy reserves that can be called on to soften the indirect blow of the global economic downturn as China has announced.

Chastened by the disastrous 1997 Asian Financial Crisis, the banking systems and their regulators have been more cautious than their American and European counterparts. Asian banking systems have been spared the worst of the subprime mortgage crisis and

ASIA PETROLEUM DEMAND

Fig. 1



related credit default swaps problems.

China and India stand out as examples of diesel oriented, fast-growing economies (Fig. 2). China and India account for nearly 10 million b/d of demand. Both these populous countries have healthy economies, expanding on the order of 7-11%/year of GDP, and low penetration of private sector automobiles.

An important factor in transportation fuel demand growth in India and China is a growing private-sector automotive fleet. High GDP growth translates directly into higher GDP per capita.

Income disparities across the economy coupled with rising GDP per capita, large population, and favorable demographics mean that large numbers of persons are entering the middle class each year. Some of those individuals are new purchasers of private sector automobiles each year and begin to contribute more to national fuel demand. That growth of the driving middle class is a far more important determinant of fuel demand than price-induced conservation.

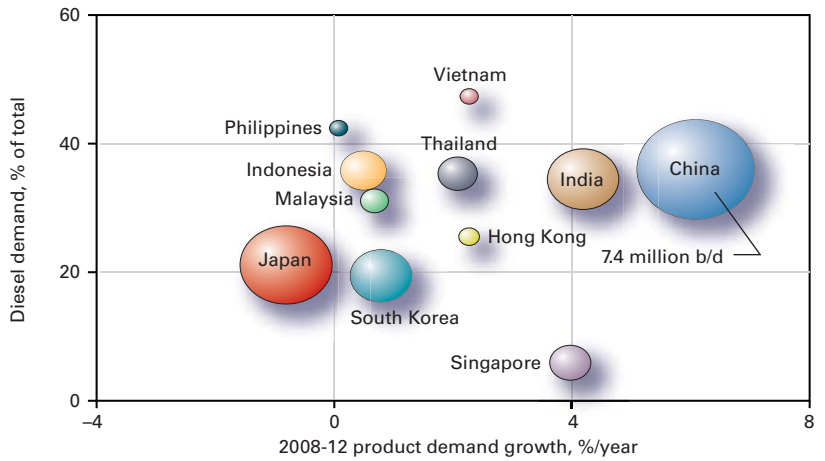
Southeast Asia has many smaller petroleum economies with slower-growing demand. Demand expansions in this region remains positive but low. Many of these countries have experienced considerable reductions due to high petroleum prices even though economic outlook for these countries remains generally favorable by international standards, about 5-7%/year GDP growth.

South Korea is a fairly static petroleum market. Wealthy by Asian standards, the South Korean economy already enjoys high penetration of private automobiles, and the outlook for growth in that sector is low.

Japan is the only sizable shrinking petroleum economy in the region. Japan's economic performance has been lackluster for more than a decade. Declines in property values and banking sector woes began in Japan in the early 1990s after the speculative bubble of the 1980s. Japanese regulators have mishandled this problem over the years.

ASIA DIESEL DEMAND*

Fig. 2



*Size of each bubble refers to total product demand.

The Japanese population has been both shrinking and aging. Birth rates in Japan are below the levels needed to sustain the population and inward migration is discouraged. Japanese regulators take Kyoto obligations toward greenhouse gas reductions far more seriously than their counterparts in Europe, and as a result considerable efficiency gains are coming in an already energy-efficient economy.

Fuel subsidies

Fuel subsidies have been overstated as a trigger for Asian petroleum demand.

In many Asian economies, petroleum pricing is not as volatile or as closely in step with international prices as compared with product prices in the US. There is some degree of cross-subsidization that occurs. For leading economies, however, prices are not very different from international prices.

China has a system of price controls on common consumer fuels. Before crude prices started to rise in 2004, China had a goal of gradually releasing prices from controls. High prices have delayed that program.

Fig. 3 shows the price track from 2003 for gasoline in South China. Prices have risen throughout that historical period. Most of the time, prices were somewhat below international parity as Chinese authorities often expected that international price rises would be transient, an expectation shared by many observers over this era.

The most serious pricing discrepancies occurred only in 2008 due to the astronomical rise in crude prices. After the more recent price collapse, while Chinese diesel remains under international parity, international product prices have fallen below domestic Chinese prices for gasoline.

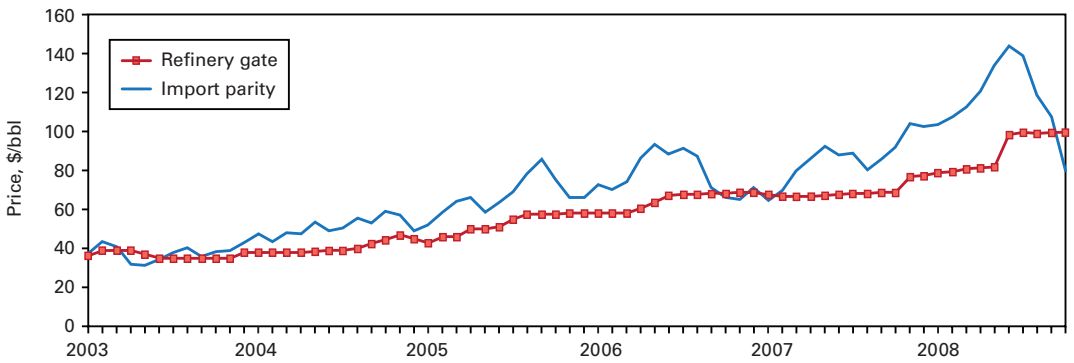
In India, the pattern is different and retail gasoline prices have generally been considerably higher than corresponding US prices. Heavy subsidies are involved in determining that price but also heavy taxes. Taxes at the state level far exceed the federal-level subsidy leading to consumer prices that are very high notwithstanding low, controlled retail margins.

In both countries, diesel prices typically are less than gasoline prices. Gasoline is often treated as a luxury item, something purchased typically by the upper social strata. Diesel fuel is treated as a more common fuel, important to commerce and agriculture. Tax and pricing treatment in many Asian countries have the effect of cross-subsidizing diesel fuel somewhat at the expense of gasoline.

Overall, the pricing structure has had relatively little influence on Asian de-

SOUTH CHINA GASOLINE

Fig. 3



mand growth. The volume of fuel sold at heavily subsidized prices in countries like Malaysia and Indonesia is far less than the volumes in markets with prices closer to or exceeding international parity levels.

China refining outlook

China continues its run of refining expansions and record-setting demand. Chinese demand is heavily oriented to light products and refinery resid production is quite low. Historically, Chinese refiners produced resid in proportions similar to US refiners—about 6.2% of total refinery product volume.

Chinese so-called "teapot" refineries have experienced difficult market conditions during the past year. The term "teapot" refinery is misleading in that many of these plants are sophisticated even if not large by worldwide standards. Some "teapots" have full conversion of heavy feedstocks combined with power production from coke.

The "teapot" refineries are outside the national system that favors CNPC and Sinopec. Consequently, they lack direct access to low-priced domestic crude and also to international crude markets. They are, nevertheless, subject to the same product price controls as the national refiners.

These refiners use residual materials historically from Russia and more recently from the Middle East via Fujairah as feedstocks. Some crude access is achieved through tie-ins with local government entities or by small but favorable deals with CNOOC or the national refiners.

The combination of product price controls and internationally priced feedstocks caused this group of refiners to suffer seriously depressed or negative margins through much of 2008. Recent price declines have eased their situation.

CHINA CAPACITY ADDITIONS*

Table 1

Year	Company	Location	Crude distillation capacity, 1,000 b/d
2008	CNPC Fushun Petrochemical	Fushun	160
	CNPC Dushanzi Refining	Karamay	200
	Sinopec Group	Qingdao	200
	Qinzhou Refinery	Guangxi	200
2009	CNOOC	Huizhou	240
	Sinopec Tianjin Petrochemical	Tianjin	200
	Fujian Oil Refining	Quanzhou	160

*Includes only projects or expansions of more than 100,000 b/d of capacity.

During 2008, the national refiners have been under margin and earnings pressure. The same factors that affected the teapot refiners affect the major refiners particularly on incremental runs of imported crude.

In 2008, leading Chinese refiners were unenthusiastic about high run rates and tended to take extended, more casual shutdowns. The Beijing government made some accommodation to these refiners both in increased product prices but also in the form of direct payments to compensate their refining losses. These accommodations were generally insufficient to offset losses and lacked predictability.

Notwithstanding that, refinery throughput in China has risen and petrochemical profitability has softened significantly since the summer due mainly to the global economic downturn.

Chinese policy for refined products calls for self-sufficiency in major refined products, gasoline, jet fuel, and diesel. These fuels are considered strategic military fuels and the Chinese government is disinclined to allow the country to require regular imports.

LPG and fuel oil are regular import items with much of the fuel oil import volume for teapot refinery feedstocks. Chinese policy favors LPG consumption in the residential-commercial sector as a clean alternative to coal.

China has been developing many refining projects to supply growing fuel requirements (Table 1). Most of the projects are purely Chinese, although some have foreign joint-venture partners. Chinese interest in joint-venture partners has waned considerably over the years and now is limited mostly to strategic suppliers of crude.

China will continue to follow its policy of supplying strategic fuels from domestic refining. That means China will be an improbable consumer of petroleum products manufactured by export refineries in other parts of Asia or the Middle East. Nevertheless, as supply and demand continue to progress, periods of imbalance will occur when products will be imported, such as in 2008.

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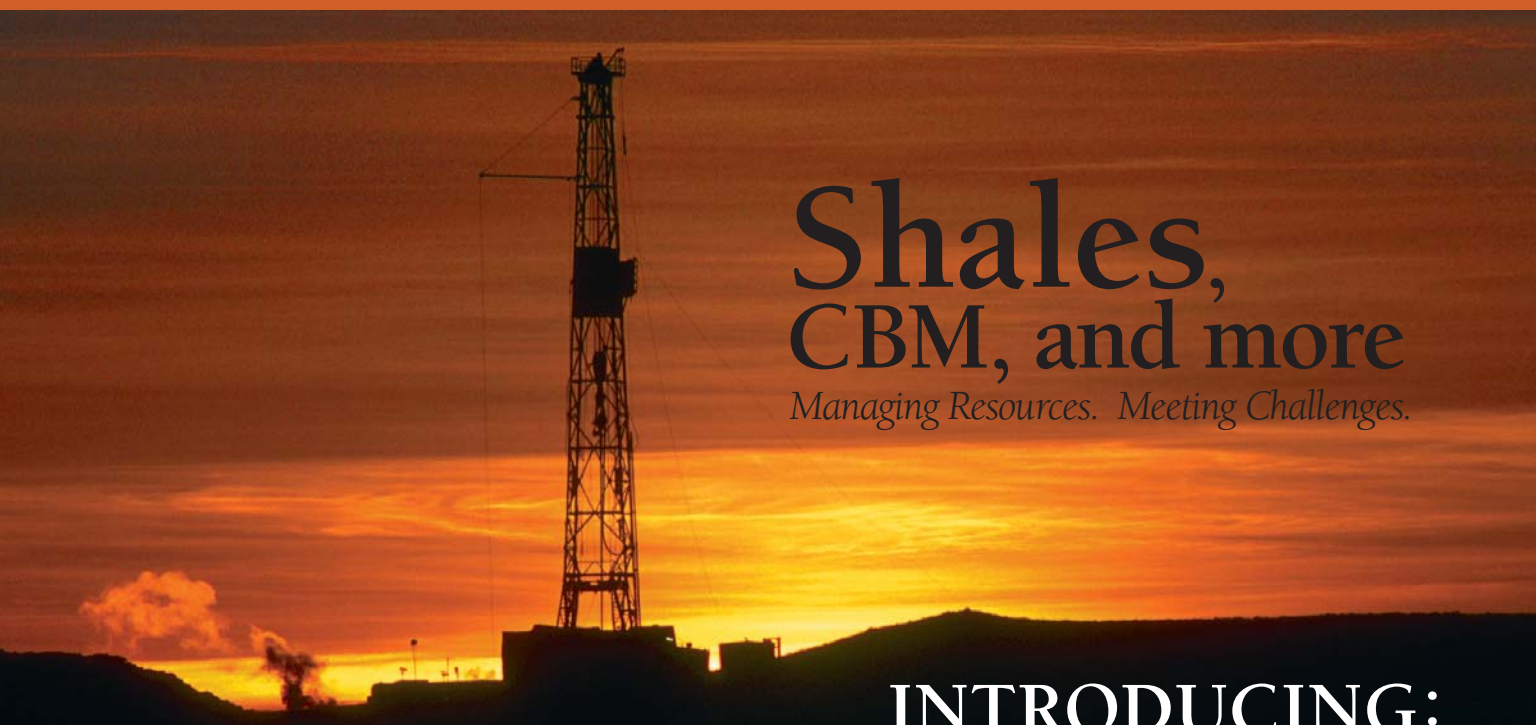

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China is an unlikely source of major export volumes. It has no comparative advantage in refining. Although China has been an exporter of gasoline at times, it is unlikely the country would install appreciable new capacity oriented to waterborne export markets. Chinese producers will have little effect on the global refining industry other than competition for crude sources.

India refining outlook

India is seeking to become a major new product exporter. India's petroleum sector is divided between the public sector units (PSU) such as Indian Oil Corp., Hindustan Petroleum, ONGC, and Bharat Petroleum, and the private sector refiners such as Reliance and Essar. Both sectors are growing.

Reliance is in the process of starting up the second train at Jamnagar in Gujarat on the northwest coast of India. Reliance took the step of declaring its existing refinery an "export oriented unit" recently, which has the effect of directing the preponderance of the refinery's output to foreign markets.

Before then, Reliance had been a supplier to the PSU companies that, as a group, have refining capacity insufficient to supply their retail market volumes. Once the second plant is running, Reliance will have about 1.2 million b/d of high conversion, heavy-crude processing oriented to export markets.

Although Reliance has discussed that the US and Europe are key export destinations, the company has opened marketing offices in Houston, London, and Singapore. Asia may become more important than earlier anticipated now that demand is soft in the Atlantic Basin.

Essar has started a major new refining operation near Jamnagar at a site called Vadinar. Essar has begun refinery operations with a cracking configuration that manufactures conventional fuels.

Essar plans a far more ambitious coking configuration that would become a third major unit oriented to export markets. Thus far, Essar's effect on global markets has been muted by India'sPSU company refining shortfalls as compared with domestic retail volume.

Long known for lackluster petroleum demand growth, Indian demand has blossomed in the past year despite higher prices. Product prices are generally at or near global levels although the net effect of taxes and subsidies is to penalize the PSU companies that control retail marketing.

Kerosine and LPG are heavily subsidized but other products are not. Development of product demand growth in India, now double digits in some states, is associated with two factors.

First, economic growth has broadened from predominantly services into more manufacturing, infrastructure development, and other more energy-intensive areas. Second, a stubborn shortfall of power has led to brownouts and installation of many private generators to maintain power during times of nonavailability.

Not just factories, but hotels and office buildings have such installations; more private homes have installed such capacity. These small generators are generally diesel powered and significantly contribute to demand. A similar situation contributed to the Chinese growth explosion of 2004.

Table 2 summarizes some of the larger refining installations starting up during the next few years. The Reliance project is starting up now and is essentially complete. The Essar project shown is only a small part of a larger project that is scheduled for 1-2 years later.

Table 2 shows several smaller refinery projects that are in PSU companies or that would contribute to PSU supplies via purchase contracts. More projects are still pursuing funding in order to enter firm status.

Unlike China, India will be a major product exporter through its private-sector refineries. The PSU refineries will export residual fuel oil and naphtha but little or none of the key transportation fuels.

INDIA CAPACITY ADDITIONS*

Table 2

Year	Company	Location	Crude distillation capacity, 1,000 b/d
2008	Reliance Petroleum Ltd.	Jamnagar	540
2011	Essar Oil	Vadinar	110
	Mangalore Refining	Mangalore	106
	Nagarjuna Group, TIDCO	Cuddalore	125
	Bharat Oman Refineries Ltd.	Bina	125

*Includes only projects or expansions of more than 100,000 b/d of capacity.

Other countries

Singapore continues as a major Southeast Asian export-oriented refining center. Historically, Singapore refiners—Shell, ExxonMobil, and Singapore Refining Co.—have served as swing producers scaling back production in times of poor margins. That role continues, although the refiners as a group have taken steps to improve their economic strength mostly through integration into petrochemicals.

Both ExxonMobil and Shell are affiliated with major ethylene and aromatics complexes in Singapore. The result has been greater staying power in times of weak margins.

South Korea has become an important, market-sensitive swing producer of products through the major refiners: Hyundai, SK, GS Caltex, and S-Oil. SK and GS Caltex are already heavily integrated into major petrochemical complexes.

South Korea is adding greater complexity through conversion processing. These refiners will tend to trim exports of fuel oil and focus more on light products.

Japan, long an inward-looking refining nation through its moto-uri companies, is becoming more outwardly focused. Faced with falling demand for both light and heavy products, the Japanese industry as a whole is recon-

ciled to the need for consolidation and closing uneconomic units. Japan, however, offers the potential for high-value exports.

Japanese refiners have been quality conscious for decades and are accustomed to manufacturing to demanding Japanese industrial specifications. With addition of some new conversion units and, more importantly, improved logistical facilities for loading export cargoes, Japan may become a new exporter of note in the next 5 years. The most likely target for Japanese products will be the US West Coast with its demanding quality requirements and relatively short-haul shipping. ✦

The author

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New pipeline profiling method helps avoid condensation, black powder

A.H. Dilawari
A.R. Saleemi
University of Engineering and Technology
Lahore, Pakistan

A new method can help avoid condensation and control hydrates in the early stages of a natural gas transmission pipeline's life, thereby helping avoid future black powder formation.

Locating areas in natural gas transmission pipelines susceptible to condensation of water vapors and higher hydrocarbons, hydrates, and black powder formation, require both temperature and pressure profiles for the gas traveling through these pipelines.

This article describes both a simplified approach for generating these profiles based on earlier work in this area and a procedure to predict soil thickness (responsible for soil resistance to heat transfer), temperature, and pressure profiles.

Background

Black powder formation occurs frequently in natural gas transmission pipelines all over the world but remains poorly understood in terms of its formation, inhibition, or prevention.[1,2] The formation chemistry of one major component of black powder, FeS, suggests hydrogen sulfide present in the gas directly reacts with the steel wall of the pipe. Sulfate-reducing bacteria on the pipe wall may also produce hydrogen sulfide. The presence of water promotes this reaction; even a small percentage will greatly accelerate production.

This relationship suggests the importance of controlling the presence of liquid water in the pipe either by reducing the amount of water vapor in the incoming gas or by selecting operating temperatures and pressures sufficient to avoid condensation of any water vapor or higher hydrocarbons present in the gas.

Hydrates form from natural gas in the presence of liquid water provided the pressure is above and the temperature below the equilibrium line of the phase diagram of the gas and liquid water.[3,4] Determining if hydrates will form requires accurate pressure and temperature profiles of the gas in pipelines. These profiles can also help determine the viability of line heaters for hydrates prevention (OGJ, Mar. 8, 1971, p. 57), the required inlet-gas temperature at each gas compressor station, and the minimum gas flow rate required to maintain a specific gas temperature at a downstream point.

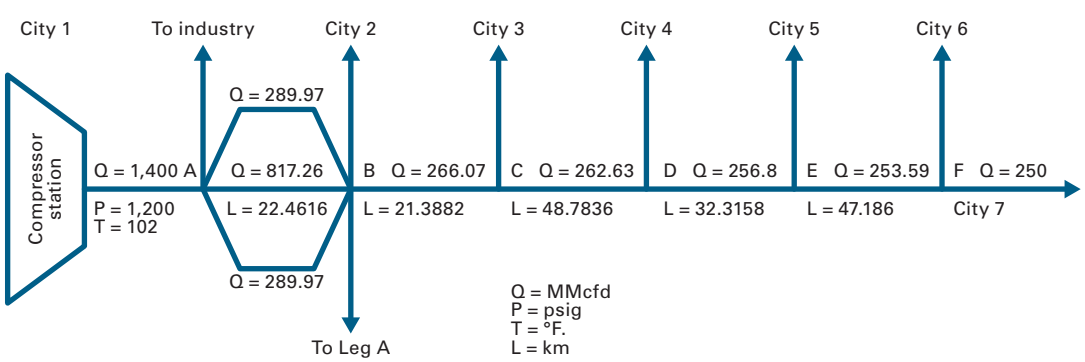
Modeling equations

Thorough discussion has already occurred of the basic equations governing such systems[5,6] and the details for solving these equations can be found in textbooks on numerical analysis.[7]

Determining the physical properties for calculating pressure drop requires knowledge of pressure and temperature at each point along the pipeline. Generating a usable temperature profile therefore requires a series of complex, interactive calculations.

NATURAL GAS TRANSMISSION PIPELINE, SEGMENT 1

Fig. 1



Equations

$$Q = 737\,E\left(\frac{T_b}{P_b}\right)^{1.02}\left(\frac{P_1^2 - e^s P_2^2}{G^{0.961} T_m \Delta L Z}\right)^{0.51} D_i^{2.53} \quad (1)$$

$$s = 0.0375\,G\left[\frac{H_2 - H_1}{T_m Z}\right] \quad (2)$$

Where: H is elevation of the pipeline, E is pipeline efficiency, D_i is pipe inside diameter, ΔL is pipeline length selected for calculation, Z is compressibility factor, G is gas gravity, T is temperature, P is pressure, and subscripts 1, 2, m, and b stand for inlet annd outlet of pipeline length selected for calculation, means, and standard conditions, respectively.

$$T_2 = T_s + (T_1 - T_s)e^{-\theta} + \phi(P_2 - P_1) \quad (3)$$

$$\theta = \frac{\pi U_i D_i \Delta L}{m_g C_p} \quad (4)$$

$$\frac{1}{U_i} = \frac{1}{h_i} + \frac{x_p D_i}{k_p D_o} + \frac{x_s D_i}{k_s D_m} \quad (5)$$

$$h_i = \frac{0.02K}{D_i}\left(\frac{D_i V \rho}{\mu}\right)^{0.8} \quad (6)$$

Where: U_i and h_i are the overall and gas film heat transfer coefficient based on ID of the pipe respectively, m_g is gas velocity, and ρ, μ, and k are density, viscosity, and thermal conductivity of natural gas of known composition. T_s is the ambient temperature of soil surrounding the pipeline, and its value is taken as 60° F. in Equation 3. The last term is added to account for the Joule - Thomson effect. The value of constant ϕ is considered a function of the operating pressure range and the temperature of flowing gas.

$$x_s = \frac{D_o}{f} \quad (7)$$

Where: f is a function of distance along the pipe.

$$Q_h = -[m_g C_p (T_2 - T_1) + \phi(P_2 - P_1)] \quad (8)$$

$$Q_h = U_i A_i (T_m - T_s) \quad (9)$$

Where: Q_h is the net rate of heat transfer from the flowing gas to the soil and A_i is the inside surface area of pipeline segment selected for calculation.

$$f = \frac{2}{e^{2N} - 1} \quad (10)$$

Where: Equations 11 and 12 apply.

$$N = \frac{K_s}{D_i}\left[\frac{1}{U_i} - \left(\frac{1}{h_i} + \frac{x_p D_i}{k_p D_o}\right)\right] \quad (11)$$

$$U_i = \frac{m_g C_p (T_1 - T_2) - \phi(P_1 - P_2)}{A_i (T_m - T_s)} \quad (12)$$

$$Q = 2Q_1 + Q_2 \quad (13)$$

$$Q_1 = \frac{Q\left(\frac{D_1}{D_2}\right)^{2.5}}{\left(1 + 2\left(\frac{D_1}{D_2}\right)^{2.5}\right)} \quad (14)$$

Where: Q is the total volmetric flow rate Q_1 and Q_2 are flow rates through pipe of ID D_1 = 23.124 in. and ID D_2 = 35 in., respectively.

Nomenclature

H	=	pipeline elevation
E	=	pipeline efficiency
D_i	=	ID
Z	=	compressibility factor
G	=	gas gravity
T	=	temperature
P	=	gas pressure
U_i	=	overall heat transfer coefficient based on D_i
h_i	=	gas film heat transfer coefficient based on D_i
m_g	=	mass flow rate of gas
V	=	average gas velocity
ρ	=	gas density
μ	=	gas viscosity
k	=	gas thermal conductivity
ΔL	=	pipeline section selected for calculation
T_s	=	ambient temperature of soil surrounding the pipeline
ϕ	=	constant to account for Joule-Thompson cooling
x_p	=	WT
x_s	=	dry soil layer thickness beyond which the temperature of soil equals ambient temperature
k_p	=	pipe thermal conductivity
k_s	=	soil thermal conductivity
Q	=	gas total volumetric flow rate
Q_1	=	gas flow rate through pipe of diameter D_1
Q_2	=	gas flow rate through pipe of diameter D_2

Environmental properties such as soil type and temperature variation along the pipeline between summer and winter complicate these calculations.

This article uses an integrated simple set of modeling equations with a set of accompanying assumptions. Equations 1 and 2 are the governing mathematical equations for the flow and heat transfer phenomena involved in the prediction of temperature and pressure variations in selected segments of natural gas transmission pipeline.

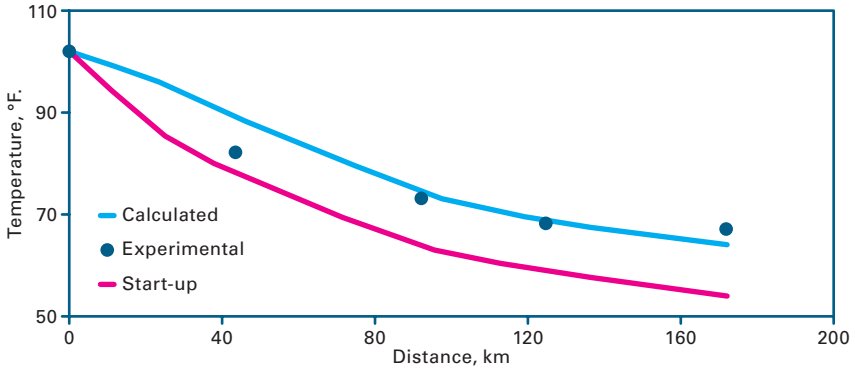
These equations are known as the revised Panhandle equations and are used for large-diameter, high pressure transmission lines. They are accurate in fully turbulent flow for Reynolds values of 4-400 × 10^6.

Equations 3-6 can calculate the temperature profile.

This article used a flowing gas temperature and pressure of 70-110° F. and 700-1,200 psig, respectively, with a value of ϕ of 0.05; equivalent to a cooling of 10° F. for every 200-psig pressure drop.

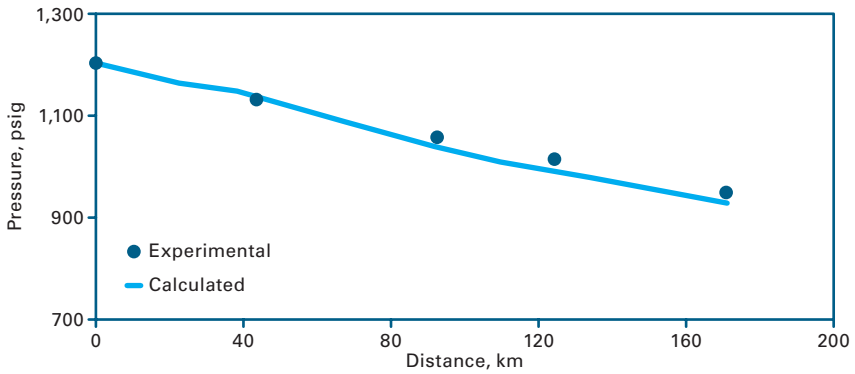
TEMPERATURE COMPARISON, SEGMENT 1

Fig. 2



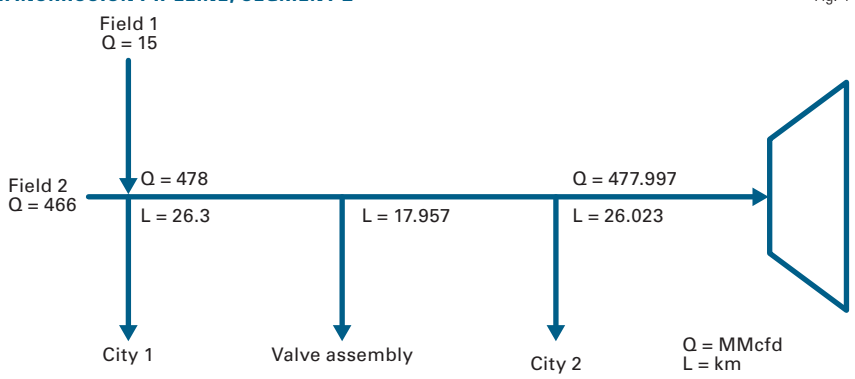
PRESSURE COMPARISON, SEGMENT 1

Fig. 3



TRANSMISSION PIPELINE, SEGMENT 2

Fig. 4



GAS COMPOSITION, SEGMENT 1

Table 1

Components	Mole %
Methane	87.777
Ethane	1.0582
Propane	0.2336
i-Butane	0.0668
n-Butane	0.0651
i-Pentane	0.0352
n-Pentane	0.0235
Hexane plus	0.1063
Nitrogen	8.7459
Carbon dioxide	1.8884
Hydrogen sulfide	6-8 ppm
Water	4-6 lb/MMcf

Equations 5-6 are well known:[8 9] x_p is the pipe WT and x_s is the thickness of the dry soil around the pipeline, beyond which the temperature of the soil equals the ambient temperature. The thermal conductivity of the pipeline material, k_p, and of the dry soil, k_s, measure 29.0 and 0.075 btu/hr-sq ft-°F., respectively.[10-12]

Equation 7 approximates the dry soil thickness; i.e., penetration thickness.

As the compressed hot gas flows in the pipe, the heat transfer rate will be highest near the entrance. As the gas cools along the line, the driving force for heat transfer decreases and accordingly the rate of heat transfer to surrounding soil also decreases. This in turn will reduce the penetration thickness along the pipe, suggesting the value of function f increases with distance along the pipe.

Equations 5-9 calculate the function f with experimental temperature and pressure data for different segments of pipeline.

The calculated values of function f support the arguments used in postulating Equation 7. Equations 10-12 also readily expresses function f.

Experimental data

Dividing an operating transmission pipeline into segments of roughly 10 miles each allowed for experimental calculations. Knowing the upstream temperature, pressure, and gas composition allowed Equations 1-7 to be solved successively for these pipeline segments (Fig. 1).

Natural gas after compression at City 1 moved to Point B through three parallel lines; one 35-in. ID and the other two 23.124-in. ID.

Equations 13-14 calculate volumetric flow rates of natural gas through these lines.

From Point B, the gas flows to City 2, Leg M, Point C, and so on. Table 1 shows composition of the flowing gas.

These calculations used the following assumptions:

- Pipeline elevation's effect is negligible and the corresponding term in Equation 1 is dropped.
- Upstream temperature at the selected section for calculation is used

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Straight-talking and no-nonsense, LongForza is a direct distributor of oilfield equipment from premium global manufacturers. And now, PennEnergy is pleased to be the exclusive source of LongForza-supplied onshore drilling rigs in 1000-, 1500- and 2000-HP configurations.

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Services
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Who we represent and the warranties we offer – it's all on the table for our customers.

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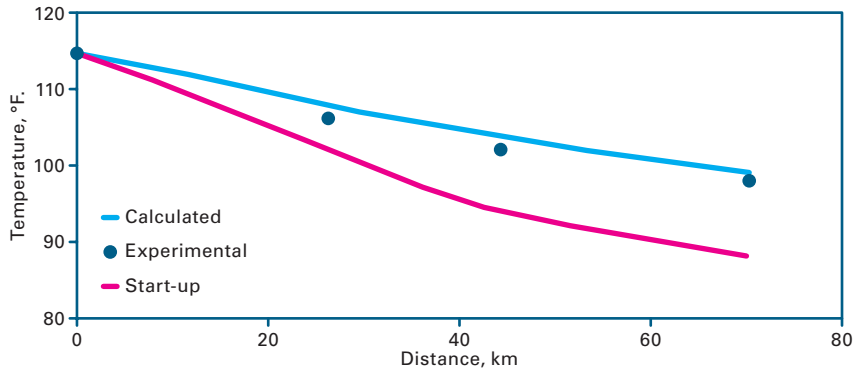
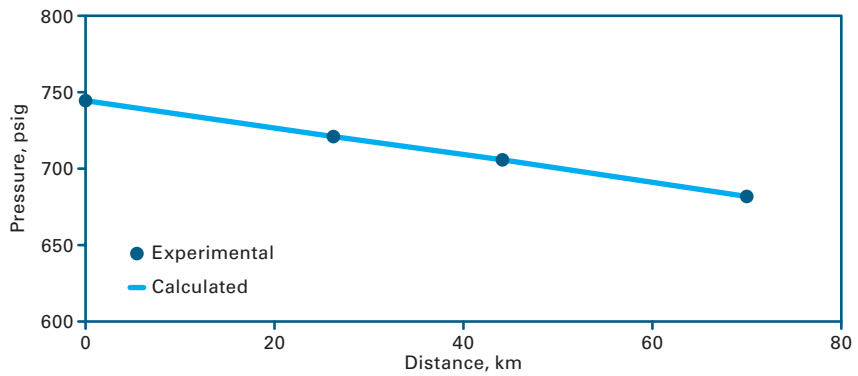
Contact Randy Hall at PennEnergy
Blackberry/Email: rhall@pennenergy.com | P: 713-499-6330

LONGFORZA CORPORATION

TEMPERATURE COMPARISON, SEGMENT 2 Fig. 5



PRESSURE COMPARISON, SEGMENT 2 Fig. 6



as mean temperature for estimating various gas properties for the selected length.

- Soil around the buried transmission pipeline is considered dry and the corresponding thermal conductivity value is used.
- Reported pipeline efficiency = 0.8.
- Resistance to flow of heat is confined in a known thickness of dry soil around the pipeline and the temperature of the soil beyond this dry soil layer is assumed to have an ambient temperature of 60° F. Equation 7 estimates this thickness. Function f in this equation depends on the distance along the pipeline, but in view of its relative influence on predicted temperature profiles, a constant value of 3 is used in this article.
- Each segment of pipe has a known upstream pressure and a calculated downstream pressure. The mean value of pressure determines property values[13] required to calculate temperature at the downstream end of a pipeline segment.

These assumptions are valid for engineering calculations and should not affect the predicted results.

Figs. 2-3 compare the predicted temperature and pressure of gas as it moves through the pipeline with the experimental data.[14] The predictions agree with available experimental data.

Technicians also applied the procedure to a pipeline segment (Fig. 4) transmitting relatively low-quality gas (Table 2). This line segment is prone to black powder formation and condensation and is being studied to suggest operating conditions to avoid black powder formation.

Figs. 5-6 compare computed results with experimental data for temperature and pressure. The computed results again agree with the experimentally measured profiles.

The maximum disagreement of prediction with experimental data for temperature generally measures less than ±5% and pressure less than ±1%.

GAS COMPOSITION, SEGMENT 2 Table 2

Components	Mole %
Methane	84.269
Ethane	1.1040
Propane	0.2850
i-Butane	0.0790
n-Butane	0.0760
i-Pentane	0.0390
n-Pentane	0.0310
Hexane plus	0.0560
Nitrogen	12.200
Carbon dioxide	1.8610
Hydrogen sulfide	14-15 ppm
Water	4-6 lb/MMcf

New pipelines

Newly laid transmission pipelines cool gas faster than pipelines already in use, the resistance offered by soil to transfer of heat increasing with time until it reaches a steady state. Condensation of water vapors and higher hydrocarbons therefore starts high in a new natural gas transmission pipeline and shrinks over time, while black powder formation gradually increases. This circumstance suggests the bulk of damage done to a pipeline occurs at and shortly after start-up and that later efforts can only hope to clean up whatever mess has occurred.

Black powder formation cannot be completely arrested once it has started. The initial operating period of a pipeline therefore requires careful modeling.

The penetration thickness (the dried soil layer of low thermal conductivity) around a newly laid transmission pipeline is essentially zero at start-up and grows during operation until a steady state is reached.

Simulating this state gives the penetration thickness approximated by Equation 7, the thermal conductivity of unaffected soil, 0.38 btu/sq ft-hr-°F.[12] Calculated temperature profiles for segments of transmission pipelines studied show faster cooling, with temperature drops below the dewpoints of gases being transmitted.

These profiles, plotted as dotted lines in Figs. 2 and 5, clearly warrant the taking of adequate measures to avoid onset of water condensation during start-up and minimize subsequent black powder formation.

Acknowledgments

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Rowan Cos. Inc.,

Houston, has named W. Matt Ralls CEO, president, and a director. He succeeds D.F. McNease, who announced his retirement in late October. Ralls most recently served as executive vice-president and COO of GlobalSantaFe Corp. from June 2005 until the completion of the merger of GlobalSantaFe with Transocean Inc. in November 2007. Prior to that, he was senior vice-president and CFO of GlobalSantaFe. He joined Global Marine Inc. in 1997 as vice-president and treasurer and was senior vice-president, CFO, and treasurer prior to the November 2001 merger that created GlobalSantaFe. Ralls previously held executive positions at two publicly traded oil and gas companies and various management positions in commercial banking. He has been a director of GP of El Paso Pipeline Partners since January 2008 and a director of Complete Production Services since 1995. Ralls has a degree in mechanical engineering and an MBA from the University of Texas at Austin.


Ralls

Rowan's board also elected Jack Lentz as chairman, effective Jan. 1, 2009. Lentz has held a position on Rowan's board since 1990. He is an advisory director of Barclays Capital and was formerly managing director of Lehman Bros. Lentz also serves on the boards of Peabody Energy Corp. and CARBO Ceramics Inc.

Rowan is a worldwide provider of contract drilling services, utilizing a fleet of 22 high-spec jack ups and 30 deep-well land rigs. The company also owns and operates a manufacturing division that produces equipment for the drilling, mining, and timber industries.

PinnacleAIS,

Houston, has announced that Pasadena Refining System Inc. (PRSI) will implement PinnacleAIS's UltraPIPE inspection data management system platform at its 120,000 b/d refinery on the Houston Ship Channel at Pasadena, Tex. The UltraPIPE platform provides the advanced mechanical integrity functionality needed to address a wide variety of refining or petrochemical facility requirements. All inspection activities, resulting data, statistical analysis, and future inspection planning are implemented into the software.

PinnacleAIS is a leading technology and services provider, specializing in wholesale improvements in asset integrity for the petroleum and chemical processing industry.

PRSI is a 50-50 joint venture of Brazilian state oil company Petroleo Brasileiro SA and Astra Holding USA.

American Electric Technologies Inc.,

Houston, has entered into an alliance agreement with Five Star Services Ltda., Macae, Brazil, and Lifting Services Ltda., Niteroi, Brazil. The newly formed AETI Alliance Group will provide full power distribution and control system design, manufacturing, and offshore services to the Brazilian offshore drilling and marine markets. To become the leading turnkey provider to the Brazilian market, the three companies have agreed to integrate their offerings and to begin the process to create a joint venture entity. AETI has allied with Lifting and Five Star Services to manufacture electrical switchgear and drives, and provide electrical services in Brazil. These products and services will be provided for oil and gas drilling, production, and service vessels. With the support of technology and manufacturing processes from AETI, the alliance will fabricate, assemble and test products in Brazil and deliver to local customers. These products will be commissioned and supported by local Brazilian technical service staff. Construction and installation services will also be available on a local basis. In addition, the alliance has the capability to fabricate steel modules and completely outfit drilling and marine electrical systems for cost-effective installations.

Lifting Services provides maintenance, repair, installation, and fabrication services for electrical and electronic equipment for the offshore drilling and marine markets in Brazil.

Five Star Services provides offshore services such as rig operations and drilling crew and manning services; maintenance, repairs, and modifications to drilling equipment; load-carrying components and well-control equipment; and engineering and construction of prefabricated solutions ranging from deck extensions and flare-booms to accommodation modules.

American Electric supplies power delivery solutions to the traditional and alternative energy industries.

Roxar ASA,

Stavanger, has appointed Ana Fonseca Nordang marketing manager for Roxar's Software Solutions division and Anne-Lisbet Hatlem Lindal marketing manager for Roxar's Flow Measurement division. Both have been tasked with leading the company's marketing and business development activities to increase Roxar's market share and bringing a series of innovative new software and instrumentation solutions to market. Prior to joining Roxar, Nordang held senior positions in Washington, DC, and London for the Corporate Executive Board, a publicly traded research and management consulting company headquartered in Virginia. She has an MBA from George Washington University. Previously, Lindal held a senior marketing position and was part of the management team with an international nonprofit organization. Lindal is a graduate of the Norwegian School of Management and is a European Board member of Sat-7, an Arabic TV channel.


Nordang


Lindal

Roxar is a leading international technology solutions provider to the upstream oil and gas industry, providing solutions in reservoir interpretation, modeling, and simulation; well and completion services; production and process solutions; and consultancy services.

New microbiocide for water-based frac fluid systems

New BE-9 bactericide can be used to help control bacteria growth in water used as the basis for fracturing fluids.

The company says the quick-acting, long-lasting mocrobiocide helps control slime-forming, iron-oxidizing, and polymer-degrading bacteria encountered in oil field applications and offers the following features:

- It can be used for batch treatments and on-the-fly treatments.
- Aqueous solution can easily be mixed with water.
- Effective over the pH range 2-12.
- Testing shows the bactericide to provide fast and sustained kill.
- Compatible with scale inhibition technology.
- Enables long-term protection since the BE-9 agent is placed at fracturing rate into the fracture network.
- Not susceptible to degradation by ultraviolet light.
- Thermally stable.
- Complements this firm's water-based fracturing fluid systems including AquaStim fluid system for water fracs, and gel-based systems including Delta Frac, DeepQuest, Sirocco, Hybor, and Omega-Frac fluids

Source: **Halliburton Co.,** Box 3, Houston, TX 77001.

New oil-based drilling fluid system

The MEGADRIL system is a new oil-based drilling fluid solution.

Its chemistry—in a single-drum emulsifier package—maximizes hole quality and penetration rates in difficult formations while minimizing base-oil volumes and reducing the need for secondary additives. The company says its one-drum package helps simplify logistics, treatment levels, and inventory control.

Designed for optimum rheological profiles and intelligent gel strengths, the system helps improve hole cleaning, limits pressure spikes, and lowers downhole losses. These features, combined with a naturally inhibitive chemistry, help achieve hole quality and minimize nonproductive time (NPT).

The system assists in achieving higher penetration rates by promoting the removal of fine low-gravity solids, which also eliminates the need for dilutions. Because the system can be run efficiently at lower than normal oil/water ratios (OWRs), the required volume of base oil can be reduced by as much as 10%, yielding a direct savings on the base-oil cost per well, the firm points out.

In a recent field test in the Bakken shale in North Dakota, the system contributed to penetration rates of 85-100 fph, while its tight rheology helped minimize mud losses and NPT through the troublesome Mission Canyon formation. The 73:27 OWR allowed a savings of $20,000 in diesel costs when compared with a typical 80:20 OWR formulation, the firm says.

Source: **M-I Swaco,** 5950 North Course Blvd., Houston, TX 77072.

Imports of crude and products

	Districts 1–4		District 5		Total US		
	11-28 2008	11-21 2008	11-28 2008	11-21 2008	11-28 2008	11-21 2008	*11–30 2007
	1,000 b/d						
Total motor gasoline	884	954	0	26	884	980	1,169
Mo. gas. blending comp.	784	894	0	17	784	911	707
Distillate	112	234	4	0	116	234	299
Residual	417	235	159	157	576	392	350
Jet fuel–kerosine	26	62	19	15	45	77	240
Propane–propylene	185	233	15	20	200	253	174
Other	456	153	52	48	508	201	860
Total products	**2,864**	**2,765**	**249**	**283**	**3,113**	**3,048**	**3,799**
Total crude	**8,664**	**9,744**	**840**	**1,215**	**9,504**	**10,959**	**9,374**
Total imports	**11,528**	**12,509**	**1,089**	**1,498**	**12,617**	**14,007**	**13,173**

*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

	*12–5–08	*12–07–07	Change $/bbl	Change, %
SPOT PRICES				
Product value	50.81	98.91	–48.10	–48.6
Brent crude	42.99	90.86	–47.87	–52.7
Crack spread	7.82	8.05	–0.22	–2.8
FUTURES MARKET PRICES				
One month				
Product value	51.54	99.11	–47.56	–48.0
Light sweet crude	45.50	88.73	–43.23	–48.7
Crack spread	6.04	10.38	–4.34	–41.8
Six month				
Product value	60.61	101.63	–41.01	–40.4
Light sweet crude	52.61	87.42	–34.81	–39.8
Crack spread	8.01	14.20	–6.20	–43.6

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

Purvin & Gertz LNG netbacks—Dec. 5, 2008

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	11.84	10.04	11.05	9.94	10.60	10.98
Everett	5.61	3.79	5.30	3.89	4.25	5.86
Isle of Grain	7.24	5.33	6.68	5.24	5.82	6.70
Lake Charles	3.79	2.20	3.60	2.34	2.49	4.31
Sodegaura	9.08	12.05	9.35	11.76	10.24	8.48
Zeebrugge	11.65	9.31	10.81	9.20	9.84	10.85

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	13,443	51,764	29,792	9,311	49,952	12,609	4,176
PADD 2	71,380	47,821	17,711	7,091	26,304	1,251	21,380
PADD 3	170,311	64,447	32,505	12,272	32,274	18,572	32,362
PADD 4	14,452	7,163	2,611	621	2,885	259	[1]2,726
PADD 5	50,786	27,747	22,910	9,272	13,558	4,465	—
Nov. 28, 2008	**320,372**	**198,942**	**105,529**	**38,567**	**124,973**	**37,156**	**60,644**
Nov. 21, 2008	**320,828**	**200,476**	**105,270**	**38,005**	**126,694**	**38,842**	**60,292**
Nov. 30, 2007[2]	**305,240**	**200,623**	**95,231**	**39,939**	**132,344**	**38,033**	**60,968**

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

Refinery report—Nov. 28, 2008

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		1,000 b/d				
PADD 1	1,301	1,311	2,272	88	427	122	78
PADD 2	3,221	3,184	2,007	175	1,051	58	204
PADD 3	6,983	6,944	2,688	654	2,089	235	595
PADD 4	567	563	282	29	176	10	[1]169
PADD 5	2,780	2,578	1,467	465	571	127	—
Nov. 28, 2008	**14,852**	**14,580**	**8,716**	**1,411**	**4,314**	**552**	**1,046**
Nov. 21, 2008	**15,173**	**14,838**	**8,962**	**1,447**	**4,609**	**555**	**1,052**
Nov. 30, 2007[2]	**15,606**	**15,450**	**9,092**	**1,461**	**4,345**	**697**	**1,156**
	17,610 Operable capacity		**84.3% utilization rate**				

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

OGJ GASOLINE PRICES

	Price ex tax 12-3-08	Pump price* 12-3-08	Pump price 12-5-07
	¢/gal		
(Approx. prices for self–service unleaded gasoline)			
Atlanta	146.4	192.9	311.9
Baltimore	141.7	183.6	304.4
Boston	146.2	188.1	301.9
Buffalo	126.9	187.8	324.0
Miami	140.3	191.9	326.4
Newark	160.2	192.8	291.9
New York	137.3	198.2	305.5
Norfolk	149.4	187.8	296.9
Philadelphia	146.5	197.2	311.4
Pittsburgh	151.4	202.1	310.4
Wash., DC	168.6	207.0	307.9
PAD I avg	146.8	193.6	308.4
Chicago	125.2	189.6	344.9
Cleveland	126.4	172.8	314.4
Des Moines	132.9	173.3	301.9
Detroit	123.4	182.8	321.0
Indianapolis	120.2	179.6	308.1
Kansas City	129.9	165.9	290.3
Louisville	134.0	174.9	304.5
Memphis	130.9	170.7	303.5
Milwaukee	123.6	174.9	314.9
Minn.–St. Paul	129.6	173.6	304.5
Oklahoma City	131.1	166.5	298.2
Omaha	122.5	167.8	287.5
St. Louis	141.9	177.9	303.4
Tulsa	133.0	168.4	295.0
Wichita	128.6	172.0	299.9
PAD II avg	128.9	174.1	306.1
Albuquerque	149.6	186.0	307.4
Birmingham	138.6	177.9	303.9
Dallas–Fort Worth	133.5	171.9	300.4
Houston	129.3	167.7	291.4
Little Rock	141.5	181.7	303.9
New Orleans	147.7	186.1	297.9
San Antonio	148.5	186.9	291.9
PAD III avg	141.2	179.7	299.6
Cheyenne	140.1	172.5	299.9
Denver	150.7	191.1	307.0
Salt Lake City	133.6	176.5	302.9
PAD IV avg	141.5	180.0	303.3
Los Angeles	142.7	209.8	332.9
Phoenix	162.4	199.8	294.9
Portland	171.4	214.8	316.9
San Diego	152.7	219.8	342.4
San Francisco	148.0	215.1	358.5
Seattle	153.9	209.8	329.9
PAD V avg	155.2	211.5	329.3
Week's avg.	**140.3**	**185.9**	**308.7**
Nov. avg.	**169.9**	**215.5**	**307.6**
Oct. avg.	**272.3**	**317.6**	**280.9**
2008 to date	**291.6**	**335.8**	—
2007 to date	**233.8**	**277.4**	—

*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

	11–28–08 ¢/gal		11–28–08 ¢/gal
Spot market product prices			
Motor gasoline (Conventional–regular)		Heating oil No. 2	
New York Harbor	121.78	New York Harbor	169.63
Gulf Coast	117.25	Gulf Coast	167.25
Los Angeles	110.00	Gas oil	
Amsterdam–Rotterdam–Antwerp (ARA)	116.99	ARA	172.97
Singapore	105.95	Singapore	156.67
Motor gasoline (Reformulated–regular)		Residual fuel oil	
New York Harbor	117.78	New York Harbor	92.57
Gulf Coast	117.50	Gulf Coast	96.74
Los Angeles	116.00	Los Angeles	105.54
		ARA	105.92
		Singapore	90.22

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

BAKER HUGHES RIG COUNT

	12-5–08	12-7-07
Alabama	4	5
Alaska	12	10
Arkansas	54	50
California	40	38
Land	40	36
Offshore	0	2
Colorado	113	117
Florida	1	0
Illinois	1	0
Indiana	2	2
Kansas	11	15
Kentucky	10	8
Louisiana	185	160
N. Land	95	60
S. Inland waters	18	27
S. Land	21	27
Offshore	51	46
Maryland	0	1
Michigan	0	1
Mississippi	19	12
Montana	8	9
Nebraska	0	0
New Mexico	71	79
New York	3	5
North Dakota	86	55
Ohio	12	13
Oklahoma	175	201
Pennsylvania	27	17
South Dakota	1	0
Texas	852	872
Offshore	7	12
Inland waters	0	1
Dist. 1	24	17
Dist. 2	33	33
Dist. 3	63	72
Dist. 4	87	79
Dist. 5	157	186
Dist. 6	126	115
Dist. 7B	27	43
Dist. 7C	61	63
Dist. 8	118	113
Dist. 8A	30	21
Dist. 9	49	44
Dist. 10	70	73
Utah	39	35
West Virginia	30	36
Wyoming	79	74
Others—NV-8; TN-4; VA-4; WA-1	17	13
Total US	**1,852**	**1,828**
Total Canada	**404**	**388**
Grand total	**2,256**	**2,216**
Oil rigs	413	340
Gas rigs	1,428	1,482
Total offshore	63	61
Total cum. avg. YTD	**1,886**	**1,765**

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	12-5–08 Percent footage*	Rig count	12-7–07 Percent footage*
0–2,500	84	3.5	63	6.8
2,501–5,000	131	53.4	114	60.7
5,001–7,500	246	13.8	216	25.1
7,501–10,000	435	2.7	442	1.5
10,001–12,500	414	1.9	434	3.5
12,501–15,000	353	0.2	283	—
15,001–17,500	157	—	117	—
17,501–20,000	81	—	64	—
20,001–over	33	—	33	—
Total	**1,934**	**6.5**	**1,766**	**8.5**
INLAND	29		41	
LAND	1,853		1,677	
OFFSHORE	52		48	

*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]12-5–08	[2]12-7–07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	20
Alaska	712	742
California	660	663
Colorado	62	66
Florida	7	6
Illinois	30	26
Kansas	110	102
Louisiana	1,169	1,170
Michigan	14	14
Mississippi	59	61
Montana	98	92
New Mexico	167	163
North Dakota	129	132
Oklahoma	181	172
Texas	1,329	1,326
Utah	55	54
Wyoming	152	149
All others	64	70
Total	**5,017**	**5,028**

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

US CRUDE PRICES

	11–28–08 $/bbl*
Alaska–North Slope 27°	93.39
South Louisiana Sweet	42.25
California–Kern River 13°	28.90
Lost Hills 30°	37.15
Wyoming Sweet	28.67
East Texas Sweet	39.75
West Texas Sour 34°	32.50
West Texas Intermediate	40.25
Oklahoma Sweet	40.25
Texas Upper Gulf Coast	35.75
Michigan Sour	33.25
Kansas Common	39.00
North Dakota Sweet	24.25

*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]	11–28–08
United Kingdom–Brent 38°	48.96
Russia–Urals 32°	46.36
Saudi Light 34°	46.36
Dubai Fateh 32°	43.84
Algeria Saharan 44°	49.38
Nigeria–Bonny Light 37°	51.42
Indonesia–Minas 34°	51.82
Venezuela–Tia Juana Light 31°	44.42
Mexico–Isthmus 33°	44.31
OPEC basket	47.36
Total OPEC[2]	46.14
Total non–OPEC[2]	45.21
Total world[2]	45.72
US imports[3]	43.61

[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]

	11–28–08	11–21–08	11–28–07	Change, %
	bcf			
Producing region	963	965	1,053	–8.5
Consuming region east	1,929	1,990	1,945	–0.8
Consuming region west	466	467	467	–0.2
Total US	**3,358**	**3,422**	**3,465**	**–3.1**
	Sept. 08	**Sept. 07**	**Change, %**	
Total US[2]	**3,163**	**3,316**	**–4.6**	

[1]Working gas. [2]At end of period.
Source: Energy Information Administration
Data available in OGJ Online Research Center.

International rig count

Region	Nov. 2008 Land	Nov. 2008 Off.	Nov. 2008 Total	Nov. 07 Total
WESTERN HEMISPHERE				
Argentina	77	1	78	75
Bolivia	3	—	3	2
Brazil	29	30	59	42
Canada	416	2	417	371
Chile	4	—	4	2
Colombia	42	—	42	38
Ecuador	12	—	12	9
Mexico	78	29	107	83
Peru	5	3	8	9
Trinidad	1	2	3	7
United States	1873	63	1935	1798
Venezuela	68	12	80	70
Other	1	—	1	3
Subtotal	**2,608**	**141**	**2,749**	**2,509**
ASIA-PACIFIC				
Australia	15	13	28	23
Brunei	1	3	4	6
China-offshore	—	22	22	21
India	55	27	82	85
Indonesia	46	15	61	64
Japan	3	—	3	2
Malaysia	—	16	16	11
Myanmar	4	2	6	7
New Zealand	3	1	4	6
Papua New Guinea	3	—	3	2
Philippines	3	—	3	1
Taiwan	—	—	—	—
Thailand	2	11	13	12
Vietnam	—	6	6	4
Other	—	2	2	3
Subtotal	**135**	**118**	**253**	**247**
AFRICA				
Algeria	25	—	25	27
Angola	—	6	6	5
Congo	—	2	2	3
Gabon	—	1	1	2
Kenya	—	—	—	—
Libya	14	1	15	14
Nigeria	2	2	4	10
South Africa	—	—	—	—
Tunisia	2	1	3	3
Other	2	1	3	5
Subtotal	**45**	**14**	**59**	**69**
MIDDLE EAST				
Abu Dhabi	8	3	11	13
Dubai	1	—	1	1
Egypt	45	10	55	48
Iran	—	—	—	—
Iraq	—	—	—	—
Jordan	—	—	—	—
Kuwait	13	—	13	12
Oman	54	—	54	51
Pakistan	22	—	22	20
Qatar	2	11	13	11
Saudi Arabia	64	12	76	75
Sudan	—	—	—	—
Syria	20	—	20	18
Yemen	14	—	14	16
Other	1	—	1	—
Subtotal	**244**	**36**	**280**	**265**
EUROPE				
Croatia	—	—	—	1
Denmark	—	2	2	2
France	1	—	1	1
Germany	12	—	12	5
Hungary	5	—	5	2
Italy	3	1	4	5
Netherlands	—	2	2	6
Norway	—	21	21	14
Poland	2	1	3	2
Romania	18	2	20	3
Turkey	6	—	6	5
UK	2	23	25	17
Other	6	—	6	8
Subtotal	**55**	**52**	**107**	**71**
Total	**3,087**	**361**	**3,448**	**3,161**

Definitions, see OGJ Sept. 18, 2006, p. 42.
Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

Oil import freight costs*

Source	Discharge	Cargo	Cargo size, 1,000 bbl	Freight (Spot rate) worldscale	$/bbl
Caribbean	New York	Dist.	200	196	1.67
Caribbean	Houston	Resid.	380	125	1.18
Caribbean	Houston	Resid.	500	121	1.15
N. Europe	New York	Dist.	200	231	3.16
N. Europe	Houston	Crude	400	162	3.27
W. Africa	Houston	Crude	910	125	2.77
Persian Gulf	Houston	Crude	1,900	58	2.39
W. Africa	N. Europe	Crude	910	120	1.97
Persian Gulf	N. Europe	Crude	1,900	66	1.97
Persian Gulf	Japan	Crude	1,750	64	1.55

*Nov. 2008 average.
Source: Drewry Shipping Consultants Ltd. Data available in OGJ Online Research Center.

Waterborne Energy Inc. US LNG imports

Country	Oct. 2008	Sept. 2008	Oct. 2007	Change from a year ago, %
	MMcf			
Algeria	—	—	—	—
Egypt	3,030	2,980	3,020	0.3
Equatorial Guinea	—	—	—	—
Nigeria	—	2,690	—	—
Norway	—	—	—	—
Qatar	—	—	—	—
Trinidad and Tobago	24,330	20,760	28,840	–15.6
Total	**27,360**	**26,430**	**31,860**	**–14.1**

Source: Waterborne Energy Inc.
Data available in OGJ Online Research Center.
No new data at press time.

Propane prices

	Oct. 2008	Nov. 2008	Oct. 2007	Nov. 2007
	¢/gal			
Mont Belvieu	104.47	73.79	143.15	155.64
Conway	103.83	79.93	140.36	151.67
Northwest Europe	108.89	71.47	143.66	168.75

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

Muse, Stancil & Co. refining margins

	US Gulf Coast	US East Coast	US Mid-west	US West Coast	North-west Europe	South-east Asia
	$/bbl					
Nov. 2008						
Product revenues	63.61	62.40	62.89	61.75	63.46	56.97
Feedstock costs	–52.83	–55.92	–51.10	–50.07	–52.85	–50.77
Gross margin	10.78	6.48	11.79	11.68	10.61	6.20
Fixed costs	–2.11	–2.44	–2.37	–2.77	–2.37	–1.85
Variable costs	–1.97	–1.33	–1.75	–2.98	–1.69	–0.69
Cash operating margin	**6.70**	**2.71**	**7.67**	**5.93**	**6.55**	**3.66**
Oct. 2008	6.71	4.61	15.79	12.54	6.57	7.72
YTD avg.	9.56	3.35	12.08	13.42	6.50	3.81
2007 avg.	12.60	6.65	18.66	20.89	5.75	2.26
2006 avg.	12.54	6.38	14.97	23.69	5.88	1.06
2005 avg.	12.53	6.98	12.31	20.55	5.51	1.52

Source: Muse, Stancil & Co. See OGJ, Jan. 15, 2001, p. 46
Data available in OGJ Online Research Center.

Muse, Stancil & Co. gasoline marketing margins

Oct. 2008	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	342.54	309.20	337.76	323.27
Taxes	59.70	38.40	62.29	52.40
Wholesale price	230.59	198.11	239.18	209.50
Spot price	196.36	174.55	210.80	185.98
Retail margin	52.33	72.69	36.29	61.37
Wholesale margin	34.23	23.56	28.38	23.52
Gross marketing margin	**86.56**	**96.25**	**64.67**	**84.89**
Sept. 2008	29.70	16.04	25.09	39.76
YTD avg.	30.94	31.21	25.12	39.40
2007 avg.	26.96	23.12	19.05	31.10
2006 avg.	19.74	20.34	18.03	27.90
2005 avg.	19.77	16.26	20.39	27.13

*The wholesale price shown for Chicago is the RFG price utilized for the wholesale margin. The Chicago retail margin includes a weighted average of RFG and conventional wholesale purchases.
Source: Muse, Stancil & Co. See OGJ, Oct. 15, 2001, p. 46.
Data available in OGJ Online Research Center.
Note: Margins include ethanol blending in all markets.

Muse, Stancil & Co. ethylene margins

	Ethane	Propane	Naphtha
	¢/lb ethylene		
Oct. 2008			
Product revenues	61.69	105.50	127.63
Feedstock costs	–20.49	–59.36	–92.41
Gross margin	41.20	46.14	35.22
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–5.49	–6.48	–8.74
Cash operating margin	**30.33**	**33.30**	**19.29**
Sept. 2008	42.83	37.66	–1.17
YTD avg.	22.13	23.99	–9.32
2007 avg.	14.41	14.14	–7.42
2006 avg.	19.53	22.44	1.34
2005 avg.	14.43	20.68	1.28

Source: Muse, Stancil & Co. See OGJ, Sept. 16, 2002, p. 46.
Data available in OGJ Online Research Center.

Muse, Stancil & Co. US gas processing margins

Nov. 2008	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	6.36	3.66
Liquids	0.73	1.94
Gas purchase cost	7.08	4.91
Operating costs	0.07	0.15
Cash operating margin	**–0.06**	**0.54**
Oct. 2008	0.20	1.42
YTD avg.	0.50	1.77
2007 avg.	0.44	1.47
2006 avg.	0.26	0.97
2005 avg.	–0.06	0.25
Breakeven producer payment, % of liquids	104%	69%

Source: Muse, Stancil & Co. See OGJ, May 21, 2001, p. 54.
Data available in OGJ Online Research Center.

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'Windfall profit' tax move leaves reason for worry

The US oil and gas industry has reason to feel relief and worry about President-elect Barack Obama's decision not to pursue a "windfall profit" tax on oil.

The Obama transition team let it be known on Dec. 2 that it had dropped the proposal from consideration. Obama earlier saw it as a way to raise money to help energy users hurt by high prices.

Industry trade associations appropriately welcomed the decision. But they and the companies they represent must stay on guard.

That the idea of a windfall profit tax had any life at all speaks ominously about US energy politics.

It indicates failure to see the importance of future oil and gas supply, which can come only through investment, which requires profit, which taxation shrinks.

The mere mention of a windfall profit tax also shows an inability to learn from history.

Congress imposed a "windfall profit" tax in 1980. The levy discouraged US exploration and development, thereby limiting supply in subsequent years, and failed to meet its revenue targets.

And it didn't tax profits, "windfall" or otherwise. It taxed the difference between the sales price of oil at the wellhead and a statutory base price that proved monstrously difficult to administer.

The windfall profit tax of the 1980s was a huge, deceptively named mistake that no government should wish to repeat.

The Obama team shows no sign of having learned the lesson. It decided not to impose a windfall profit tax, said an aide, because the price of crude oil had fallen and seemed likely to stay below $80/bbl.

The implication is that if crude prices exceed $80/bbl again—which they will someday, quite possibly during the Obama presidency—a windfall profit tax will receive new consideration.

That's not good enough. It leaves a factor of uncertainty at work in planning for investments crucial to US energy supply—a price trigger for new taxation.

The Obama team would have done American energy users and taxpayers a favor by saying it no longer was considering a windfall profit tax on oil because it was a mistake ever to have done so.

(Online Dec. 5, 2008; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

A turbulent year

The waning year of 2008 is sure to be remembered as one of the most turbulent in the history of the oil and gas industry, said energy analysts.

Some earlier assumed it would take years for crude to climb to the record high of $147.27/bbl that it achieved in July on the New York Mercantile Exchange. At one time, it also seemed inconceivable that a front-month crude contract could plunge from nearly $150/bbl to less than $45/bbl in just 6 months. The January contract for benchmark US sweet, light crudes dropped to $43.67/bbl Dec. 4—the lowest closing on NYMEX since January 2005. "It is now becoming apparent that we live in a world that is much faster moving and more interconnected than we appreciated," said analysts at KBC Market Services, a division of KBC Process Technology Ltd. in Surrey, UK.

Energy markets suffered a psychological blow Dec. 1 when the National Bureau of Economic Research (NBER) confirmed the US economy has been in recession since December 2007. NBER said US employment and incomes peaked last December; industrial production peaked in January; and sales peaked in June. "Almost the entire developed world is, to all intents and purposes, deep in recession with economic growth almost certain to be negative in 2009," said KBC analysts. It's the first time since World War II there have been simultaneous recessions in the US, the UK, Europe, and Japan.

Recession cuts demand

In the Houston office of Raymond James & Associates Inc., analysts said, "The global financial meltdown is now likely causing meaningful oil demand destruction around the world. As a result, we are taking down our 2009 oil price forecast from $90/bbl to $60/bbl. We readily admit that our visibility and confidence in these new estimates are very low. There are simply too many moving parts to get any confidence in near-term oil prices." Still, they said, "Intuition would suggest that the market's recent rush to liquidity has caused oil prices to overshoot on the downside. Unfortunately, we don't know whether or not the market liquidation of virtually all commodities is over."

While short-term issues and energy prices remain anyone's guess, "eventual improvements on the demand side and additional OPEC cuts will turn crude prices around by the second half of 2009," said Raymond James analysts. The general consensus is that the Organization of Petroleum Exporting Countries will cut production by 1 million b/d Dec. 17 in Oran, Algeria.

Oil markets are so focused on demand rather than supply that a production reduction of 2 million b/d may not have any more effect on oil prices than a cut of 1 million b/d, said Paul Horsnell, Barclays Capital Inc., London.

Meanwhile, many observers suspect OPEC members have not been consistent in complying with the 1.5 million b/d production reduction that began Nov. 1. Although the group's output declined in November for the third consecutive month, other sources indicate only 66% of that most recent cut has been made, not yet enough to offset the decline in oil demand. Total OPEC output was down to 31.2 million b/d in November from 32.17 million b/d in October. The 11 OPEC members supposed to comply with the group's quotas produced 28.07 million b/d in November compared with 29.06 million b/d in October.

Most reductions have been among some OPEC members bordering the Gulf of Iran, with Saudi Arabia down almost 500,000 b/d. But no major reductions were yet evident among economically troubled members such as Iran and Venezuela.

Horsnell said, "Ultimately we expect that the market will get overtightened, but it will be an incidental effect of further severe disappointments in non-OPEC supply, rather than the result of any direct OPEC policy to overdo the supply-side contraction.

In New Orleans, Pritchard Capital Partners LLC analysts said, "There is simply no faith that global supply will tighten in the next 60 days, and the 'great unwinding' of leverage is still an ongoing process. Oil prices are not likely to rebound until either OPEC makes a substantial production cut or the economy begins to recover and refined product demand firms up."

KBC analysts surmised, "Higher prices will inevitably return." They expect world oil demand to grow by 21 million b/d between 2007 and 2030 at an average annual rate of nearly 1 million b/d, with China in the lead. "Total non-OPEC crude oil production will peak at the end of the next decade, and the world will need more oil from OPEC—biofuels will barely make a significant contribution," they predicted.

(Online Dec. 8, 2008; author's e-mail: samf@ogjonline.com)

2008 LNG World Trade

December 2008

Prepared by: Warren R. True, Chief Technology Editor – LNG/Gas Processing, Oil & Gas Journal

Poster layout and graphics by Robert Rowan | www.rowangraphics.com

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LNG importing countries, 2007

Importing country	Million tonnes	Bcf	Part of total, %	Change from 2006, %
Japan	66.98	3.26	35.20	+0.90
Korea	26.29	1.28	13.81	+3.00
Spain	16.63	0.81	8.74	-1.00
US	13.82	0.74	5.20	+36.70
France	9.81	0.47	5.40	-37.00
Taiwan	8.22	0.41	4.30	+7.10
India	7.96	0.38	4.60	+27.80
Turkey	4.28	0.20	2.40	+9.10
China	3.89	0.15	1.40	+298.60
Portugal	2.11	0.10	1.29	+79.50
Belgium	2.08	0.10	1.20	-33.30
Mexico	1.85	0.09	1.10	+220.00
Italy	1.73	0.08	1.00	-23.70
UK	1.32	0.06	0.40	-56.50
Greece	0.97	0.05	0.40	+60.00
Puerto Rico	0.58	0.03	0.30	+0.20
Dominican Rep.	0.42	0.02	0.20	+61.00
Total	170.82	8.32	100.00	+7.0

LNG exporting countries, 2007

Exporting country	Million tonnes	Bcf	Part of total, %	Change from 2006, %
Indonesia	29.52	1.39	17.00	-0.9
Malaysia	23.63	1.11	13.31	+4.2
Australia	15.39	0.74	8.90	+8.2
Brunei	7.07	0.34	4.20	-4.1
Qatar	29.30	1.42	17.20	+18.5
Oman	9.96	0.46	5.60	+9.4
Abu Dhabi	5.84	0.28	3.40	+5.2
Eq. Guinea	1.30	0.05	0.60	
Nigeria	16.67	0.82	9.80	+23.4
Algeria	17.87	0.87	10.50	+7.1
Libya	8.59	0.43	4.90	+15.8
Egypt	10.00	0.44	5.90	-8.7
Trinidad & Tobago	12.51	0.66	7.90	+24.1
VEI	9.96	0.94	9.56	-21.5
Total	178.84	9.37	100.00	+7.6

Global LNG trade

Legend

LNG liquefaction plant
- Existing site
- Existing and operating
- Under construction
- Approved

LNG receiving terminal
- Existing site
- Existing and operating
- Under construction
- Approved

( ) Total after expansion

LNG trade route

LNG conversions[1]

	LNG, million tonnes	LNG, billion cu m	Gas,[2] billion cu m	Gas,[2] billion cu ft
LNG, million tonnes	1	0.0024	1.36	48.7
LNG, billion cu m	417	1	575	20,260
Gas, billion cu m	0.735	0.0017	1	35.3
Gas, billion cu ft	0.0205	0.00005	0.0283	1

[1] Based on conversion factors published by the US Department of Energy.
[2] Typical conversion for an ambient condition. Actual range of 1.35–1.37.

Worldwide natural gas reserves

Proved reserves as of Jan. 1, 2008

Eastern Europe and FSU

Country	Bcf
Albania	28
Azerbaijan	30,000
Belarus	150
Bulgaria	150
Croatia	1,000
Czech Republic	190
Georgia	660
Hungary	280
Kazakhstan	100,000
Kyrgyzstan	200
Lithuania	—
Poland	5,820
Romania	2,225
Russia	1,680,000
Serbia	1,700
Slovakia	500
Tajikistan	200
Turkmenistan	265,000
Ukraine	39,000
Uzbekistan	65,000
Total Eastern Europe and FSU	2,036,700

Middle East

Country	Bcf
Abu Dhabi	194,100
Bahrain	3,250
Dubai	4,000
Iran	948,200
Iraq	111,940
Israel	1,075
Jordan	233
Kuwait	63,070
Neutral Zone	1,500
Oman	30,000
Qatar	901,200
Ras al Khaimah	1,200
Saudi Arabia	252,600
Sharjah	10,700
Syria	8,200
Yemen	16,900
Total Middle East	2,549,000

Western Europe

Country	Bcf
Austria	170
Denmark	3,490
France	257
Germany	9,000
Greece	70
Ireland	350
Italy	3,075
Netherlands	50,000
Norway	79,130
Spain	90
Turkey	300
UK	14,500
Total Western Europe	160,733

Africa

Country	Bcf
Algeria	159,000
Angola	9,500
Benin	40
Cameroon	4,770
Chad	—
Congo (Former Zaire)	35
Congo Brazzaville	8,250
Egypt	58,500
Equatorial Guinea	1,300
Ethiopia	380
Gabon	1,000
Ghana	800
Ivory Coast	1,000
Libya	46,200
Mauritania	1,000
Morocco	50
Mozambique	6,500
Namibia	2,200
Nigeria	181,900
Rwanda	3,000
Senegal	350
South Africa	—
Sudan	6,000
Tanzania	230
Tunisia	2,000
Total Africa	488,000

Asia-Pacific

Country	Bcf
Afghanistan	1,750
Australia	35,000
Bangladesh	5,000
Brunei	13,000
China	80,000
China, Taiwan	220
India	37,000
Indonesia	92,500
Japan	730
Malaysia	83,000
Myanmar	19,000
New Zealand	1,044
Pakistan	29,000
Papua New Guinea	9,000
Philippines	3,480
Thailand	13,197
Viet Nam	6,000
Total Asia-Pacific	415,295

Western Hemisphere

Country	Bcf
Argentina	15,750
Barbados	0
Belize	—
Bolivia	26,500
Brazil	17,280
Canada	58,190
Chile	3,460
Colombia	4,347
Cuba	2,500
Ecuador	—
Guatemala	—
Mexico	23,850
Peru	11,939
Suriname	—
Trinidad and Tobago	18,770
United States	211,080
Venezuela	166,260
Total Western Hemisphere	544,959
Total world	5,193,687
Total OPEC	3,191,542


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Algeria
Libya
Egypt
Qatar
Abu Dhabi
Oman
Yemen
India
Nigeria
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Abstract Submittal

Abstracts must have a title and list all authors. Full contact information for the primary contact author (company affiliation, telephone, fax number and email address) must be provided. Please designate which author will be the speaker. Presentations must be of interest and of practical value to executives, managers, engineers, and geologists and geophysicists engaged in the petroleum industry. Papers will be selected based on a review of abstracts by the Program Committee. Papers must not be commercial in nature. Please submit a 150 – 400 word abstract around one or more of the technical focus areas by **6 March 2009**.

Deadline for abstract submission | **6 March 2009**

DOT Call for Presentation Abstracts

Information for Authors

1. Final selection of papers will be determined by the DOT Conference Advisory Board. Papers will be evaluated on the basis of abstract submitted. The papers should be in English, completely original, and address deepwater and ultra deepwater issues as outlined in the conference focus areas. Papers and presentations should avoid any commercialism.

2. The following criteria will be observed by the Conference Advisory Board in the selection of papers:
   a. The paper should be of interest for deepwater, ultra deepwater, and/or frontier applications.
   b. The paper should emphasize innovative technologies including and analysis of research.
   c. The paper should address case studies and/or technical interest for indicated topics.

3. Twenty-minutes are programmed to present a paper (presentation in English). A ten-minute discussion will follow each presentation.

4. Authors of papers selected for the DOT program will be notified by the end of **June 2009**.

5. A manuscript and technical presentation will be required for each paper selected. Manuscripts should be provided to DOT with the text by email in MS Word format and PDF format. Copyright of papers and presentations belongs to DOT.

6. Maximum length of paper shall be 15 typewritten pages, including references. Bibliography tables should not exceed 6 pages. Photographs should be sent as black and white prints.

7. Full instructions on preparation of manuscripts and presentations will be sent to authors of selected papers. Complete manuscripts and the draft version of the PowerPoint presentation must be provided by **3 August 2009**. Slides, sketches, graphs or photographs to illustrate the presentation shall be provided in a PowerPoint document by **12 October 2009**.

8. Complimentary conference registration will be provided only for authors who present a paper (1 author per paper). DOT assumes no obligation for expenses incurred by authors for travel, lodging, food, or other expenses.

9. Recognizing the importance of attracting young talent to the industry, DOT has established the George Murray Award for Best Presentation by a Young Engineer (aged 35 or younger). The future of this industry depends on attracting bright, new talent. Innovative thinking by younger engineers should therefore be recognized and rewarded accordingly. To this end, the DOT offers discounted registration fees for attendees, under the age of 35, as well as first time attendees and encourage them to submit technical abstracts for consideration.

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Choose from the folloing technical focus topics and submit an abstract by **6 March 2009**.

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- Subsea Boosting & Processing
- Floating Production Systems
- Mobile Offshore Drilling Units
- Flow Assurance
- Flowlines & Pipelines
- Deepwater Mooring & Stationkeeping
- Deepwater Drilling Operations
- Deepwater Completions
- Well Construction
- Tubulars

Management

- Benchmarking
- Drilling Economics
- Human Resource & Training
- Integrated Solutions
- Logistics
- Project Execution and Management
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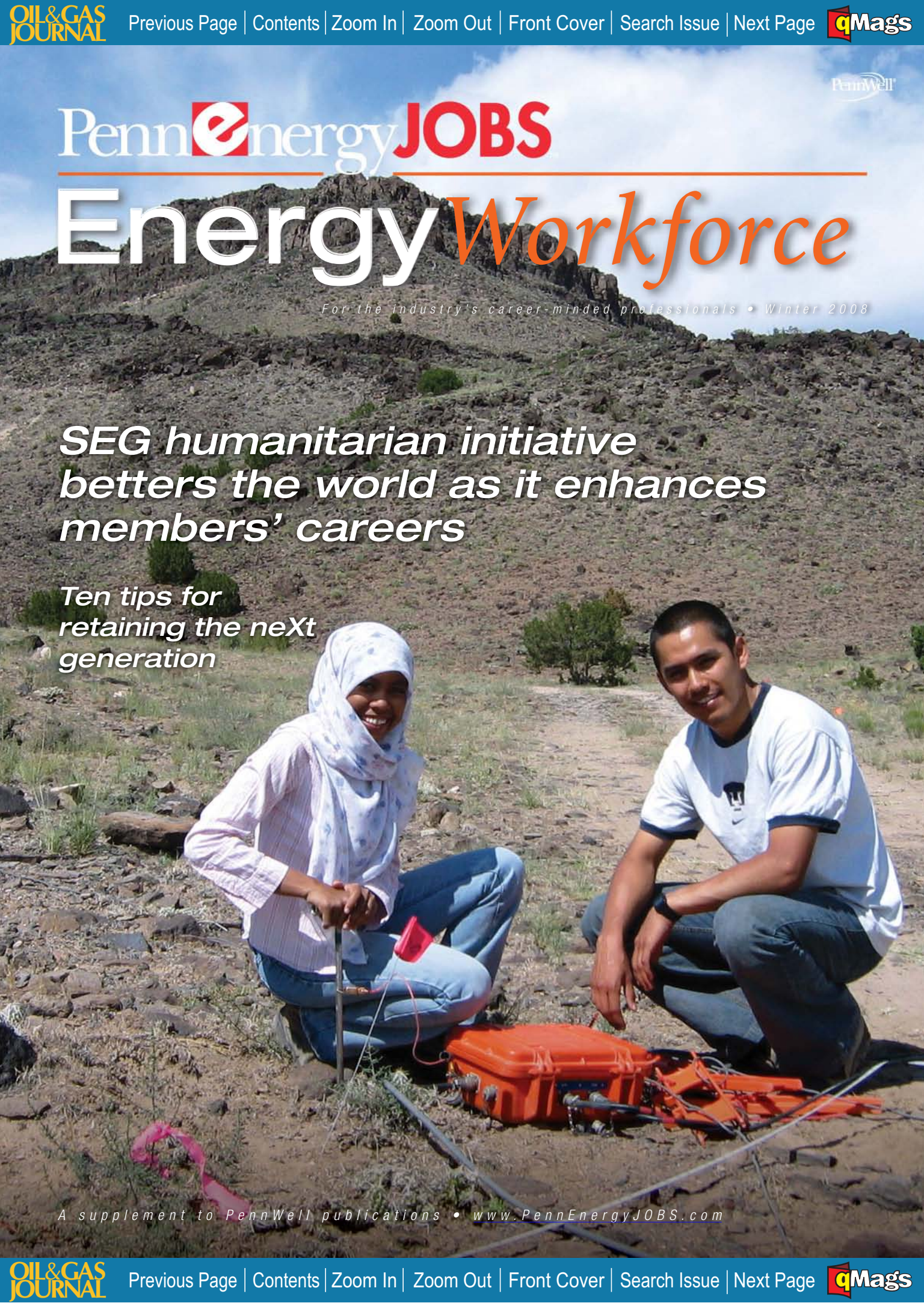
Ten tips for retaining the neXt generation



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PennEnergyJOBS Energy Workforce

On the cover: Students Yusliza Sufian and Jose Carrillo-Rangel are in the field acquiring electromagnetic data for groundwater applications during a Summer of Applied Geophysical Experience (SAGE) field camp in New Mexico in July 2004. Such projects involving geoscience students will increasingly be directed toward communities in need under the new SEG (Society of Exploration Geophysicists) Foundation program Geoscientists Without Borders, which is profiled in an article beginning on p. 4. SAGE is a unique educational program designed to introduce students in geophysics and related fields to "hands-on" geophysical exploration and research. SAGE is hosted by the Los Alamos National Laboratory branch of the Institute of Geophysics and Planetary Physics, University of California, and supported by SEG and other organizations. Photo by Matthew Ludwig courtesy of SAGE.

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Telecommuting benefits outweigh negatives

Telecommuting at least part of the time makes workers more productive and happier at their jobs…[and] retention is probably the No. 1 staffing concern in the energy industry. So even if the energy savings and environmental benefits aren't enough justification, that would be the clincher in convincing management to be more flexible on the issue.

Dear Reader,

How effective would you be in your job if you worked at home?

Some of us would see productivity gains; others would fare better in an office setting.

The high costs of transportation fuel has many companies reviewing their policies for flexible working arrangements and telecommuting. And with good reason.

The Consumer Electronics Association conducted a study recently that found that telecommuting has "terrific" potential for reducing US energy consumption. Presently, 3.9 million people in the US work from home at least 1 day a week. With the average commute put at 22 miles, this saves 840 million gallons of gasoline per year—but that's against total US gasoline consumption of 146 billion gallons/year.

However, CEA also found that as many as 53 million people *could* telecommute. Even at just 1 day per week, that works out to an 8% reduction in annual gasoline use.

The study found that the current level of telecommuting saves the equivalent energy of the amount of electricity used by about 1 million US households each year. It also reduces carbon dioxide emissions equivalent to removing 2 million vehicles from the road every year.

The CEA study took into account increased home-based carbon emissions resulting from telecommuting and found that they were more than offset by the savings in gasoline consumption and, in some cases, part of the energy consumption associated with commercial office space.

But if millions more workers started telecommuting 1 or more days per week, it would represent a sea change in the American workplace. Concerns have been raised by management and staff alike as to what widespread telecommuting would do to the workplace. Some managers remain concerned about worker productivity and team interaction. Some workers worry about career prospects and the intrusion of work into the home space.

A recent study by Penn State University revealed some interesting findings about the purportedly negative aspects of telecommuting. The study found that, overall, it improved productivity, enhanced morale, reduced conflicts between work and family, did not damage career prospects, and did not—if limited to 1 or 2 days—harm workplace relationships.

The key finding of the study is that telecommuting gives employees a sense of freedom or greater control over their work environment. From this the other benefits flow. There seems to be inherent limits, however. According to the study, working from home more than 2 days a week, while still benefiting the family, tended to have a negative effect on workplace relationships. And managers have to adapt to this new workstyle; micromanagers will have the biggest challenge.

Still, the results of the study are clear: Telecommuting at least part of the time makes workers more productive and happier at their jobs. As articles in this publication have shown, retention is probably the No. 1 staffing concern in the energy industry. So even if the energy savings and environmental benefits aren't enough justification, that would be the clincher in convincing management to be more flexible on the issue.

Sincerely,

Jamie Matlin,
Publisher & Director of Recruitment Advertising

America's 'invisible' energy efficiency boom

Tucked into the massive $700 billion bailout—uh, "economic rescue" plan—that Congress passed and President Bush signed into law in early October was a pretty hefty wish list for proponents of greater energy efficiency. These new energy efficiency tax provisions include:

- Extending the tax credit for efficient furnaces, boilers, air conditioners, water heaters, and insulation and window upgrades for existing homes.
- Extending the new energy-efficient home tax credit 1 year.
- Providing 3 years of manufacturer tax credits for sales of high-efficiency refrigerators, clothes washers, dishwashers, and dehumidifiers.
- Extending the commercial buildings tax deduction to yearend 2013.
- Adding a new tax credit for plug-in hybrid vehicles.
- Adding a new 10% investment tax credit for combined heat and power systems.
- Extending fuel cell and microturbine credits to yearend 2016.
- Accelerating depreciation for smart meters and smart grid systems.
- Establishing a new energy conservation bond program to help local and state governments fund energy conservation efforts.
- Extending an existing bonding program for green buildings and sustainable design.

The National Electrical Manufacturers Association applauded the passage of these tax provisions, noting that some "provide the private sector the needed longer-term certainty for business investment and planning…."

If NEMA is happy, then the American Council for an Energy-Efficient Economy must be positively giddy. ACEEE describes energy efficiency as America's "invisible" energy boom, having slashed US energy consumption per dollar of economic output in half since 1970, from 18,000 BTUs to about 8,900 BTUs in 2008.

ACEEE contends that energy efficiency is underdeveloped and that the US could cost-effectively reduce energy consumption by another 25–30% during the next 25-30 years. (One presumes that is measured in BTUs per dollar of GDP again, not in absolute terms.)

ACEEE also claims that the $300 billion the US invested in energy efficiency in 2004 was triple the amount invested in traditional energy infrastructure.

Turns out that $300 billion represents "the full cost associated with the efficiency technology investments, including the base cost of the technology needed to simply maintain previous levels of energy intensity, as well as the incremental cost needed to provide the increased level of productivity," according to ACEEE. Well, OK then.

Energy efficiency by itself is no more a silver bullet to solve our energy woes than any other single solution. At a time when the whole world is staring into an economic abyss, any energy solution has to be pay for itself in fairly short order.

In any event, promoting further energy efficiency gains is certainly laudable, but the key here is ACEEE's reference to cost-effectiveness. Energy efficiency by itself is no more a silver bullet to solve our energy woes than any other single solution. At a time when the whole world is staring into an economic abyss, any energy solution has to be pay for itself in fairly short order. For example, Consumer Reports advises against buying costly tankless water heaters because they won't pay out before they give out, despite their 22% energy savings.

The omnibus bailout bill pays for these energy efficiency tax credits in part by shaving some standard business tax credits from oil and gas companies. That's billions of dollars that won't be invested in finding and producing more oil and gas, which of course, carries its own short-term and long-term costs.

If we're going to rob Peter to pay Paul, let's make sure Ponzi isn't in on the deal too.

Bob Williams,
Managing Editor

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SEG humanitarian initiative betters the world as it enhances members' careers

The Society of Exploration Geophysicists Foundation has embarked on an ambitious new program that deepens the foundation's involvement in humanitarian activity—and by turn, SEG members' commitment to giving back to the world community.

Geoscientists Without Borders is designed to benefit disadvantaged communities by funding projects that apply geophysical and geoscience technologies to meeting community needs. These humanitarian projects are intended to create a brighter future for communities in need while raising the profile of applied geoscience. Universities and students will be heavily involved.

The seed for the program was planted in a response to the horrific December 2004 Asian tsunami that killed more than 230,000 people and displaced millions more.

Geophysics played a role in helping recovery efforts of local populations. For example, Germany's BGR (Federal Institute for Geosciences and Natural Resources) conducted a post-tsunami helicopter electromagnetic survey along the coasts of Aceh, northern Sumatra, to discriminate between fresh-water and saltwater aquifers, according to Geoscientists Without Borders committee member Louise Pellerin of Green Engineering Inc.

"Saltwater intrusion occurred close to the coast as a result of the tsunami, and deep saltwater occurrences—particularly around 30 m depth—were mapped up to several kilometers inland," she said. "Based on the survey results, recommendations were made to locate shallow, hand-dug wells and medium-depth (60 m) water wells."

Program details

Geoscientists Without Borders was largely the brainchild of Craig Beasley, a Schlumberger executive who was SEG president for 2004-2005 and who had exhorted his fellow members to help the tsunami-devastated communities of Asia with a call to action that "we have a significant contribution to make as geophysicists."

Schlumberger stepped up to launch Geoscientists Without Borders with a funding commitment of $1 million in late 2007.

The SEG Foundation program was launched in May 2008, when the request for first-phase project proposals was published and a July 2008 deadline set.

Program committee members have recommended the first two projects for award, and those details were to be announced after this publication's presstime, at the foundation's donor luncheon at SEG's annual meeting in Las Vegas in November. The second round of first-phase proposals was due for submissions in early October, and those recipients would be announced in December 2008 or January 2009.

Qualifying projects will be required to demonstrate that they will deliver humanitarian and environmental benefits through application of geophysical and geoscience expertise. These benefits could include a wide range of projects, such as locating fresh-water supplies, pollution remediation, natural hazard detection, manmade hazard

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— Dalton Boutte, WesternGeco

mitigation, sustainable resource development, and related education. Anyone interested in applying for grants or offering their services as mentors should visit the SEG website at http://www.seg.org/foundation.

SEG is the global professional organization dedicated to advancing the science and technology of applied geophysics. It serves more than 30,000 members and student sections at 204 academic institutions worldwide. Members are involved in oil and gas, mining, environmental, and other industries and research efforts that benefit from applied geophysics.

The SEG Foundation is the society's charitable organization dedicated to advancing the mission of the society through grant and award programs. The foundation provides scholarship opportunities, travel grants, and funding for field camp programs and other projects of merit made available to student members worldwide, as well as global education programs for practicing members.

Program benefits

Beasley, a vice-president of WesternGeco, a business segment of Schlumberger, and chair of the SEG Foundation Committee for Geoscientists Without Borders, concurs with the view that volunteer and charity work enhances the career of a petroleum professional.

"Like many people in the petroleum industry, I have had the opportunity to travel extensively and experience firsthand the poverty in underdeveloped parts of the world," he said. "I think it has an effect on all of us when we live and work with people coming from these circumstances. So it is gratifying to do something that can directly improve the lives of people in need."

Beasley also acknowledges the benefits to the industry that result from petroleum professionals "giving back"

"Certainly having visibility in helping people improves a company's image—for any type of company," he said. "But one of the most important aspects of the Geoscientists Without Borders program is that it establishes links on a global basis among professionals, their companies, students, universities, and people in need. This direct, person-to-person contact can have a large effect on perceptions of the petroleum industry."

Dalton Boutte, executive vice-president of Schlumberger and president of WesternGeco, underscored the Geoscientists Without Borders program goals in announcing his company's funding commitment to the SEG Foundation: "When we looked at the technologies we have developed in the oil and gas sector and the potential benefits to humanitarian efforts, we were interested in enabling these applications through interaction with the academic community, students, and the SEG Foundation.

"We are proud to be able to help establish a program that will focus on humanitarian applications of geoscience and inspire students to use their skills in the geosciences to make the world a better place."

Academia benefited

Students and universities also benefit from the important role they will play in the success of the program. Students will benefit personally through the experience of planning and executing such projects.

According to Gabriel Borges, outgoing 2007 president of the SEG Student Section at the University of Oklahoma, "The program represents a great opportunity for geoscience students to provide an early contribution to the professional community while building their technical

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skills and assuming a leadership role in the global fight for human dignity in these disadvantaged communities."

The Schlumberger commitment to the program was made to the SEG Foundation's major gift campaign, *Advancing Geophysics Today, Inspiring Geoscientists for Tomorrow*. SEG Foundation Board Chairman Gary Servos noted the importance of this new investment in the future of geophysics: "SEG Foundation has a long history of supporting students and universities engaged in the study of applied geophysics. We are proud to work with Schlumberger to raise this engagement to a new level. Geoscientists Without Borders will strengthen university programs, introduce students to the practical and humanitarian benefits of geophysics and geoscience, and make a difference to the quality of life in many of the world's most disadvantaged communities." —EW

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Ten tips for retaining the neXt generation

Justin G. Roy, SullivanKreiss

Generations X and Y will continue to challenge us as firm owners and managers; they will test the waters and will sometimes go overboard.

However, their style is here to stay, and trying to fit them into the what-worked-before model will only cause headaches

Of course, we all know there are fewer people in the next generations, making it that much more important to focus on recruiting and retaining them. How can a firm overhaul its entire approach to employee recruiting and retention when half their staff is still sold on and used to the old way? Baby steps, that's how.

Here are some tips to implement into your day-to-day retention strategy.

- **Encourage them to use online social networks.** Take the site-block off of MySpace and Facebook and LinkedIn. These sites offer more than one would think; besides a good way to blow off steam during the day (we all need a 5-minute break), they offer much more. As online social networking grows, these sites become much larger hubs of information, which, when used correctly, can benefit your firm. The sites allow people to keep in touch and see what their friends and connections are up to. Within a few minutes, you could know who is looking to make a job change (great recruiting strategy), who is relocating to your area, what firms are hiring, etc.

- **Flex time.** The option to come in early and leave early or come in late and leave later is very appealing to these generations. Some are trying to balance a social life, while others are trying to balance their family life. Offering your employees the benefit of arriving at work an hour early or later gives them the flexibility to schedule "life issues" such as daycare, eldercare, or doctor appointments. With this flexibility also comes a great benefit to the employer; it allows the employee to be in the office for a "full shift" rather than having to take extra time off for an appointment.

- **Flex office.** "If I can get it done, and get it done well, why does it matter where I work?" From working at a coffee shop to working from home, the technology age has allowed us to be more mobile than ever. Put together a laptop, cellular telephone, and an internet connection, and you have an instant office. In fact, most people will never know that you are not in the office (with calls forwarded to the cell phone).

- **Reward based on merit.** More and more people in the workforce do not believe in the old equation of time put in = promotion. They look at their individual contribution to the company and to the team as a metric for promotion and merit rewards.

- **Be a socially conscious organization.** "Sustainability" and "green" are the hot words today. The younger generations are very interested in social and environmental happenings, both through the media as well as through their employer. Communicate what your firm does to better society and benefit the environment. If you come up empty-handed, ask your employees to come up with a program. It can be as simple as volunteering at a reading program, spending a day rebuilding or renovating a house for somebody in your community, planning ways to make your office "green." Get everybody involved, and you create emotional equity, making it a bit more difficult for these folks to leave your firm.

- **Training.** Offer opportunities for your staff to further their knowledge, for work-related functions as well as career-focused training. People are always excited and interested in furthering their knowledge and see it as a huge benefit when a firm offers these courses. If you cannot afford to hold them at your office, send candidates out to a training program for a day or two out of the office; when they come back, ask them to make a presentation to the rest of the company about what they learned.

- **Management style.** Flat-line management is top choice lately, and for a lot of good reasons. How many times have you been on top of—or at the

bottom of—a delivered message, only to find out the end person heard a very different version? This is a good example of the telephone game.

- **Spend time and mentor.** Make sure you spend time with every employee, on a project, by the water cooler, or even at a one-on-one lunch. These conversations will help others understand who and what management is and will help you create a bond with your employees. The same adage goes with being a manager as it does with networking: If you do not know three things about the other person that are not work-related, then you need to rethink your style.

> *"Take the site-block off of MySpace and Facebook and LinkedIn. These sites offer more than one would think; besides a good way to blow off steam during the day (we all need a 5-minute break), they offer much more. As online social networking grows, these sites become much larger hubs of information, which, when used correctly, can benefit your firm. The sites allow people to keep in touch and see what their friends and connections are up to. Within a few minutes, you could know who is looking to make a job change (great recruiting strategy), who is relocating to your area, what firms are hiring, etc."*

- **iPod Friday.** Quite a few firms have been banning the use of iPods in the office, noting the loss of collaboration opportunities between colleagues, loss of communication, and missed mentoring opportunities that could have been seized by simply listening to more experienced staff in

'Sustainability' and 'green' are the hot words today. The younger generations are very interested in social and environmental happenings, both through the media as well as through their employer. Communicate what your firm does to better society and benefit the environment. If you come up empty-handed, ask your employees to come up with a program. It can be as simple as volunteering at a reading program, spending a day rebuilding or renovating a house for somebody in your community, planning ways to make your office 'green.' Get everybody involved, and you create emotional equity, making it a bit more difficult for these folks to leave your firm."

the office. The younger generations, however, justify the use of iPods, saying they help concentration, allow them to be more creative, and help get the job done faster. Allow your employees to bring in and wear their iPods on Friday (or another day). Make known the expectation that it should not hinder their work or ability to get the job done. Of course, guidelines will need to be set, such as volume (so they can still hear the telephone), but try to work with rather than against them.

- **Gym membership.** Offer discounted or free membership to a local gym, or build your own. While our belts seems to be getting tighter by the day, this generation is growing up with the overhaul in the fast food industry. Ask any of them who Jared (Fogle) is; I bet you they will mention Subway. Take a look at the McDonald's menu now—they are offering fruit and milk Obesity and healthy eating are today's headlines. I have seen this benefit sway a potential employee to

signing the papers with one company versus the other. It is also no secret that healthy employees tend to take less time off and have fewer health problems. This benefit is one that can add to your bottom line.

Are some of these ideas and tips extremely wild? Of course they are. But so is the next generation. Being proactive on retention today will yield a much higher return than the firms who are reactive tomorrow. —EW

The Author:

Justin G. Roy is the chief operating officer of SullivanKreiss, a national executive search firm that serves the engineering, environmental consulting engineering, planning, architecture, and landscape architecture sectors. He is responsible for the management of recruiting operations, along with client and project development. Roy also advises clients on recruitment strategy, compensation, relocation, outplacement, and other human resources issues. He is also the cofounder of Networking for a Cause, a non-profit organization dedicated to raising awareness for non-profits and like-minded people. Roy has a BA in international business with a concentration in Spanish studies from Assumption College in Worcester, Mass. He was the recipient of the 2004 Crown and Shield Award for his civic and global service and leadership.

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Strategies to Address the Problem of Exiting Expertise in the Electric Power Industry

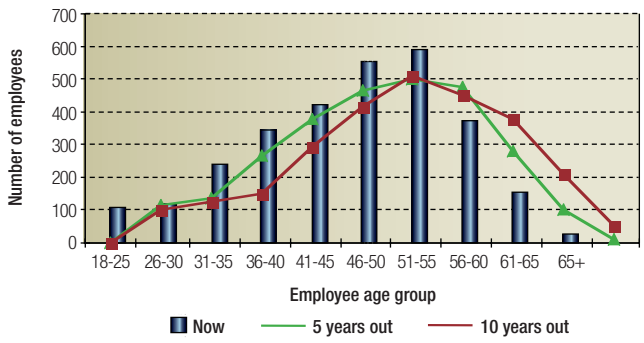
Dennis Ray, Power Systems Engineering Research Center
Bill Snyder, Quanta Technology

Retirements, restructuring, and technology changes are producing an accelerating exodus of expertise from the electric power industry. In this article, the authors review the major approaches to address that challenge: managing available resources, outsourcing, automating, recording, and educating. The approaches may all be used in a comprehensive strategy to overcome exiting expertise. Each approach has different implications for the resources needed to be successful. The responses to date have not been sufficiently comprehensive and of adequate scale to address the looming workforce losses. The authors contend that the needed leadership by executives, policymakers, and academia to comprehensively address the expertise exodus challenge will be enhanced by a better understanding of the diverse approaches and of where effective intervention with sufficient resources is needed.

The coming mass exodus of expertise in technicians and engineers in the electric power industry is a well-expected phenomenon. The loss has been the subject of workshops, conferences, and symposia. It has been the focus of work by industry professional societies, the National Academy of Engineering, and the National Science Foundation. A better understanding of the scale of workforce needs is being studied: IEEE's Power Engineering Society has begun a detailed study of the workforce environment in the electric power delivery industry in North America, as has already occurred in other countries.

Manpower issues are increasingly listed among top strategic concerns of industry executives. The principal reason for the expertise exodus is the aging workforce.

Fig. 1. The aging of the utility workforce



Source: KEMA analysis

Fig. 1 illustrates the distribution of ages in the utility workforce now and in 5 and 10 years. The Nuclear Energy Institute estimated that 73.2% of direct employment in the nuclear generation sector is between the ages of 43 and 57 and that 28% of those employees will retire within 5 years, with another 18% leaving for non-retirement reasons. The prediction by Keith Mueller is that the "tipping point" in accelerating retirements will come at the end of this decade. Some utilities report that as much as 40% of their employees will be eligible for retirement in the next 5 years; however, the average may be more on the order of 20% over the next 5 years and 50% over the next 10 years. Besides retirements, other reasons for the exodus include industry restructuring and internal reorganizations.

Actions being taken in response to the rapidly approaching tipping point are summarized in four approaches:

- Human resource management—identification and evaluation of knowledge and skills at risk and strategies to address the risk.
- Automating—applying technology to complete tasks.
- Recording—putting knowledge into accessible records.
- Educating—transferring knowledge to the next generation of engineers and technicians.

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The responses to date do not seem to be sufficiently comprehensive and of adequate scale to address the looming workforce losses. Technology deployment does not appear fast enough. University power programs face significant shortfalls in resources and faculty. In sum, the needed leadership by executives, policymakers, and academia to comprehensively address the expertise exodus will be enhanced by a better understanding of the diverse responses and of where effective intervention with resources can occur to make a difference in addressing the expertise exodus problem.

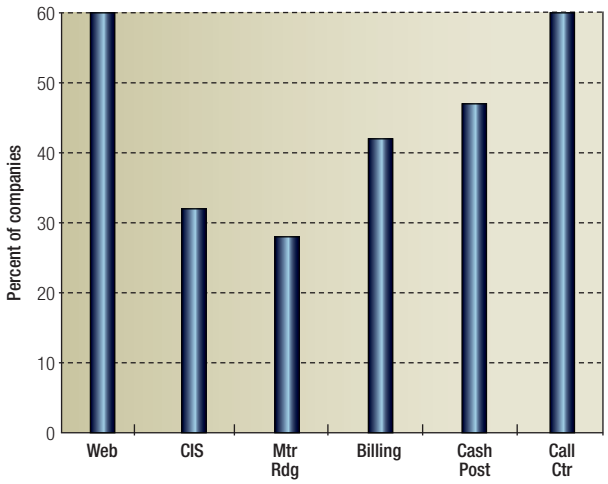
Human resources management

The human resources issues associated with an aging workforce require new practices and policies around recruitment, retention, and other traditional human resources concerns. For operations management, the challenges can require daily juggling of resources and priorities based on workload, emergencies, manpower availability, and many other variables. These are not new challenges for operations and engineering organizations; however, the added variables of shrinking workforce and diminished organizational experience compound current decisionmaking and prioritization challenges—and thus increase the probability of important work being done as a lower priority, to a lower standard due to lack of time and expertise, or at higher costs. These are not acceptable options, so risk mitigation is critical.

There are strong parallels to be made between the focus of the industry today on asset management strategies and the challenge the industry faces in managing the aging workforce. Both issues are fundamentally rooted in the need to develop operating strategies and practices that optimize the available resources. This could mean scarce financial resources for system expansion, improvement, and maintenance. It also could mean scarce human resources (and experience) for daily work management and task completion.

One asset management philosophy, described by Richard Brown and Bruce Humphrey, identifies three primary areas of competency for a robust asset management structure: management, engineering, and information. Workforce management must consider people, processes,

Fig. 2. Outsourced utility functions in 2003



and technology. To optimize the human capability within the organization, that capability must be inventoried and evaluated. In addition, an assessment is needed of the business processes and technologies supporting those processes. This comprehensive evaluation offers both the challenge and opportunity to identify operational strengths and weaknesses and to prioritize the areas requiring immediate action. As with asset management, workforce management requires a comprehensive understanding of the current condition, the areas of greatest risk, and the timing of required actions.

Management skills

Operations management today faces the challenges of workforce attrition, aging physical infrastructure, rapidly changing technology, increasing customer expectations for reliable service, and continuing cost pressures to maintain acceptable financial performance of the company. Significant workforce attrition due to retirements is an additional factor to be addressed as part of a holistic management approach to business operations. Such a comprehensive approach involves the study and consideration of all tools available to management to meet the company objectives, not solely the human resources component. The business processes and technology currently in place combine with the human element to create a complete business operations and management system. When addressing a specific change in one element of the system, it is necessary to consider all elements of the system. Attrition due to an aging workforce can be a driver for improving overall operational efficiency through a comprehensive review of how people, processes, and technologies are used.

During the 1990s, in their efforts to contain costs and increase efficiencies, utilities endeavored to "reengineer" business processes, and replace or install information technology systems to support the newly designed processes. The practice of "reengineering" evolved to "business process management," and then to "operational innovation." The concepts underlying these practices have a place in the overall strategy to manage the aging workforce challenge. Activities such as codification of information, knowledge management system creation, business process redesign, work process automation, and outsourcing are all elements of a comprehensive strategy. The issue for management is how to best use these tools and activities.

Outsourcing

Utility companies have used outsourcing as a tool to supplement the permanent workforce and manage peaks in workload. Here, outsourcing refers to temporary employees and contract labor forces. For example, utilities often supplement construction and maintenance forces with line construction contract companies. The contractors can be used as workload dictates, and the company workforce can be used primarily for critical operations activities. Similarly, temporary workers have been used to supplement many operations functions when workload dictates the need.

As a temporary workload management option, outsourcing has been a normal operating process. But what about outsourcing work as a permanent operating practice? Can this be successful? Is it confined to specific functions, and what are they? How do we determine when and how to apply outsourcing as a primary tool for workforce management? These are all questions that should be answered for outsourcing to be a more permanent solution to workforce attrition due to aging.

Because retiring employees often have an interest in continuing their professions, outsourcing sometimes takes the form of contracting with former employees. This approach avoids significant loss of institutional knowledge, but it creates a change in the fundamental business relationship between company and employee. While this can be a non-issue, it must be addressed to ensure thorough understanding of the expectations of both parties. Complete outsourcing of selected business processes is an option in addressing exiting expertise. As illustrated in Fig. 2, certain administrative functions are already outsourced by many utility companies, and because the industry

spends an estimated $19.1 billion on selling, general, and administrative functions, there are many vendors who offer comprehensive outsourcing options. The outsourcing of engineering and operations activities is more complex, however, because those activities involve critical tasks associated with electric system integrity.

Task and skill analysis

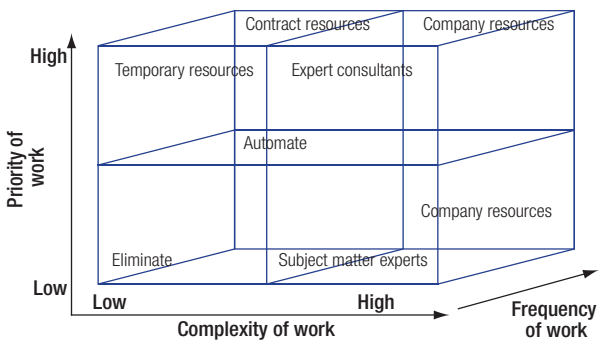
As utility companies evaluate their needs, resources, and capabilities, they ultimately consider the tasks to be performed within an organization and the skills required to proficiently execute those tasks. This is fundamental job-task analysis. Most often the existing paradigm is to base workforce planning on in-house execution of the expected or average work load and to manage workload peaks by exception, either through overtime, temporary personnel, or contractors. This is a tried and proven approach, but not necessarily the most effective approach when considering limited resources and lack of requisite skills in any given task area. The challenge is to consciously and actively evaluate specific job requirements to determine what workforce management philosophy best suits the needs of the company or offers alternatives that facilitate achievement of multiple operating objectives.

In the utility industry this may involve determining which operating tasks contractors can perform and which tasks company employees must always perform. The determinants may be issues of safety, security, knowledge, or skills, among other considerations. In an engineering organization, for example, this may involve decisions on whether company employees, contract engineers, or consultants should do design, planning, or forecasting tasks. The analysis also forces consideration of what skill level is required of in-house employees for specific processes and job tasks.

A structured approach to process analysis involves evaluation of the business process and tasks from several perspectives. One approach is a formalized job-task evaluation that includes assessment of what tasks are priorities, what skill

level is required, and how often a task is performed. Once these parameters are established, an evaluation can be made of what would be the most efficient and effective manner of task completion. Fig. 3 represents a model for evaluating tasks and options for completion.

Fig. 3. Process evaluation model



For example, a low-complexity, high-frequency, high-priority process would be an excellent candidate for system automation. Consider remittance processing as an example of a process that meets this description. Every day, companies handle thousands of customer payments that require immediate handling to properly reflect the customer's payment as well as to optimize revenue collection for the company. This process was automated years ago in most utilities and has evolved to electronic payment capabilities to further accelerate the process. Automated meter reading is an example of a current generation business process that is being evaluated against these criteria with decisions being made on how to best allocate limited resources. In the past, a primary driver for initiating process change was improving the efficiency and reducing the cost of operations. With the aging workforce, the driver for initiating process change is different, but the manner in which the issues are addressed can be similar, if not the same.

As with all elements of work management and manpower planning, there is no one right solution for all operations. The framework for analysis, however, is useful in forcing discussion and rigorous consideration of all options available to management to meet overall business objectives. At the very least, the evaluation provides inputs to a business decision process addressing the optimal utilization of financial resources.

The evaluation of work processes, options for carrying out those processes, and overall effectiveness of the organization provides information for a business case analysis. Again, applying the premise that the objective is optimal resource utilization, the analysis must consider the question of effectiveness of resources consumed, or more directly, what "bang for the buck" is being achieved. Is it more effective to buy an employee's services with all the additional costs of training, benefits, and facilities, or is it more effective to buy services from a vendor? Or a third option may be to buy a technology to do the work. All of these issues carry different weights and priorities in different companies, and management must determine what best suits their culture, business model and service delivery objectives.

Automating

One of the process management options to be considered, as illustrated in Fig. 3, is automation or the application of technology to complete tasks. A comprehensive evaluation of technology available to support business processes is a fundamental element of process design and, in the case of replacing an aging workforce, technology can be an important element of a comprehensive strategy. Recent industry events as well as operating policies mandated by legislation demand more sophisticated technological tools and solutions in the industry.

As processes and operations become more dependent upon automated solutions, the importance of human skills to use and support the technology increases significantly. It is not enough to understand the business processes, rules, standards, procedures, or science associated with a job function. The employee must also have a working knowledge of the technologies or applications that are used to support or perform the job functions. Each technological innovation requires some new degree of skill by the employee using or depending on the technology. Even without an aging workforce issue, the increasing use of technology for operations and management demand new skills in the workforce

The aging workforce again may be the catalyst for automation that, until now, has been considered too expensive, too complex, or just too new. As the aging workforce "tipping point" approaches, management should consider what additional business functions or opportunities exist with the application of a particular information technology. With the automated meter reading example, if the intent is simply to perform the meter reading function as a cost-reduction initiative, the business case is generally weak; however, the business case is improved when management considers

that value of the expanded functionality available through the technology for load control functions, customer data gathering, and a number of other activities that could drive additional business revenue opportunities or reduce other costs in addition to the labor for reading the meter.

Utilities have over the past decade greatly increased the use of new technologies in operating processes. Automation expenditures—about $700 million in 2005—will fall into two principal areas: real-time automation and controls, and geospatial and field automation. Expenditure growth rates are on the order of 20–30% per year. Geographic information systems, substation automation (SCADA), AMR, mobile work management, outage management, load control systems, and CMMS are all widely deployed in the industry.

A common issue, however, is the integration of the various applications both from an information technology perspective and a business process perspective. Many automated systems have been implemented to support a narrowly defined process that is confined to one function or organization. The future need to address the exiting human expertise as well as the need to be operationally efficient and effective will drive an integrated approach to technology across all operational functions and organizations. This requires a high-level technology roadmap that identifies the overall strategy and direction for using automation in the organization. Developing the roadmap is another fundamental element of a comprehensive business operations plan.

The financial evaluations of new technology applications also require a slightly different approach compared with traditional methods. Cost-benefit analyses would show that the costs of many automated tools are still too high to justify their adoption. In using automation to replace aging workers, the analysis must go beyond the immediately identifiable costs and consider the implications of not implementing the technology for the future. The technology business case must quantify and evaluate this risk factor in order to fully address the issue.

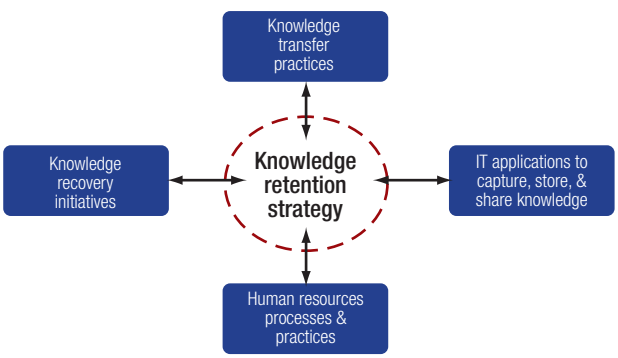
Implementation and operational reliance on technology or automation presents human resource issues in the areas of recruitment, retention, and employee skills. As companies work to recruit and retain new workers, they are continually competing for technologically savvy workers who do not think of the electric utility industry as a center of sophisticated technology applications. How much more successful can utilities be in recruiting and retaining workers if the technology used to engineer, operate, and maintain a power grid is leading-edge, both for the industry and in development of automated tools in general? It is safe to assume that the odds of attracting technical talent will be improved. There is no question that "Generation Y" workers expect to be involved with technology both as a tool for their work and as the subject of their work, so any business that does not have a high component of technology in their work will be less attractive to the best and the brightest employees of the future.

Recording

The retention of knowledge held by workers about to retire is an immediate concern and a challenge for utility companies. Before a knowledge retention program or activity can begin, the company must have some sense of what is critical knowledge and where it is held. The task to understand these issues is daunting and, in many companies, is without process or precedence. Some early mover companies have explored this issue for a number of years and have developed effective process models for determining what is critical knowledge and who has it. In most cases, the activity to address knowledge retention involves a comprehensive organizational survey activity, coupled with a well-defined process for recording, cataloging, and storing the information acquired through interviews and surveys. How this is done is a function of the culture and practices within the specific company. In all cases, however, there is a strong management commitment to provide the time and resources to make the process successful.

D.W. DeLong presents a four-pronged strategy for dealing with knowledge retention in an organization (as illustrated in Fig. 4). This model calls for a multi-dimensional

Fig. 4. Framework for organizational knowledge retention



approach to knowledge retention that is customized to the individual company's needs, capabilities, and culture and has the long-term commitment of management.

Perhaps most significant in DeLong's knowledge retention strategy is the component of knowledge recovery. The need for knowledge recovery initiatives recognizes that, regardless of systems and processes and procedures, some critical institutional knowledge will undoubtedly be lost with exiting workers. It is imperative that companies acknowledge this and have an active strategy to deal with lost knowledge. That strategy may involve hiring retired workers as consultants or contractors or using expert consultants to address specific issues. In any case, the company must be prepared with a strategy and action plan to mitigate the impact of knowledge loss. Technology can be a key component of an effective knowledge retention strategy. Various knowledge management programs and applications are available "off the shelf" today, as well as customized solutions. For operating utility companies, however, the most effective initiatives for knowledge retention will likely be in areas other than a technology for knowledge retention and management. The operating systems used in the business, as well as ongoing mentoring and training of new workers, will be the primary vehicles for retention of information for daily operations.

Education

Education is making a critical contribution to addressing the exiting expertise problem. Industry is enhancing in-house education capabilities and working with education organizations to develop new approaches to life-long learning and to educating the next generation of technicians and engineers. Universities are altering their curricula to respond to the new skill and knowledge requirements of today's engineering workforce.

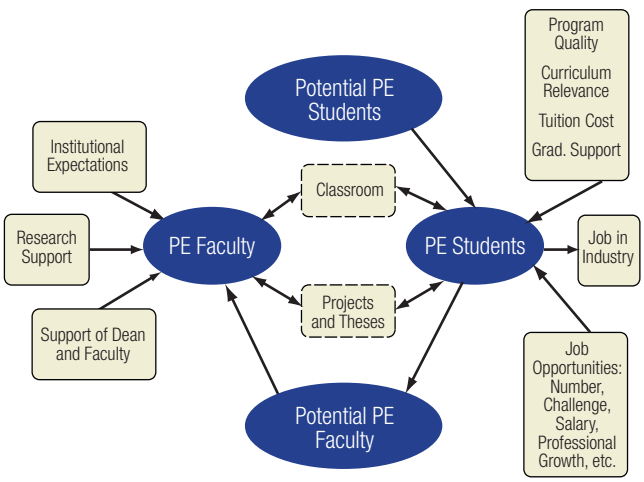
Yet major concerns remain about the sustainability of university power programs. The good news is that the number of undergraduate and graduate students has probably bottomed out or even started to grow after reaching a high in the early 1980s (although the recent growth in the number of graduate students at US institutions may be offset by declines in international student applications due to US visa barriers and preferences by international governments for their students to get graduate degrees in their home countries to avoid "brain drain"). The bad news is that the growth in students is probably insufficient to meet the coming demand.

Worse yet, the university infrastructure for supporting that growth is weakening. The major US power programs are not adding new young faculty members at a rate sufficient to make up for the anticipated loss of retiring faculty just at the time that major losses will be occurring in the workforce. The following section addresses the problem of sustaining university power engineering (PE) programs

Sustaining university power programs

To understand what is required to sustain university power programs, it is useful to understand the core decision influences affecting decisions to become a PE student or faculty member and interactions between faculty and students. A simple model of the interactions may be useful, as illustrated in Fig. 5. What this model shows is that universities, industry, and government can—or indeed must—contribute to sustaining university power programs.

Fig. 5. Model of university faculty and students: interactions and decision influences



Assuming for the moment that the objective is to fill Jobs in Industry (as shown in Fig. 5) to address the exodus of expertise, it is necessary that potential PE students consider PE as a career. Since the decision to enter into a power program, whether as an undergraduate or graduate student, has to be made in advance of actually going on the job market, perhaps by as much as 4 years, student perceptions of future Job Opportunities are important. They will consider the number of potential job openings, the challenge and career progression opportunities, salary, job security, among other factors. Ross Schifo outlined a comprehensive "professional core values model" that describes factors that someone might consider in choosing PE as a career.

Potential PE students will also consider the quality and cost of the education that they will get. Will the tuition be worth it? Three basic considerations will be the perceived Program Quality, Curriculum Relevance, and Tuition Cost. For a potential graduate student, the availability of Graduate Support will be a prime consideration.

Students taking a Job in Industry will help with the expertise exodus problem directly. However, sustaining power programs requires new faculty. Graduate students at the doctoral level may also consider the possibility of becoming PE faculty members and enter the pool of Potential PE Faculty. This pool is also composed of people in industry with doctorates who want to go back to academia.

A graduate student's decision to actually pursue a PE Faculty position will be influenced by a number of factors. Foremost, there have to be PE faculty positions available. There are few such positions opening up for entry by young faculty. The Support of Dean and Faculty engineering programs has been difficult to obtain in recent years; they are cutting back on power programs because of greater research funding opportunities in other fields, reduced stature of PE as an engineering field due to the misperception that significant new innovations are not needed or anticipated, and perceptions about low student interest in the field.

Even if a position is available, a Potential PE Faculty member must consider the likelihood of getting tenure. That likelihood is based on the understanding of the Support of Dean and Faculty, anticipated opportunities for Research Support, and Institutional Expectations regarding teaching load and tenure requirements, among other considerations. Without Research Support, the young faculty member will not be able to establish the research and publishing record necessary for tenure. And that research support needs to be sufficient to carry graduate students through their own program: the young faculty member-graduate student relationship is synergistic, with each relying on the other for reaching their separate objectives: tenure and graduation. Faculty need to be able to attract quality students for the graduate programs, and the ability to provide Graduate Support is a critical decision factor for the potential graduate student.

The fundamental interactions among faculty and undergraduate and graduate students occur either in the Classroom or on Projects and Theses. It is those interactions that determine the quality of the education experience. And the higher the quality of the education experience, the greater will be the contribution that student will be able to make in restoring expertise in the industry—and the greater the likelihood of success of a graduate student as a PE Faculty member. There is an axiom that says, "What goes around, comes around." In this case, a quality education breeds quality teachers that in turn produces quality education. In this circle, research provides support of faculty and graduate students but also enhances the education experience.

What then is the fundamental basis of a sustainable power program? It is the stature of the program in the eyes of the Dean, fellow faculty members, industry, and students. Major drivers of that stature are:

- Ample R&D funding, particularly of a nature that gives graduate students support through their program and produces new knowledge that both solves industry challenges and advances the quality of education.
- Ample attractive positions in industry that motivate students to take PE courses and enter into PE graduate programs.
- High quality and affordable cost of the education.

Producing next PE generation

Using the model given in Fig. 5, it is possible to see where focus needs to be given to increase the number of PE graduates to address the exodus of expertise.
Based on the model, a comprehensive strategy to attract more students to the PE field would:

- Increase the number of Potential PE Students
- Improve power Program Quality and Curriculum Relevance.
- Control Tuition Costs, perhaps providing targeted tuition assistance when needed to advance diversity.
- Increase Graduate Support.
- Improve Job Opportunities.
- Improve the quality of interactions among faculty and students in the Classroom and in Projects and Theses.

To get more PE Faculty to sustain power programs, the model suggests such objectives as:

- Increase Research Support.
- Increase support by engineering Deans and Faculty.

- Equitable and reasonable Institutional Expectations, particularly of new faculty.

Importantly, the model reveals that industry, government, and universities all have a role to play. For each objective, strategies can be identified for each of the three vested interests. For instance, more Research Support is needed from industry and government to support faculty and to enhance classroom and project learning experiences; universities also need to look at new models of industry-government-university interactions to make that support attractive beyond simply supporting power programs.

To get more PE Students requires that industry make Job Opportunities more attractive relative to other fields, that industry and government help support Tuition Cost and Graduate Support, and that universities ensure that they are offering the best possible education at an affordable Tuition Cost.

Thus there exists a need for greater attention to the problem of sustaining power programs while increasing interest in PE education. A comprehensive strategy is needed with collaboration among industry, government, and universities to develop a plan for educating the next generation of power engineers. As Schifo noted, such collaboration needs to articulate a "compelling mission," but with the realization that industry, government, and university all have something to bring to (and take from) the table.

Conclusions

The exodus of technical expertise is accelerating in the electric power industry. Of the four approaches to addressing this exodus described in this article, utilities are probably most frequently relying on short-payback, low-cost solutions, such as operations management improvements, outsourcing with previous employees, and in-house training programs. It is necessary to view the exodus not as a short-term problem, but as a long-term opportunity to rebuild the companies around the next generation of engineers and technicians. Decisions on investments in people are just as important as the decisions on investments in the aging infrastructure.

A priority investment in people should be in the current and potential organization leaders who demonstrate the skills, capability, and forward thinking to envision and create an organizational capability for self-renewal through knowledge retention and transfer. This capability may occur through direct human interaction and training, various technological solutions, or most likely a combination that supports the organization knowledge base.

The urgency for the investments in people is felt in professional engineering meetings and in the workplace. But the public discourse among executives and policymakers does not reveal the same sense of urgency. This is also seen in the declining level of research funding of universities even though research is the lifeblood of the research and education mission of universities.

The exiting workforce, the limited labor pool for experienced workers, and the diminished pipeline of newly educated engineers to fill vacant positions challenge all electric power interests to evaluate new educational methods and practices, new work processes, new technology, and new methods for knowledge retention. At all levels of the issue there is a need for comprehensive strategies to address attracting and retaining more power engineering students, to evaluate and integrate new technologies into daily utility operations, and to develop innovative operating models that incorporate the best of people and technology to optimize the effectiveness of scarce human and financial resources. —EW

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