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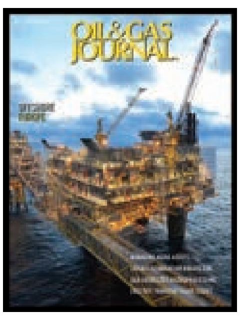
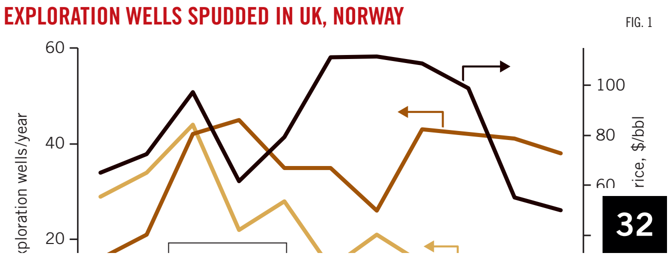
Aug. 1, 2016 Volume 114.8

GENERAL INTEREST

COVER



Norway's Oseberg field *is one example of the country's continuing oil and gas developments. Offshore Europe in general has seen less exploration and development since oil prices declined. Northern North Sea activity is expected to decline through 2017. In mid-June, Norway's Ministry of Petroleum and Energy approved Statoil ASA's plan for development and operation of Vestflanken 2 in the northern North Sea, 9 km from the field center, shown. OGJ's annual Offshore Europe special report begins on p. 32. Photo from Harald Pettersen for Statoil.*



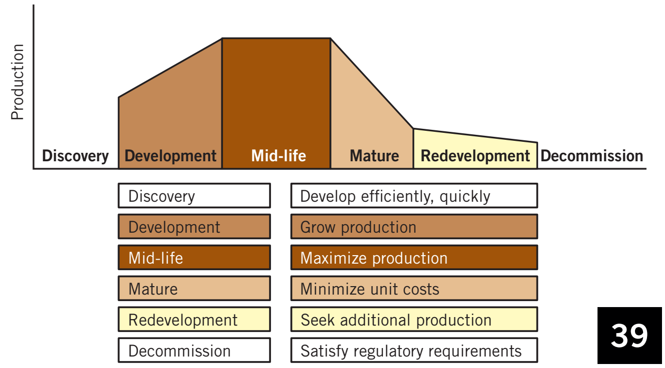
SPECIAL REPORT
OFFSHORE EUROPE

REGULAR FEATURES

OIL&GAS JOURNAL

LIFE-CYCLE PHASES, OPERATIONS FACTORS

FIG. 1



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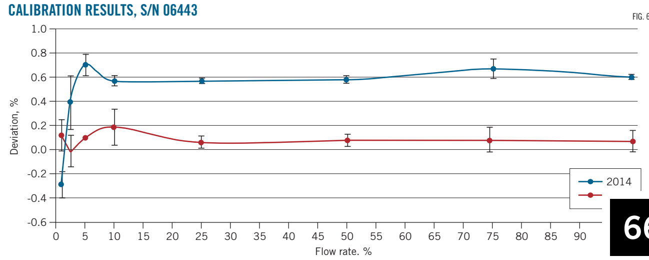
CALIBRATION RESULTS, S/N 06443

FIG. 6



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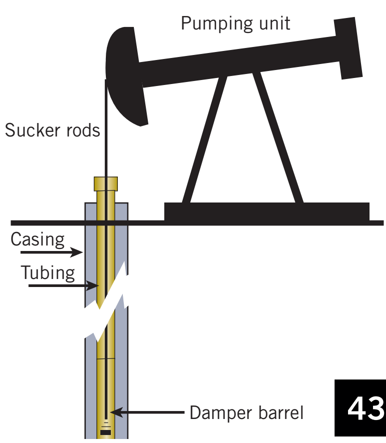
TECHNOLOGY...

TOOL COMPONENTS

FIG. 1



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Aug. 1, 2016

GENERAL INTEREST QUICK TAKES

BP posts first-half net loss of $2.73 billion

BP PLC recorded a $2.25-billion net loss in the second quarter and $2.73-billion net loss for the first half. Those totals compare with a $6.27-billion net loss in second-quarter 2015 and $4.16-billion net loss for first-half 2015.

The firm says its quarterly results were impacted by lower oil and gas prices and significantly lower refining margins, partly offset by the benefit of lower cash costs throughout the group as well as lower exploration write-offs.

The second-quarter results include the previously reported $5.2-billion pretax charge for the Macondo well blowout, whose total cumulative pretax charge to BP is $61.6 billion (OGJ Online, July 15, 2016).

Companywide production during the quarter averaged 2.09 million boe/d, down 1% year-over-year. First-half production averaged 2.26 million boe/d, up 2.3% year-over-year. BP expects planned new upstream projects to add 800,000 boe/d of production by 2020, with 500,000 boe/d of new capacity expected by yearend.

Organic capital expenditure for the first half was $7.9 billion. Full-year capex is now expected to be below $17 billion. During the half, BP received $1.9 billion from divestments, including the partial sale of its interest in Castrol India.

"We continue to reset our capital and cost base and are moving steadily towards our aim of rebalancing organic sources and uses of cash by 2017 in a $50-55/bbl oil-price range," said Brian Gilvary, BP's chief financial officer.

Interests, roles shifting in Argentina block

Holders of interests in the Coiron Amargo Block in Argentina's Nequen basin and a unit of Royal Dutch Shell PLC have entered a series of agreements that would subdivide the southern part of the 100,000-acre tract and adjust holdings and roles.

The block has conventional oil production from the Jurassic Sierras Blancas formation and unconventional potential in the Lower Cretaceous Vaca Muerta shale. It's divided into a northern exploitation concession of 26,598 acres and a southern evaluation concession of 72,738 acres.

According to Madalena Energy Inc., Calgary, which holds 35% interest in the total block, the agreements would divide the southern concession into two evaluation lots: Coiron Amargo Southeast and Coiron Amargo Southwest.

Parties to the agreements, in addition to Madalena, are Shell unit O&G Developments Ltd. SA, not previously an interest holder in the block; ROCH SA; Apco Oil & Gas International Inc., a subsidiary of Pluspetrol Resources Corp.; and provincially owned Gas y Petroleo del Nequen SA.

Subject to governmental approvals, Madalena will assign its interest in Coiron Amargo Southwest to the counterparties and increase its working interest in Coiron Amargo Southeast to 90% and become operator. Gas y Petroleo will retain its 10% working interest in Coiron Amargo Southeast.

Madalena will continue to hold 35% working interest in the northern exploitation concession, where Apco will become operator.

ROCH has been operator of the Coiron Amargo block with a 10% interest. Besides the ROCH and Madalena shares, interests before the new agreements take effect are Apco 45% and Gas y Petroleo 10%.

Silver Run to buy Delaware basin producer

Silver Run Acquisition Corp., Houston, has agreed to acquire a controlling interest in Centennial Resources Production LLC and expects to be renamed Centennial Resource Development Corp.

Centennial, formed in 2013 by an affiliate of NGP Energy Capital Management LLC of Irving, Tex., has producing acreage in the Delaware basin of Texas.

Silver Run's acquisition, subject to conditions including approval by its shareholders, will occur under an assignment from Riverstone Holdings LLC, which on July 6 agreed to buy 89% interest in Centennial from funds controlled by NGP.

Riverstone will buy Silver Run Class A common stock for about $810 million. Funds managed by Capital World Investors and by Fidelity Management & Research Co. will buy $200 million of Silver Run stock.

Proceeds of those stock sales will fund part of the cash consideration in the Centennial acquisition.

After closing, Riverstone and affiliates will own about 51% of Silver run. NGP will retain an equity stake of about 11%.

Mark Papa, a Riverstone partner who was chairman and chief executive officer of EOG Resources Inc. during 1999-

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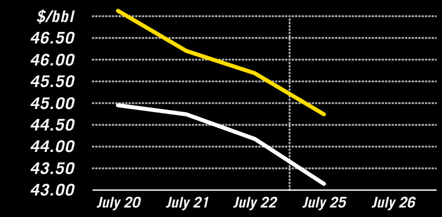
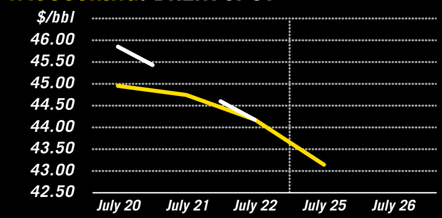
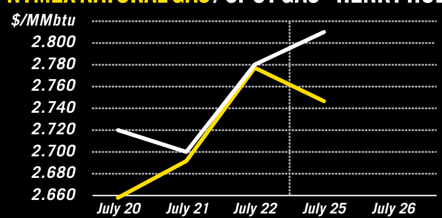
ICE BRENT / NYMEX LIGHT SWEET CRUDE



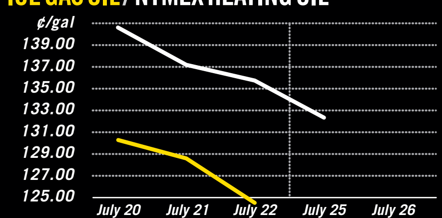
WTI CUSHING / BRENT SPOT



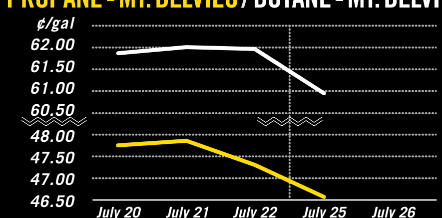
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



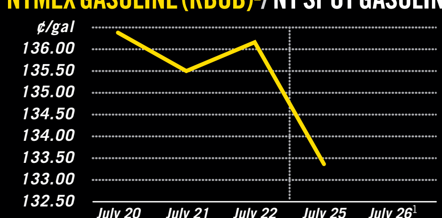
ICE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[2] / NY SPOT GASOLINE[3]



[1]Not available [2]Reformulated gasoline blendstock for oxygen blending
[3]Nonoxygenated regular unleaded

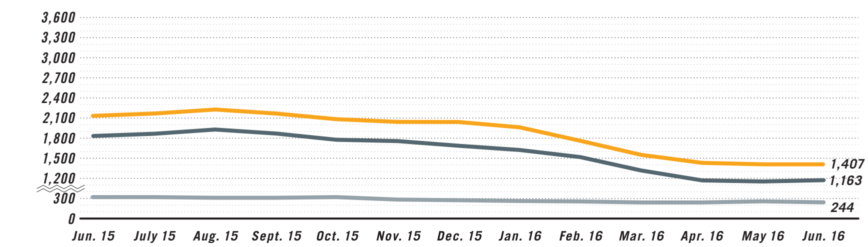
US INDUSTRY SCOREBOARD — 8/1

Latest week 7/15	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Product supplied, 1,000 b/d						
Motor gasoline	9,730	9,604	1.3	9,405	9,073	3.7
Distillate	3,764	3,792	(0.7)	3,749	3,988	(6.0)
Jet fuel	1,715	1,580	8.5	1,599	1,548	3.3
Residual	228	193	18.1	289	206	40.3
Other products	4,888	4,796	1.9	4,922	4,805	2.4
TOTAL PRODUCT SUPPLIED	20,325	19,965	1.8	19,964	19,620	1.8
Supply, 1,000 b/d						
Crude production	8,507	9,580	(11.2)	8,913	9,402	(5.2)
NGL production[2]	3,507	3,247	8.0	3,416	3,115	9.7
Crude imports	7,973	7,531	5.9	7,842	7,263	8.0
Product imports	2,459	2,305	6.7	2,163	2,097	3.1
Other supply[2 3]	2,588	2,424	6.8	2,114	2,323	(9.0)
TOTAL SUPPLY	25,034	25,087	(0.2)	24,448	24,200	1.0
Net product imports	(1,435)	(1,437)	—	(1,731)	(1,540)	—
Refining, 1,000 b/d						
Crude runs to stills	16,697	16,848	(0.9)	16,163	16,132	0.2
Input to crude stills	16,984	17,066	(0.5)	16,376	16,368	0.0
% utilization	92.8	94.6	—	89.8	91.2	—

Latest week 7/15	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	519,462	521,804	(2,342)	463,885	55,577	12.0
Motor gasoline	241,000	240,089	911	216,285	24,715	11.4
Distillate	152,783	152,997	(214)	141,515	11,268	8.0
Jet fuel–kerosine	41,902	40,638	1,264	44,108	(2,206)	(5.0)
Residual	42,076	41,337	739	39,265	2,811	7.2
Stock cover (days)[4]			Change, %		Change, %	
Crude	31.1	31.4	(1.0)	27.8	11.9	
Motor gasoline	24.8	24.7	0.4	22.5	10.2	
Distillate	40.6	40.7	(0.2)	37.3	8.8	
Propane	104.8	109.1	(3.9)	95.4	9.9	
Futures prices[5] 7/22			Change		Change	Change,%
Light sweet crude ($/bbl)	44.75	45.59	(0.84)	51.69	(6.94)	(13.4)
Natural gas, $/MMbtu	2.72	2.73	(0.02)	2.87	(0.15)	(5.4)

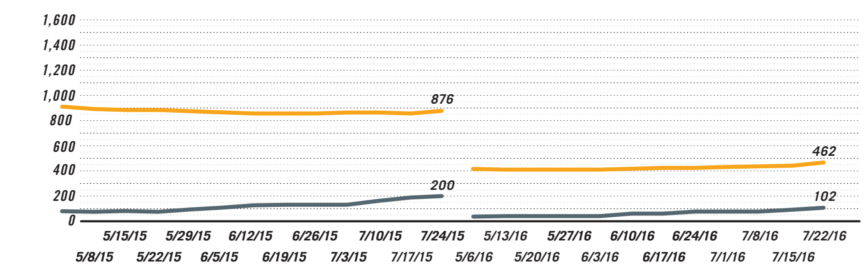
[1]Based on revised figures. [2]OGJ estimates. [3]Includes other liquids, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average of daily closing futures prices.
Source: Energy Information Administration, Wall 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

2013, will lead Centennial after the transaction.

Centennial holds 42,500 net acres, mainly in Reeves and Ward counties and produces about 7,200 boe/d net to its interests. It estimates net proved reserves at 48.6 million boe.

The company has identified 1,357 gross potential locations for horizontal drilling.

Silver Run estimates the initial enterprise value of the combined company at $1.735 billion and the equity value after closing of $1.835 billion. OGJ

EXPLORATION & DEVELOPMENT QUICK TAKES

Lundin begins three-well campaign in Barents Sea

Lundin Norway AS, a wholly owned subsidiary of Lundin Petroleum AB, has begun its 2016 exploration and appraisal campaign in the Loppa High area of the southern Barents Sea.

Comprising three wells to be drilled by the winterized Leiv Eiriksson semisubmersible drilling rig, the campaign begins with the reentry of the Alta-3 appraisal well 7220/11-3A, which was drilled last year on the eastern flank of the Alta discovery (OGJ Online, Sept. 30, 2015).

Occurring on PL609, the objective of the reentry is to deepen the well to further assess the quality of the Permian carbonate reservoir section and to conduct a production test.

The original Alta-3 well found a gross hydrocarbon column of 120 m, and all three Alta wells drilled to date have proven pressure communication. The Alta discovery is estimated to contain gross contingent resources of 125-400 million boe.

Following completion of the Alta-3 well, the rig will move farther north on PL609 to reenter the suspended Neiden exploration well 7220/6-2 that was partially drilled last year.

The well was suspended immediately above the prognosed reservoir section last October because of winter restrictions for the Island Innovator drilling rig. The Neiden prospect is estimated to hold gross unrisked prospective resources of 204 million boe.

The third well to be drilled in the campaign is an exploration well targeting the Filicudi prospect on PL533 to the northwest of the Alta discovery and south of the Statoil ASA-operated Johan Castberg discovery.

The prospect is expected to contain Jurassic sandstone reservoir analogous to the Johan Castberg discovery. Filicudi is estimated to contain gross unrisked prospective resources of 258 million boe.

Lundin Norway is operator of both PL609 and PL533 with 40% and 35% working interest in the licenses, respectively. The Leiv Eiriksson rig has been contracted for three firm well slots with an additional six optional well slots.

Aramco lets for gas field off Saudi Arabia

Saudi Aramco has let a $1.6-billion engineering, procurement, construction, and installation (EPCI) contract to Chiyoda Corp. to complete the second phase of Hasbah natural gas field, part of the two-field Al Wasit gas project.

The consortium will be involved in the construction of two streams of three wellhead platform topsides, one tie-in platform with flare platforms, and bridges tied together by umbilicals and in-field pipelines. Other work includes interconnecting trunk lines to the Fadhili gas plant onshore. According to Chiyoda, the scope covers 40% of the contract value.

Aramco commissioned the field in March and expects to reach a combined 2.5 bcfd from Hasbah and nearby Arabiyah fields (OGJ Online, Mar. 24, 2016). Both fields are in about 50 m of water, 150 km northeast of Jubail.

The Emas Chiyoda Subsea joint venture includes Chiyoda Corp. and Ezra Holdings Ltd., both with equal holdings. The contract term is 6 years, with an option to extend by another 6 years. The engineering and fabrication component has commenced with the offshore execution phase commencing in fourth-quarter 2017.

BOEM schedules Lease Sale 248 for western gulf

The US Bureau of Ocean Energy Management has scheduled western Gulf of Mexico Lease Sale 248 for Aug. 24 in New Orleans (OGJ Online, Apr. 5, 2016).

The auction includes all available unleased areas in the western gulf planning area for oil and gas exploration and development, covering 23.8 million acres located 9-250 nautical miles offshore Texas. It includes 4,399 blocks in 16-10,975 ft of water.

As a result of offering this area for lease, BOEM estimates a range of economically recoverable hydrocarbons to be discovered and produced of 116-200 million bbl of oil and 538-938 bcf of natural gas.

Lease Sale 248 will be the 11th offshore sale in the gulf and the final sale for the western planning area under the Obama administration's Outer Continental Shelf oil and gas leasing program for 2012-17. BOEM says the sale builds on the first 10 in the current 5-year program, which offered more than 60 million acres and netted nearly $3 billion.

Leases issued from this sale will also be the first for which BOEM will accept requests for extended initial periods, and confirm whether the lessee has earned such extension, a task previously performed by the Bureau of Safety and Environmental Enforcement.

BOEM releases draft EIS for possible Cook Inlet sale

The US Bureau of Ocean Energy Management released a draft environmental impact statement for a potential oil and gas lease sale in Alaska's Cook Inlet. The sale currently is scheduled for June 2017, the US Department of the Interior agency said.

A notice of the draft EIS's availability was scheduled to appear in the Federal Register on July 22, opening a 45-day comment period ending on Sept. 6, BOEM said in its July 15 announcement. Public meetings also will be held in Anchorage on Aug. 15, Homer on Aug. 17, and Kenai-Soldotna on Aug. 18.

BOEM said that the draft EIS analyzes important environmental uses and resources within the inlet off Alaska's south-central coast. These include sea otter and beluga whale populations, human subsistence activities, and commercial salmon and Pacific halibut fishing. The draft EIS also analyzes a range of alternatives which will be considered.

Specifically, the area identified for the potential OCS Sale No. 244 is close to existing leases in state waters, avoids nearly all of the areas designated as critical habitat for the beluga whale and northern sea otter, avoids the critical area for the Stellar sea line, and excludes much of the subsistence-use area for the Alaska Native villages, BOEM said. OGJ

DRILLING & PRODUCTION QUICK TAKES

BLM to review second NPR-A production well plan

The US Bureau of Land Management said it intends to conduct an environmental review for what would be the second oil and gas production well in the National Petroleum Reserve-Alaska.

ConocoPhillips Alaska Inc. submitted in August 2015 an application for the Greater Mooses Tooth-2 (GMT-2) project, which would include a drill site, access road, pipelines, and other facilities, BLM's Alaska State Office in Anchorage said.

It said the proposed project would be on BLM-managed land that has been selected for conveyance to Kuukpik Corp., an Alaska Native corporation organized under the 1971 Alaska Native Claims Settlement Act.

An associated pipeline and access road would cross both Kuukpik Corp. and BLM-managed public land within the 23 million-acre NPR-A and connect with the Greater Mooses Tooth-1 (GMT-1) development project that BLM finally approved in February 2015, BLM's Alaska office said.

The site is 8 miles southwest of GMT-1 and about 20 miles southwest of ConocoPhillips Alaska's producing Alpine field on Alaska state land, it added. BLM originally analyzed the proposed development in its 2004 Alpine Satellite Development Plan (ASDP), and it also is subject to the 2012 NPR-A Integrated Activity Plan, which was approved in February 2013, BLM said.

BLM now will prepare a supplemental environmental impact statement to the ASDP to evaluate new circumstances and information, including changes to the project's design, new data on climate change, and the US Fish and Wildlife Service's 2008 listing of the polar bear as a threatened species, it indicated.

BLM Alaska said that a 30-day public comment period on the proposed draft supplemental EIS for GMT-2 began on July 29, when it was slated to be published in the Federal Register.

Noble begins production at Gunflint in Gulf of Mexico

Noble Energy Inc., Houston, has started production at the Gunflint oil development on Mississippi Canyon Block 948 in the deepwater Gulf of Mexico.

The two-well field is ramping up and is expected to reach minimum gross production of 20,000 boe/d, with oil representing 75% of the produced volumes. The net amount to Noble is expected to be at least 5,000 boe/d, with potential for additional volumes depending on available capacity at the third-party host facility.

The development is a subsea tie-back to the Gulfstar One facility owned by Williams Partners LP and Marubeni Corp. Noble operates Gunflint with 31.14% working interest. Partners are Ecopetrol America Inc. 31.5%, Samson Offshore Mapleleaf LLC 19.13%, and Marathon Oil Corp. 18.23%.

Over the past year, Noble has overseen the gulf startups of the Big Bend and Dantzler developments. It also has interest in the Marathon Oil Corp.-operated Alba B3 compression platform offshore Equatorial Guinea, where production startup was reported this month (OGJ Online, July 14, 2016).

Badra field oil production reaches 67,000 b/d

PJSC Gazprom Neft says oil production has reached 67,000 b/d from Badra field in eastern Iraq. The company recently commissioned its tenth production well, the P-07, which is producing more than 6,500 b/d.

Gazprom Neft is drilling four other wells: P-10, BD-2, P-14, and P-19. In addition, a third process line was constructed at the field's central processing facility in June, and the first line of an associated petroleum gas treatment facility is 60% complete.

The field began producing May 31, 2014. It reached 45,000 b/d in September 2015.

Operator Gazprom Neft has 30%. Other partners are Iraqi Oil Exploration Co. 25%, Korea Gas Corp. 22.5%, Petronas 15%, and TPAO 7.5%. OGJ

PROCESSING QUICK TAKES

Firms eye development of USGC petchem complex

Saudi Arabian Basic Industries Corp. (SABIC) and ExxonMobil Corp. affiliate ExxonMobil Chemical Co. are exploring potential development of a jointly owned grassroots petrochemical complex to be built at the US Gulf Coast.

If developed, the project—which would include a steam cracker and derivative units—would be built in Texas or Louisiana near natural gas feedstock, ExxonMobil said.

Before making final investment decisions for the project, the companies said they first plan to conduct necessary studies as well as work with state and local officials to help identify a potential site with adequate infrastructure access.

Further details regarding the proposed development, including an estimated cost and timeline for construction, were not disclosed.

This latest possible joint venture involving SABIC follows an announcement by the company last month that it has partnered with Saudi Aramco to conduct a joint feasibility study for development of a fully integrated crude oil-to-chemicals complex in Saudi Arabia (OGJ Online, June 28, 2016).

ExxonMobil's Beaumont refinery due new unit

ExxonMobil Corp. will add a new unit designed to increase production of ultralow-sulfur fuels at its 345,000-b/d refinery in Beaumont, Tex.

Due to begin construction during this year's second half, the project will involve installation of a 40,000-b/d selective cat-naphtha hydrofining unit (SCANfining) unit to produce gasoline that will meet the US Environmental Protection Agency's Tier 3 gasoline sulfur specifications, which take effect Jan. 1, 2017, ExxonMobil said.

To be ExxonMobil's largest capital investment in more than a decade at Beaumont's refining operations, the unit addition will improve product yield as well as help increase energy efficiency at the plant, said Fernando Salazar, manager of the Beaumont refinery.

Licensed by ExxonMobil, SCANfining hydroprocessing technology is a catalytic hydrodesulfurization process based on a proprietary catalyst system developed specifically for selective removal of sulfur from fluid catalytic cracking (FCC) naphtha that limits olefins hydrogenation to preserve octane content.

The SCANfining unit at Beaumont is scheduled for startup in 2018. This latest project at Beaumont follows ExxonMobil's 2015 announcement that it will expand the refinery's capacity to accommodate increased processing of light crudes from US shale (OGJ Online, Aug. 12, 2015).

Intended to add capacity for advantaged domestic crudes as well as to improve overall energy efficiency at the complex, the proposed 20,000-b/d expansion is due to be commissioned sometime in 2017, the company told investors on May 25.

Alongside the Beaumont refinery's crude unit expansion, ExxonMobil also is executing work to capture price-advantaged US crude supplies at its 500,000-b/d Baton Rouge, La., refinery, including projects to increase the plant's ability to process a wider slate of feedstock, as well as improvements to midstream infrastructure at the site.

ExxonMobil plans to complete the feedstock and logistics flexibility projects at Baton Rouge by yearend.

Par Pacific acquires Wyo. refinery, logistics assets

Par Pacific Holdings Inc., Houston, has completed its previously announced deal with Black Elk Refining LLC for the purchase of Wyoming Refining Co., which operates an 18,000-b/d refinery in Newcastle, Wyo., and through its wholly owned subsidiary Wyoming Pipeline Co. LLC, related logistics assets in the region (OGJ Online, June 15, 2016).

Par Pacific closed the transaction on July 14 for a total consideration of $271.4 million, including an assumption of about $58 million of debt, the company said.

With the acquisition of Wyoming Refining and Wyoming Pipeline now finalized, Par Pacific has taken ownership of the Newcastle refinery as well as the following assets:

- The 140-mile Thunder Creek crude oil pipeline gathering system in northeast Wyoming that provides the refinery direct access to Power River basin crude feedstock as well as direct connection to the Butte pipeline, which enables access to Bakken crude supplies.
- A 40-mile clean products pipeline system that feeds into the Magellan Products pipeline to serve markets in Rapid City, SD.
- A proprietary jet fuel terminal in Rapid City and jet fuel pipeline connecting the terminal to Ellsworth Air Force Base.
- About 650,000 bbl of crude and refined product tankage, with opportunities to expand these already identified.

Upon announcing the proposed deal in June, Par Pacific said it plans to add 4,000 b/d of isomerization capacity at the Newcastle refinery by yearend.

The refinery, which generates a clean product yield of about 95%, currently features the following processing capacities: crude distillation, 18,000 b/d; residual fluid catalytic cracking, 7,000 b/d; catalytic reforming, 3,300 b/d; alkylation, 1,300 b/d; naphtha hydrotreating, 3,300 b/d; and diesel hydrotreating, 6,000 b/d. OGJ

TRANSPORTATION QUICK TAKES

Canada speeds ban on type of oil rail car

The Canadian government is accelerating its phaseout of railroad tank cars of the type involved in the fatal 2013 derailment of a train hauling crude oil in Quebec. The accident killed 47 persons and destroyed downtown Lac-Megantic (OGJ Online, Aug. 20, 2014).

Starting Nov. 1, transport of crude oil will be prohibited in tank cars designated DOT-111, which are considered the least crash-resistant units in use.

The ban takes effect 6 months earlier than originally scheduled for DOT-111 cars with shells lacking outer steel covers called jackets and 16 months earlier for jacketed DOT-111 cars.

DOE-111 cars are to be phased out for all flammable liquids by Apr. 30, 2025.

Replacement cars have added safety features such as thicker steel, end shields, thermal protection, and valve covers.

Golar, Schlumberger JV targets stranded gas

Golar LNG Ltd. and Schlumberger Ltd. have formed joint-venture OneLNG in an effort to rapidly develop low-cost gas reserves to LNG. The firms say the combination of Schlumberger's reservoir knowledge, wellbore technologies, and production management capabilities, with Golar's low-cost floating LNG approach, will offer gas resource owners faster and lower-cost development, increasing resources' net present value.

Golar owns 51% of the JV and Schlumberger 49%. The firms made an initial commitment covering investment to develop the JV's first project. They will discuss additional debt capital as required on a project-by-project basis.

After reviewing current market opportunities and describing 40% of the world's gas reserves as stranded, the firms expect to conclude five projects within the next 5 years.

Golar last year signed a binding heads of terms with Ophir Energy PLC to supply the Gimi FLNG vessel for use in developing Equatorial Guinea Block R. Gimi is Golar's second FLNG vessel following Hilli, which is scheduled to begin commercial operations off Cameroon in first-half 2017 (OGJ Online, May 6, 2015). OGJ

■ *Denotes new listing or a change in previously published information.*

AUGUST 2016

SPE/AAPG/SEG Unconventional Resources Technology Conference (URTeC), San Antonio, web site: www.urtec.org/ **1-3.**

Society of Petroleum Engineers (SPE) Nigeria Annual International Conference & Exhibition, Lagos, web site: connect.spe.org/spenc/naice/naice2016/ **2-4.**

International Conference on Oil Reserves & Estimation Techniques, Seattle, web site: waset.org/conference/2016/08/seattle/ICORET **8-9.**

NAPE Expo, Houston, web site: napeexpo.com/shows/about-the-show/houston/ **10-11.**

EnerCom's The Oil & Gas Conference-2016, Denver, web site: www.theoilandgasconference.com/ **14-18.**

4th International Conference on Petroleum Engineering, London, web site: www.petroleumengineering.conferenceseries.com/ **15-17.**

IADC/SPE Asia Pacific Drilling Technology Conference & Exhibition, Singapore, web site: www.spe.org/events/apdt/2016/ **22-24.**

GeoBaikal 2016: Expand Horizons, Irkutsk, Russia, web site: www.eage.org/event/index.php?eventid=1433&Opendivs=s3 **22-26.**

SPE Asia Pacific Hydraulic Fracturing Conference, Beijing, web site: www.spe.org/events/aphf/2016/pages/general/call_for_papers.php **24-26.**

2nd International Congress & Expo on Biofuels & Bioenergy, Sao Paulo, web site: biofuels-bioenergy.conferenceseries.com/ **29-31.**

15th European Conference on the Mathematics of Oil Recovery (ECMOR XV), Amsterdam, web site: www.eage.org/event/index.php?eventid=1416&Opendivs=s3 **Aug. 29-Sept. 1.**

Offshore Northern Seas, Stavanger, web site: www.tofairs.com/expo.php?fair=103366 **Aug. 29-Sept. 1.**

2nd International Congress & Expo on Biofuels & Bioenergy, Sao Paulo, web site: biofuels-bioenergy.conferenceseries.com/ **29-31.**

Ultradeepwater & Onshore Technology Conference, Galveston, Tex., web site: www.rpsea.org/events/503 **30-31.**

SEPTEMBER 2016

Second Applied Shallow Marine Geophysics Conference, Barcelona, web site: www. Eage.org/event/index.php?eventid=1421&Opendivs=s3 **4-8.**

EAGE First Conference on Geophysics for Mineral Exploration and Mining, Barcelona, web site: www.eage.org/event/?eventid=1420 **4-8.**

European Association of Geoscientists & Engineers (EAGE) First Conference on Geophysics for Mineral Exploration & Mining, Barcelona, web site: www.eage.org/event/index.php?eventid=1420&Opendivs=s3 **4-8.**

22nd European Meeting of Environmental and Engineering Geophysics, Barcelona, web site: www.eage.org/event/index.php?eventid=1419&Opendivs=s3 **4-8.**

SPE Offshore Europe, Aberdeen, web site: www.offshore-europe.co.uk/ **5-8.**

SPE Intelligent Energy Conference, Aberdeen, web site: www.intelligentenergyevent.com/ **6-8.**

NACE Egypt Corrosion Conference, Cairo, web site: egyptcorrosion.nace.org/ **6-8.**

AAPG SEG International Conference & Exhibition 2016, Cancun, web site: www.aapg.org/publications/blogs/events/article/articleid/23667/increase-your-exposure-exhibition-and-sponsorship-opportunities-available/ **6-9.**

AAPG SEG 2016 International Conference & Exhibition, Cancun, web site: www.aapg.org/events/conferences/ice/announcement/articleid/20311/aapg-seg-2016-international-conference-exhibition-cancun **6-9.**

23rd Annual India Oil & Gas Review Summit & International Exhibition, Mumbai, web site: www.oilgasevents.com/india-oil-gas **9-10.**

International Conference on Chemical Engineering, Phoenix, web site: chemicalengineering.conferenceseries.com/ **12-14**.

Geomodel 2016, Gelendzhik, Russia, web site: www.eage.org/event/index.php?eventid=1448&Opendivs=s3 **12-15.**

ESOPE International Exhibition & Symposium for the Pressure Equipment Industry, Paris, web site: www.esope-paris.com/ **13-15.**

SPE Deepwater Drilling & Completions Conference, Galveston, Tex., web site: www.spe.org/events/ddc/2016/ **14-15.**

2nd Annual IoT in Oil & Gas, Houston, web site: energy-conferencenetwork.com/iot-in-oil-and-gas-2016/**14-15.**

Rio Oil & Gas Expo & Conference, Rio de Janeiro, web site: www.whereinfair.com/rio-oil-gas-expo/rio-de-janeiro/2016-Sep/ **14-16.**

International Conference on Oil & Gas Transportation, Zurich, web site: waset.org/conference/2016/09/zurich/ICOGT **15-16.**

Turbomachinery & Pump Users Symposium, Houston, web site: tps.tamu.edu/event-info **15-17.**

Iran International Petroleum Congress (IIPC), Tehran, web site: www.iranpetroleumcongress.com/ **19-21.**

The CWC World LNG & Gas Series: Asia Pacific Summit, Singapore, web site: asiapacific.cwclng.com/ **20-23**.

■ 2016 Deloitte Oil & Gas Conference, Houston, web site: www2.deloitte.com/us/en/pages/energy-and-resources/events/oil-and-gas-conference.html **21**.

SPE Liquids-Rich Basins Conference—North America, Midland, Tex., web site: www.spe.org/events/lrbc/2016/ **21-22.**

International Conference on Petroleum Industry & Energy, Los Angeles, web site: www.waset.org/conference/2016/09/los-angeles/ICPIE **22-23**.

Eastern Section, American Association of Petroleum Geologists 2016 Annual Meeting, Lexington, Ky., web site: www.es-aapgmtg.org/ **25-27.**

Corrosion Technology Week 2016, Houston, web site: ctw.nace.org/ **25-29**.

■ Operational Excellence in Refining & Petrochemicals, Houston, web site: www.opexinrefiningandpetrochem.com **26-28.**

SPE Annual Technical Conference & Exhibition (ATCE), Dubai, web site: www.spe.org/atce/2016/ **26-28.**

SPE Annual Technical Conference & Exhibition, Dubai, web site: www.spe.org/events/calendar/ **26-28.**

US-China Oil & Gas Industry Forum (OGIF), Tysons Corner, Va., web site: www.cvent.com/d/hfqw6c **27-29.**

Flexible & Cost Effective Well Site Facilities Onshore 2016, Houston, web site: www.facilities-design-onshore.com **28-29.**

3rd Annual Unconventional Production & Well Site Facilities Design, Onshore 2016, Houston, web site: www.facilities-design-onshore.com/program/ **28-29.**

Global Oil & Gas South East Europe & Mediterranean Conference, Athens, web site: www.oilgas-events.com/Global-Oil-Gas-Black-Sea-Mediterranean-Conference/ **28-29.**

International Conference on Petroleum & Petrochemical Engineering, London, web site: www.waset.org/conference/2016/09/london/ICPPE **29-30.**

International Conference on Geophysics, Vancouver, web site: geophysics.conferenceseries.com/ **29-30.**

OCTOBER 2016

ICOGPE 2016: 18th International Conference on Oil, Gas & Petrochemical Engineering, Barcelona, web site: www.waset.org/conference/2016/10/barcelona/ICOGPE **3-4.**

■ SPE African Health, Safety, Security, Environment & Social Responsibility Conference & Exhibition, Accra, Ghana, web site: www.spe.org/events/en/2016/conference/16hsea/homepage.html **4-6.**

Kazakhstan International Oil & Gas Conference (KIOGE) 2016, Almaty, Kazakhstan, web site: kioge.kz/en/conference/about-conference **5-6.**

USEA 9th Annual Energy Supply Forum, Washington, DC, web site: https://www.usea.org/event/usea-9th-annual-energy-supply-forum **6.**

International Conference on Geosciences, Orlando, web site: geosciences.conferenceseries.com/ **6-7.**

Cyber Security for Critical Assets LATAM, Rio de Janeiro, web site: www.criticalcybersecurity.com/latam/ **6-7.**

23rd World Energy Conference, Istanbul, web site: www.wec2016istanbul.org.tr/ **9-13.**

International Conference on Oil Reserves & Energy Management, New York, web Site: www.waset.org/conference/2016/10/new-york/ICOREM **10-11.**

The 2016 API Tank, Valves, & Piping Conference & Expo, Las Vegas, web site: www.api.org/events-and-training/calendar-of-events/2016/tvp **10-13.**

SEG International Exhibition and 86th Annual Meeting, Dallas, web site: www.seg.org/web/annual-meeting-2016/ **16-21.**

International Conference on Oil Reserves & Production, London, web site: www.waset.org/conference/2016/10/london/ICORP **17-18.**

The 8th Saudi Arabia International Oil & Gas Exhibition (SAOGE), Dammam, web site: www.saoge.org/ **17-19.**

SPE Well Construction Fluids 2025 Forum: Meeting the Challenges, Dubai, web site: www.spe.org/events/16fmel/ **17-19.**

2016 Fall Committee on Petroleum Measurement Standards Meeting, Los Angeles, web site: www.api.org/Events-and-Training/Calendar-of-Events/2016/fallcopm **17-21.**

Permian Basin International Oil Show, Odessa, Tex., web site: www.pboilshow.org **18-20.**

The 37th Oil & Money Conference, London, web site: www.oilandmoney.com/ **18-19.**

Society of Petroleum Engineers (SPE) African Health, Safety, Security, Environment & Social Responsibility Conference & Exhibition, Accra, Ghana, web site: www.spe.org/events/hsea/2016/ **18-20.**

SPE Latin America & Caribbean Heavy Oil & Extra Heavy Oil Conference, Lima, web site: www.spe.org/events/laho/2016/ **19-20.**

Arctic Technology Conference (ATC), St. John's, Newfoundland & Labrador, web site: www.arctictechnologyconference.org/ **24-26.**

SPE Russian Petroleum Technology Conference & Exhibition, Moscow, web site: www.spe.org/events/rpc/2016/ **24-26.**

SPE North America Artificial Lift Conference & Exhibition, The Woodlands, Tex., web site: www.spe.org/events/alce/2016/ **25-27.**

SPE Asia Pacific Oil & Gas Conference & Exhibition (APOGCE), Perth, web site: www.spe.org/events/apogce/2016/ **25-27.**

The 10th Element Oilfield Engineering with Polymers Conference, London, web site: oilfieldpolymers.nace.org/ **25-27.**

Bottom of the Barrel Technology Conference (BBTC) Middle East & Africa 2016, Manama, web site: www.bbtc-mena.biz **26-27.**

International Conference & Expo on Oil & Gas, Rome, web site: oil-gas.conferenceseries.com/ **27-28.**

Gulf Safety Forum (GSF) 2016, Doha, web site: www.gulfsafetyforum.com/ **30-31.**

23rd Africa Oil Week Africa Upstream Conference 2016, Cape Town, web site: www.oilgas-events.com/Find-an-Event/Africa-Oil-Week/ **Oct 31-Nov 04.**

NOVEMBER 2016

■ SPE Annual Caspian Technical Conference & Exhibition, Astana, Kazakhstan, web site: www.spe.org/events/en/2016/conference/16ctce/homepage.html **1-3.**

4th Iran Europe Oil & Gas Summit, Berlin, web site: www.iran-summit.com/**1-3.**

2nd International Conference & Expo on Oil & Gas, Istanbul, web site: oil-gas.omics-group.com/ **2-3.**

■ 7th Annual Summit Operational Excellence in Oil & Gas, Houston, web site: www.opexinoilandgas.com 7**-9.**

The Abu Dhabi International Petroleum Exhibition & Conference, (ADIPEC), Abu Dhabi, web site: www.adipec.com/ **7-10.**

RefComm Mumbai 2016, Mumbai, web site: refiningcommunity.com/refcomm-mumbai-2016/ **7-11.**

International Petroleum Technology Conference (IPTC), Bangkok, web site: www.iptcnet.org/pages/about/future-dates.php **14-16.**

4th East Africa Oil & Gas Summit & Exhibition, Nairobi, web site: eaogs.com/**15-17.**

21st Annual Oil & Gas of Turkmenistan (OGT) Conference 2016, Ashgabat, web site: ogt.theenergyexchange.co.uk/ **16-17.**

International Conference on Shale Oil & Gas Engineering, London, web site: www.waset.org/conference/2016/11/london/ICSOGE **24-25.**

5th International Conference on Petroleum Geology & Petroleum Industry, Dubai, web site: petroleumgeology.conferenceseries.com/ **24-25.**

Oil & Gas Safety & Health Conference 2016 OSHA Exploration & Production, Houston, web site: www.oshasafetyconference.org/Events/ugm/Osha2016/default.aspx **29-30.**

■ SPE Thermal Well Integrity & Design Symposium, Banff, Alta., web site: www.spe.org/events/en/2016/symposium/16twid/homepage.html **Nov. 29-Dec. 1.**

Society of Petroleum Engineers (SPE) Middle East Artificial Lift Conference & Exhibition, Manama, Bahrain, web site: www.spe.org/events/meal/2016/ **Nov. 30-Dec. 1.**

DECEMBER 2016

International Conference on Energy Engineering & Oil Reserves, Hong Kong, web site: www.waset.org/conference/2016/12/hong-kong/ICEEOR **5-6.**

International Conference on Oil Reserves & Energy Technologies, Hong Kong, web site: www.waset.org/conference/2016/12/hong-kong/ICORET **5-6.**

■ SPE/AAPG Africa Energy & Technology Conference, Nairobi City, Kenya, web site: www.spe.org/events/en/2016/conference/16afrc/homepage.html **5-7.**

5th World Congress on Petrochemistry & Chemical Engineering, Phoenix, web site: www.petrochemistry.omicsgroup.com/ **5-7.**

Third EAGE Integrated Reservoir Modelling Conference, Kuala Lumpur, web site: www.eage.org/event/index.php?eventid=1477&Opendivs=s3 **5-7.**

OpEx MENA 2016—Operational Excellence in Oil, Gas & Petrochemicals, Abu Dhabi, web site: www.opex.biz **5-7.**

Oil & Gas Supply Chain Procurement, Houston, web site: energyconference.network.com/oil-gas-supply-chain-procurement-2016/ **6-7.**

SPE Heavy Oil Conference & Exhibition, Kuwait City, web site: www.spe.org/events/hoce/2016/ **6-8.**

Green Forum: Oil, Gas & Petrochemicals, Abu Dhabi, web site: www.greenforum.ae **8.**

ICOGPE 2016: 18th International Conference on Oil, Gas & Petrochemical Engineering, Dubai, web site: www.waset.org/conference/2016/12/dubai/ICOGPE/home/ **26-27**.

JANUARY 2017

Global Oil & Gas Middle East & North Africa Conference, Cairo, web site: www.oilgas-events.com/Find-an-Event/Global-Oil-Gas-Middle-East-North-Africa-(1) **24-26.**

SPE Hydraulic Fracturing Technology Conference, The Woodlands, Tex., web site: www.spe.org/events/hftc/2017/ **24-26.**

NACE International Pipeline Coating Technology Conference, Houston, web site: pipelinecoating.nace.org/ **24-26.**

Offshore West Africa, Lagos, web site: www.offshorewestafrica.com/index.html **24-26.**

2017 API Inspection Summit, Galveston, Tex., web site: www.

Mature basins enter final phase

TAYVIS DUNNAHOE
Exploration Editor

The UK Continental Shelf (UKCS) is home to more than 4,000 wells drilled since the passing of the country's Continental Shelf Act in 1964. More than £50 billion has been invested in the last half-century, and the UKCS has produced more than 45 billion boe during the same period.

Potential remains: The region contains an estimated 20-30 billion boe of undeveloped resources. But due to flagging exploration and development amid the downturn, an aging infrastructure, and a lack of clear regulation guiding these offshore assets, opportunity is drawing to a close in the next 2 years.

This is an opinion shared by several respondents to a report published by PricewaterhouseCooper LLP (PwC) titled "Sea Change: The future of North Sea Oil & Gas" published June 13. The report summarizes responses from more than 30 high-level leaders in the North Sea's offshore industry. While areas like Norway and the UK's northern North Sea continue to see some development, the central and southern North Sea offshore the UK is declining at a rapid rate.

Ongoing exploration

Areas such as West of Shetland, the Atlantic Margin, and several large discoveries on the border between the UK and the Norwegian Continental Shelf each stand as future potential developments. Some of these will see activity through subsequent years despite variations in oil price, but others may likely see no investment before higher prices stabilize.

With the UK's recent vote to exit the European Union and an already struggling offshore industry, the country is moving to bolster its domestic production through new tax regimes and the establishment of a central Oil and Gas Authority to ease the process of future licensing and permitting.

The near-term future of North Sea exploration and development is assured with projects such as Clair Ridge, Kraken, Catcher, Mariner, Laggan-Tormore, the Quad 204 (Schiehallion) redevelopment, and the giant Johann Sverdrup discovery near the NCS-UKCS border.

PwC's report specified that respondents referring to "terminal decline" were speaking literally about the UK basin's oil potential. This term is factual in that regard, however, the report added, "The key is how we manage that decline for the greater good of all stakeholders in the basin."

The general consensus among respondents is that the North Sea has a future, despite the region's high operating costs and impact of lower oil prices.

Decommissioning

The big concern for the UKCS central and southern North Sea areas involves the ramp up of decommissioning to 2020. In May, OGJ reported that the North Sea could see more than $80 billion of investment through 2040 (OGJ, May 2, 2016, p. 54). Much of this work is targeted for the southern and central North Sea.

Beginning with the start of natural gas production from West Sole in 1967 on Block 48/6 and oil production from Argyll and Duncan in 1975 on Blocks 30/24 and 30/25a, the UK is home to some 300 platforms operated by 75 companies and more than 1,500 licenses.

PwC's Sea Change report refers to decommissioning as the "elephant in the room," but cites that the looming expense of these endeavors could be turned into a positive if operators can align planning to maximize further extension on late-life assets. The real risk for the UKCS is an historically add-on infrastructure in which most of the region's platforms are interconnected on some level. As assets are retired, this could create a domino effect for other platforms in the same network.

In addition, the UK may become the largest scale decommissioning project the industry has yet experienced. On a global scale, the North Sea has been a major source of oil and gas for more than 50 years. As the central and southern North Sea matures, the UK is seeking the best methods of transition toward its final phase. According to PwC's Sea Change report, opportunities remain, one of which may in fact be a graceful retirement of the UKCS. OGJ api.org/Events-and-Training/Calendar-of-Events/2017/inspection **Jan. 30-Feb 2.**

FEBRUARY 2017

7th Basra Oil & Gas International Conference & Exhibition, Basra, web site: www.basraoilgas.com/Conference/ **8-11.**

SPE Canada Unconventional Resources Conference, Calgary, web site: www.spe.org/events/en/2017/conference/17urc/homepage.html **15-16.**

SPE Canada Heavy Oil Technical Conference, Calgary, web site: www.spe.org/events/en/2017/conference/17choc/homepage.html/ **15-16.**

NAPE Summit, Houston, web site: napeexpo.com/shows/about-the-show/summit **15-17.**

International Conference on Petroleum & Petrochemical Engineering, London, web site: www.waset.org/conference/2017/02/london/ICPPE **16-17.**

19th International Conference on Oil, Gas & Petrochemical Engineering (ICOGPE 2017), Venice, web site: www.waset.org/conference/2017/02/venice/ICOGPE **16-17.**

Society of Petroleum Engineers (SPE) Reservoir Simulation Conference, Montgomery, Tex., web site: www.spe.org/events/rsc/2017/ **20-22.**

Australasian Oil & Gas Exhibition & Conference (AOG), Perth, web site: aogexpo.com.au/ **22-24.**

Nigeria Oil & Gas Conference & Exhibition, Abuja, web site: www.cwcnog.com/ **Feb. 27-Mar. 2.**

MARCH 2017

Society of Petroleum Engineers (SPE) 20th Middle East Oil & Gas Show & Conference (MEOS), Manama, Bahrain, web site: meos17.com/ **6-9**.

SPE 20th Middle East Oil & Gas Show & Conference (MEOS), Bahrain, web site: meos17.com/ **7-9.**

SPE/IADC Drilling Conference & Exhibition, Dublin, web site: www.spe.org/events/dc/2017/ **7-9.**

15th Global Oil & Gas Turkey, Istanbul, web site: www.global-oilgas.com/Turkey/Home/ **15-16.**

SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, Houston, web site: www.spe.org/events/ctwi/2017/ **21-22.**

Corrosion 2017 Conference & Expo, New Orleans, web site: nacecorrosion.org/ **26-30.**

SPE Oklahoma City Oil & Gas Symposium, Oklahoma City, web site: www.speokcsymposium.org/ **27-31.**

APRIL 2017

AAPG 2017 Annual Convention & Exhibition, Houston, web

The energy platforms—Conclusion

Three third parties

Among the five US political parties on general-election ballots in 10 or more states this year, the Green Party has by far the longest platform on energy and the environment. The Libertarian Party has the shortest. They are so-called third parties--different from the mainstream Democratic and Republican powerhouses that dominate media coverage and nearly always win.

This editorial series, after reviewing major-party energy platforms last week, turns now to what the Green, Libertarian, and Constitution parties say they believe about the subject. It does so because third-party prospects are unusually high. Because the Republican and Democratic presidential candidates are extraordinarily unpopular outside their support bases, disillusioned voters might seek refuge in third-party alternatives. If fatefully focused and located, the effect might siphon away enough electoral-college votes to keep either mainstream candidate from winning outright.

In this rambunctious political season, stranger things have happened.

Third-party platforms

The Green Party's energy policies reflect its assertion that climate change represents "the gravest environmental, social, and economic peril that humanity ever has met." Pursuing large cuts in emissions of greenhouse gases, the party proposes a "fee-and-dividend" system--essentially a carbon tax that fluctuates with the global concentration of carbon dioxide in the atmosphere. Imported oil and gas would pay double the fee. The Greens would eliminate "subsidies for fossil fuels," including much of the military budget, which they call "an indirect subsidy for oil and gas corporations."

The party would set mandates for "clean fuels," make the US pay for adaptations to climate change by countries deemed less responsible for the phenomenon, set aggressive energy-conservation targets, create a program "to train workers for the new, clean-energy economy," and in other ways pursue "the post-fossil fuel economy of 2050."

Governmental activism central to the Green energy platform appears nowhere in the Libertarian vision.

"Competitive free markets and property rights stimulate the technological innovations and behavioral changes required to protect our environment and ecosystems," the Libertarians declare. The "vested interest" of private landowners and conservation groups can be trusted to maintain natural resources. "Governments are unaccountable for damage done to our environment and have a terrible track record when it comes to environmental protection," the Libertarian platform says, rejecting subsidies for any energy form. "We oppose all government control of energy pricing, allocation, and production."

The Constitution Party, which says its goal is "to limit the federal government to its delegated, enumerated, constitutional functions," similarly upholds market freedom and private property rights. It wants to dismantle the Department of Energy. "The federal government should not interfere with the development of potential energy sources, including natural gas, hydroelectric power, solar energy, wind generators, and nuclear energy," it says.

The Constitution Party supports "realistic efforts to preserve the environment and reduce pollution--air, water, and land." But it rejects arguments based on the "perceived threat of global warming," which it says has been refuted by many scientists. "The globalists are using the global warming threat to gain more control via worldwide sustainable development," it says.

The party supports the use of eminent domain for public use such as military reservations and government buildings, but not for public ownership, such as urban renewal, environmental protection, and historic preservation. It calls for a return to states of lands held by the federal government without authorization of the Constitution, repeal of federal wetlands legislation, and repeal of the Endangered Species Act. It opposes US participation in many United Nations programs and in environmental treaties and conventions.

Fundamental differences

Energy platforms reviewed in this series are easy to summarize. Democrats and Greens predicate energy policy on apocalyptic beliefs about climate change and demand state-centered overhaul of energy economics. Republicans, Libertarians, and Constitution Party members worry less about climate change and resist manipulation of markets by the government.

The differences are fundamental and hugely consequential. Whether they matter enough to voters to affect elections remains far from certain. OGJ site: www.aapg.org/events/conferences/ace/ **2-5.**

International Conference on Petroleum Industry & Energy, Brisbane, web site: www.waset.org/conference/2017/04/brisbane/ICPIE **3-4.**

Ocean Business 2017, Southampton, UK, web site: www.ths.org.uk/event_details.asp?v0=512 **4-6.**

SPE International Conference on Oilfield Chemistry, Montgomery, Tex., web site: www.spe.org/events/en/2017/conference/17occ/homepage.html/ **3-5.**

SPE Asia Pacific Health, Safety, Security, Environment & Social Responsibility Conference, Kuala Lumpur, web site: www.spe.org/events/en/2017/conference/17aphs/homepage.html/ **4-6.**

Gastech Conference & Exhibition, Tokyo, web site: www.gastechevent.com/ **4-7.**

11th Global Oil & Gas Atyrau Conference, Kazakhstan, web site: www.oilgas-events.com/Oiltech-Atyrau-Conference/ **11-12.**

Neftegaz 2017 17th International Exhibition for Equipment & Technologies for Oil & Gas Industries, Moscow, web site: www.neftegaz-expo.ru/en/neftegaz_2017/ **17-20.**

Society of Petroleum Engineers (SPE) Health, Safety, Security, Environment & Social Responsibility Conference–North America, New Orleans, web site: www.spe.org/events/hsse/2017/ **18-20.**

MAY 2017

International Conference on Oil Reserves & Energy Systems, Rome, web site: www.waset.org/conference/2017/05/rome/ICORES **4-5**.

Colombia Oil & Gas Conference & Exhibition, Cartagena, web site: 10times.com/colombia-oilgas-exhibition **7-9.**

International Oil Spill Conference, Long Beach, Calif., web site: iosc2017.org/ **15-18.**

SPE Latin America & Caribbean Petroleum Engineering Conference, Buenos Aires, web site: www.spe.org/events/en/2017/conference/17lacp/homepage.html/ **17-19.**

International Conference on Shale Oil & Gas Engineering, Paris, web site: www.waset.org/conference/2017/05/paris/ICSOGE **18-19.**

JUNE 2017

International Conference on Oil Reserves & Energy Management, New York, web site: www.waset.org/conference/2017/06/new-york/ICOREM **4-5.**

International Conference on Oil Reserves & Environmental Policy, Copenhagen, web site: www.waset.org/conference/2017/06/copenhagen/ICOREP **11-12.**

The 16th Asian Oil, Gas & Petrochemical Engineering Exhibition, Kuala Lumpur, web site: www.oilandgas-asia.com/home/index.php **11-13.**

Brasil Offshore, Rio de Janeiro, web site: www.brasiloffshore.com/en/Home/ **20-23.**

13th Russian Petroleum & Gas Congress (RPGC), Moscow, web site: www.oilgas-events.com/RPGC-Congress/ **27-29.**

14th Moscow International Oil & Gas Exhibition (MIOGE), Moscow, web site: www.oilgas-events.com/MIOGE-Exhibition **27-30.**

JULY 2017

22nd World Petroleum Congress (WPC), Istanbul, web site: www.22wpc.com/ **9-13.**

The 16th Asian Oil, Gas & Petrochemical Engineering Exhibition, Kuala Lumpur, web site: www.oilandgas-asia.com/home/index.php **11-13.**

SEPTEMBER 2017

SPE Offshore Europe Conference & Exhibition, Aberdeen, web site: www.offshore-europe.co.uk/ **5-8.**

Global Oil & Gas Middle East & North Africa Conference, Cairo, web site: www.oilgas-events.com/Find-an-Event/Global-Oil-Gas-Middle-East-North-Africa-%281%29 **17-19**.

Oil & Gas Indonesia 2017, Jakarta, web site: oilgasindonesia.com/ **20-23.**

3rd Oil & Gas Conference, Houston, web site: oil-gas.omicsgroup.com/ **21-22.**

Argentina Oil & Gas Expo 2017, Buenos Aires, web site: www.aogexpo.com.ar/en **25-28.**

OCTOBER 2017

Society of Petroleum Engineers Annual Technical Conference & Exhibition, San Antonio, web site: https://www.expocheck.com/en/expos/2378-spe-atce-society-of-petroleum-engineers-annual-technical-conference-and-exhibition **9-11.**

AAPG SEG 2017 International Conference & Exhibition, London, web site: www.aapg.org/events/conferences/ice/announcement/articleid/5666/aapg-seg-2017-international-conference-exhibition-london **15-18.**

Louisiana Gulf Coast Oil Exploration (LAGCOE), Lafayette, La., web site: www.lagcoe.com/ **24-26.**

Offshore Technology Conference Brazil, Rio de Janeiro, web site: www.otcbrasil.org/ **24-26.**

FEBRUARY 2018

ICOGPE 2018: 20th International Conference on Oil, Gas & Petrochemical Engineering, Istanbul, web site: www.waset.org/conference/2018/02/istanbul/ICOGPE **16-17.**

MARCH 2018

ICOGPE 2018: 20th International Conference on Oil, Gas & Petrochemical Engineering, Rome, web site: www.waset.org/conference/2018/03/rome/ICOGPE **5-6.**

Offshore Technology Conference Asia, Kuala Lumpur, web site: 2018.otcasia.org/ **20-23.**

MAY 2018

AAPG 2018 Annual Convention & Exhibition, Salt Lake City, web site: www.aapg.org/events/conferences/ace/ **20-23.**

JUNE 2018

ICOGPE 2018: 20th International Conference on Oil, Gas & Petrochemical Engineering, Copenhagen, web site: waset.org/conference/2018/06/Copenhagen/ICOGPE **11-12.**

World Gas Conference, Washington, DC, web site: wgc2018.org/contact-us/ **25-29.**

JULY 2018

ICOGCT 2018: 20th International Conference on Oil, Gas & Coal Technology, Zurich, web site: www.waset.org/conference/2018/07/zurich/ICOGCT **29-30.**

MARCH 2019

ICOGPE 2019: 21st International Conference on Oil, Gas & Petrochemical Engineering, London, web site: www.waset.org/conference/2019/03/london/ICOGPE **14-15.**

MAY 2019

AAPG 2019 Annual Convention & Exhibition, San Antonio, web site: www.aapg.org/events/conferences/ace/ **19-22.**

APRIL 2020

AAPG 2020 Annual Convention & Exhibition, San Francisco, web site: www.aapg.org/events/conferences/ace/ **5-8.**

US oil, gas producers post 1Q net loss on weak commodity prices

Conglin Xu
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A sample of 90 US-based oil and gas producers and refiners posted a combined net loss of $17.74 billion for this year's first quarter compared with a combined net loss of $7.05 billion for the same period in 2015. The group's collective revenues for the first 3 months ended Mar. 31 were $153.31 billion compared with revenues of $216.79 billion for first-quarter 2015.

Crude oil prices during this year's first quarter averaged the lowest level since 2004, significantly reducing operating cash flow and earnings for oil and gas companies. To adapt to the low-price environment, oil and gas firms continued to reduce operating costs and increase selectivity of capital expenditures.

According to analysis from the US Energy Information Administration, first-quarter financial results from US onshore producers reveal an improving balance between capital expenditure and operating cash flow. Although operating cash flow was the lowest in any quarter in the past 5 years, larger reductions to capital expenditure brought these companies closest to self-finance, when capital investment can be paid entirely from operating cash flow.

US refiners' earnings for the first quarter, meanwhile, were down sharply from a year earlier because of lower refining margins.

A sample of 11 oil and gas producers and pipeline companies with headquarters in Canada posted combined net earnings of $537 million (Can.) for this year's first quarter compared with a combined net loss of $3.09 billion in the same quarter in 2015. The improvement in earnings was primarily attributable to foreign exchange gains associated with a weaker Canadian dollar, less severe asset impairments relative to a year ago, and solid performance of pipeline companies. The group reported revenues of $30.42 billion for the 2016 first quarter, compared to revenues of $37.47 billion for the 2015 first quarter.

The Canadian group excludes Canadian Oil Sands Ltd. because of its acquisition by Suncor Energy Inc. on Feb. 5.

Market review

Brent crude oil prices averaged $33.84/bbl and West Texas Intermediate averaged $33.35/bbl in this year's first quarter, down from $53.97/bbl and $48.48/bbl, respectively, in the same quarter in 2015. Front-month natural gas on the New York Mercantile Exchange averaged $1.99/MMbtu in this year's first quarter vs. $2.81/MMbtu a year earlier.

US crude oil production of 9.16 million b/d for this year's first quarter was down from 9.48 million b/d a year ago, according to EIA data. US natural gas production totaled 7.21 bcf for the first quarter vs. 7 bcf for first-quarter 2015.

During the quarter, the number of US active rigs dropped to 450 from 698, according to data from Baker Hughes Inc. Rigs drilling for oil declined by 174 to 362 at the end of the first quarter, while the number of gas rigs shrank by 74 to 88 rigs drilling.

Refining profitability, which tends to be seasonally weak in the first quarter, was negatively impacted by reduced fuel margins, especially distillate margins, given high refining industry production levels and a warm winter, narrower WTI discounts relative to the Brent benchmark, and higher costs for renewable identification number (RIN) credits to meet the Renewable Fuel Standard (RFS). Continued growth in North American gas supply partly offset these factors.

According to Muse, Stancil & Co., cash margins in this year's first quarter averaged $7.84/bbl for Midwest refiners, $12.38/bbl for West Coast refiners, $10.12/bbl for Gulf Coast refiners, and $1.99/bbl for East Coast refiners. In the same quarter of the prior year, these refining margins were $16.78/bbl, $20.59/bbl, $12.11/bbl, and $6.01/bbl, respectively.

During this year's first quarter, the Canadian dollar weakened relative to the US dollar largely reflecting lower crude oil prices. The Canadian dollar averaged 73¢ in this year's first quarter, a decrease of 8¢ from first-quarter 2015.

Western Canada Select averaged $19.30/bbl and $33.88/bbl, respectively, for the first quarters of 2016 and 2015.

US firms

ExxonMobil Corp. reported estimated first-quarter earnings of $1.78 billion compared with $5 billion in first-quarter 2015. The impacts of sharply lower commodity prices and weaker refining margins were partly offset by strong chemical results. Capital and exploration expenditures for the quarter were reduced 33% to $5.1 billion year-over-year.

US OIL AND GAS FIRMS' FIRST-QUARTER 2016 REVENUES, EARNINGS

Table 1

	Revenues		Net income	
	1st quarter			
	2016	2015	2016	2015
	Million $ (US)			
Abraxas Petroleum Corp.	9.6	18.7	(40.9)	(0.7)
Anadarko Petroleum Corp.	1,674.0	2,321.0	(998.0)	(3,236.0)
Apache Corp.	1,052.0	1,818.0	(561.0)	(4,636.0)
Approach Resources Inc.	17.6	33.3	(13.7)	(7.7)
Bill Barrett Corp.	29.5	49.3	(46.5)	(11.7)
BreitBurn Energy Partners LP	148.0	306.3	(104.0)	(58.9)
Cabot Oil & Gas Corp.	281.9	464.8	(51.2)	40.3
California Resources Corp.	322.0	577.0	(50.0)	(100.0)
Callon Petroleum Co.	30.7	30.4	(41.1)	(10.2)
Carrizo Oil & Gas Inc.	81.3	100.1	(311.4)	(21.2)
Chaparral Energy Inc.	48.2	93.1	(138.4)	4.2
Chesapeake Energy Corp.	1,953.0	2,760.0	(921.0)	(3,720.0)
Chevron Corp.	23,553.0	34,558.0	(707.0)	2,600.0
Cimarex Energy Co.	240.6	361.0	(186.1)	(414.9)
Clayton Williams Energy Inc.	30.3	64.1	(35.3)	(18.2)
Comstock Resources Inc.	36.9	66.5	(56.6)	(78.5)
Concho Resources Inc.	283.6	413.5	(1,020.5)	7.5
ConocoPhillips	5,015.0	8,082.0	(1,456.0)	286.0
Consol Energy Inc.	181.3	273.6	(23.5)	76.0
Contango Oil & Gas Co.	17.6	30.6	(11.4)	(18.6)
Continental Resources Inc.	453.2	625.6	(198.3)	(132.0)
Denbury Resources Inc.	194.8	307.6	(185.2)	(107.7)
Devon Energy Corp.	2,126.0	3,265.0	(3,468.0)	(3,589.0)
Diamondback Energy Inc.	87.5	101.4	(35.6)	6.4
Dorchester Minerals LP	6.1	8.8	1.5	4.0
Earthstone Energy Inc.	6.9	11.3	(6.4)	(1.1)
Energen Corp.	128.2	221.9	(203.1)	(15.4)
EOG Resources Inc.	1,354.3	2,318.5	(471.8)	(169.7)
EQT Production	478.0	502.2	(11.3)	185.8
EV Energy Partners LP	38.3	47.2	(29.0)	(61.7)
Evolution Petroleum Corp.	5.1	7.1	(129.6)	0.7
Exco Resources Inc.	51.6	86.3	(130.1)	(318.1)
ExxonMobil Corp.	48,707.0	67,618.0	1,781.0	5,075.0
Forestar Group Inc.	5.4	47.8	(12.4)	(8.2)
Freeport McMoRan Inc.	295.0	500.0	397.0	3,471.0
Gastar Exploration Inc.	14.8	34.4	(69.9)	0.6
Goodrich Petroleum Corp.	6.2	24.0	(18.7)	(21.1)
Gulfport Energy Corp.	157.0	176.3	(242.3)	25.5
Halcon Resources Corp.	81.3	136.2	(540.0)	(587.6)
Hess Corp.	993.0	1,550.0	(488.0)	(389.0)
HollyFrontier Corp.	2,018.7	3,006.6	43.4	242.7
Kinder Morgan CO_2 Co. LP	302.0	446.0	186.0	336.0
Laredo Petroleum Inc.	106.6	150.7	(180.4)	(0.5)
Legacy Reserves LP	65.9	81.7	105.3	(228.9)
Linn Energy LLC	414.8	916.5	(1,347.7)	(339.2)
Marathon Oil Corp.	730.0	1,532.0	(407.0)	(276.0)
Marathon Petroleum Corp.	12,830.0	17,240.0	(78.0)	903.0
Matador Resources Co.	44.7	72.4	(107.7)	(50.2)
Memorial Production Partners LP	60.9	92.8	(38.1)	(162.7)
Memorial Resource Development Corp.	141.9	179.8	(32.4)	(112.1)
Mid-Con Energy Partners LP	13.9	19.2	(3.3)	(4.1)
Midstates Petroleum Co. Inc.	52.0	111.2	(179.3)	(193.6)
Murphy Oil Corp.	430.3	921.7	(198.8)	(14.4)
Newfield Exploration Co.	284.0	349.0	(624.0)	(480.0)
Noble Energy Inc.	724.0	759.0	(287.0)	(22.0)
Northern Oil & Gas Inc.	31.8	76.1	(126.6)	(229.7)
Oasis Petroleum Inc.	130.3	180.4	(64.5)	(18.0)
Occidental Petroleum Corp.	2,281.0	3,096.0	78.0	(218.0)
Panhandle Oil & Gas Inc.	7.6	14.7	(7.4)	0.7
PDC Energy	90.8	144.6	(71.5)	17.1
Penn Virginia Corp.	30.5	74.5	(33.5)	(57.2)
PetroQuest Energy Inc.	17.3	33.5	(37.6)	(121.0)
Phillips 66	17,760.0	23,426.0	398.0	997.0
Pioneer Natural Resources Co.	685.0	868.0	(267.0)	(78.0)
PrimeEnergy Corp.	131.6	22.8	(1.2)	(0.2)
QEP Resources Inc.	261.3	491.6	(863.8)	(55.6)
Range Resources Corp.	331.4	462.6	(91.7)	27.7
Resolute Energy Corp.	19.0	41.1	(85.3)	(208.2)
Rex Energy Corp.	30.5	54.1	(60.1)	(16.5)
Ring Energy Inc.	6.1	6.0	(15.3)	(1.0)
Sabine Oil & Gas Corp.	48.2	98.0	(135.1)	(284.0)
Sabine Royalty Trust	7.0	15.1	6.2	14.6
Sandridge Energy Inc.	90.3	215.3	(313.2)	(1.2)
Seneca Resources Corp.	143.8	165.5	(213.3)	(53.6)
SM Energy Inc.	143.1	365.9	(347.2)	(53.1)
Southwestern Energy Co.	579.0	933.0	(1,132.0)	78.0
Stone Energy Corp.	80.8	153.6	(188.8)	(327.4)
Swift Energy Co.	34.3	68.3	(108.3)	(477.1)
Synergy Resources Corp.	18.3	23.7	(51.4)	4.7
Tesoro Corp.	5,101.0	6,463.0	109.0	188.0
Triangle Petroleum Corp.	44.4	118.3	(94.1)	(180.2)
Ultra Petroleum	159.4	219.3	(21.8)	25.2
Unit Corp.	136.2	255.1	(41.1)	(248.4)
Valero Energy Corp.	15,714.0	21,330.0	513.0	968.0
Vanguard Natural Resources LLC	113.2	157.9	(145.3)	(118.8)
W&T Offshore Inc.	77.7	127.9	(190.5)	(255.1)
Wexpro	83.3	91.1	26.2	27.7
Whiting Petroleum Corp.	292.0	529.2	(171.8)	(106.1)
WPX Energy Inc.	216.0	572.0	(12.0)	68.0
Yuma Energy Inc.	3.3	5.9	(3.7)	(4.0)
Total	**153,314.8**	**216,790.3**	**(17,747.5)**	**(7,047.9)**

Upstream earnings declined $2.9 billion from first-quarter 2015 to a loss of $76 million. Oil equivalent production increased 1.8% from first-quarter 2015, with liquids up 11.5%, reflecting new project capacity additions, and gas down 9.3%. The US upstream operations recorded a loss of $832 million compared with a loss of $52 million in first-quarter 2015. Non-US upstream earnings were $756 million, down $2.2 billion from the prior year's first quarter.

Downstream earnings were $906 million, down $761 million from first-quarter 2015. Weaker margins decreased earnings by $860 million. Chemical earnings increased 38% to $1.4 billion on stronger margins and higher sales volumes.

Chevron Corp. reported a net loss of $707 million for this year's first quarter compared with earnings of $2.6 billion in 2015's first quarter. Foreign currency effects decreased earnings in this year's first quarter by $319 million compared with an increase of $580 million a year earlier. Capital and exploratory expenditures in first-quarter 2016 were $6.5 billion, down from $8.6 billion in the corresponding 2015 period.

US upstream operations incurred a loss of $850 million in this year's first quarter compared with a loss of $460 million a year earlier. International upstream operations incurred a loss of $609 million in the first quarter compared with earnings of $2.02 billion in first-quarter 2015. Worldwide net oil-equivalent production was 2.67 million b/d in this year's first quarter compared with 2.68 million b/d in 2015's first quarter.

US downstream operations earned $247 million in the first quarter compared with earnings of $706 million a year earlier. The decrease was primarily because of lower margins on refined products, an asset impairment, higher operating expenses primarily due to planned turnaround activity in this year's first quarter, and lower earnings from half-owned Chevron Phillips Chemical Co. LLC (CPCC). International downstream operations earned $488 million in the first quarter compared with $717 million in first-quarter 2015.

ConocoPhillips reported a first quarter net loss of $1.45 billion compared with first-quarter 2015 earnings of $286 million. Excluding special items, the firm reported an adjusted first-quarter net loss of $1.2 billion compared with a first-quarter 2015 adjusted net loss of $222 million. Special items of the current quarter were related to noncash impairments in the Gulf of Mexico and UK and pension settlement expense.

ConocoPhillips's production for the first quarter was 1.57 million boe/d, a decrease of 32,000 boe/d compared with the same period a year ago. This was because of normal field decline and impacts from dispositions, the company said. Operating costs were lower by more than 20% year-over-year.

Chesapeake Energy Corp. reported a net loss of $921 million for this year's first quarter compared with a net loss of $3.7 billion in 2015's first quarter. Included in the first-quarter loss was a noncash impairment of the carrying value of Chesapeake's oil and natural gas properties of $853 million. A $4.9-billion property impairment was incurred in 2015's first quarter.

Chesapeake's revenues in this year's first quarter declined 39% year-over-year. Total capital investments were $365 million during this year's first quarter, down from $1.5 billion in 2015's first quarter.

EOG Resources Inc. reported a first-quarter net loss of $471.8 million compared with a first-quarter 2015 net loss of $169.7 million, as lower commodity prices more than offset well productivity improvements and cost reductions. During this year's first quarter, the company's lease and well expenses decreased 29% and transportation costs decreased 12% compared with the same period a year ago, both on a per-unit basis.

EOG's exploration and development expenditures, excluding property acquisitions, for this year's first quarter decreased 61%, while total crude oil and condensate production declined 10% compared with first-quarter 2015. Total natural gas production for this year's first quarter decreased 3% vs. the prior year period.

Occidental Petroleum Corp. announced net income of $78 million for this year's first quarter. Core income for the first quarter was a loss of $426 million. Total company first quarter capital spending declined $500 million from fourth-quarter 2015.

The company's total oil and gas aftertax results reflected a loss of $388 million for this year's first quarter compared with losses of $189 million for fourth-quarter 2015 and $22 million for first-quarter of 2015, caused by the continued decline in commodity prices.

The company's Permian resources production increased 30%, or 30,000 boe/d, year-over-year, in the first quarter, while operating costs improved 33%. Total oil and gas cash operating costs were 23% lower compared with first-quarter 2015.

Hess Corp. reported a net loss of $488 million in this year's first quarter compared with a net loss of $389 million in the same quarter in 2015. Adjusted first-quarter net loss was $509 million compared with adjusted net loss of $279 million a year earlier. First-quarter results reflected lower realized selling prices, partially offset by lower operating costs and other expenses vs. the prior-year quarter.

The company's exploration and production capital expenditures were $544 million in this year's first quarter, down from $1.24 billion in the prior-year quarter.

Refiners

Valero Energy Corp. reported net income of $513 million for this year's first quarter, down from $968 million for first-quarter 2015. First quarter net income included a net aftertax benefit of $212 million related to the company's lower of cost or market (LCM) inventory valuation reserve.

The refining segment reported $695 million of adjusted operating income for this year's first quarter compared with $1.6 billion for first-quarter 2015, primarily attributable to weaker distillate margins.

Valero's refineries achieved 96% throughput capacity utilization and averaged 2.9 million b/d of throughput volume in this year's first quarter, an increase of 169,000 b/d from first-quarter 2015, attributable primarily to less maintenance activity in the first quarter.

HollyFrontier Corp. reported first-quarter net income of $43.4 million for this year compared with first-quarter 2015 income of $242.7 million. The decrease in net income reflected lower refining margins, and the costs associated with blending ethanol and purchasing RINs to comply with the RFS mandate. Included in the quarter results was a noncash inventory valuation adjustment that increased aftertax earnings by $37 million.

The firm's consolidated refinery gross margin was $7.59/bbl, a 55% decrease vs. $16.69/bbl for first-quarter 2015. Margins were impacted by seasonally weak gasoline cracks and continued weakness in diesel cracks.

Phillips66 reported first-quarter earnings of $398 million compared with $997 million in first-quarter 2015. Refining adjusted earnings were $86 million, down from $495 million in first-quarter 2015, because of weaker gasoline and distillate margins. Chemical adjusted earnings, reflecting Phillips66's equity investment in CPCC, were $156 million compared with $203 million in first-quarter 2015, because of lower polyethylene sales prices.

Marathon Petroleum Corp. reported a net loss of $78 million for this year's first 3 months compared with earnings of $903 million in 2015's first quarter. Its refining and marketing segment lost $62 million in this year's first quarter compared with an income of $1.29 billion in first-quarter 2015. The decline in first-quarter earnings was largely attributable to weak crack spreads in this year's first quarter compared with unusually strong first-quarter crack spreads in 2015, as well as higher direct operating costs related to increased turnaround activity.

CANADIAN OIL AND GAS FIRMS' FIRST-QUARTER 2016 REVENUES, EARNINGS

	Revenues		Net income	
	1st quarter			
	2016	2015	2016	2015
	Million $ (Can.)			
Baytex Energy Corp.	119.0	226.7	0.6	(175.9)
Canadian Natural Resources Ltd.	2,178.0	3,034.0	(105.0)	(252.0)
Cenovus Energy Inc.	2,245.0	3,141.0	(118.0)	(668.0)
Enbridge	8,795.0	7,929.0	1,347.0	(221.0)
EnCana Corp.	976.4	1,619.6	(491.5)	(2,213.5)
Husky Energy Inc.	2,524.0	3,956.0	(458.0)	191.0
Imperial Oil Ltd.	5,222.0	6,203.0	(101.0)	421.0
Penn West Petroleum Ltd.	184.0	274.0	(100.0)	(248.0)
Sherritt International Corp.	58.4	829.0	(47.8)	(56.8)
Suncor Energy Inc.	5,577.0	7,386.0	257.0	(341.0)
TransCanada Corp.	2,547.0	2,874.0	354.0	469.0
Totals	**30,425.8**	**37,472.3**	**537.3**	**(3,095.2)**

Canadian firms

All financial figures in this section are presented in Canadian dollars unless noted otherwise.

Suncor Inc. recorded net earnings of $257 million in this year's first quarter compared with a net loss of $341 million in first-quarter 2015. Net earnings for this year's first quarter included a noncash aftertax foreign exchange gain on the revaluation of US dollar denominated debt of $885 million compared with an aftertax foreign exchange loss of $940 million in the same quarter a year ago.

The company's operating losses in this year's first quarter were $500 million compared with operating earnings of $175 million in 2015's first quarter. This reflected the 31% decline in the WTI benchmark price, a 43% decline in the WCS benchmark price, combined with a wider bitumen-to-WCS differential, as well as a decrease of 40% in benchmark crack spreads compared to first-quarter 2015.

The company's total upstream production was 691,400 boe/d in this year's first quarter compared with 602,400 boe/d in the prior year's first quarter, with the increase due mainly to an additional 36.74% working interest in Syncrude associated with the Canadian Oil Sands Ltd. acquisition and increased oil sands operations production.

During this year's first quarter, Suncor began planned maintenance at its Commerce City refinery. Average refinery utilization remained strong at 91% in the first quarter compared with 95% in 2015's first quarter, despite weaker demand and the planned turnaround.

Encana Corp. reported a net loss of $491.5 million in the first quarter compared with a loss of $2.21 billion in first-quarter 2015. Aftertax noncash ceiling test impairments were $787 million and $1.58 billion, respectively, for this year's first quarter and first-quarter 2015. This year's first-quarter results included a nonoperating foreign exchange gain of $382 million, while first-quarter 2015 recognized a foreign exchange loss of $659 million.

The company's total liquids production for the quarter averaged 130,800 b/d, an increase of 8% from the same period in 2015. Natural gas production in the first quarter averaged 1.5 bcfd.

Imperial Oil Ltd.'s net loss for this year's first quarter was $101 million compared with a net income of $421 million for 2015's first quarter. Capital expenditures for the first 3 months of this year were $408 million, down from $1.05 billion a year earlier.

The company's upstream segment recorded a net loss in the first quarter of $448 million compared with a net loss of $189 million in first-quarter 2015, reflecting lower crude prices, partially offset by the impact of a weaker Canadian dollar. Production for the first quarter averaged 421,000 boe/d, up 26% from 333,000 boe/d a year ago.

Downstream net income was $320 million in the first quarter compared with $565 million in the same period in 2015. Earnings decreased mainly because of lower refinery margins.

Cenovus Energy Inc. ended this year's first quarter with a net loss of $118 million compared with a net loss of $168 million in the same period of 2015. The improvement was primarily because of nonoperating unrealized foreign-exchange gains of $413 million compared with unrealized losses of $514 million a year ago, offset by lower commodity prices this year and an asset impairment of $170 million related to its northern Alberta conventional oil assets.

During the first quarter, the company's upstream operating cash flow was down 63% to $167 million. Oil sands operating costs were also down 13% to $9.52/bbl compared with the same period in 2015.

Refining and marketing operations had an operating cash flow loss of $23 million during this year's first quarter compared with operating cash flow of $95 million in the same period a year ago. This was primarily because of a 41% decline in market crack spreads driven by seasonal weakness, high storage levels for refined product, and the narrowing of the Brent-WTI price differential compared with the same period a year ago.

Enbridge Inc.'s first-quarter earnings were $1.347 million compared with a loss of $221 million in first-quarter 2015. Adjusted earnings for this year's first quarter were $663 million compared with adjusted earnings of $468 million in 2015's first quarter. The increase was driven by record throughput growth on the liquids mainline system and the impact of new projects coming into service in second-half 2015. OGJ

WoodMac: US Lower 48 producers record $150 billion in capex cuts during 2016-17

The US Lower 48 has accounted for $150 billion of the $370 billion in global capital expenditure reductions by upstream firms during 2016-17, according to analysis from WoodMackenzie.

The dramatic cuts by US operators are largely due to shorter lead times and the less capital-intensive nature of the US unconventional space, the research and consultancy firm explains.

"The plays that saw the highest proportion of their capital expenditure cut were in the Eagle Ford and the Bakken," said Jeanie Oudin, WoodMac senior research manager, Lower 48. "That's because the two plays were in full-scale development, with most operators' acreage held by production at the time oil prices began to fall, allowing for a more responsive slowdown in activity."

The Bakken and Eagle Ford alone has accounted for 36% of US capex cuts during 2016-17. Spend across the Rocky Mountains region, namely in the Bakken-Three Forks and Niobrara, has taken the deepest cuts, down 66%, or $44 billion. The Gulf Coast region has been similarly hard hit, particularly in the Eagle Ford, whose cuts have comprised nearly 20%.

Although reduced service costs and overall cost deflation have also contributed to falling spend, deferred investment continues to be the foremost influence on capex declines in the US Lower 48.

Output decline below expectations

As rig counts have plummeted, a large backlog of drilled but uncompleted (DUC) wells has provided cash flow to operators, allowing them to focus on completions as rig contracts expire—meaning production volumes are no longer tied directly to rig count.

"People expected that overall tight oil production would collapse when companies stopped drilling. However, it hasn't collapsed—it's only declined," said Oudin. "Not only have operators built up a backlog of DUC wells, they are also utilizing longer laterals and enhanced completions to increase the productivity of wells as they bring them online. They're just not adding new volumes as quickly."

The current WoodMac production outlook expects a 7 billion-boe decline in production globally through 2020, with 70% of those volumes lost from the US Lower 48 in the near term, through 2017.

The Midland and Delaware basins, meanwhile, have experienced smaller declines in drilling activity. The Permian's resilience is partly due to many of its rigs being concentrated in the best areas and the stacked pay potential of the plays.

WoodMac says largely mature producers and basin incumbents have the most remaining economic inventory. Although some of these established operators are less characterized by the high-growth metrics of some of their offset-acreage peers, they have a bright and sustainable future, the firm adds.

"Combined with our outlook for Permian production growth, this is extremely positive for Midland and Delaware stakeholders," noted Oudin. "The Midland and Delaware basins hold the largest number of undrilled, low-cost tight oil locations in the Lower 48. No other region comes close." OGJ

ExxonMobil to acquire InterOil in deal valued above $2.5 billion

Rick Wilkinson
OGJ Correspondent

ExxonMobil Corp. has agreed to acquire all outstanding shares of InterOil Corp. for more than $2.5 billion. The deal is expected to close in September. Oil Search Ltd. in turn has withdrawn from its InterOil takeover attempt. An initial agreement between Oil Search and InterOil was announced in May (OGJ Online, May 20, 2016).

Under terms of the agreement, InterOil shareholders will receive $45/share of InterOil paid in ExxonMobil shares at closing, and a contingent resource payment (CRP), which will be an additional cash payment of $7.07/share for each tcfe gross resource certification of Elk-Antelope field above 6.2 tcfe up to 10 tcfe.

InterOil's resource base includes interests in six licenses in Papua New Guinea covering about 4 million acres, including PRL 15. Elk-Antelope field in PRL 15 is the anchor field for the proposed Total SA-led Papua New Guinea LNG project. ExxonMobil says its separately developed Papua New Guinea LNG project is now exceeding production design capacity, and the firm will work with coventurers and the government to evaluate processing of gas from Elk-Antelope field by expanding the PNG LNG project.

InterOil earlier this week confirmed the bid from ExxonMobil, which was deemed superior by InterOil's board compared with its May agreement with Oil Search (OGJ Online, July 18, 2016).

Under its $2.2-billion deal with Oil Search, InterOil was permitted to engage in further discussions and negotiations with any third party after the agreement (OGJ Online, July 1, 2016). InterOil terminated its agreement with Oil Search immediately prior to entering into its agreement with ExxonMobil, which is paying Oil Search a termination fee on behalf of InterOil.

Oil Search's standing

In deciding to step back from its offer, Oil Search has paved the way for greater synergy, perhaps even some form of unitization, between the PNG-LNG and the Papua LNG projects. ExxonMobil's agreement for InterOil means Oil Search and ExxonMobil will be members of both the PNG-LNG and Papua LNG consortia.

Oil Search Managing Director Peter Botten said that Total and Oil Search had already signaled their desire to cooperate with the PNG-LNG project to maximize synergy values for all stakeholders. "Should ExxonMobil be successful in its proposed bid for InterOil, its entry into Papua LNG would significantly enhance the likelihood of material project cooperation," he said prior to the deal's formal announcement.

"Opportunities to add value include possible project acceleration, capital and operating cost savings, resource utilization optimization, and various operating, financing, and marketing synergies." Botten added, "Considerable work remains to be done by all stakeholders to realize these opportunities, but the entry of ExxonMobil into Papua LNG would be a material step forward."

He went on to say that Oil Search was pleased to have created a catalyst for potential LNG project cooperation in PNG. "For Oil Search shareholders a successful takeover of InterOil by ExxonMobil will deliver a major part of our original objectives in the acquisition of InterOil and our agreement with Total, without shareholder dilution and any acquisition risk," Botten said.

Oil Search is now keen to continue strong working relationships with all PNG-LNG joint venturers and the PNG government so that there can be a progression of the potential expansion of PNG-LNG and the development of Papua LNG as soon as possible.

In Oil Search's second-quarter report, also released July 21, Botten said that based on current forecast cash flows, which assume an ongoing gradual recovery in oil prices, Oil Search expects to be able to fund all its proposed capital expenditure programs, including its share of LNG expansion project, right through to the beginning of production. OGJ

Enbridge resolves federal charges stemming from 2010 pipeline leaks

Nick Snow
Washington Editor

Enbridge Energy Partners LP agreed to pay $177 million to resolve federal charges stemming from 2010 leaks from crude oil pipelines in Illinois and Michigan, the US Department of Justice and US Environmental Protection Agency jointly announced. They said that the proposed settlement includes a commitment to spend at least $110 million to prevent spills and improve operations across nearly 2,000 miles of pipelines in the Great Lakes region.

The agreement settles federal charges stemming from a July 25, 2010, rupture of EEP's Line 26B near Marshall, Mich., which leaked at least 20,082 bbl (OGJ Online, July 29, 2010), and a Sept. 9, 2010, rupture of its Line 6A near Romeoville, Ill., where at least 6,427 bbl leaked. The US Pipeline and Hazardous Materials Administration subsequently proposed a record $3.7 million and 24 enforcement actions against EEP for the Michigan accident (OGJ Online, July 2, 2012).

"From the beginning, we've taken responsibility for the Line 6B release. We accept the civil penalties and enhanced safety measures in the decree," EEP Pres. Mark Maki said in response to DOJ and EPA's July 20 announcement. "The enhanced safety measures it includes are consistent with our approach to safety and integrity and our current practices, and have largely been implemented over the past 6 years." He pledged the partnership's cooperation with DOJ and EPA in fulfilling the agreement's terms.

EEP also agreed to pay $62 million in fines for allegedly violating the federal Clean Water Act, $61 million for the Michigan incident and $1 million for the one in Illinois. The proposed settlement also resolves the Enbridge Inc. division's liability under the 1990 Oil Pollution Act, based on the Houston limited partnership's commitment to pay more than $5.4 million to reimburse the government for cleaning up the Marshall spill and all future costs incurred in connection with that accident, DOJ and EPA said.

They said that the settlement includes specific requirements to prevent spills and enhance leak detection capabilities throughout EEP's Lakehead pipeline system, a network of 14 pipelines spanning 2,000 miles across seven US states that handles 1.7 million b/d of crude. EEP also agreed to take major actions to improve its spill preparedness and emergency response programs, and replace close to 300 miles of one of its pipelines after obtaining all necessary approvals, the federal entities indicated.

They said that EEP agreed to spend at least $110 million to specifically:

- Improve leak detection and control room operations.
- Commit to meet additional leak detection and spill prevention requirements for a portion of its Line 5 that crosses the Mackinac Straits in Michigan.
- Create and maintain an integrated data base for the Lakehead pipeline system.
- Enhance its emergency response preparedness by conducting four spill response exercises to test and practice its response to a major inland oil spill.
- Improve training and coordination with state and local emergency responders by requiring incident command system training for employees, providing training to local responders, participating in area response training, and organizing response exercises.
- And hire an independent third party to assist with reviewing implementation of the proposed settlement's requirements.

DOJ filed the proposed settlement on July 20 in US District Court for Western Michigan's Southern District, with a 30-day comment period before it becomes final.

Commenting on the agreement, Enbridge Chief Executive Al Monaco said that what the company has learned in the 6 years since the accidents have made it better, and changed the ways that it thinks about safety.

Monaco said that following the Marshall spill, Enbridge and EEP significantly enhanced efforts between 2010 and 2014 to better understand its pipelines' conditions and mitigate risks, while increasing staffing dedicated to preventative measures, maintaining system fitness and leak detection and pipeline control. Enterprise-wide, it spent nearly $5 billion to execute a comprehensive maintenance and inspection program using the most sophisticated inspection tools that were available, he indicated. OGJ

Trade link seen lifting Canadian oil revenue

Access to waterborne trade would increase revenue to oil and gas producers of western Canada by billions of dollars per year, according to the Fraser Institute.

Analysts at the Canadian think tank, which uses measurement to assess government policies, said delays in the essential pipeline connections put conventional and unconventional production in western Canada "at risk of being displaced by increasing US oil production."

With access to global markets limited, crude and bitumen produced in western Canada sell at a discount against widely traded crudes such as North Sea Brent, even after adjustments for quality differences and transportation costs.

Proposals for pipeline projects targeting the Atlantic and Pacific coasts face opposition from environmental and some First Nations and local groups. The US has rejected the border crossing of the Keystone XL system expansion, which would increase transport capacity to the Gulf of Mexico.

The Fraser Institute analysts, Gerry Angevine and Kenneth P. Green, estimated the revenue effects, in Canadian dollars, of the ability to export 1 million b/d through ocean ports at varying crude prices, in US dollars.

Assuming that 1 million b/d of waterborne export capacity were available and that most exported heavy oil and bitumen continued to flow to the US, they found producer revenue would be as much as $2 billion/year higher at a crude price of $40/bbl.

At $60/bbl, the incremental revenue would be $4.2 billion/year. At $80/bbl, it would be $6.4 billion/year.

If higher netbacks from markets accessed via tidewater connections were realized by all western Canada heavy oil production, annual benefits at the asserted crude prices could reach $8.9 billion, $18.5 billion, and $28.2 billion, the analysts said.

"Every effort should be made to expedite pipeline project review and assessment processes before windows of opportunity for access to new markets are largely preempted by competitors," the analysts said, suggesting federal intervention might be needed "if the legislated regulatory review process with regard to a particular project is unduly delayed." OGJ

PHMSA proposes crude-by-rail response, data-sharing procedures

Nick Snow
Washington Editor

The US Pipeline & Hazardous Material Safety Administration proposed new oil spill response and information procedures for high-hazard flammable trains (HHFT) in coordination with the Federal Railroad Administration.

The new rule would update and clarify comprehensive spill response plan requirements for HHFTs and require railroads to share information with state and tribal emergency commissions to improve accident preparedness, PHMSA said July 13. It also would incorporate a test method for the initial boiling point of flammable liquids into hazardous materials regulations, the US Department of Transportation agency said.

"The substantial surge in our country's production of crude oil is creating a serious need for improved response and communication between railroads and the communities through which they travel," PHMSA Administrator Marie Therese Dominguez said. "This rule would help to ensure that railroads provide vital information to first responder to help them prepare for and respond to a derailment involving crude."

Specifically, the proposed rule would expand comprehensive oil spill response plans under the federal Clean Water Act to certain HHFTs based on the amount of crude being transported. These changes mean that certain HHFTs would need comprehensive plans, instead of the basic plans which are required currently, PHMSA said.

The proposal also would require the train's operator to be prepared to respond to an incident involving a worst-case discharge, or the largest quantity of crude expected to be release during an incident. It also would codify the requirement that railroads share information about all HHFT operations with state and tribal emergency response commissions, in accordance to the 2015 Fixing America's Surface Transportation (FAST) Act.

PHMSA said the rule proposes requiring railroads to provide monthly notification or certification of no change to state and tribal emergency response commissions and relevant emergency responders for HHFTs, including:

- A reasonable estimate of the number of HHFTs that are expected to travel, per week, through each county within the state.
- The routes over which the affected trains will move.
- A description of the materials shipped and applicable emergency response information required by hazardous materials regulations.
- At least one point of contact at the railroad, including name, title, phone number, and address, for the state and tribal emergency response commissions, and relevant emergency responders related to the railroad's transportation of affected trains.
- For oil trains subject to the Comprehensive Oil Spill Response Plan under 49 CFR part 130, the contact information for the qualified individuals and description of response zones must also be provided to state and tribal emergency response commissions, or other appropriate state-delegated entities.

A notice about the proposed rule was scheduled to be published in the July 29 Federal Register, and a 60-day public comment period will begin at that time, a PHMSA spokesman told OGJ. OGJ

Angola seen facing oil-related instability

Angola struggles with economic problems and the potential for political instability as a presidential election approaches, warns an analyst at Verisk Maplecroft, Bath, UK.

The country is a member of the Organization of Petroleum Exporting Countries with production averaging 1.75 million b/d.

According to Senior Analyst-Africa Maja Bovcon at the risk-intelligence firm, Angola during 2010-15 depended on oil for 90% of its foreign currency earnings, 75% of fiscal revenues, and 50% of gross domestic product.

Central to that dependency is the state-owned oil company, Sonangol, which Bovcon says is reported to have ceased paying into state coffers in January because of financial problems related to the oil-price slump.

Doubt grows that Sonangol can honor debt to European banks of $13 billion, the analyst reports. In June, the company failed to provide evidence of a healthy debt-to-capital ratio required by a loan agreement with a UK bank.

Sonangol is as important politically as it is economically, Bovcon notes.

It allows President Jose Eduardo dos Santos "to buy the loyalty of the country's elites," she writes in a research note.

In June, dos Santos appointed his daughter, Isabel, to head Sonangol. The move evoked speculation that she was being positioned to replace her father on his announced retirement in 2018. He is expected to win reelection in voting next year.

According to Bovcon, Isabel dos Santos is one of the most trusted members of her father's "small inner circle" and is considered by many foreign investors to be competent enough to rescue Sonangol.

Foreign oil companies welcomed her decision to retain US-based consultancies to advise her on the company's overhaul. But the challenge is great.

"Unless there is a sudden rebound in oil prices, the national oil company will not be able to uphold its role in the economic and political system," Bovcon says.

Economic problems will worsen before next year's election. This month, the government lowered its growth forecast for 2016 to 1.3% from 3% and cut spending by 20%. The country's debt-to-GDP ratio is rising rapidly, and spending probably will increase before the election.

Bovcon says dos Santos, having won reelection, might step down as promised and transfer power to "his chosen heir" or postpone retirement, as he has done in the past.

"Either way, Sonangol's rescue is vital if the dos Santos family wish to retain power," she says.

Failure would push Angola toward economic collapse and the ruling party, "with a much-reduced oil bonanza to distribute as patronage," toward a loss of power within a decade.

But if Isabel dos Santos succeeds in turning around Sonangol, "she will strengthen her position to step into her father's shoes and ensure the survival of Angola's political and economic system." OGJ

BHI: Behind big gains in Texas, US rig count jumps 15 units

Matt Zborowski
Staff Writer

The US drilling rig count gained 15 units to 462 during the week ended July 22, representing its biggest increase since this week a year ago, according to Baker Hughes Inc. data. Fourteen of the units to come online are oil-directed.

Rising in 7 of the last 8 weeks, the count has added 58 units since its first increase in 41 weeks on June 3 (OGJ Online, July 15, 2016). Last summer's short-lived rebound comprised just a 28-unit gain between June 19 and Aug. 21.

Oil and gas consulting service Rystad Energy last week noted in its shale newsletter that US "operators immediately began adding rigs targeting their most prolific shale areas" during June as Brent and West Texas Intermediate crude oil prices hovered just below $50/bbl.

Specifically, it cited Concho Resources Inc. and Energen Corp. respectively adding 7 and 6 units in the Permian during the month. The firm expects a more cautious approach from large operators such as EOG Resources Inc., Chesapeake Energy Corp., and Devon Energy Corp.

A persistent oil price of about $50/bbl—a threshold that's far from a given to be reached again in the near term in light of recent declines—would enable shale drilling in the core regions. Rystad believes 70% of the shale drilling activity in North America would be concentrated in the top activity plays, namely the Eagle Ford, Bakken, Permian, and Niobrara.

"With the oil price expected to surpass $50/bbl as early as 2017, drilling activity can potentially start again in the noncore areas," the firm said. The US Energy Information Administration this week noted that, amid lower budgets and higher oil prices, cash flow is now covering a larger portion of US onshore operators' capital expenditures (OGJ Online, July 18, 2016).

Data from fellow consulting firm Douglas-Westwood, meanwhile, suggests that 16% of the North American rig fleet has been scrapped since January 2015.

"Like the operators, rig contractors themselves are focused on free cash flow," it explained last week. "Efficiency of operations and uptime are critical, and key rig components are being recycled from one rig to another to minimize spend on new hardware. Where new rig components are required, our clients are reporting a trend towards increasing adoption of Chinese-manufactured parts. Efficiency and safe operations are also boosted by the continued uptake in automated rig equipment."

Onshore oil rigs streaking

Up 14 this week, the count of active oil-directed rigs now totals 371, a rise of 55 units since May 27. Compared with its peak in BHI data on Oct. 10, 2014, the total is now down 1,238 units.

Gas-directed rigs edged down a unit to 88, while 2 rigs considered unclassified started operations to bring its count to 3.

Land-based rigs jumped 18 units to 440. A majority of those were horizontal, whose count rose 13 units to 357, up 43 units since May 27 and down 1,015 units since a peak in BHI data on Nov. 21, 2014. Directional drilling rigs edged up a unit to 44.

Three units stopped work offshore Louisiana, erasing last week's 3-unit gain and returning the overall US offshore count to 19. Three rigs remain operating in inland waters.

Canada's count continued its upward momentum with a 7-unit increase this week to 102, up 66 units since May 6. Oil-directed rigs rose 4 units to 48 while gas-directed rigs rose 3 units to 53.

Texas lifts US count

A main hub of US oil and gas activity, Texas posted its largest increase this week in nearly 2 years, gaining 15 units to 217 rigs working, up 44 units since May 27. Compared with its peak in BHI data on Aug. 29, 2008, the state is down 741.

The Permian rose 8 units to 168, an increase of 34 units since May 13. After nearly halving last week, the tally of active rigs in the Barnett added 3 this week, bringing its total to 8. The Eagle Ford gained 2 units to 35. The Granite Wash increased 1 unit to 9.

Amid the recent rebound in the Permian, Wood Mackenzie notes that the Midland and Delaware basins have experienced smaller declines in drilling activity compared with their peers since the drilling dive began. The firm attributes the Permian's resilience partly to many of its rigs being concentrated in the best areas and the stacked pay potential of its plays.

"The Midland and Delaware basins hold the largest number of undrilled, low-cost tight oil locations in the Lower 48. No other region comes close," said Jeanie Oudin, WoodMac senior research manager, Lower 48, in the analysis released by the research and consultancy firm this week.

Elsewhere, California recorded its first multi-rig increase since late 2014, gaining 2 units to 7. New Mexico rose a unit to 26, up 7 units over the past 3 weeks.

Other basins to record an increase were the DJ-Niobrara, up 2 to 18; and Mississippian, up 1 to 6. The Cana Woodford dropped a unit to 28.

Three states posted declines. Louisiana fell 2 units to 44. Alaska lost a unit to 6. Kansas's only active rig went offline.

Among the first major US exploration and production firms to release its second-quarter results, shale gas producer Southwestern Energy Co. said it plans to increase its companywide rig count to 5 by the end of the third quarter. The firm this week reinitiated drilling with its first rig in Northeast Appalachia.

Of the 5 rigs, 2 will be in Northeast Appalachia, 2 in Southwest Appalachia, and 1 in Fayetteville. Southwestern also expects to complete 90-100 wells in the second half, including new wells drilled and a portion of its inventory of previously drilled but uncompleted wells. OGJ

TAEP: Tough times 'not over' for Texas oil, gas industry

Crude oil prices in Texas averaged $45.19/bbl in June, marking the fourth straight monthly increase since the average monthly price fell to a low of $27.08/bbl in February.

As a result, the average statewide rig count during the month was higher than the previous month's count for the first time in 2 years, and the 656 drilling permits granted was 28% more than the low ebb in February. The rate of industry job-loss slowed in June as well, with an estimated 900 shed by upstream firms.

However, despite the signs of recovery, the Texas Alliance of Energy Producers' latest Texas Petro Index (TPI) indicates the tough times haven't ended based on its analysis of the first 6 months of industry activity.

"Even with deep declines in activity levels, oil production in Texas has been slow to respond," explained Karr Ingham, economist and TPI creator. "In fact, crude output in Texas this year through June declined only about 5% compared to the first 6 months of 2015."

A composite index based upon a comprehensive group of upstream economic indicators, the TPI in June declined for the 19th straight month to 155.8, down 39% from its June 2015 level and less than half the value of the peak TPI of 313.4, which occurred in November 2014.

The index shows that production has been slow to respond to lower wellhead prices, with statewide crude output in 2015—the year after prices began their dive from more than $100/bbl in summer 2014—increased 11.5% compared with its 2014 level. Production in every month of 2015 was up compared with the same month a year earlier, and the first year-over-year production decline measured by the TPI didn't occur until January.

"Virtually nothing in this cycle that would correct the current contraction has occurred quickly or within the time frames that many had forecast," Ingham said. "The sharp price decline and resulting industry downturn was the direct result of market imbalance and rising crude oil supplies."

He said, "Concerns about these very things remain in place, and there is presently no great sense that the difference will be made up on the demand side. Hence, while the end may be near in terms of TPI decline, there is every chance that the recovery ahead will be frustratingly slow."

June index indicators

Crude production in Texas during June totaled an estimated 96.3 million bbl, down 7.2% from the June 2015 estimate. The value of Texas-produced crude totaled $4.35 billion, down 25.5% year-over-year.

Estimated Texas natural gas output was 697.4 bcf, down 3.2% from the June 2015 number. With natural gas prices in June averaging $2.41/Mcf, the value of Texas-produced gas declined 13.2% to $1.68 billion.

The Baker Hughes Inc. count of active drilling rigs in Texas averaged 185 compared with 363 in June 2015. Drilling activity in the state peaked in September 2008 at a monthly average of 946 rigs before falling to a trough of 329 in June 2009.

In the most recent economic expansion, which began in December 2009, the statewide average monthly rig count peaked at 932 in May and June 2012. The statewide rig count was at 906 as recently as the third week of November 2014.

The number of Texans on upstream payrolls averaged an estimated 204,100, down 20.9% year-over-year, according to statistical methods based upon the Texas Workforce Commission's Quarterly Census of Employment and Wages.

Calculations based on TWC's Current Employment Statistics (CES) data show a record 306,000 Texans held upstream jobs in December 2014. Using the CES as a benchmark, Ingham calculated the nadir of upstream oil and gas industry employment in Texas before the December 2014 record to be 175,700 in October 2009. OGJ

Aramco lets contracts for Fadhili gas project

Robert Brelsford
Downstream Technology Editor

Saudi Aramco has let a series of new contracts for development of the Fadhili gas program in the eastern province of Saudi Arabia, north of Jubail.

Aramco signed four major contracts for development and execution of the megaproject with a mix of service providers in a ceremony on July 20, the state-owned company said.

The latest contract awards, which involve engineering, construction, procurement, and ancillary services for components of the project, include:

- Larsen & Tubro Ltd. for offshore facilities.
- Saudi KAD Contracting Co. for downstream works.
- Saudi Electric Co. and Engie Group PLC for a combined heat and power plant.
- Mohammed I. Al Subeae & Sons Investment Holding Co. for a residential camp.

Aramco disclosed no further details regarding either the value or scope of work to be covered by the individual contracts.

These four contracts join 10 major contracts previously awarded for the gas project (OGJ Online, Nov. 24, 2015; Dec. 20, 2013).

To be developed at a cost of more than 50 billion riyals, the project comes as a key component of the kingdom's master gas system, and together with Aramco's two other new major gas projects Wasit and Midyan, will boost Saudi Arabia's nonassociated gas processing capacity by more than 5 bcfd and lift overall natural gas supplies to more than 17 bcfd by 2020, Aramco said.

Specifically, Fadhili will process a total of 2.5 bcfd of nonassociated gas, including 2 bcfd of Hasbah offshore gas and 500 MMcfd of Khursaniyah onshore gas to produce 1.5 bcfd of sales gas.

Designed for a maximum sulfur recovery of 99.9%, the Fadhili gas processing plant also will use tail gas treatment to produce about 4,000 tonnes/day of sulfur.

The gas plant additionally will supply 470 MMcfd of gas to an adjacent cogeneration power plant, which will provide Fadhili with power and steam requirements as well as supply 1,100 Mw of electricity to the domestic grid.

Due to be Aramco's first project to run on low-btu gas, Fadhili is scheduled for startup by yearend 2019.

Aramco said it also is exploring opportunities to improve environmental performance at Fadhili, which could include future construction of new plants for recovery helium and carbon dioxide. OGJ

Tesoro, Par Pacific refineries agree to further reduce emissions

Robert Brelsford
Downstream Technology Editor

Tesoro Corp. and Par Pacific Holdings Inc. have reached an agreement with US regulators under which the companies will spend a combined $425 million to settle past violations of the Clean Air Act (CAA) and reduce future air pollution from six US refineries.

As part of the agreement, the firms have agreed to invest $403 million to install and operate advanced pollution control equipment and technologies at refineries in Alaska, California, Hawaii, North Dakota, Utah, and Washington to protect surrounding communities from further toxic air emissions from those operations, the US Environmental Protection Agency and the US Department of Justice said.

Lodged in US District Court for the Western District of Texas, the July 18 consent decree requires Tesoro to pay all applicable fines and penalties agreement, including a total civil penalty of $10.45 million divisible among federal and state governments to resolve a range of alleged CAA violations occurring at the refineries, all six of which belonged to Tesoro prior to Par Pacific's purchase of the Kapolei, Ha., refinery in 2013 (OGJ Online, Sept. 27, 2013).

In addition to the civil penalty, the agreement stipulates that Tesoro must invest $12.2 million to improve public health in communities previously impacted by pollution from operations via three environmental projects, including:

- Installation of infrared gas-imagining cameras at its refineries in Anacortes, Wash.; Kenai, Alas.; Mandan, ND; and Salt Lake City, Utah, that will be used to locate fugitive emissions of volatile organic compounds (VOC) to plan for and execute corrective actions to address emissions ($400,000).
- Installation and subsequent performance testing of ultralownitrogen oxide (NO_x) burners on the ultraformer furnace at its Salt Lake City refinery to establish a NO_x limit for this unit, which will be used to reduce NO_x emissions from the unit by about 11 tonnes/year ($10.8 million).
- Contribution of funds to a school district in Contra

Costa County, Calif., that will enable replacing a minimum of four diesel-fueled school buses with new compressed natural gas buses to help decrease emissions of NO_x, sulfur dioxide (SO_2), particulate matter (PM), greenhouse gases (GHG), and other air pollutants ($1 million).

Alongside reducing GHG emissions from flaring at the refineries by more than 60% from current levels, the government agencies said they expect new controls and requirements under the consent decree, once fully implemented, will reduce the facilities' emissions of pollutants as follows: NO_x by 407 tpy; SO_2 by 773 tpy; VOCs by 1,140 tpy; hazardous air pollutants by 27 tpy; hydrogen sulfides (H_2S) by 20 tpy; and GHGs (as CO_2 equivalent) by 47,034 tpy.

Par Pacific, which currently is executing routine maintenance at the Kapolei refinery, has expanded the scope of its scheduled turnaround to undertake additional capital improvements aimed at advancing the plant's compliance with requirements of the consent decree. The expanded turnaround is to include: improvements to reduce emissions of air pollutants, improvements to provide for certain NO_x and SO_2-emission controls and monitoring, and installation of certain leak detection-and-repair equipment.

In addition to work related to installation and improvement of flare-gas recovery and enhanced leak detection-and-repair systems at all six refineries, the agreement requires Tesoro and Par Pacific operating units to comply with refinery-specific mandates, a selection of which follows:

Tesoro Alaska Co. LLC's Kenai refinery: upgrade of H_2S or total-sulfur continuous monitoring system for main refinery flare and refinery fuel gas systems; installation of one or more aboveground storage tank(s) sufficient to replace the capacity of the API canals; reporting of each acid-gas flaring event with information related to the event, including its cause as well as available measures to reduce likelihood of its recurrence; and installation of an ambient SO_2 monitoring system as well as continuous measurement and reporting of ambient SO_2 concentrations in the event three acid-gas flaring events occur within any 12-month period.

TRMC's Martinez, Calif., refinery: at the fluid catalytic cracking unit (FCCU), final NO_x emission limits of 40 ppm on a 7-day rolling average basis and 20 ppm on a 365-day rolling average basis; a CO-emission limit of 180 ppm on a 365-day rolling average basis; and NO_x continuous emissions monitoring systems on stack to demonstrated compliance with NO_x limits; at the delayed coker, a drum-depressurization standard of 2 psig and quench-cycle requirements, including restrictions on quench-water quality and feed as well as quench-water fill time of at least 5 hr/cycle, to control VOCs and other pollutants; at the delayed coker, at least 30-ft walls surrounding the coke pit to control PM; at the sulfuric acid plant (SAP), SO_2-emission limits of 1.85 lb/tonne of sulfuric acid produced on a 3-hr rolling average basis and 1.7 lb/tonne produced on a 365-day rolling average basis, as well as implementation of monitoring and operation-and-maintenance plans; and at the sulfur recovery plant (SRU), optional routing of sulfur-pit emissions from SRU to SAP, subject to SAP limits.

Par Hawaii Refining LLC's Kapolei refinery: on 11 heaters and boilers, implementation of NO_x limits along with either ultralow-NO_x burners or flue gas recirculation; for all heaters and boilers, restriction of fuel oil burning in combustion units to control SO_2; installation of NO_x continuous emissions monitoring systems; upgrading or replacement of H_2S continuous monitoring systems; and implementation of an operation-and-maintenance plan for the systems; and at the SRU, SO_2-emission limit of 180 ppm on a 365-day rolling basis; implementation of SO_2 continuous emissions monitoring systems; and implementation of an operation-and-maintenance plan for those systems.

TRMC's Mandan refinery: at the FCCU, execution of annual PM stack testing at the unit; development of a comprehensive continuous monitoring system operation-and-maintenance plan that is designed to enhance the per-formance of system components, improve system accuracy and stability, and minimize periods of system downtime; and execution of a continuous monitoring system root-cause failure analysis as well as development of a downtime corrective-action plan for any continuous monitoring system having a downtime of more than 5% of the total time for each of two consecutive calendar quarters.

TRMC's Salt Lake City refinery: at the FCCU, installation of a nonregenerative wet-gas scrubber as well as either a LoTOx system or equivalent-NO_x control technology on the unit; at the FCCU, NO_x-emission limits of 20 ppm on a 7-day rolling average basis and 10 ppm on a 365-day rolling average basis; SO_2-emission limits of 18 ppm on a 7-day rolling average basis and 10 ppm on a 365-day rolling average basis; and CO-emission limits of 500 ppm on a 1-hr block average and 100 ppm on a 365-day rolling average; and at the FCCU, installation of NO_x, SO_2, and CO continuous emissions monitoring systems to demonstrate compliance. OGJ

OGJ's 2016 Worldwide Refining Survey

Forms for the 2016 edition of OGJ's annual Worldwide Refining Survey were sent to respondents via e-mail during the first 2 weeks of August. Completed survey forms must be returned by Oct. 1, 2016, to guarantee inclusion of respondents' data in this year's published survey, which will be available for download by OGJ subscribers on Dec. 5, 2016. For past and new respondents, if you have not received the annual survey package and feel this has occurred in error, please contact Robert Brelsford, OGJ Downstream Technology Editor, at rbrelsford@ogjonline.com or (713) 963-6232.

Norway remains active, UK seeks change

Tayvis Dunnahoe
Exploration Editor

SPECIAL REPORT

EXPLORATION & DEVELOPMENT

Like most offshore regions, the North Sea is experiencing a temporary slowdown in exploration and development (E&D). Predominant activities in the near term include development drilling and some minor seismic work. While Norway's production has remained relatively stable, output from the UK Continental Shelf (UKCS) has continued to decline.

Although E&D opportunities remain offshore Europe, low oil prices are testing the industry's resilience. The North Sea's status as a mature basin draws operators wanting to take advantage of the certainty in developing discoveries near existing fields and infrastructure. Limited profitability and the lack of investment in the region, however, are leading operators to venture outside such areas to test regions with more viable development potential.

Offshore activity in Europe remains concentrated in Norway and the UK. But as drilling has slowed in the last few years, no major discoveries have occurred in the North Sea. Smaller countries in northwest Europe, such as Ireland and the Netherlands, are maintaining their assets during the down cycle, but it is likely that major exploration programs will remain deferred until the industry realizes stable, higher prices for oil and natural gas. In the Mediterranean, Greece and Cyprus have giant offshore gas deposits with future E&D potential. But given current pricing, operators have postponed these developments until further notice.

According to analyst Ben Wilby of Douglas Westwood, shorter term activity in the region is moving forward as operators follow through on commitments, but this may not be an indication that the market has improved. "Offshore Europe will look busy, but in practice, most of the current activity was ordered before the price decline," he told OGJ.

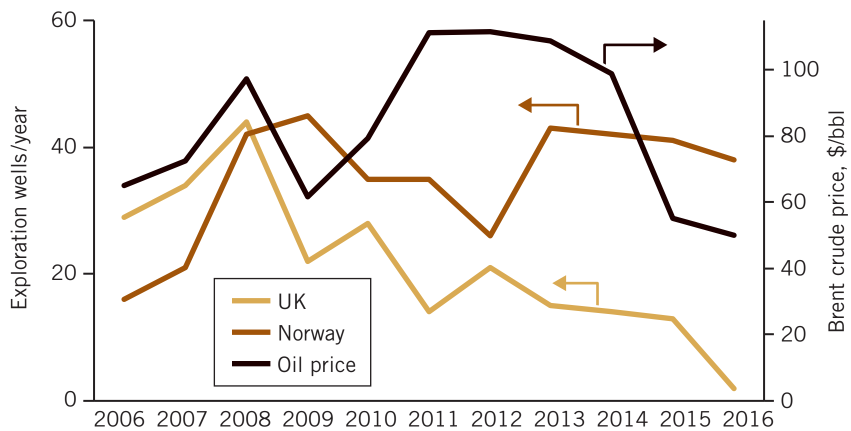
Norway

In 2013 global exploration yielded 142 discoveries. The number of discoveries dwindled to 62 in 2015, of which 15 were offshore Europe and most were small deposits discovered in Norway near existing fields. "Norway's existing fields and infrastructure makes this region better suited for development drilling than elsewhere offshore Europe," Wilby said. "Companies have moved to where they know they can find success."

Norway's offshore activity will remain stable, but discoveries are often small. "The average discovery size in the Norwegian North Sea from 2011-15 was just 34 MMboe," Ed Shires, senior consultant with London-based consulting firm StrategicFit, told OGJ. "In the 5 years before this (2006-10), the average was 145 MMboe," he added. This number includes the 1.9 bil-

EXPLORATION WELLS SPUDDED IN UK, NORWAY

FIG. 1



*Data for 2016 are estimates based on spudded wells through June 2016.
Source: StrategicFit, NPD, UK Oil & Gas data

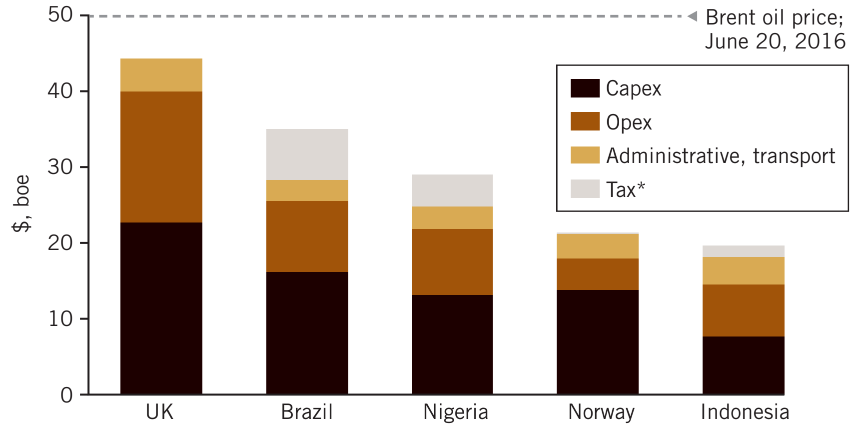
lion boe Johan Sverdrup field (OGJ Online, June 6, 2016). Excluding this discovery, the average was 50 MMboe/field.

Operators have spudded 18 exploration wells offshore Norway so far in 2016. "If this rate carries into the second half of the year, this will be in line with trend," said Chris Jones, senior consultant with StrategicFit. Since 2008, with the exception of 2012, Norway has seen 35-45 wells spudded each year (Fig. 1).

The Northern North Sea (Quads 31, 32, 34, and 35) has been the most active area on the Norwegian shelf with 12 of the 18 wells drilled this year (OGJ Online, June 10, 2016). "This is a relatively mature area in easy reach of infrastructure at the Oseberg, Troll, and Gjoa fields," Shires said.

AVERAGE PRODUCTION COST/BBL

FIG. 2



*Tax shown is tax directly impacting cost of production. Taxes on profits may indicate a higher breakeven for some projects.
Source: Wall Street Journal, StrategicFit

In Norway, the tax system is set up so that companies only pay 22% of their exploration costs. The rest is refunded by the state. This, along with greater yet-to-find volumes, makes exploration in Norway more attractive than other regions, including the UK.

Norway suffers from high capital costs. But some newer and larger fields, along with numerous subsea installations, will make operating costs more competitive over time.

Norway sometimes struggles to attract exploration investment when companies compare the country to other regions, according to Shires. Operators often evaluate opportunities on a pretax basis. Norwegian opportunities become favorable only after factoring in the exploration tax rebate: finding costs were $8/boe pretax, $1.7/boe after tax (2011-15). "When considering developments, the tax drag on full-cycle returns may still reduce the region's attractiveness," Shires said.

Meanwhile, "frontier drilling has dropped off the map completely," Wilby said. Development may lag in the Barents Sea Arctic region as economic success requires a stable oil price of $80/bbl. Long lead-times (10+ years) for Barents Sea Arctic projects will likely allow companies to benefit from the evenatual price recovery.

The recent 23rd Licensing Round in the Norwegian Barents Sea showed frontier opportunities are attracting interest despite low oil prices. The Norwegian Barents Sea produced four of the five largest discoveries in Norway during 2011-15. There were four firm wells committed in the newly offered acreage in the East Barents (on the Russian Border), despite high commerciality thresholds of 0.5 billion boe of oil or 6 tcf of gas.

"Some explorers are taking a long-term mindset, and are looking to find large discoveries in relatively undeveloped areas of Europe despite no quick commercialization pathway," Jones said. The companies who were awarded licenses in the region are experienced Barents Sea operators (Statoil ASA, Det norske oljeselskap AS, Lundin Petroleum AB) and supermajors (ConocoPhillips, Chevron Corp.).

"It is not yet clear if any of these discoveries are large enough to warrant new infrastructure," Shires said, referring to four of the five largest discoveries in the region. The Johan Castberg discovery (0.6 billion boe) is subject to delays and development remains uncertain (OGJ Online, Mar. 6, 2015).

"Projects are not being sanctioned now, leading to a decline in spend in the last few years of the decade," Wilby said, but 2019 could see an increase in newly sanctioned projects. Aasta Hansteen, Europe's first spar platform, is one of the largest projects headed for first production in the near term. But this development was committed to before oil price fell.

Statoil in August 2015 completed construction of the 482-km Polarled pipeline to connect to Aasta Hansteen (OGJ Online, Aug. 21, 2015). The operator cancelled its contract in May 2016 for Seadrill Ltd.'s West Hercules semisubmersible drilling rig, which was scheduled to begin drilling on the Aasta Hansteen license in 2017 (OGJ Online, May 23, 2016). Statoil has pushed Aasta Hansteen's start up to first-half 2018.

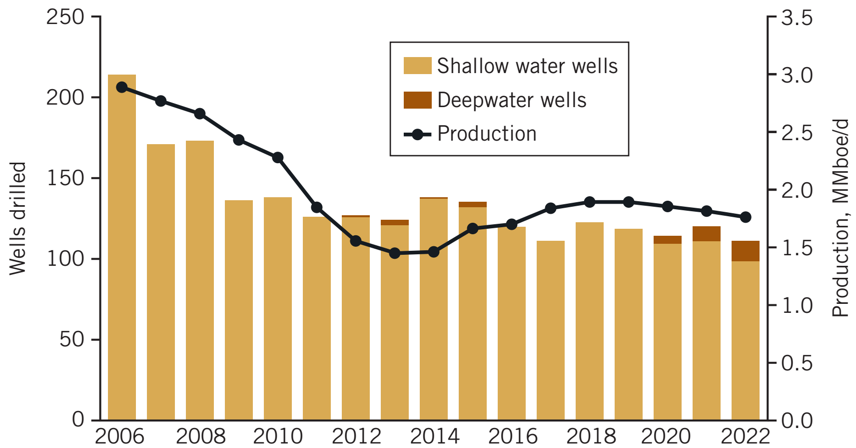
Norway's economy has been hit hard as oil provides 22% of the country's GDP and 67% of its exports. "The price drop is having a bigger impact than the 2008 financial crisis," Shires said.

UK

The oil and gas industry in the UK is struggling to remain competitive. High operating costs, aging infrastructure, and a lack of recent discoveries contribute to the region's problems. Only one exploration well has spudded in the UK in 2016 (Fig. 1). "Exploration drilling in the UK has not recov-

UK DRILLING, PRODUCTION

FIG. 3



Source: Douglas-Westwood

ered from the last oil price dip during 2008-09," Shires said. Well spuds fell to 22 in 2009, down from 44 in 2008. Since 2011, well spuds have remained at 15-20 per year. The impact of lower prices was not fully realized in 2015 as the UK saw 13 wells spudded. "These were probably planned and approved before the full price drop, which is now reflected in the lack of drilling in 2016," Shires said.

The UK North Sea decline is not a new problem. ConocoPhillips drilled 10 UK exploration wells in 2006 and a single well in 2011. Shires attributed this to the company's strategy of focusing on its onshore operations in other regions. Total viewed the UK as a high growth area in 2011-12, but its high risk exploration strategy was unsuccessful. "Now only one of more than 30 of Total's high impact wells (2016-18) is in the UK," Shires said.

Producing oil and gas in the UK comes at a higher cost per barrel than in other offshore regions (Fig. 2). Operating costs are driven by aging infrastructure with low throughput and capital costs are compounded by high labor and engineering costs combined with typically small fields.

Operators historically have worked to extend the life of offshore fields in the UK. Redevelopment continues to be an option but maintenance costs, new recovery techniques, and upgrades can become expensive. Operators in the UK may shut in production below $50/bbl. "Rig rates are cheaper now, and infill drilling may be advantageous for some UK fields," Wilby said.

According to IHS's Upstream Capital Cost Index, global cost base fell 21% between the fourth quarters of 2014 and 2015. Rig rates for northwest Europe jack ups are down to $100,000/day from the mid-2014 high of $175,000/day. "These effects will be felt globally so northwest Europe may remain comaparitively expensive," Shires said.

Some UK projects are moving ahead. EnQuest PLC expects first production from its Kraken fields in first-half 2017. The development includes a floating production, storage, and offloading vessel with 25 development wells (OGJ Online, Feb. 22, 2016).

Capital constraints will continue to affect new development as part of UK North Sea operations. "Less than $1 billion of new capital is expected to be committed in the UK in 2016," Shires estimated. The $8 billion/year average since 2011 shows the extent to which projects are now being deferred.

In Norway, third-party access to infrastructure is guided by commercial negotiation, with voluntary practices and an ability to refer disputes to the secretary of state. This is not the case in the UK, which makes it difficult for companies to agree on commercial terms. The establishment of UK's Oil and Gas Authority (OGA) may foster more collaboration, which will be required to sustain the country's offshore industry.

The UK changed its fiscal regime in the wake of the price decline. "The Petroleum Revenue Tax for pre-1993 fields, which was 50% at the start of 2015, has been effectively abolished," Shires said. Additionally, the supplementary charge companies pay above corporation tax has been cut to 10% from 32%.

"The impact of these tax changes is questionable, given the tax is levied on profits," Shires said. Only three companies operating in the UK were profitable in 2015. Companies also have losses to offset future profit, which will defer tax payments once profitability returns. The benefits of the UK's new tax regime will not be felt in the near term. "Norway's effective exploration rebate has been more effective in sustaining drilling," Shires said.

By contrast, where the price decline has negatively impacted Norway's economy, the UK's economy is expected to benefit from "lower-for-longer" oil prices, which will lower the cost base for other industries.

Development vs. decommissioning

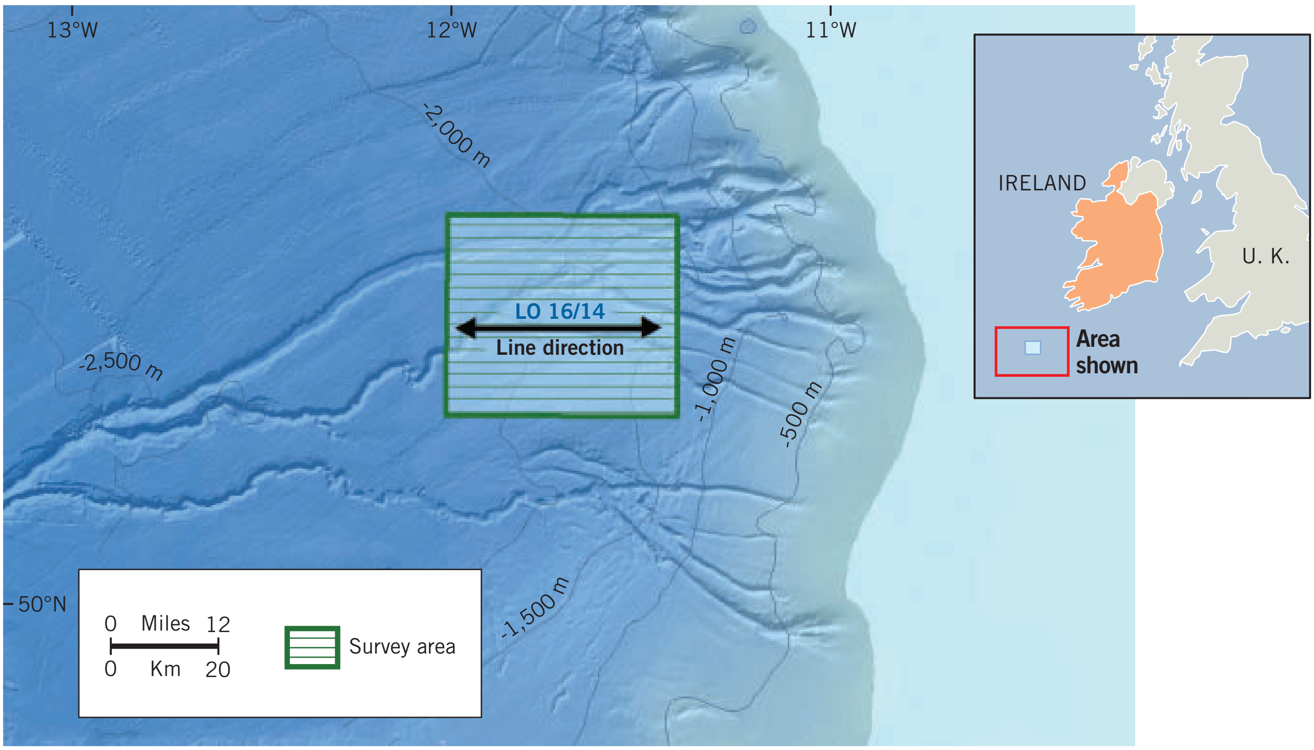
For aging assets in the UK and Norway, lower oil prices are forcing operators to decide whether to redevelop mature fields or shut in current production in preparation for decommissioning (Fig. 3).

"The UK dominates in fixed platforms with around 300 of these assets compared to Norway, which has around 100," Wilby said. "UK production is mature and companies are not producing the same amounts of oil and gas they were 10 years ago," he added.

The UK is expected to be the first major petroleum province to see widespread decommissioning. "Five fields have already been announced to cease production in 2016," Shires

PROPOSED GRANUAILE SEISMIC SURVEY

FIG. 4



Source: Irish Offshore Operators' Association

said. More than 140 fields could follow in the next 5 years if prices remain low and cause older fields to become uneconomic.

"The UK will need to strengthen its parameters on decommissioning to avoid additional expense as this trend continues," Wilby said. The country currently offers a 50% rebate on decommissioning. A ramp up in decommissioning to 2020 could further burden the UK tax base. "Now is the time to decommission," Wilby said.

Decommissioning initially costs more than maintaining a facility, but it's a onetime expense. If the price for oil remains low for an extended period of time, maintenance and overhead could override the lump sum attributed to decommissioning.

Development continues in Norway and decommissioning may not occur to the same extent as in the UK.

Turning around

PricewaterhouseCoopers LLP (PwC) surveyed leading executives and academics associated with the North Sea's offshore oil and gas industry in its report "A Sea Change: The Future of the North Sea Oil & Gas," which was released June 2016.

Respondents agreed that the window of opportunity to transform North Sea business is slowly closing. Alison Baker, leader of PwC's UK and EMEA (Europe, Middle East, and Africa) oil and gas team, said, "The North Sea is one of the oldest producing basins in the world and has contributed to the European economy for more than 50 years." Companies must determine how, or if, they will work together as they either decommission or maintain aging infrastructure and move forward with further extraction while competing for capital with lower-cost basins having greater returns.

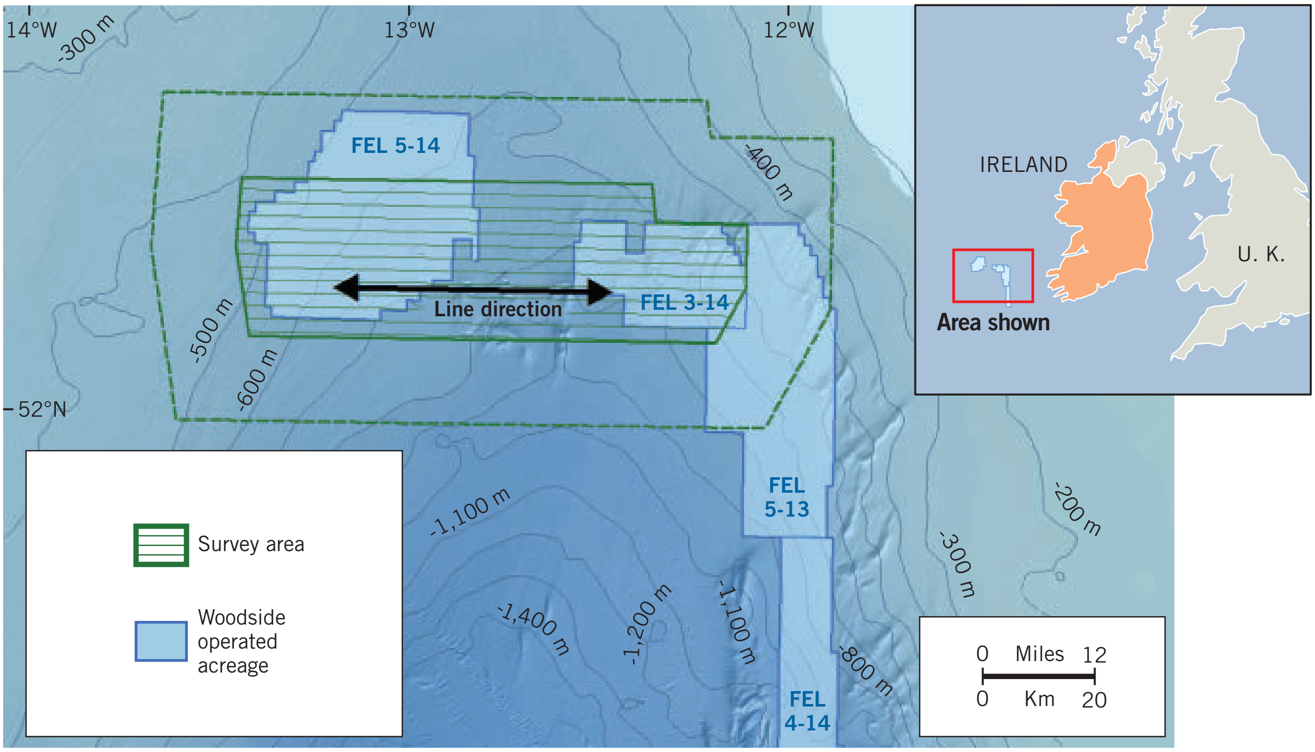
"Norway is a different play, and participants were more optimistic, as opportunities exist in this region," Baker said. The South and Central North Sea are the regions losing momentum in the current downturn. In reference to the window of opportunity, Baker said, "The impetus is on the speed at which the industry transforms. Collaboration needs to occur more often and more quickly."

The major concerns from the UK perspective, according to the respondents in the Sea Change report, are access to capital and getting costs under control, including improved technology and innovation. "The UK has produced 42 billion bbl of oil, and there are some 20-30 billion boe of undiscovered resources," Baker said. Opportunities exist, but financing has become constrained. For UK exploration, equity financing "dried up around 5 years ago," she added.

The concept of "super joint venture (JV)" was introduced by several respondents in the report. "The concept relies on looking at other basins and industries where operating models were reinvented through crisis," Baker said. Cost sharing, improved

PROPOSED BREANANN SEISMIC SURVEY

FIG. 5



Source: Irish Offshore Operators' Association

supply chains, and sustaining access to infrastructure are key objectives of the concept.

UK operators and field partners must carry the full cost of servicing or decommissioning. A super JV could develop cost-sharing mechanisms to maintain current production assets in exchange for future access.

"We believe the UK represents an opportunity to build a new model for commissioning the final cycle in a mature basin," Baker said. Finding new methods of collaboration can transfer knowledge to other basins. "Tried and tested ways of working together in the final phase of UK North Sea development will provide a model for other regions in the future," she added.

The recent Brexit referendum has added a layer of uncertainty to UK North Sea operations given the oil and gas industry's global nature, raising confidence in the UK economy to the fore (OGJ Online, June 27, 2016). According to Baker, "The industry has remained resilient and wants to work together to maintain it's activities in the UK."

Opportunities, outcomes

The offshore industry across Europe is struggling in the current down-cycle. The UK sector has lost more than 100,000 jobs. Job loss is at 40,000 in Norway (OGJ Online, June 20, 2016). Despite the increased demand for natural gas in Europe, both oil and gas projects are struggling. Operators are generally exploring for oil over gas, and in frontier regions such as the Barents Sea and West of Shetland, initial infrastructure for gas is cost prohibitive. "All but the biggest projects are uneconomic," Shires said.

Despite the situation in the UK North Sea, frontier basins in other portions of the European Continental Shelf are generating interest.

Frontier drilling is down in the near term as companies cut back costs, but many operators see frontier regions as a source of material discoveries in northwest Europe. As a result, offshore acreage is being picked in areas like the Barents Sea and Ireland as interest in exploration remains high among companies with capital to invest.

The 2015 Atlantic Margin licensing round had the highest number of applications for any Irish offshore round (43) and 28 new licenses were awarded. The offer of awards involved 11 companies: AzEire Petroleum Ltd., Capricorn Ireland Ltd., Europa Oil & Gas (Holdings) PLC, Faroe Petroleum Ltd., Petrel Resources PLC, Predator Oil & Gas, Providence Resources, Ratio Petroleum, and Scotia Oil & Gas Exploration Ltd., as operators, along with Theseus, which will partner with Predator, and Sosina Exploration Ltd. which will partner with Providence.

The first half of this round, announced February 2016, included Woodside Energy (Ireland) Pty. Ltd (OGJ Online, Feb. 15, 2016). The operator began seismic work on its Gran-

Statoil's expansion plans for the Snorre field in the Norwegian North Sea have been reengineered. The operator originally planned to add a production platform , but earlier this year let a contract to Wood Group for a subsea development plan that will cost 30-40% less than the additional platform. (Fig. 6). Photograph from Harald Pettersen, Statoil ASA.

uaile prospect (Petroleum Production License (PPL) No. 2/16) with the Ramford Vanguard (Fig. 4). The vessel was expected to shoot 1,600 sq km of 3D seismic through late June. An additional seismic shoot is slated for Woodside's Breanann prospect, the Ramford Vanguard scheduled to acquire 2,400 sq km of 3D seismic over Frontier Exploration Licenses (FEL) 3/14 and 5/14 (Fig. 5). Weather permitting, the acquisition is expected to be completed in late August 2016. The blocks are in the Porcupine basin 150 km off the west coast of Ireland.

No exploration wells have been committed, but the attraction to Ireland's 2015 round indicates that commitments may be on the horizon. Operators have drilled 159 exploration and appraisal wells offshore Ireland since 1970. There have been four commercial gas discoveries and 11 oil and gas condensate discoveries. None of the latter discoveries have led to commercial development.

In the UK, more than 4,000 wells have been drilled, resulting in more than 350 producing oil and gas fields. In Norway, more than 1,200 wells have been drilled. The contrast highlights the underexplored territory offshore Ireland.

The deepwater West of Shetland and North Sea high pressure, high temperature (HPHT) plays present additional opportunities. But the HPHT environment increases exploration costs. "This area could present a counter cyclical opportunity," Shires said, "but this would require a unique risk-appetite and access to capital."

The need for such an appetite is highlighted by the reality that exploration budgets have shrunk. "A number of exploration managers believe the HPHT play has great petroleum potential, and many operators would have liked to explore there," Shires said. Despite falling rig rates, however, most operators cannot justify this play's well costs.

One benefit of this down cycle and the onslaught of deferred offshore projects is the closer attention operators have paid to spending. Costs tend to sky rocket in a stable oil price environment and by early 2014 were too high for development once the price declined.

"Companies are now looking at standardization as a means of lowering costs," Wilby said. In addition to standardization, the lull in offshore activity has given operators and service contractors opportunities to revisit newer production designs and reengineer projects within current cost constraints.

The most recent example of this is Statoil's Snorre field (Fig. 6). In 2013, the operator ordered an additional tension leg platform (TLP) to increase recovery from the field (OGJ Online, Oct. 28, 2013). After the price shock of mid-2014, the TLP field expansion became uneconomic and earlier this year was scrapped and exchanged for a subsea development plan (OGJ Online, Apr. 25, 2016). The change is expected to save 30-40% and boost recovery from Snorre field to 2040.

Lack of investment in North Sea infrastructure and near-field exploration now could lead to lost opportunities in the future. Hubs and pipelines may become uneconomic before surrounding prospects have been exploited. "This is especially so in the UK, where much of the infrastructure is interlinked," Shires said. "A 'domino effect' might occur where production ceases on one field forcing others further down the infrastructure chain into early abandonment."

Near-term operation

The current downturn has led to returns of offshore licenses, globally. Asset swaps are becoming more common as larger companies look to rationalize their portfolios and reduce European assets. Many small- to mid-sized companies will enter the offshore market in Europe in the next few years.

The region benefits from active regulators and regularly occurring license rounds, which provide frequent opportunities for organic growth. "License commitments are followed up, which churns viable exploration acreage and avoids dormancy," Shires said.

UK's OGA is working to ensure maximum recovery from it's offshore areas. But the country stands as the most critical area in the current price climate. Decommissioning will ramp up in the near term, but further collaboration among UK operators and an improved regulatory system could sustain its longer-term offshore market. OGJ

Integrity management improves long-term profitability in aging assets

Tom Nolan
Gareth Burton
ABS Group of Companies Inc.
Houston

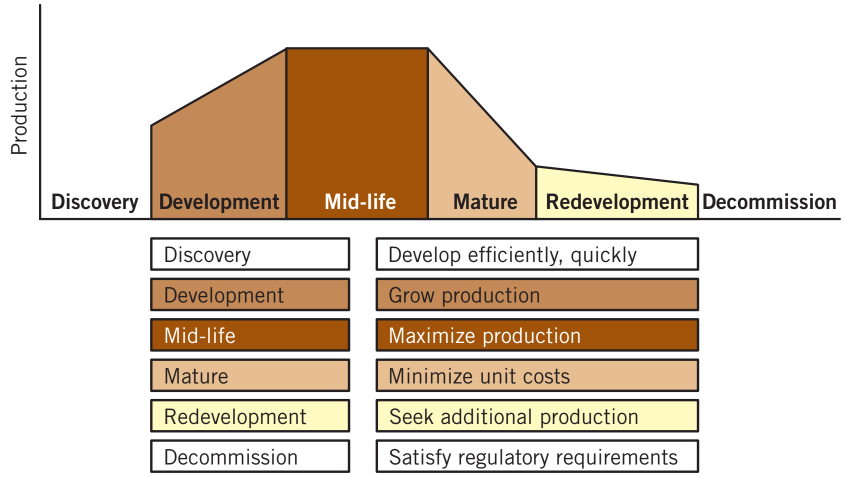
As offshore production facilities near the end of their design-lives, operators often increase focus on maintaining asset integrity. Some mature fields could deliver additional resources with more efficient production assets, but achieving this goal can be problematic without an asset integrity management (AIM) program. An operator at some point must decide either to extend the life of an asset or decommission it (Fig. 1).

Maintaining structural, mechanical, and control systems integrity effectively can drive production gains in aging assets and maturing fields.

Wood Mackenzie Ltd. has reported that, given the current oil price, 142 fields will cease production by 2020. With a continued low-price environment, an additional 50 fields could discontinue production earlier than originally planned. Fig. 2 shows the UK's dominance in offshore North Sea installations. Statistics from the UK Department of Energy & Climate Change show cessation of production (COP) declarations in the North Sea peaking in 2020 and declining with periodic rallies through 2040 (Fig. 3). Assets that discontinue production will need

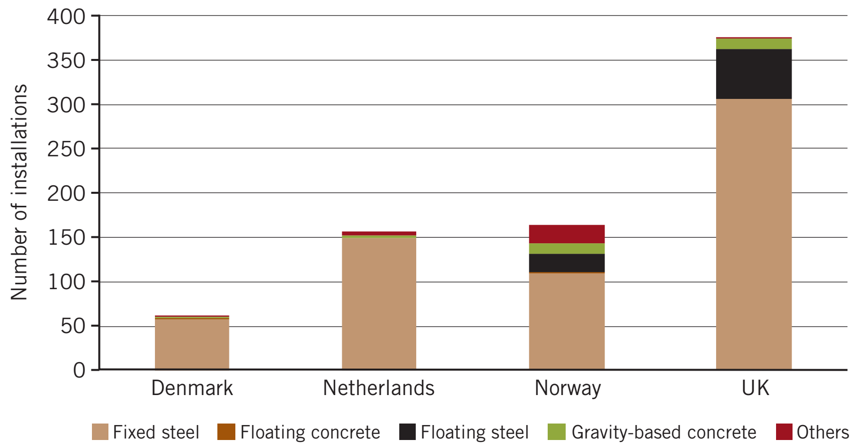
LIFE-CYCLE PHASES, OPERATIONS FACTORS

FIG. 1



NORTH SEA OFFSHORE INSTALLATIONS

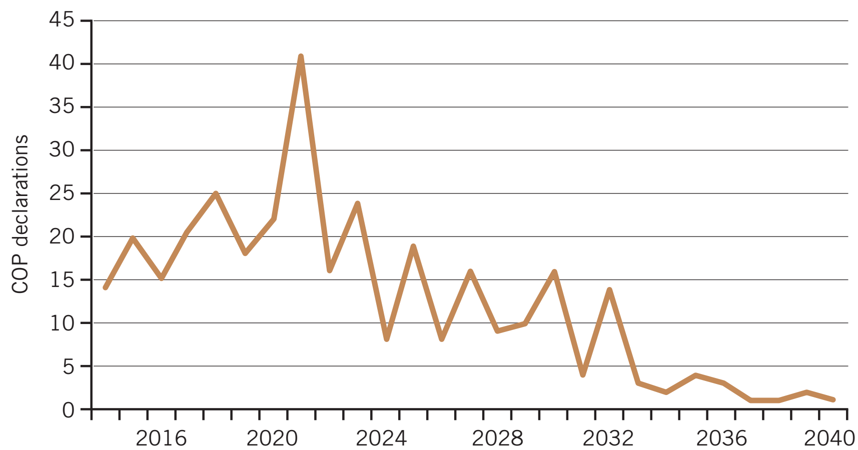
FIG. 2



Source: Inventory of Offshore Installations, OSPAR Commission

NORTH SEA PRODUCTION CESSATION

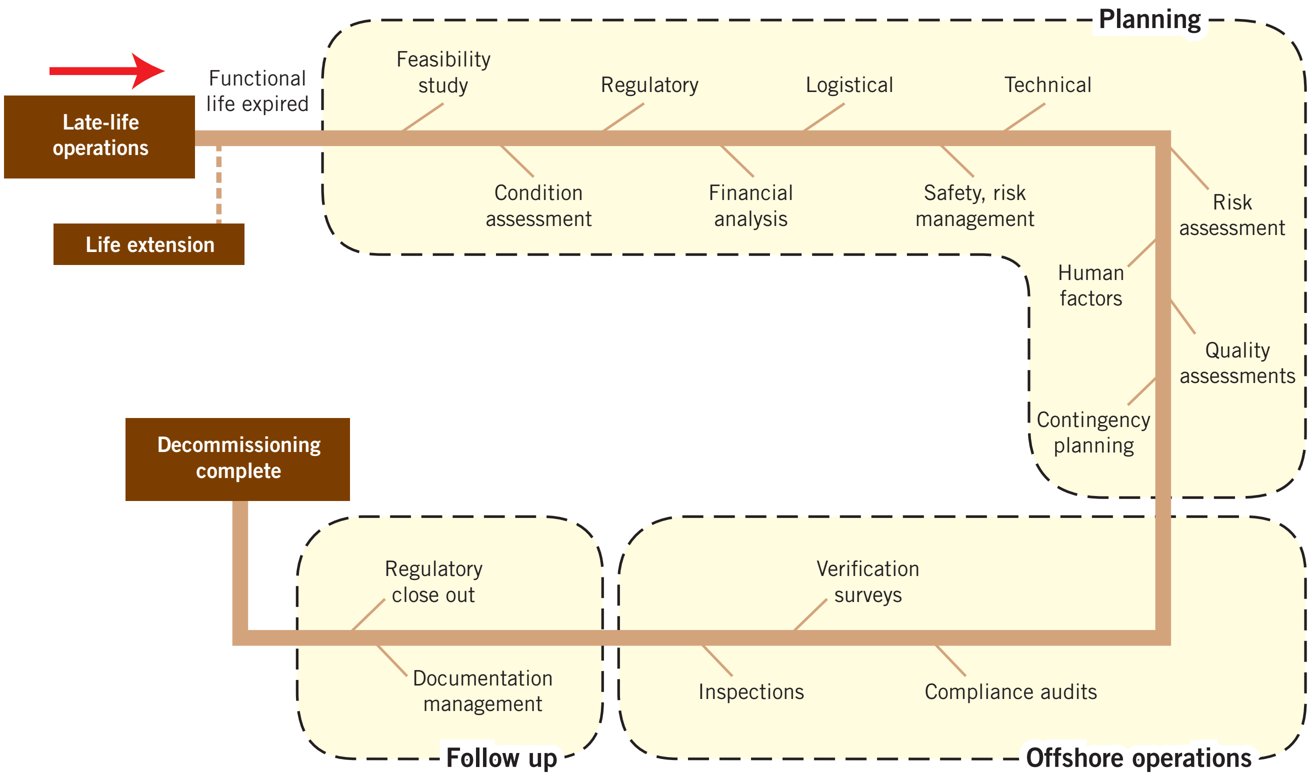
FIG. 3



UK Dept. of Energy & Climate Change; 2015

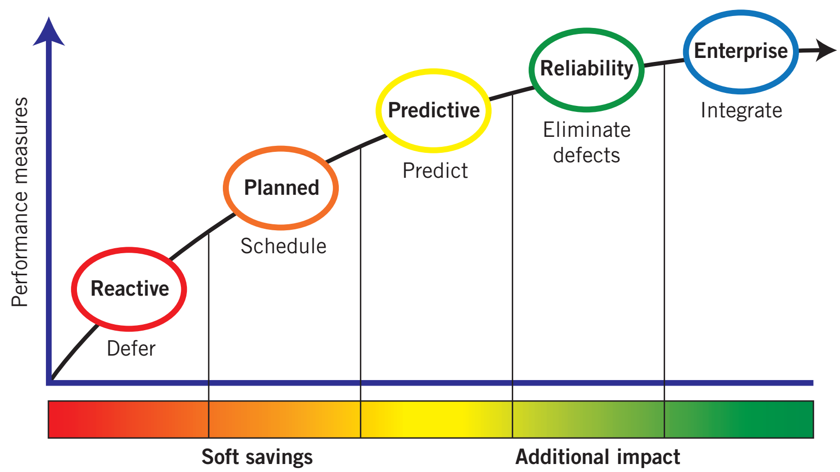
LATE-LIFE, DECOMMISSIONING PHASES

FIG. 4



AIM METHODOLOGY

FIG. 5



to be managed carefully through the end of their productive life cycles.

Engineering assessment

An asset management plan should be aligned with classification-society surveys. Inspections, engineering assessments, class, and regulatory work must be planned and executed according to a predetermined timeline.

A successful approach considers end-of-life maintenance as part of the complete asset life cycle and focuses on delivering safe, responsible, and compliant operations in a reliable, efficient, and cost-effective way (Fig. 4).

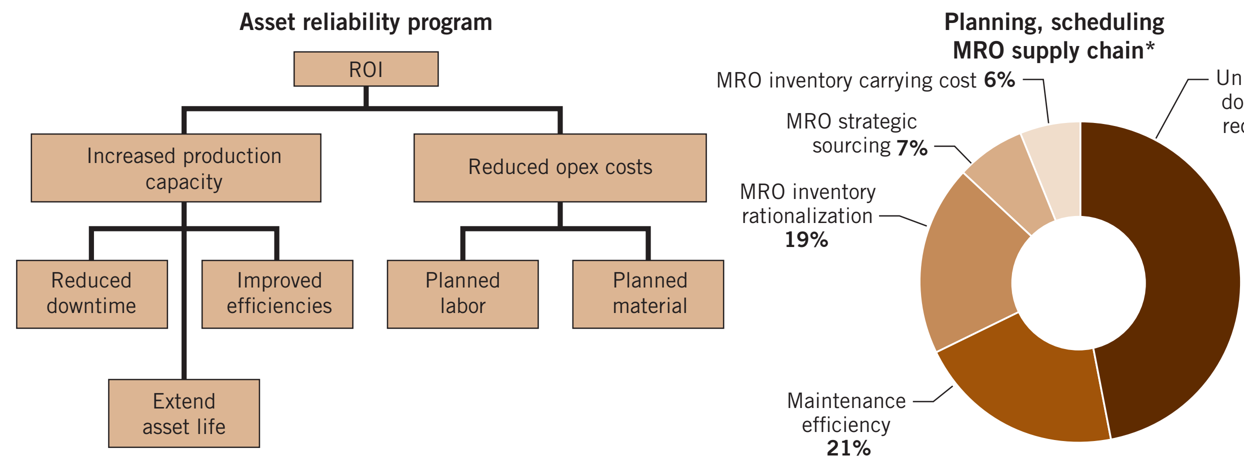
An integrated AIM solution in conjunction with risk-based inspection (RBI) can help decrease cost, prevent nonproductive time (NPT), and increase efficiency over the remaining or extended service life of the asset (Fig. 5).

Risk factors, failure modes

RBI focuses on failure modes initiated by material deterioration and their consequences. The process is controlled primarily through equipment and structure inspection in conjunction with reliability analysis. The methodology combines criticality, risk assessment, and risk management techniques with inspection activities—such as planning, documentation, and data analysis, in addition to inspection itself—to develop plans that focus on areas of highest risk. RBI can be applied to all types of material deterioration that can cause loss of integrity for pressure-retaining equipment and structural components.

ROI BREAKDOWN

FIG. 6



*MRO = maintenance, repair, and operations. Percentages represent breakdown of the total cost savings.

Identifying and managing risk factors that impact the safety, environmental integrity, and reliability of complex offshore assets is critical to avoiding NPT. Experience has shown that adopting a systematic, risk-based approach to inspecting structures, machinery, equipment, and control systems allows for more effective management of the risks encountered offshore.

Managing these risks includes assessing the integrity framework of the asset, benchmarking its integrity maturity relative to industry peers, identifying areas for improvement, developing improvement programs, and providing technical support during implementation. For units with a longer remaining field life, AIM programs also can improve profitability (Fig. 6).

Life extension

Operators should consider service-life extension well before the field approaches the end of its life cycle. The process is dependent on available records, such as asset condition assessments and historic field data and maintenance records. It can take years to compile the original design criteria documents, planning and inspection reports, engineering assessments, and the appropriate technical specifications and regulatory approvals that are used as a baseline for evaluating remaining life.

With all of the documents in hand, operators can develop an upgrade or mitigation plan along with an in-service inspection plan that includes any corrective actions needed.

Managing asset integrity

In a recent application of the AIM program, engineers worked with an operator contending with frequently overloaded maintenance backlogs for its FPSO fleet. As in any maintenance operation, the goal was to minimize downtime and carry out the necessary work as safely as possible within the parameters of applicable regulations.

After identifying each piece of equipment to create a master asset list and carefully evaluating each system and subsystem, the engineers developed a comprehensive asset criticality ranking to identify specific maintenance approaches for each asset based on operational and safety criteria.

Applying a risk-based approach, engineers defined the extent and frequency of maintenance needed for each piece of equipment and implemented a preventive-predictive maintenance program to form a complete mechanical integrity plan. The specific needs of each critical component, including its usage and exposure to wear, drove the recommendations.

The process included a review of the client's computerized maintenance management system (CMMS) data and the development of a plan for prioritizing concerns. The engineering team then implemented new maintenance schemes and updated the process flow in the CMMS to manage ongoing scheduling and maintenance frequency.

Identifying the specific equipment maintenance needs and eliminating unnecessary or overscheduled maintenance resulted in a 40% reduction in the work-order backlog. The operator can now better prioritize and complete critical maintenance projects without interference or duplication of maintenance from standard scheduled maintenance tasks.

In addition to addressing the primary issue of the maintenance backlog, the engineers reviewed and made improvements to more than 20% of the critical system maintenance plans, rationalizing the maintenance process, avoiding excessive downtime, and reducing overall operating costs. OGJ

Data gathering, decommissioning studies

Wood Mackenzie estimates £55 billion will be invested in decommissioning on the UKCS within the next 5 years (OGJ Online, June 6, 2016). Upcoming projects for the region include eight concrete platforms, 21 floating production systems, 225 jackets, 278 subsea production systems, and 3,000 pipelines.

As the UK North Sea enters the final phase of decommissioning, several joint-industry projects have worked to gather data related to health, safety, and environmental (HSE) incidents as well as determining best methods for removing platforms and subsea infrastructure with consideration toward current technology and cost feasibility.

Safetec Nordic AS, an ABS Group company, developed a JIP in 2010 to gather HSE incident data from projects in the North Sea. The JIP brings major operators together to share data and experience to safely and effectively manage future decommissioning operations.

The primary goal is to improve hazard identification for future projects by identifying the main causes of the most common HSE incidents, estimating accident rates for different decommissioning activities, gathering experiences and lessons learned, and proposing appropriate risk-reducing measures.

Event data are recorded in a database available to participating industry partners as well as regulatory bodies HSE (UK) and Norway's Petroleum Safety Authority. The JIP has collected and input hundreds of HSE incidents from North Sea decommissioning activities. The principle aim now is to expand the database by adding new events as they occur so the data can be analyzed to identify continuous safety improvements.

Facilities decommissioning can often be carried out through standardized methods. For the UK, subsea bundles provide an additional engineering consideration for operators seeking to remove subsea pipelines and infrastructure. International Association of Oil and Gas Producers (IOGP) published "Options for Decommissioning Subsea Bundles" in June 2014 to identify technologies, costs, and legislation associated with bundle decommissioning.

Subsea bundles are a complex multipath form of subsea pipeline that have been integrated into a single piece of infrastructure containing all the required flowlines, control systems, and manifold structures needed to tie back a subsea a field to a host facility. Subsea bundles typically range up to 7.5 km in length and 300-1,250 mm in diameter.

Each bundle is individual by design, and the first North Sea bundle was installed in the Murchison field in 1980. More than 70 bundles have been installed since then. The JIP was sponsored by eight North Sea operators, and outlines two primary options: full removal or leaving bundles in place.

According to the study, the UK Department of Energy and Climate Change (DECC) emphasizes that bundle removal be considered on a case-by-case basis. But DECC also calls for new bundle designs to address removal. To date no bundles have been decommissioned in the North Sea or elsewhere. The report states that full removal of a bundle by reverse installation is impractical with current technology and the absence of experience.

Additional cost to recover all bundles installed in the North Sea, compared to leaving them in place could increase North Sea decommissioning estimates to £1.67 billion. IOGP anticipates a bundle decommissioning project within the next 5 years, which will provide a better understanding of the actual costs and technical issues related to future bundle decommissioning projects.

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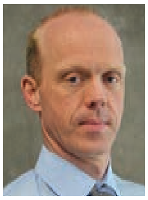

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DRILLING & PRODUCTION

Seismic stimulation advances EOR technology

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Seismic stimulation can arrest oil production decline rates in mature fields. The method has proved effective on diatomite, sandstone, and carbonate reservoirs. It holds promise as an alternative to refracturing in shale plays.

Operators frequently use gas injection, chemical injection, and thermal techniques for enhanced oil recovery (EOR). But these methods, including waterflooding, often prove too costly for smaller fields and ineffective in highly heterogeneous reservoirs.

Seismic stimulation for EOR works best in reservoirs featuring barriers to flow, creating pockets of bypassed oil. The immobile oil droplets are dislodged when downhole elastic waves propagate horizontally and vertically..

Los Alamos Laboratory studies found a pressure change as small as 0.01 psi can move an oil droplet.[1] Shockwaves exit the stimulation tool at a wavefront pressure-amplitude of 3,500 psig. The waves travel at 1.5 miles/sec, reaching distances of 1.5 miles in carbonates and more than 1 mile in sandstones.

Seismic stimulation is unique compared with other EOR methods because the created elastic waves have no barriers, either in the vertical or horizontal plane.

Fault blocks, stratification, and changes in phase do not stop the stimulation as they would conventional, fluid-based EOR methods. A single seismic tool can stimulate large areas of a field that is either highly faulted or contains a series of pay zones.

This article examines how operators have used seismic stimulation for EOR in various settings.

Seismic stimulation

Reports of low-frequency, high-energy elastic waves mobilizing oil first emerged in the early 1950s when earthquakes were shown to increase production by up to 45%. The first manmade low-frequency, high-energy oil mobilization used Russian surface vibroseis stimulation.

Russian researchers discussed cyclic application of elastic waves as yielding optimal results and how application of elastic waves at various frequencies enhanced results.[2-3-4]

A conventional pumping unit powered the tool used in this study, which crews can install in abandoned wells at 700-10,000-ft depths.

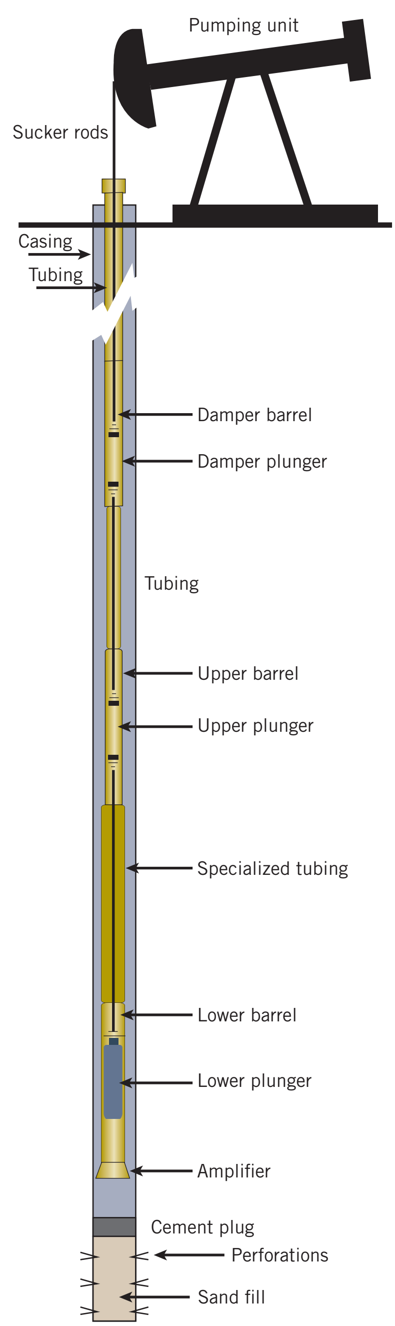
Tool transport occurs in a 1 × 2 × 25-ft container, holding three preassembled sections. Joining the sections on location takes about 2 hr. Tool operation requires no major maintenance.

Fig. 1 shows the tool's components. Sand fill is in the well from its bottom to above perforations. Above the sand fill, a cement plug stops gas from entering the wellbore and tool.

Gas in the tool's compression chamber prevents creation of elastic waves. The tool is installed into the wellbore, connected to the rod string, and then to a pumping unit.

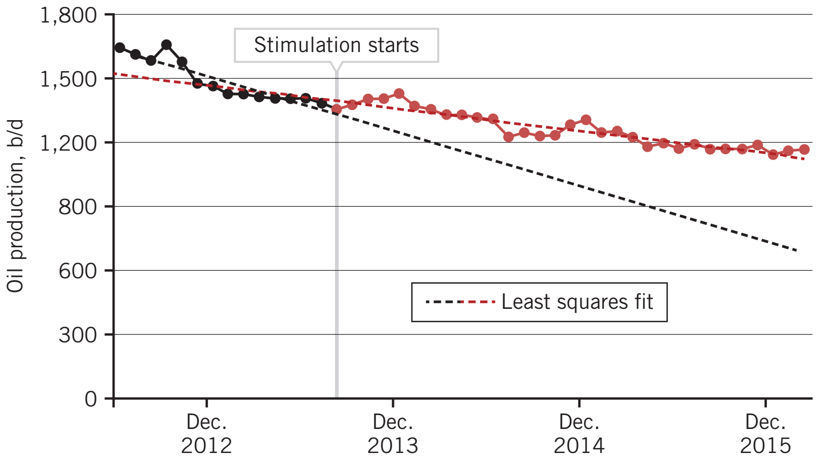
TOOL COMPONENTS

FIG. 1



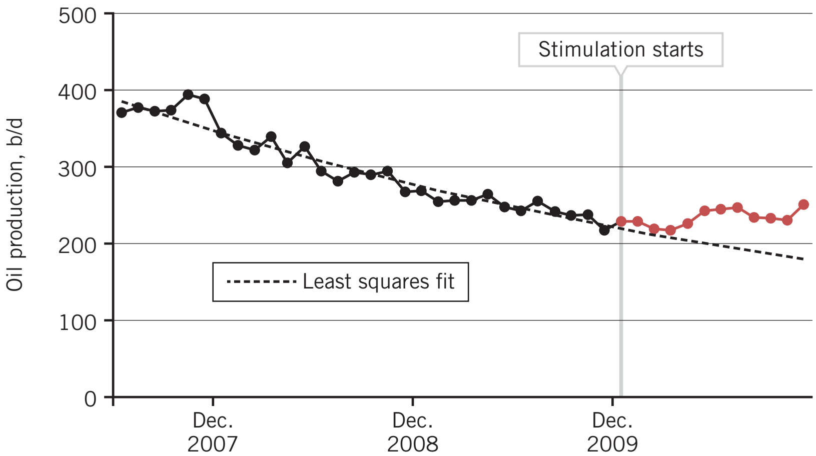
PERMIAN BASIN CARBONATE RESPONSE

FIG. 2



UNCONSOLIDATED SANDSTONES RESPONSE

FIG. 3



The pumping unit drives movement of three plungers within the tool in unison. The lowest plunger contains a traveling valve to bring in fluids. When the plunger reaches the top of its stroke, it exits the lower barrel to release highly compressed fluids, creating the shockwaves.

Fluids, compressed between the lower plunger and the middle plunger, are released in milliseconds. Specialized tubing acts as a compression chamber. The upper assembly acts as a damper to decelerate the upward velocity the system experiences on firing.

The damper maintains a minimum 2,500-lb load on the pumping unit to prevent zero loading.[5]

The process repeats itself as water is drawn into the tool and released. Seismic stimulation has zero environmental impact. The tool releases 2 gal of fluids and has no hydraulic connection to the reservoir. Only the sound of the pumping unit is heard at the surface. The shockwaves' momentum will not damage the cement bond or wellbore integrity.

Seismic stimulation does not work for all reservoirs. It works best in reservoirs with barriers to flow in the horizontal or vertical plane.

The tool-created elastic waves mobilize the lightest phase first, resulting in less water production and more oil production in a water-oil system. The presence of gas attenuates the waves' amplitude, making them less effective and limiting coverage.

The technology is best applied to fields having gas-oil ratios of less than 2,000 scf/bbl. Thick oil is less inclined to move regardless of the elastic wave strength.

Field trials showed that stimulation is unlikely for oil having gravity lower than 14° API. There is no depth limit, but deeper wells have increased rod stretch and require a larger pumping unit.

Permian basin

Carbonates respond to seismic stimulation with a discrete change in decline for as long as the method is applied. The Permian basin's San Andres, Clearfork, and Glorietta fields have all been good candidates.

Fig. 2 shows seismic stimulation results for a Permian basin North Robinson Clearfork carbonate in Gaines County, Tex. Energen Resources owns the field and has ongoing stimulations in several fields, including a San Andres formation.[6]

The stimulation affected wells within a radius of 1.25-miles. Decline before stimulation was 21%. It dropped to 10% with seismic stimulation, resulting in an average 60% increase in oil production.

Seismic stimulation is certified by the Texas Railroad Commission as an official EOR process, granting Texas operators a 50% severance tax reduction for 10 years.

Abraxas Petroleum Corp. used seismic stimulation to enhance oil production from a carbonate on its Bishop-Huddleston lease in West Texas (OGJ, Dec. 5, 2011, p. 86).

Response tends to be similar in unconsolidated sandstones as in carbonates. Fig. 3 shows results from a field in Egypt, which experienced nearly 40% increased oil production after seismic stimulation.

Seismic stimulation can be used in different types of formations (Table 1). Increased oil production after stimulation compares favorably with historic trends. All fields' stimulation represents total response of multiple wells within the radius of affection.

Stimulation also works across barriers. The method was helpful in an unconsolidated sandstone field in North Africa that involved a highly layered system. Producing horizons were all squeezed except the target zone, creating a good configuration to explore cross-layer stimulation, with the elastic waves exiting only the bottom set of perforations.

The stimulation resulted in:

- Total production increase of 1,200 b/d.
- Decreased water cuts.
- All wells except one showing significantly increased oil production.

Tubing pump problems during stimulation prevented increased production from Well 112-94. Overall results demonstrate that seismic stimulation works across flow barriers.

Fracturing

Industry's use of extensive hydraulic fracturing and long horizontal wells in US shale plays created a massive network of microperm fractures that adsorb, trap, hold, and otherwise fail to release water and unbroken gel.[7]

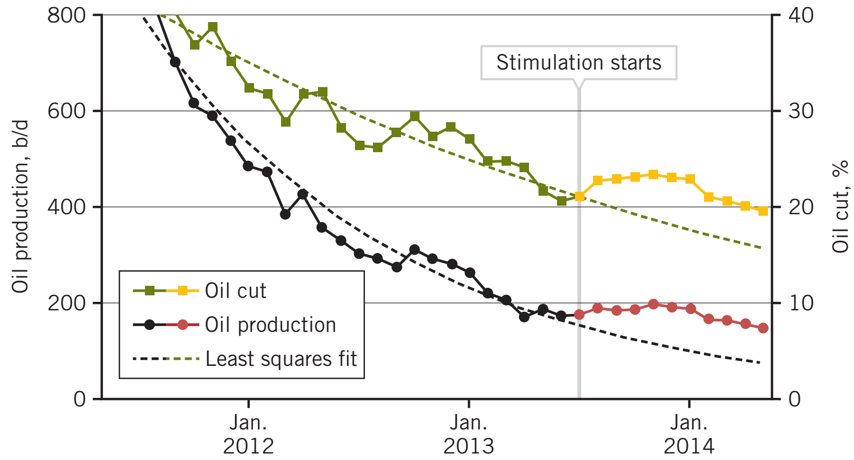
Seismic stimulation helps break down a gelling agent in fracturing fluid, release water, and open pore throats to flow, as well as enhancing already existing flow.

Unconventional oil production can create an extremely rapid shift in oil's relative phase-permeability when pressure drops at the wellbore, resulting in gas coming out of solution exceptionally quickly.

This is often a local phenomenon extending only a few feet into the reservoir above bubble-point. Large oil reserves could be just feet away from the wellbore and seismic stimulation will produce a good response in such cases.

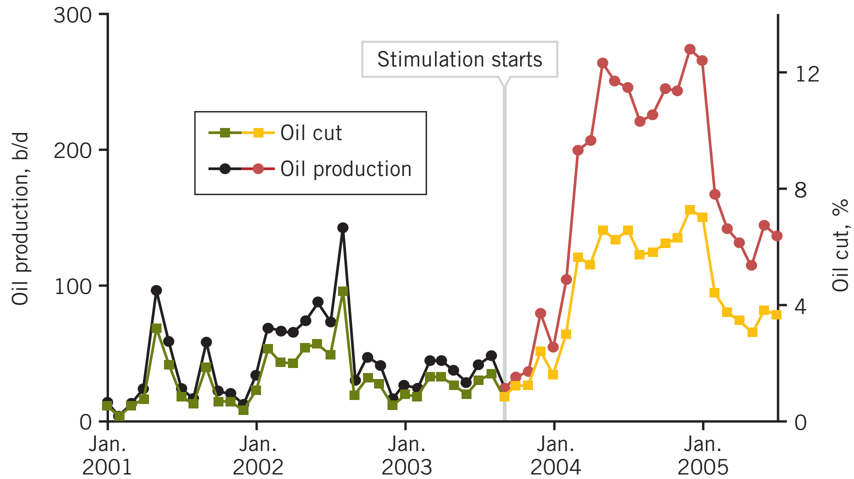
CANADA HORIZONTAL WELL RESPONSE

FIG. 4



WATER-DRIVEN MATURE FIELD RESPONSE

FIG. 5



SEISMIC STIMULATION RESULTS

Table 1

Austin chalk	20-200
Clearfork carbonate	25
Deese, Sims, Morris sandstones	18
Diatomite	14-16
Dolomite – highly cemented	—too homogeneous
Haima-Mahwis, Al Khlata, Gharif, Natih sandstones	30-34
James lime	122
Lewisville sandstone	11-200
Lime mudstone	< 8
Lower Clearfork and Glorietta carbonates	16-18 each
Pecan Gap chalk	0 – 200
Repetto, Puente, Puente-Topanga: sandstones	10
Robinson sandstone	—too homogeneous
Rodessa limestone, sandstone, shale	13-32
San Andres Carbonate waterflood	24-55
San Andres Carbonate, non-waterflood	65
Sandstone – tight, non-waterflood	30-125
Shale-sandstone – tight, non-waterflood	25-35
Stevens sandstone	30-50
Strawn/Canyon sandstone and San Andres carbonate	50% each
Tulare sandstone	15-30
Upper Carlisle shale	20
Upper Tuscaloosa sandstone	—tar from well damaged tool
Woodbine Sandstone	15-25
Zeit, S Gharib, Hamman, Feiran, Sidry, Kareem, Rudeis: halites, anhydrites, and sandstones	28

NORTH AFRICA STIMULATION

Table 2

Offset well	Zones	Before stimulation: Gross rate, cu m/d	Before stimulation: Water cut, %	Before stimulation: Oil rate, cu m/d	Stimulation response: Gross rate, cu m/d	Stimulation response: Water cut, %	Stimulation response: Oil rate, cu m/d	Net oil, cu m/d
112-08	II,II-A	200	85.0	30	200	80.0	50	20
112-80H	II-A	150	80.0	30	145	37.5	80	50
112-81H	II	170	77.0	35	170	71.2	49	14
112-94	V	200	79.0	42	140	70.0	40	–2
112-95	V	340	90.0	55	250	56.2	110	55
112-125	V	115	80.0	23	12	29.9	84	61
113-72	IV,V	115	69.3	35	125	67.7	40	5

Seismic stimulation also eliminates the need to repeat hydraulic fracturing, greatly improving shale-field economics.

High-energy elastic waves applied during fracturing will increase fracture propagation, accelerate gel breakdown, and boost recovery of fracturing fluids. This enhances oil recovery and potentially decreases the amount of fluids and gels left behind, lessening the induced-stress fields created by fracturing.

Two major operators plan seismic stimulation pilots to their shale fields once oil and gas prices recover. Production from exceptionally low-permeability fields that cannot be waterflooded falls off precipitously. Horizontal wells often are drilled in these fields, but even horizontal-well production plummets after initial results.

Multi-stage fracturing significantly improves initial production rates and extends drainage areas. Refracturing often renews production rates, but is also prohibitively expensive at current oil prices.

Seismic stimulation coupled with long horizontal wells and well-placed perforations might help eliminate both initial fracturing and refracturing in low-permeabililty fields. Operators could save thousands of dollars by eliminating fracturing, potentially altering field economics.

EOG Resources Inc.'s Waskada field in Canada featured a predominantly shale formation with some sand. Permeability tended to be significantly less than 0.1 md. Vertical wells were marginally productive. Horizontal-well production showed a rapid falloff.

A small tool available in a 4½-in. casing and having about 20% the power of the standard tool for 7-in. casing or larger, increased oil cut by 30% and oil production by 90% (Fig. 4).

Brownfield revitalization

Water production can eclipse oil production in mature fields, making them unviable. A strong water-drive exists in Occidental Petroleum's Elk Hills field, coming down the fault lines to oil-bearing areas in the field's southwestern portion.

Oxy slowed encroachment by adding dewatering wells and producing them at extremely high rates. This provided an opportunity to study seismic stimulation in revitalizing brownfield reservoirs.

After installing the tool in an abandoned well central to the watered-out area of the front, the study monitored six dewatering wells, some running across fault blocks, for changes in oil cut and oil production. The furthest-most dewatering well was 1 mile from the seismic stimulation well. Fig. 5 shows the six dewatering wells' response. Initial response was negligible, making it appear that the watered-out region would not respond. Other areas of the same field had experienced early success with non-watered out wells. The reservoir was highly faulted, unconsolidated sand that held considerable bypassed oil.

Both oil cut and oil production began to improve during the third month of stimulation, the latter reaching 240 b/d from 35 b/d for the six monitored wells. Fluid production remained the same at around 3,500 b/d.

Oil cut increased from less than 1% to more than 7%. Both oil production and oil cut immediately dropped when stimulation stopped, although production and oil cut levels stayed higher than before stimulation, indicating new oil was mobilized. OGJ

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DRILLING & PRODUCTION

Cost-cutting not enough to hit IOC growth target

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International oil companies (IOCs) responded to low oil prices by cutting spending and costs while seeking to deliver more production. Corporate filings show costs will have to fall below 2010 levels for companies to reach production targets.

Companies grew exploration and development capital spending by 57% to 2014 from 2010, but still were unable to increase either production or reserves organically. Organic growth refers to finding reserves through the drillbit rather than buying reserves through acquisitions.

IOCs are cutting frontier exploration. But further change is needed if companies want to sustain their business models.

IOCs set the tone for the rest of industry. This article compares publicly available information from Chevron Corp., ConocoPhillips Inc., Eni SPA, ExxonMobil Corp., Royal Dutch Shell PLC, Total SA, and BP PLC.

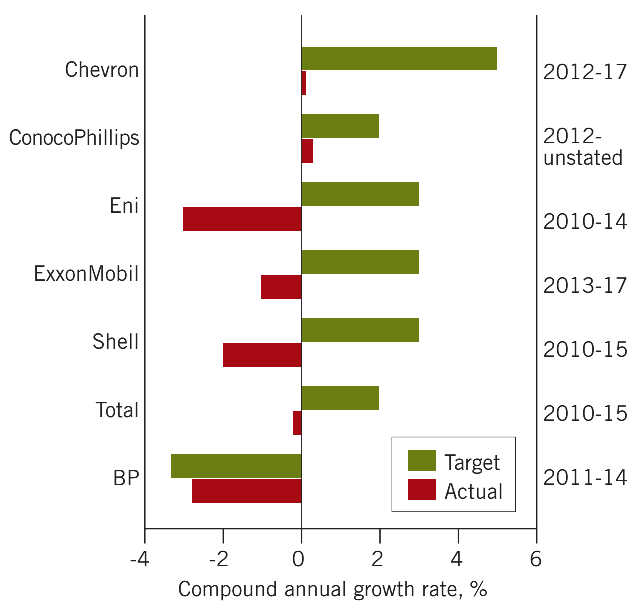
Investors grew increasingly concerned during the last decade about declining upstream capital efficiency. Companies tolerated inefficiencies while revenues rose along with oil prices. Growth was the 2010-14 priority while industry remained optimistic and opened new frontiers.

IOC spending ballooned. Executives justified the increased budgets by citing rich asset bases and sanctioned projects. The companies chased increasingly marginal barrels to meet production-growth targets, underestimating the consequences of growing project complexity, a sharply tightening supply chain, and project-schedule uncertainty.

New reserves' unit costs peaked in 2014. IOCs started to review their cost base and returns on investment even

PRODUCTION GROWTH TARGET VS. ACTUAL[1]

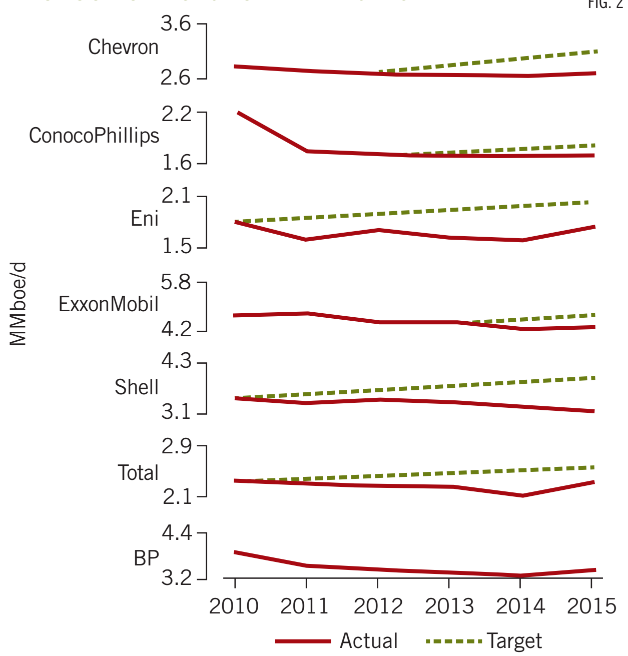
FIG. 1



[1]Companies set different target periods. Actuals are for 2010-14.

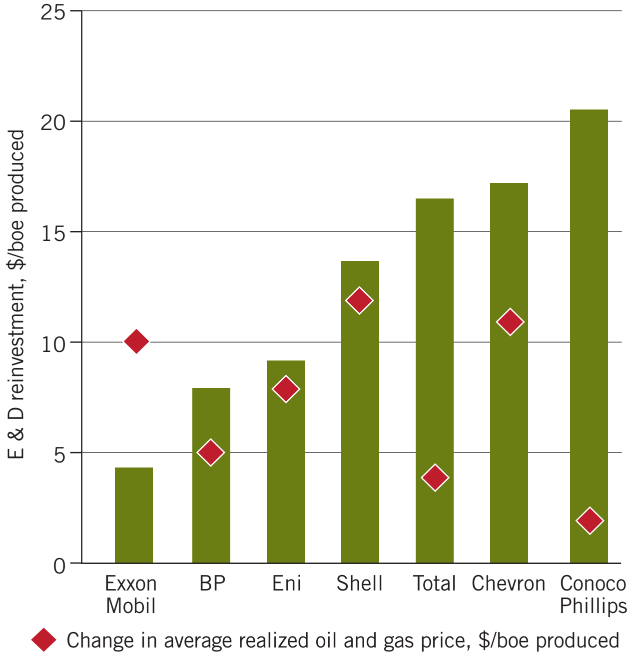
PRODUCTION VS. GROWTH TARGETS

FIG. 2



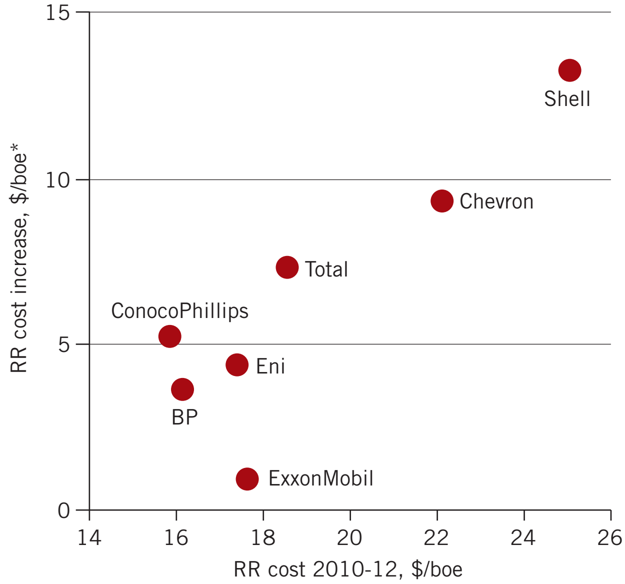
INCREASED REINVESTMENT RATE, 2010-14

FIG. 3



RESERVE REPLACEMENT COST VS. INCREASE IN RR COST

FIG. 4



*Cost increase compares averages from 2010-12 vs. 2012-14 for property acquisitions and exploration-development activities divided by proved oil equivalent reserves additions, including purchases.

before the oil-price slump. Falling prices added urgency.

Current budgets and production growth plans only can be achieved with large reductions in unit finding and development (F&D) costs or acquisitions. The changes will require one or a combination of the following actions:

• Reducing F&D costs by 60% from 2014 levels to achieve the capital efficiency needed to reach production-growth targets within existing budgets. Companies will need to find opportunities with enough scale to make them worthy of development investment.

• Increasing exploration and development (E&D) capital spending 100% compared with 2016 levels. If costs cannot be brought down, spending will have to rise to pursue sufficient exploration and produce reserves.

• Acquisitions providing 50% of new reserves and production. IOCs will need to take advantage of acquisitions as increasingly distressed opportunities become available.

It will be difficult for management teams to achieve sustainable capital-efficiency improvements. IOCs have focused on maintaining their financial position and short-term returns to investors since the oil-price plunge but are reconsidering their strategies. Executives are asking themselves if they should add a shrink-to-grow option, accelerate acquisitions to refresh assets, form new international partnerships to access new resources, or negotiate very different working arrangements with service companies.

OPTIONS TO MEET NEW PRODUCTION TARGETS[1]

Table 1

	F&D cost, $/boe, 2012-14	Reduced F&D costs,[2] $/boe	Additional capital E&D spend,[2] $ billion	Acquisitions, million boe[2]
Chevron	30	–17	21.4	707
ConocoPhillips	20	–9	5.7	281
Eni	22	–11	9.9	455
ExxonMobil	19	–8	13.0	689
Shell	38	–13	14.5	387
Total	28	–17	26.4	954
BP	19	–8	9.0	473

[1]Assumes companies maintain 2015 reserve-production ratio.[2]Assumes companies maintain other parameters.

Production targets

IOCs started outlining annual production-growth targets of 2-5% beginning in 2010 when prices stabilized above $80/boe. BP was the exception because it preserved cash to handle the legal and financial aftermath of the April 2010 Macondo deepwater well blowout.

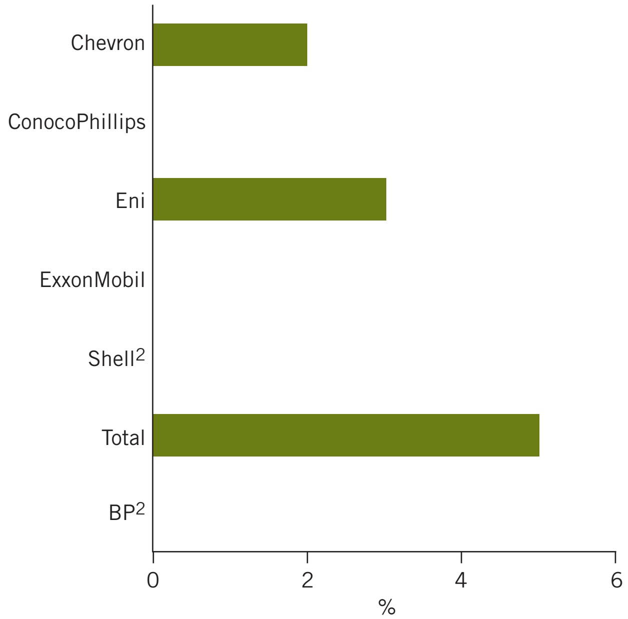
Growth targets implied increased production of 1.9 million b/d across the six majors by 2015 (Fig. 1). This growth was larger than Eni's current production. The IOCs collectively fell 2.4 million boe/d short of targets (Fig. 2).

Organic growth always has been problematic for IOCs. Targets set for 2000-05 and 2005-10 also were missed.

The main lever management has to address major project overruns or delays is to spend more or spend more

ANNUAL PRODUCTION GROWTH TARGETS[1]

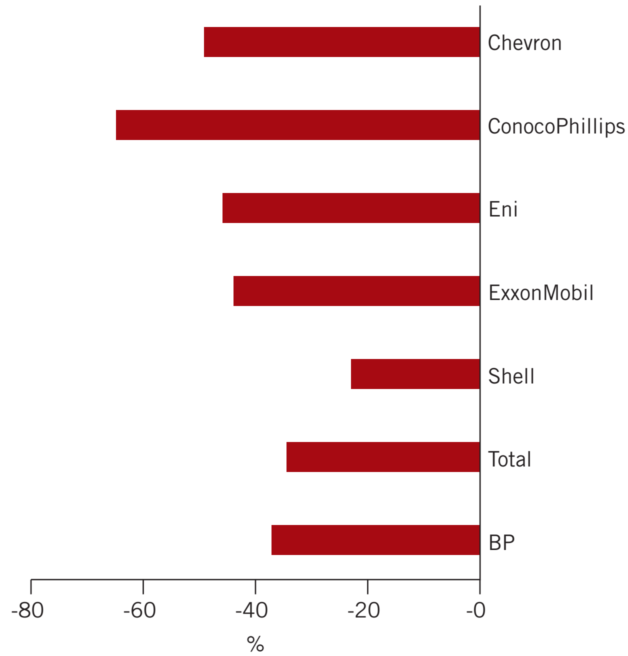
FIG. 5



[1]Target periods vary by company and cover 4-6 years. [2]No target explicitly stated.

E & D BUDGET REDUCTION, 2014-16

FIG. 6



quickly. All firms increased organic capital spending per barrel of production.

Reinvestment grew much faster than unit revenue in some cases (Fig. 3). Only ExxonMobil increased unit spending more slowly than the rise in realized price.

Total production across the seven firms fell 2 million boe/d during 2010-15. Production growth is sustainable only if reserves also grow. Lowering the reserve-to-production ratio is sustainable only if companies start with abnormally high reserves after large exploration successes or change the fundamentals of the time required to move from discovery to production.

Neither of these was true for the IOCs in 2010. Project complexity and lead times tended to increase during the period. Only Conoco and Eni grew reserves organically, but both also divested heavily to consolidate their assets (Fig. 3). Total and ExxonMobil increased reserves through large acquisitions.

Reserve replacement was less difficult for large independents. The authors' analysis of company filings for certain international independents showed these companies maintained or grew reserves 2010-14.

The analysis included Anadarko Petroleum Corp., Hess Corp., Marathon Oil Corp., Noble Energy Inc., and Premier Oil PLC.

Independents unable to grow reserves through the drillbit relied on acquisitions to replace production.

The importance of capital discipline and return-on-capital-employed (ROCE) tends to follow exploration and production cycles. Periods of lower prices lead executives to promote capital efficiency and returns, while production growth moves to the forefront with rising prices.

The years 2010-14 were no exception. Fig. 4 shows that all IOCs experienced higher reserve-replacement (RR) costs as they pursued production growth. Companies that started with poor capital discipline found themselves less able to control cost increases.

The rise in cost cannot simply be explained by general increases in costs in the supply chain. IHS CERA's upstream capital cost index[1] only rose 15% during 2010-14, despite high oil prices. The pressure to deliver growth forced some companies to chase volumes despite diminishing returns in their portfolios.

Two other underlying causes exist for both the higher costs and unrealized growth:

- Industrywide growth tightens the service sector more quickly than it can add capacity. Costs escalate as experienced workers become scarce.
- Medium-term production targets require delivering large projects on schedule. Given the uncertainties involved in these complex projects—be they regulatory, commercial, or technical—forecasting production becomes troublesome. Projects are more likely to be delayed than delivered early.

The future

Updated strategies presented in the second-half 2015 and first-half 2016 set production growth targets for five of the seven firms (Fig. 5). Four companies set growth targets of 2-5% for the next 4 years or longer. Lower budgets are the new normal while oil prices stay at current levels.

Falling oil prices have forced the IOCs to reassess strategy. Cutting operating costs and reducing capital budgets have become priorities and the reduction in spending is dramatic (Fig. 6).

There's no sign E&P fundamentals have radically changed. Companies have no reason to substantially reduce reserve-production ratios.

Additional reserves will need to replace production. The IHS CERA upstream capital cost index1 suggests costs have fallen by 24% from second-quarter 2014 to Dec. 31, 2015. Table 1 outlines the choices companies face in achieving new targets. Companies could choose a combination of options

F&D costs will need to come down another 15-35% and stay there to achieve required reserve growth. Even this, however, assumes that companies have equally prospective opportunities to explore at a time when frontier exploration budgets have been slashed or eliminated. Only Shell has substantially renewed its portfolio, by acquiring BG Group.

It's far from clear that current budgets can meet the targets. If companies continue to perform at 2012-14 levels of unit-RR cost, E&D budgets will have to rise substantially. First-quarter financial filings indicate that operating cash flow barely covers capital spending at current prices.

The table's acquisitions column indicates the annual proved reserves each company would need to acquire if current budgets delivered new volumes at the 2012-14 F&D cost.

Many mid-sized companies face cash-flow shortfalls. Banks are increasingly reluctant to expand E&P exposure. More oil and gas asset transactions are likely.

IOCs typically have focused primarily on the short-term by cutting costs to maintain investor confidence in response to low oil prices. Credit-rating agencies, meanwhile, have downgraded the ratings of most majors, despite ambitious targets.

Investors familiar with poor IOC track-records have little confidence that IOC executives will deliver on future promises without significantly changing their strategies. CEOs need to think beyond short-term needs and adapt to sustain long-term operations. OGJ

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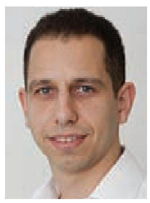

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AFPM Q&A—1

Refiners tackle Tier 3 compliance at annual conference

PROCESSING

During the 2015 American Fuel and Petrochemical Manufacturers Q&A and Technology Forum (Oct. 4-7, New Orleans), US domestic and international refiners dedicated time to discussing trends in hydroprocessing operations, with an extended focus on issues of safety, phosphorous poisoning, and meeting the US Environmental Protection Agency's (EPA) more stringent Tier 3 gasoline standards that take effect Jan. 1, 2017.

This annual meeting addresses real problems and issues refiners face in their plants and provides an opportunity for members to sort through potential solutions in a discussion with panelists and other attendees.

This is the first of three installments based on edited transcripts from the 2015 event. Part 2 in the series (OGJ, Sept. 5, 2016) will highlight discussion surrounding processes associated with crude-vacuum distillation and coking, while the final installment (OGJ, Oct. 3, 2016) will focus on fluid catalytic cracking (FCC).

The session included six panelists comprised of industry experts from refining companies and other technology specialists responding to selected questions and then engaging attendees in discussion of the relevant issues (see accompanying box).

The only disclaimer for panelists and attendees was that they discuss their own experiences, their own views, and the views of their companies. What has worked for them in their plants or refineries might not be applicable to every situation, but it can provide sound guidelines for what would work to address specific issues.

Safety

What are the likely causes for temperature excursion events in a hydrogen plant?

Epstein Hydrogen plant temperature excursions are possible in several of the catalyst vessels and are usually observed in association with the water-gas shift reaction. During normal operation, the high, medium, and low-temperature shift reactors display an exothermic reaction. Changes to feed quality can increase this exotherm and cause the operating temperature to exceed the maximum allowable working temperature. A critical alarm on a high-reactor discharge temperature is typically used to protect against this condition, with precursor alarms as needed.

A similar exotherm is observed during the reverse water-gas shift reaction over nickel catalyst in the methanator, which can increase under a change in feed quality. The exotherm generated by this reaction is significant enough that commonly occurring initiating events, such as the CO_2-removal system's pump tripping, can cause the excursion. A safety integrity level

The panel

Paul Epstein, senior process engineer lead, Flint Hills Resources LP

Scott McArthur, senior hydroprocessing engineer, Phillips 66

Dr. Andrew Moreland, hydroprocessing and hydrocracking technology advisor, Valero Energy Corp.

Mike Pedersen, senior technical service specialist, UOP LLC

Paul Temme, hydroprocessing technical supervisor, Albemarle Corp.

Samuel Wright, senior process engineer, Hunt Refining Co.

The respondents

Mike Adkins, KP Engineering LP
Jeff Johns, Chevron USA Inc.
Nagashyam Appalla, Reliance Industries Ltd.
James Prorok, Husky Energy Inc.
Maureen Price, Fluor Corp.
Sal Torrisi Jr., Criterion Catalysts & Technologies LP
Dominic Varraveto, Burns & McDonnell
Mel Larson, KBC Advanced Technologies Inc.
Wendy Wildenberg, Flint Hills Resources LP

(SIL)-rated system is typically used to isolate and depressurize the methanator if an excursion is detected.

I have personally observed an unexpected temperature excursion on startup of a combined feed pretreatment system with a catalyst containing nickel, molybdenum, cobalt, and zinc oxide used to combine qualities of hydrotreating and desulfurization beds into a single media.

During startup, the natural gas feed was introduced along with a very high hydrogen-recycle flow at normal operat ing temperature and pressure. The unit operating procedure called for starting the hydrogen-recycle flow at its full-flow rate followed by slowly ramping up the natural gas feed, which we did.

Under these conditions, it appeared that the hydrogen, CO_2, and natural gas reacted exothermically through the reverse water-gas shift reaction, similar to the methanator. The catalyst also was very dry after prolonged nitrogen circulation. It appeared that the water generated by the reverse reaction was absorbed by the catalyst, causing it to heat up and initiate a reduction reaction that lead to the temperature excursion. Stopping the hydrogen flow discontinued all of this, and we were able return to a safe temperature level. According to the catalyst supplier, this was the first observation of such an issue with this material.

Wright We approached the question from a different angle. We recently experienced a temperature excursion caused by falling refractory in our transfer line. The transfer line is the pipe in between our reformer box and our first waste-heat boiler. The line consists of a metal shell with refractory on the inside. The top portion of the refractory fell, allowing the hot syngas access to the metal shell. The line quickly developed a fish-mouth rupture. Fortunately, no one was hurt, but there were cosmetic damages on the underside of the heater.

Other than that, in the past, we have just had out-of-the-pipe issues, such as leaky flanges around some feed heat-exchangers. We have had leaks around our pressure-swing adsorber valves, which caused fires. One time, we had a fire caused by corrosion and erosion from attemperator water used to control the inlet temperature to a shift converter.

Moreland At Valero, we have experienced high bed temperatures in hydrogen plants in the high-temperature shift reactor due to failure of the control system or control valve in the upstream process gas boiler resulting in high inlet temperatures. Additionally, the catalyst was very dry upon startup, with the heat of absorption resulting in temperatures of more than 1,200° F. In the methanator, as Paul mentioned, we have also had an issue with a failure in the upstream CO_2-removal system. No catalyst damage, however, was observed in that experience.

Adkins I know this is not directly related to excursions in the reactor, but as far as temperature excursions in general, in one particular plant I experienced the failure of some of the safety systems related to a steam generator. The No. 1 process steam generator blew out because it ran out of water. So definitely keep in mind that you should be looking at level instrumentation and safety practices.

Phosphorus poisoning

Phosphorus-based chemicals are used to neutralize naphthenic acids. Drilling and completion fluids also can contain phosphorus, so it may be in crude oil. What are your best practices to protect active hydrotreating catalyst from phosphorus poisoning?

Moreland I am going to give a little background on phosphorous poisoning and then share one specific example we have seen in one of our refinery units. First of all, phosphorus is a strong catalyst poison. In our course materials, we say that 1 wt% phosphorous on catalyst will reduce activity by 50%, so it is a significant poison. There have been examples of up to 3 wt% phosphorous completely destroying the exotherm from a bed. The deactivation mechanism is pore-mouth plugging through surface deposition similar to nickel or vanadium. The common sources are crudes, drilling fluids, phosphorous-based corrosion inhibitors, and flow improvers. In particular, we have had more and more experience with phosphorous-based corrosion inhibitors, and the example I am going to discuss deals with that.

We have seen, in this example, the spent catalyst from the skim indicated up to 20 wt% phosphorous on top-bed grading. After seeing the exotherm decline during this cycle, when it came time to reload, we switched from the phosphorous-based naphthenic acid corrosion inhibitor to a sulfur-based inhibitor, which halted the decline in differential temperature (DT).

The unit in question contains two reactors in series with two beds each (Beds 1, 2, 3, and 4). Throughout the beginning of the first cycle, the DTs were stable, with the total rise in temperature distributed across the four beds.

When the phosphorous-based corrosion inhibitor was started, however, Bed 1's temperature rise started to decline. We tried to increase inlet temperatures to recover the DT, but it continued to decline. As you would expect from plug flow and metals deposition, Bed 1's declining DT eventually spread across Beds 2, 3, and 4.

We ended up changing the catalyst out in the cycle ahead of schedule. When the catalyst samples were pulled from the spent-catalyst load, Bed 1 catalyst samples exceeded 20 wt% phosphorous. While Bed 2 catalyst samples also exceeded our threshold of 1 wt% phosphorous, we did have lower levels of phosphorous in Beds 3 and 4, which is where the bulk of hydrodesulfurization catalyst was located.

At the beginning of the next cycle, the DT continued to decline across all four beds, which occurred during the time

Valero Energy Corp. in March 2016 completed a $40-million project to expand capacity by 15,000 b/d at the gas oil hydrocracker of its St. Charles refinery in Norco, La. Photograph from Valero.

it took us to receive spent-catalyst sample results from the previous cycle. When we unload the catalyst and send it to our supplier, we do not get those results back for several months. This reinforces that having good technical service and timely return of spent-catalyst samples can really help us make a change.

As soon as we saw the high levels of phosphorous after receiving spent-catalyst samples back from the first cycle, however, we worked with our chemical supplier and the refinery switched to a sulfur-based corrosion inhibitor. Upon switching to that sulfur-based corrosion inhibitor, DT stabilized. While there was still some decline as a result of the rampant metals poisoning previously occurring in the unit, the rapid decline that we observed during the previous cycle was not repeated.

Our best practice for phosphorous poisoning, then, is to minimize the source of phosphorous poisoning. While we do still use phosphorous-based corrosion inhibitors for their effectiveness against naphthenic acid corrosion, there has to be an economic justification between their use for protecting vacuum gas oil (VGO) circuits and any deactivation that may occur in a VGO hydroprocessing unit.

There are demetallization catalysts that would be used for nickel and vanadium; they are also effective for trapping phosphorous. But still, a small amount of phosphorus goes a long way in terms of catalyst deactivation.

Temme That is a really powerful example. Phosphorous is definitely becoming more problematic, especially with treatment programs for crudes that have a high total acid number (TAN). Phosphorous will cause pore-mouth plugging leading to diffusion limitations. The mechanism is more pronounced with high-temperature, high-pressure operations. The pore-mouth plugging will have a greater impact on small pore-size, smaller median pore-distribution sized catalysts. We have seen that phosphorous deposition of 2 wt% can result in a 50% loss of catalyst activity. In terms of assessing and dealing with phosphorous trapping, as Andy indicated, getting good spent catalyst samples is essential for assessment. There are catalyst-handling companies that have core sample machines which work very well for getting a good axial core-bed sample.

Instead of having to try and vacuum off or pick samples out of flow bins, we want to make sure to get enough samples to define the extent of the problem. It does not hurt to get some third-party testing done, especially if they can do it in a quicker turnaround and get a baseline of the phosphorous and the catalyst substrate from the vendor to ensure that you have good accounting.

And yes, phosphates can be removed using guard catalysts. They are designed for iron, nickel, and vanadium pickup, especially catalysts with pore architecture that will minimize pore-mouth plugging. We feel that catalysts with minimal diffusion limitations will deal best with phosphorous trapping.

Pedersen I will add that it is important to identify not only the concentration of phosphorus contaminant but also the type of material with which this phosphorus is associated. The more acidic the phosphorus compound, the more lethal it is to your catalyst.

Johns I am curious about comments from the panel about protection from phosphorus in crude. Is there any monitoring program or other procedures you have instituted to be able to prevent that poisoning?

As an example, just so people are aware that this is a real problem, we had a diesel hydrotreater that completely went through a cycle in about 6 weeks due to phosphorus from crude poisoning. So what have you done?

McArthur I will say that we do not have a unit that has really had a significant phosphorus poisoning problem yet. So I do not think we have installed what I would call a top-of-the-line phosphorus monitoring program.

Moreland All I want to say, Jeff, is that we would have been caught by something like that, too. We do not typically monitor for phosphorus in diesel streams. We have seen some phosphorus in some kerosine (kero) streams at one of our plants and some phosphorus-based fouling in the crude tower in the kero circuit. So maybe it is a similar case, but it did not seem to affect operations. In that refinery, jet fuel is not hydrotreated, so we would not have seen it in the hydrotreater. We have monitored it in VGO, but in diesel, we do not look for phosphorus very often.

Appalla I have two specific questions. First, is there any industry-wide accepted limit of phosphorus in the gas oil stream going to the hydrotreater? Does anyone monitor this, and is there any permissible limit for the phosphorus levels?

Secondly, in the presentation, it was mentioned that the customer switched from phosphorus-based chemistry to sulfur-based chemistry. Phosphorus-based chemistry is known to provide a better protection against the attack of naphthenic acid by forming a more stable Fe-S-P scale. Sulfur-based inhibitors are not found to provide that level of protection. Also, as per experimental studies, the sulfur-based inhibitors need to be dosed in a higher proportion than the phosphorus-based to get the same level of protection. How did the customer ensure the same level of protection against corrosion from the naphthenic acid by switching to sulfur-based chemistry?

Moreland I can answer the second question. I do not know about the first one. In answer to the second part, we understood that switching to the sulfur-based inhibitor would be less effective for protecting against naphthenic acid corrosion. So the higher dosing went into the economic equation of how much high-TAN crude we process at this particular facility.

We have two different plants at which we are using the phosphorus-based corrosion inhibitor. One plant stayed with it and even dealt with the penalty on the hydrotreater downstream. The other plant, in the example I gave, switched away from the phosphorus-based to the sulfur-based inhibitor and then reduced its throughputs of high-TAN crudes. As far as acceptable levels, I do not really have a number.

McArthur The only time we review feedstock for phosphorus is if we have an opportunity feedstock come in, at which point we would look for elevated phosphorus levels. We would steer away from something that had any appreciable amount of phosphorus, but I do not have a number off the top of my head.

Prorok About fouling in the crude tower, at the Lima refinery, we experienced phosphorus fouling in a light gas oil cooler. We also experienced it in the "water white" kerosine cooler–a separate air cooler at the refinery–that basically plugged up with the same material and shortened the life of the diesel hydrotreater catalyst.

Moreland We saw it in deposits in the crude tower. I do not know if we knew it ahead of time, because when we analyzed those deposits, that is when we saw phosphorus in those deposits. Is that a similar experience?

Prorok After the pressure dropped in the kerosine section of the crude tower, we retrieved a sample of the solids that were caught in a strainer on a pump, had them analyzed, and found out that there was phosphorus in that circuit. Then, we saw phosphorus in the heat exchangers downstream of that, on the way to the distillate hydrotreater (DHT).

Price There is a question on this in the Crude Q&A that covers phosphorous deposits in the crude unit equipment that may provide additional insight.

Torrisi The panel talked about solids in the crude tower, and the focus of the question was activity on the catalyst. Can anyone on the panel comment about any impacts on pressure drop related to phosphorus?

McArthur I do not have any experience with it, but my understanding is that there will be a pressure drop problem with phosphorus fouling on a catalyst, especially if you have a very low void space where it is collecting. But again, we have not had that problem yet.

Torrisi The experience I have seen has been more with regard to accelerated fouling in the feed preheat exchangers than in the catalyst bed itself.

Moreland Sal, you are probably as familiar with the unit as I am, so all I will add is that when you lose the activity this fast from phosphorus, the time on stream is not sufficient for development of a significant pressure-drop issue. We have seen pressure drop start to increase, however. We ended up doing reactor skims before it really became a run limiter.

Torrisi Okay, thanks. I was wondering about that because what happens is you use a corrosion inhibitor to neutralize the acids, and if you are not consistently neutralizing, organic iron can form as a result of the reaction of the acids with the equipment.

We have observed organic iron being converted back to solid iron sulfide by reaction with H_2S in the reactor at the same time we observed the phosphorus being deposited in the catalyst bed. That is a secondary indicator that you may have a phosphorus issue because you are just starting to see some iron sulfide formation due to conversion of iron naphthenates, which can go hand-in-hand with phosphorus.

Tier 3

How is your company planning to meet Tier 3 gasoline regulations?

Wright Currently, our gasoline runs at 12 ppm sulfur. There are two sour components: our light straight-run (LSR) and butane. Some approaches we are contemplating for compliance are hydrotreating the LSR, reducing the sulfur via dilution, or restarting an out-of-service Merox unit.

Epstein Flint Hills Resources includes two refineries. Our Pine Bend refinery will increase the amount of hydrotreating in gas oil hydrotreaters to remove sulfur from fuel products to meet Tier 3 regulations. Our Corpus Christi refinery is reconfiguring its ultralow-sulfur gasoline unit in order to meet these requirements.

McArthur Phillips 66's compliance strategy varies by refinery. Our West Coast sites are generally already at a Tier 3-performance level. We have some unit revamps to allow for higher severity operation of our FCC-feed hydrotreaters. We have some new Merox units we are installing, and where necessary, we are adding some additional hydrotreating capability.

Moreland For the 14 Valero refineries, three are not affected by Tier 3, either in Europe or California. Prior to Tier 3, Valero met gasoline sulfur requirements with just FCC-pretreat at three of our refineries that process light sweet crudes.

For two of those three refineries, we are going to build grassroot gasoline desulfurization units, while at the third, we have shut down the FCC. So for compliance with Tier 3, all Valero refineries will have FCC gasoline hydrotreating or post-treatment units. I also would like to add that for Tier 3 gasoline, a lot of our front-end studies have had to do more with how we deal with crude-unit naphtha than with FCC-gasoline naphtha. In many of our cases, the crude-unit naphtha is not hydrotreated to meet the 30 ppm pool but must now be hydrotreated to meet the 10 ppm pool. Tier 3 will require refiners to hydrotreat a lot of straight-run naphtha.

Nelson-Farrar cost indexes[1]

Refinery construction (1946 basis)
Explained in OGJ, Dec. 30, 1985, p. 145.

	1962	1980	2013	2014	2015	Apr. 2015	Mar. 2016	Apr. 2016
Pumps, compressors, etc.	222.5	777.3	2,221.1	2,271.9	2,313.6	2,313.3	2,336.9	2,336.9
Electrical machinery	189.5	394.7	516.7	515.8	516.5	516.8	513.2	513.2
Internal-comb. engines	183.4	512.6	1,046.8	1,052.9	1,062.3	1,064.1	1,035.7	1,037.0
Instruments	214.8	587.3	1,509.9	1,533.6	1,554.4	1,553.2	1,581.2	1,594.8
Heat exchangers	183.6	618.7	1,293.3	1,305.0	1,305.0	1,305.0	1,221.2	1,221.2
Misc. equip. average	198.8	578.1	1,317.5	1,335.8	1,350.3	1,350.5	1,337.6	1,340.6
Materials component	205.9	629.2	1,538.7	1,571.8	1,434.9	1,456.5	1,353.6	1,389.9
Labor component	258.8	951.9	3,123.4	3,210.7	3,293.8	3,269.2	3,370.8	3,383.5
Refinery (inflation) index	237.6	822.8	2,489.5	2,555.2	2,550.2	2,544.1	2,563.9	2,586.1

Refinery operating (1956 basis)
Explained in OGJ, Dec. 30, 1985, p. 145.

	1962	1980	2013	2014	2015	Apr. 2015	Mar. 2016	Apr. 2016
Fuel cost	100.9	810.5	1,123.7	1,264.8	915.9	893.0	748.0	774.1
Labor cost	93.9	200.5	308.3	312.8	319.2	317.1	350.4	355.0
Wages	123.9	439.9	1,506.4	1,541.3	1,584.4	1,582.8	1,646.5	1,682.2
Productivity	131.8	226.3	489.1	493.1	497.1	499.1	469.9	473.9
Invest., maint., etc.	121.7	324.8	905.3	939.4	948.0	945.8	925.6	933.6
Chemical costs	96.7	229.2	502.6	472.3	434.6	430.3	398.5	402.2
Operating indexes[2]								
Refinery	103.7	312.7	661.8	688.5	660.0	655.8	643.6	651.5
Process units	103.6	457.5	802.6	865.3	748.1	738.7	690.9	704.2

[1]These indexes are published in the first of each month and are compiled by Gary Farrar, OGJ Contributing Editor.
[2]Add separate index(es) for chemicals, if any are used. Indexes of selected individual items of equipment and materials are also published on the Quarterly Costimating page in first issues for January, April, July, and October.

Varraveto My question regarding Tier 3 compliance has to do with the strategy or use of credits and how that fits in for any of the operating companies represented on the panel or in the audience.

Moreland Since the EPA has allowed us to use 5 years' worth of credits, Valero has sufficient credits built up to maybe delay startup of those two grassroots units I referred to earlier.

Larson Considering not only Tier 3 but also the emissions requirements, I am curious why more FCC-feed hydrotreating will not be the preferred option. Feed pretreating improves stack emissions compliance as well as fuel side issues.

It seems like that is the direction the industry is moving: to zero flue-gas sulfur that you get two for one (i.e., lower emissions and increased hydrogen content of feed, which improves conversion flexibility and selectivity). And if you are building new FCC-pretreat capacity, it will justify expense on a per-barrel basis vs. the lower pressure post-treatment units.

Wildenberg We found that managing hydrogen recycle and hydrogen purity can keep our deactivation rates low. Even though we are more severely hydrotreating, it seems like our crude people keep finding harder and harder things for us to hydrotreat. So at the Pine Bend refinery, we have been enjoying very low deactivation rates. But, like I said, it requires a lot of management, catalyst strategy, and careful management of higher hydrogen purity-higher hydrogen recycle.

I also have been asked about run length and product sulfur. One example is our heavy coker, heavy vacuum gas oil (HVGO) hydrotreater, that has minimal catalyst deactivation. This unit shut down after 3 years at the scheduled turnaround, but it could have gone longer. It has been averaging 0.05-0.07 wt% product sulfur with 3.5 wt% sulfur feedstock, so it is doing well.

Moreland Do you still get all the way to 10 ppm on FCC gasoline with feed from that cat feed hydrotreater?

Wildenberg We get to 30 ppm or less on the FCC gasoline from that feedstock. We have two gas oil hydrotreaters that hydrotreat 100% of the gas oil the Pine Bend refinery runs. The lighter feedstock goes to the 900-psig unit, and the heavier feedstock goes to the 600-psig unit. So we managed these units and their catalyst strategies very diligently.

Moreland In our refinery in Wilmington, Calif., Valero is running similar coker gas oil and HVGO to produce FCC feed with 500-700 ppm sulfur content. We typically only get a 2-year cycle.

Wildenberg We went back and looked at a lot of the deactivation times we had been doing and discovered that we had done a lot of it to ourselves. We were either cutting hydrogen too far or raising temperature too much. So we really steadied down our temperature moves. We do not target the product sulfur and move temperatures around. We allow the sulfur to move around some to keep the temperature very steady, and then we are able to not deactivate. It was definitely helpful. OGJ

PROCESSING

Examples illustrate sour-gas processing megaproject metrics

Nick Amott
Stephen Mogose
Fluor Ltd.
Hampshire, UK

Increased recovery of hydrocarbon resources containing high amounts of H_2S has spurred ongoing development of projects to gather and process large volumes of extremely sour gas. As a result of their physical size, capacity, and quality of feedstock, these megaprojects involve unique process and design considerations operators must address to ensure technical feasibility and potential profitability.

While initial megaprojects tested boundaries on cost, size, and technology requirements, they also provided opportunities for overcoming common problems associated with handling large volumes of sour gas, helping establish design and operational precedents now in place for future projects of this scope.

To develop the first of these sour gas megaprojects, Tengizchevroil LLP engaged consortia led by Fluor Ltd., Hampshire, UK, to provide a mix of front-end design (FEED) and engineering, procurement, and construction (EPC) services for its Tengiz asset development in West Kazakhstan. This experience and Fluor's global reach leveraged work for Abu Dhabi National Oil Co. (ADNOC) subsidiary Abu Dhabi Gas Development Co. (Al Hosn Gas) on the recently commissioned Shah gas development in the United Arab Emirates (OGJ Online, Apr. 26, 2016).

Using Fluor's direct experiences on the Tengiz and Shah developments, this article describes a selection of key metrics that led to successful conception, design, and execution.

Located in western Kazakhstan on the northeastern shore of the Caspian Sea, Tengiz development includes one of the world's largest SRUs still in reliable operation (Fig. 1). Photograph from Tengizchevroil.

Project drivers

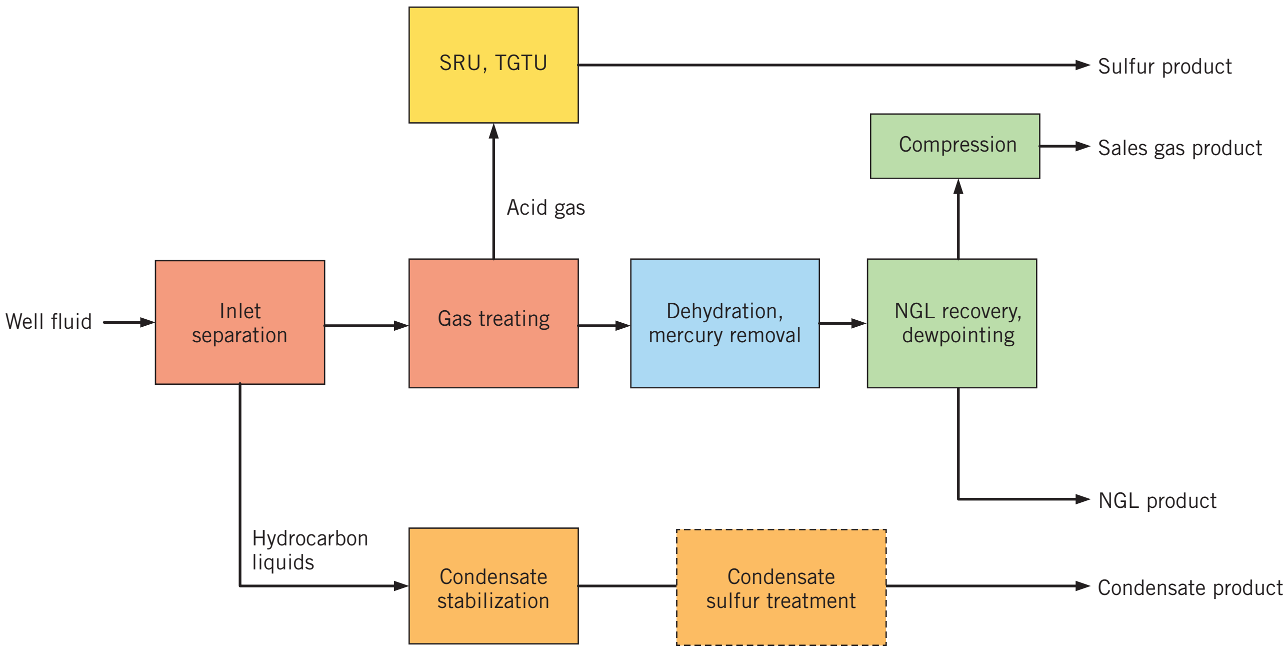
Because of large investments required to build complex plants for gathering and processing sour gas, development of resources containing significant amounts of H_2S historically has lagged. Shah field and its associated $10-billion processing plant were on hold for almost 50 years, while Tengiz remained undeveloped until the late 1980s.

Projects of this magnitude had to await improved technologies for handling sulfur as well as evolution of definitive end-user markets to

Based on a presentation to Gas Processors Association Europe Spring Conference, Paris, Apr. 20-22, 2016.

TYPICAL SOUR GAS PLANT WITH NGL RECOVERY

FIG. 2



justify operators' investments.

A particular project's strategy and design always will be influenced by several factors, including geography, access to markets (gas infrastructure), process-fluid production types, and location-specific product values.

Even within the same region, however, project drivers vary. In some remote Middle Eastern locations, thin regional demand and transportation constraints limit rates of return on finished products, offering little incentive for operator investment in large-scale sour projects. At other locations, with acute shortfalls in gas availability but large sour reserves, the production, sweetening, and export of gas can serve as megaproject drivers, with produced liquids becoming an additional revenue stream to help project economics.

Current projects in the UAE and Commonwealth of Independent States (CIS), particularly Central Asia, require processing well fluids containing up to 10 mole % CO_2 and 23 mole % H_2S, with future projects potentially to see higher H_2S levels. Alongside handling production of oil and condensate, these projects are configured to treat and process sour gas flows up to 1 bcfd and recover NGLs and LPGs. These sour gas megaprojects also include the world's largest sulfur plants, capable of treating up to 10,000 tonnes/day of elemental sulfur.

Primarily an oil development, Tengiz always has had difficulty making production and export of gas economic due to costs associated with pipeline transportation of finished product to market.

Major Tengiz expansions during the past 10 years have therefore used conventional amine sweetening units and sulfur recovery units (SRU) to extract and convert the gas stream's H_2S into sulfur.

The Tengiz Second Generation Project (SGP) used super high-pressure compressors to pioneer reinjection of 275 MMcfd sour gas (25 mol % H_2S) at 620 barg as a reservoir pressure-maintenance and miscible-flood agent. Future Tengiz developments under design, and for which the procurement phase was recently approved (OGJ Online, July 5, 2016), will rely solely on sour-gas injection as their gas-disposal method.

Fig. 1 shows the SRU and tail-gas treating unit (TGTU) installed to improve plant economics at Tengiz SGP.

In the Middle East, where produced or associated gas has a far higher market value, megaproject drivers focus on sweetening gas for export as well as dealing with the low-pressure stream of acid gas resulting from sweetening.

While conversion to elemental sulfur is the most widely applied choice for handling this byproduct gas, acid gas injection (requiring compression from very low to significantly higher pressures required for injection into a disposal or producing formation) is another possible option. Its complexity, however, has limited acid gas injection primarily to Canada.

Sulfur forms

The primary focus in sour reservoir development is H_2S due to its toxicity and relatively high concentration in many sour fields, which can require major additional investments for gas treating, SRU, or sour gas injection operations.

In some regions reservoirs also are prone to organic sulfur species occurring predominantly as mercaptans (RSH)

The Tengiz SRU features a 328-tonne, first-stage sulfur condenser (Fig. 3). Photograph from Tengizchevroil.

SOUR GAS COMPOSITIONS, CONTAMINANTS Table 1

Component	Mole %
H_2S	15 – 30
CO_2	5 – 15
C_1	50 – 70
C_2	5 – 10
C_3	2 – 5
C_4	1 – 5
C_5+	1 – 5
COS	0 – 500 ppm
Other organic sulfur	0 – 100 ppm
Elemental sulfur	0 – 500 lb/MMcf

of varying chain lengths but also as carbonyl sulfide (COS).

RSH compounds' toxicity and odor require the light mercaptans (methyl, ethyl, and sometimes propyl) and COS to be limited by specification. Amine sweetening, however, does not necessarily extract organic sulfur as effectively as it extracts H_2S.

As the concentration of H_2S in reservoir fluid increases, there also is a tendency (though not a direct correlation) for levels of organic sulfur to increase. Geography and geological history play a strong role in this situation, but since highly sour fields tend to be deep, high-pressure reservoirs (Tengiz is 4,500 m deep with 550 bar shut-in pressure), this can be a major concern for project developers. As the concentration of organic sulfur species increases, the objective shifts from needing to recognize and report sulfur levels to requiring removal of organic sulfur to meet specifications.

As the level of sulfur in produced fluid rises, elemental sulfur can also emerge. This sulfur leads to specification problems, but more fundamentally, it can lead to production issues resulting from blockage as the sulfur condenses and then deposits as a solid. Typical coproduction of water also creates a high risk of aggressive wet-sulfur corrosion. The base propensity to deposit elemental sulfur does not occur in some fields in spite of high H_2S levels because coproduced liquid hydrocarbons (such as oil or heavier condensates with naphtha-like constituents) can act as a solvent for sulfur and prevent it from depositing by keeping it in solution in an elemental form. This characteristic is used by new technologies designed to control the risk of elemental sulfur deposition.

Table 1 shows the range of sour gas compositions and relevant contaminants.

Sour-gas treatment

While several technologies are available to treat sour-gas streams, the workhorse for many years has been amine solvents. Use of these solvents generally entails absorption of acid gas in a solvent solution and subsequent solvent regeneration by heating. This heating, which uses large amounts of steam, requires utilities not typically found at sites processing sweet gas or light oil.

Application of other technologies primarily depends on contaminant concentrations. Other solvents, such as methanol or a generic group known as physical solvents (vs. chemical solvents like amines) are sometimes used

Other niche applications use molecular sieves to adsorb the contaminant, requiring regeneration to release sulfur compounds and then further treatment of regeneration gas.

Solid absorbents, or scavengers, also are applicable for levels of contamination low enough to allow disposal of the scavenger. Liquid scavengers can be applied as well.

Diluted caustic (NaOH) reacts with the sulfur species, but also produces byproducts that must to be dealt with later.

Fig. 2 shows the configuration of a typical sour-gas processing plant equipped with NGL-recovery.

Fields with highly sour reservoirs typically use amines, physical solvents, or a combination of the two for sour-gas treatment.

Amines remove H_2S from the gas well, with some modified amines better suited for CO_2 removal. Amines, however, are not good at removing organic sulfur compounds, particularly mercaptans. Varying percentages of removal can occur, but high-removal rates are beyond the capability of amines in tight-specification environments. Simulation can predict mercaptan removal by an amine, but not accurately.

The best prediction method uses existing plant operational data, benchmarking the simulation where possible by developing a set of binary interaction parameters or adjusting simulation parameters to emulate the operating plant.

Physical solvents have an inherently superior ability to absorb mercaptans and often are more appropriate for achieving a specification limit.

While using both solvent systems in series can be effective, it raises costs. Full removal of COS is also best achieved by absorption in an amine, particularly diglycolamine (DGA). Another effective approach uses a hydrolysis reaction to convert COS to H_2S in the presence of aqueous amine. This reaction, however, is slower and best promoted by additives or catalyst.

Amines are used as aqueous solutions of varying concentrations, while physical solvents are pure and nonaqueous. The hydrolysis reaction, therefore, cannot occur with a physical solvent alone.

Amines are effective in H_2S removal and can assist in removing COS, but a physical solvent is required for deep removal of mercaptans unless a subsequent unit dedicated to their removal is added in series. This can be either a molecular sieve with regeneration gas cleanup or a caustic treatment enhanced by a catalyst, most commonly the proprietary Merox treating process.

COMPARATIVE SOLVENT PERFORMANCE

Table 2

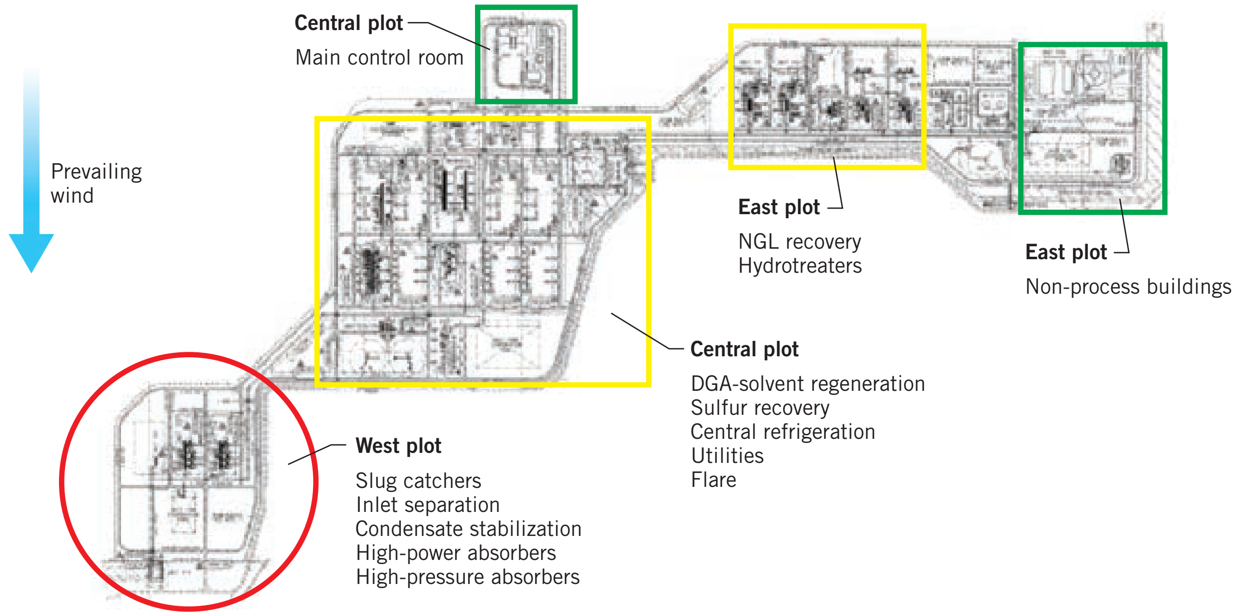
	COS	RSH	BTX	C_5+, nonaromatic
	%			
Methyldiethanolamine	~ 40	~ 10	Low	Lowest
DGA	~ 98	~ 10	Moderate	Low
Physical solvent	~ 80	100	100%	Highest
Mixed solvent	~ 98	100	High	High

Another option is to blend the two solvent types in one circulating mixture to create a hybrid solvent, often a combination of proprietary enhanced aqueous amine solutions with additives and physical solvents offered by various technology licensors. Hybrid solvents, however, present additional problems by absorbing CO_2 in the gas. This may be desirable, however, particularly for cases in which a heating-value specification for the gas can only be met if CO_2 is partially removed.

The physical solvent component of the hybrid mixture will remove essentially all CO_2, creating side effects in the downstream acid gas processing unit (typically SRU) and re-

SHAH SOUR GAS PLANT

FIG. 4



Source: Abu Dhabi Gas Development Co. (Al Hosn Gas) and Fluor Ltd.

ducing the volume of treated export gas. If this gas is sold on a volume rather than calorific-value basis, the CO_2 removal may affect project economics.

Physical solvents can coadsorb heavier hydrocarbons in sour gas. Since most sour gases are produced in the presence of condensates or oil, the sour gas will be rich in heavier hydrocarbons that will end up in the acid gas. This can lead to SRU-catalyst fouling and poor-quality sulfur.

Physical solvents can also absorb aromatics such as benzene, toluene, and xylenes (BTX) naturally present in well fluids, not always a desired outcome.

Table 2 shows the generalized performance of solvents when treating gas containing secondary contaminants beyond the prime basic acid gases H_2S and CO_2.

Highly sour-gas megaprojects require massive train throughputs for acid-gas removal units (AGRU) and especially SRUs. Tengiz SGP's single-train, 380-MMcfd amine unit, which continues to treat 16 mole % H_2S content of gas with a 2,000-tonne/hr amine circulation rate, was the largest unit-design possible upon its 2008 startup.

The massive amine units at the Shah gas development, which treat 1 bcfd of gas containing 23 mole % H_2S and 10% CO_2 in four trains at a similar amine circulation rate to Tengiz, also were designed to maximum possible capacities. Shah's amine units yield 500 MMcfd of treated gas (after acid-gas removal). SRUs at the project produce 9,200 tonne/day of sulfur.

SRU design implications

Designing SRUs to handle production from large sour-gas fields requires consideration of four major factors:

- Increasingly strict environmental performance parameters.
- H_2S-to-CO_2 ratio.
- Heavy hydrocarbons in the acid gas feed.
- Overall capacities of the megaproject and its benchmark units.

The SRU combusts the H_2S-rich acid gas in a reaction furnace (RF) before progressively converting it to elemental sulfur in the multistage Claus reactors and sulfur condensers. Treatment in a TGTU and a tail-gas incinerator follow.

Environmental performance parameters for SRUs, however, have become more stringent globally, moving from 93% sulfur recovery requirements for simpler Claus SRUs to current requirements of 99.9% sulfur recovery. This demands increasingly sophisticated tail-gas treating operations.

Heat energy generated from the RF, sulfur condensers, and incinerators is used in the heat-consuming TGTU in the form of steam that, like the AGRU, leads to a key additional utility system for water treatment and steam generation.

SRU combustion in the reaction furnace primarily relies on the heating value of acid gas to achieve good combustion. If BTX, for example, also is present in the acid gas, then higher temperatures are required to ensure BTX destruction. A similar constraint applies for ammonia destruction from sour water strippers, but this is more prevalent in refinery units.

While H_2S has an inherent (albeit relatively low) heating value, CO_2 has none. This means that an acid gas stream with too high a concentration of CO_2 will not achieve satisfactory combustion, particularly in cases where ratios of CO_2 exceed roughly 50 mole %.

Ways around this constraint exist, depending on the degree to which the acid gas is fuel-poor. Simple measures include preheating acid gas and combustion air, or adding supplemental fuel gas to increase the heating value. More sophisticated measures include bypassing certain feeds around the furnace, using oxygen enrichment to reduce the inerts content of combustion air, or using acid gas enrichment (AGE), which involves removing some amount of CO_2 from the acid gas.

The Shah gas development geographically separates low-risk areas of the plant from higher-risk areas containing high-pressure, toxic fluids (Fig. 5). Photograph from Al Hosn Gas.

The simpler solutions quickly present limitations, as either capacity or the degree of shortcoming in heating value increases. Using fuel gas to increase heating value partly negates the gas plant's main objective of producing sales gas.

Oxygen enrichment typically serves to increase overall SRU capacity or debottleneck existing plants by reducing the volume of inerts present in air passing through the process that otherwise would increase both equipment size and pressure drop. Oxygen enrichment is a costly approach for smaller capacity step changes but can yield significant dividends when used for larger capacity increases.

Introducing heavy hydrocarbons present in acid gas to the SRU impacts both the unit's catalyst performance and the quality of its sulfur output. While a typical Claus sulfur plant yields a premium-quality, bright-yellow sulfur, heavy hydrocarbons present in acid feed gas will combust and taint the yellow sulfur, creating a harder-to-sell brown product.

More critically, these hydrocarbons deposit on the Claus catalyst, causing premature deactivation. Typically, Claus catalyst loading will ensure full run-length between scheduled plant turnarounds (roughly 4 years). While the catalyst performs well at the start of a run, premature fouling accelerates catalyst degeneration to a near end-of-run state, requiring early shutdown and catalyst change.

Probably the most important consideration in SRU design for sour-gas megaprojects is handling massive amounts of sulfur using the smallest possible number of trains. The Tengiz SRU pushed the capacity envelope to 2,350 tonnes/day by using twin parallel RFs to overcome RF-size challenges and constraints on the single-burner design scale (Fig. 3). Based on benchmarks established by the Tengiz project, the Shah plant includes four parallel SRU trains, each equivalent in capacity to one of the Tengiz plants.

High temperatures

Solvents used in both the AGRU and TGTU function optimally at temperatures that usually cannot be achieved solely with air cooling at ambient temperatures much above 35° C. Since cooling water in many hot, arid climates is either rare or nonexistent, adequate cooling in summer months with a reasonable temperature approach and exchanger design can only be achieved by supplementary chilling, which requires refrigeration.

On a sour-gas megaproject, these refrigeration requirements develop into huge systems requiring massive refrigeration compression powers, air-cooled condensers, and large piping and vessel inventories. This either adds to power-generation requirements or requires adding large gas-turbine driven compressors.

Optimization of amine systems to limit chilling duty can result in substantial savings when done early in design simply by recognizing the size of the duty. This optimization may drive the need for specialist and proprietary solvents or other open-art or patented techniques or configurations.

The TGTU quench system has particular potential for optimization. While heat removal is achieved by water circulation, this also requires cooling that typically can be accomplished with air coolers.

Heavier hydrocarbons in the sour gas entering the AGRU also have knock-on effects in the unit's solvent system, including promotion of foaming, excessive flash-gas generation in the rich solvent, and, most critically, absorption into the acid gas, which will negatively impact SRU performance.

One remedy to this issue is reducing heavy hydrocarbon content upstream of the AGRU absorber. Chilling at this point in the process must consider hydrates and associated approach temperatures. This chilling will add to overall refrigeration load but can yield marked benefits in processing configuration and plant performance.

As a safety measure, high-pressure amine absorbers at the Shah gas development provide workers access via an extensive series of stairwells (Fig. 6). Photograph from Al Hosn Gas.

Safety

Alongside proven and reliable technologies, a primary consideration of design impact on safety is site location and plant layout.

Preliminary analyses of absolute H_2S concentration and partial pressure can help define potential leak scenarios as well as the scope of hazardous zones. Operators often use color codes while planning individual plant areas to graphically differentiate between zones.

Although the limits and use of coding may vary for each plant owner, specific colors are assigned to identify processing zones and designate a far wider emergency protection zone, a radius within which the public is restricted from entering.

Layout may also account for required distances between high-risk (red) and medium-risk (yellow) zones (Fig. 4), typically in relation to simultaneous operation distances or separation required between an operating part of the high-risk plant and a unit or item on which work is planned.

This approach opens up the plant layout and increases plot-space requirements, separating areas of the plant that do not contain toxic or flammable fluids at a sufficient distance from risk zones to establish areas for unrestricted worker access during normal plant operation (Fig. 5).

Design also should include identification of other safety considerations, including distances relating to possible vapor-leak dispersion, proximity to safety equipment, stairway systems (Fig. 6), safe refuges, and emergency exit pathways. OGJ

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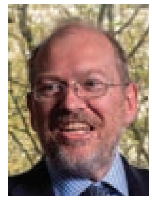

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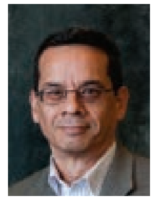

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Early detection of custody-transfer gauge issues keys successful use

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Proper calibration can yield savings of 0.4% over the typical 25-year life of a large natural gas transfer metering system, equaling $120-330 million of extra revenue for the system examined, depending on commodity pricing. Determining early that meters are properly calibrated is key to realizing these savings.

TRANSPORTATION

Different manufacturers specify different inlet requirements for custody-transfer ultrasonic gas flow meters. Traditional designs usually require relatively long inlet piping and a flow conditioner. Organisation Internationale de Metrologie Legale (OIML) R 137[1] forces ultrasonic flow meter (UFM) manufacturers to develop newer state-of-the-art devices to meet its Class 0.5 performance requirements. The maximum error allowable due to installation is ± 0.17%, almost half of what is required by the American Gas Association (AGA) and International Standards Organization (ISO) 17089-1.

The newer meters operate with short inlet piping lengths and no longer require a flow conditioner, immediately reducing space, weight, and overall material costs. Longer-term benefits include cost savings from avoiding the pressure drop created by the flow conditioner's removal, eliminating performance-loss from fouling of the flow conditioner, and performing periodic calibration at the test facility without having to send both the field calibration spool and its attached flow conditioner.

Several meter-design parameters affect ultrasonic flow measurement accuracy:

- Number of paths.
- Path type, direct or reflective.

Pipes used for the downstream meter tube had longitudinal seam welds (Fig. 1).

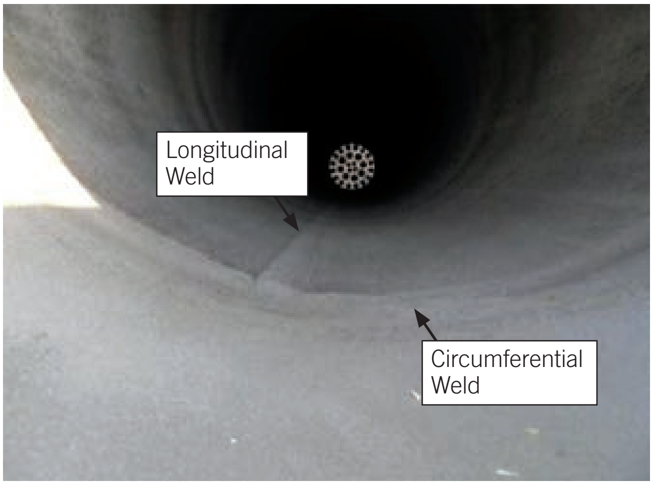
System integrator

"Dear Sir, We confrim receipt of your detailed inspection report with deviations....
We are convinced that the skid which we supplied is perfectly fit for the intended purpose, i.e. accurate gas measurement, and lives up to good engineering practice.
We have, however, commented on each individual remark and are aiming at finding an acceptable solution for each point at the soonest ..."

System integrator's senior UFM engineer

"...According to the FSD the use of welded pipe for meter tubes is allowed only for 24-in. size and larger. However, internationally accepted standards like AGA 9 and ISO 17089-1 allow the use of welded pipe for all sizes as long as the meter tubes comply with the applicable requirements to avoid disturbance of the gas velocity profile (AGA 9 §7.2.3 and ISO 17089-1 §5.9.3.3).
It can be assumed that the use of welded pipe has no effect on the measurement accuracy of the ultrasonic meters because:

- The meter tubes comply with AGA 9 and ISO 17089-1.
- The upstream meter tubes after the flow conditioner have been included with the calibration (AGA 9 §6.4).
- The calibration results comply with AGA 9 §5.1...."



Pipes used for the upstream meter tubes featured both longitudinal and circumferential seam welds that had not been ground smooth from the inside (Fig. 2).

- Path locations.
- Paths in one or different planes.
- Paths of different lengths.
- Average flow velocity calculation method.

Custody transfer meters normally have four to eight paths, either reflective or direct, in one or two planes. Meter design can aim to achieve high accuracy, high flow-disturbance tolerance, and self-checking diagnostic data. The ideal design would include all these criteria, but this may not be feasible and explains why such a large variety of meter designs exist.

Three different approaches have evolved to meet operational preferences:[2]

• Approach 1: Installation of a flow conditioner to establish a flow profile. Adequacy of the profile is confirmed using meter diagnostics, which then validate meter accuracy. A reduced bore can also act as a flow conditioner.

• Approach 2: Designing the meter to detect flow disturbances and be immune from them, confirming its accuracy.

• Approach 3: Designing the meter to measure profile factor, swirl, cross flow, distortion, and turbulence and using them to correct flow measurement.

The price for Approach 1 is the cost of pressure drop caused by the flow conditioner and loss of performance if the conditioner becomes fouled. Any changes to the flow conditioner design defeat the purpose of its installation. The advantage of Approaches 2 and 3 is elimination of flow conditioners.

Requirements

AGA 9[3] states in Section 7.2.3:

"Changes in internal diameters and protrusions should be avoided at the [ultrasonic meter] UM inlet because they create local disturbances to the velocity profiles. The UM flanges and adjacent upstream pipe should all have the same inside diameter, to within 1%, and be carefully aligned to minimize flow disturbances, especially at the upstream flange section. The adjacent upstream flange internal welds should be ground to a smooth transition with the pipe wall."

ISO 17089-1[4] states in Section 5.9.3.3:

"Changes in inside diameters and protrusions should be avoided at the [ultrasonic meter] USM inlet to avoid the disturbance of the velocity profile, unless the meter is classified as "reduced bore", see 5.2.4.

The flanges and adjacent upstream pipe shall be straight, cylindrical, and have the same inside diameter throughout as the inside diameter of the inlet of the meter, preferably within 1% but at maximum within 3%. These components shall be carefully aligned to minimize flow disturbances, especially at the upstream flange."

Item C from the same section says:

"For a minimum upstream length of 2D, there shall be no flow disturbances from flanges, flow straighteners, etc. Over a length of at least 10D or L_{min} upstream of the meter, whichever is smaller, the pipe section(s) shall fulfil the following requirements: c) the internal weld of the downstream flange of the upstream piping shall be ground smooth and no part of the upstream gasket or flange face edge shall protrude into the flow stream."

AGA 9 states in its Section 6.4:

"The metering package will consist of the ultrasonic meter, adequate upstream and downstream piping, as defined in Section 7.2.2, along with thermowell(s), sample probe, and any flow conditioning to ensure that there is no significant difference between the velocity profile experienced by the meter in the laboratory and the velocity profile experienced in the final installation. It is a requirement that all custody transfer metering packages be flow-calibrated in a flow calibration facility or by a calibration system that is traceable to a recognized national/international standard."

ISO 17089-1 states in Section 6.3.1:

EQUATIONS

$$FWME = \sum\left[\left(\frac{q_i}{q_{max}}\right)\times E_i\right] \div \sum\left(\frac{q_i}{q_{max}}\right) \quad (1)$$

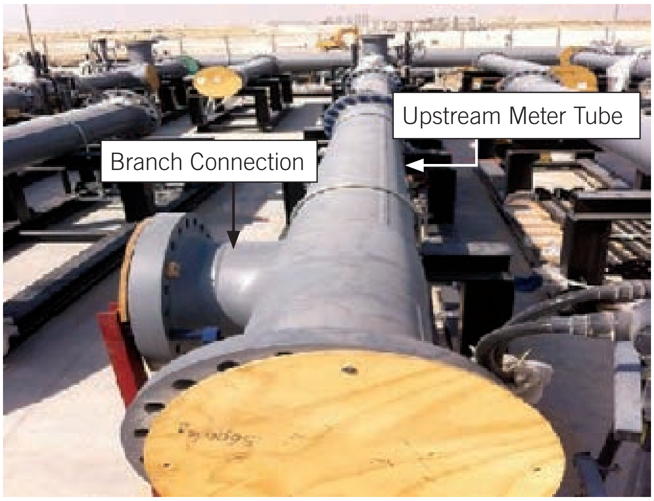
Where:

q_i/q_{max} = a weight factor for each test flow point; also defined as wf_i

E_i = indicated flow rate error % at the test flow rate q_i

q_{max} = maximum flow rate indicated in calibration certificate

$$F = \frac{100}{(100 + FWME)} \quad (2)$$



Branch-connector positioning such as that shown here prevents removal of the upstream meter tube (Fig. 3).

The internal surface of this meter tube shows signs that it was not protected by a non-toxic vapor phase corrosion inhibitor (Fig. 4).

"All Class 1 meters shall be calibrated under flowing conditions during which the meter shall not generate any critical alarms. For Class 2 meters this flow calibration is highly recommended. The calibration of meters under flowing conditions (flow or flow calibration) may also be required because of: national legal requirements, high accuracy requirements, the application for custody transfer."

Item H from section 6.3.2.1 states:

"To minimize the uncertainty of the calibration, the calibration shall be conducted: h) whenever possible, by using the upstream and downstream meter spools or dedicated calibration spools and flow conditioners (when applicable)."

Correction measures

The flow-weighted mean error (FWME) factor allows corrections using a single calibration factor. A single-calibration factor technique will be used later in this article to evaluate calibration of a given meter with two different piping fin-

This same meter tube shown in Fig. 4 also has internal circumferential girth welds not ground flush with the pipe wall (Fig. 5).

ishes.

If a UFM's flow measurement output is linear over the operational flow range of the meter, the FWME correction method can minimize the meter's measurement bias error. If a UFM's flow measurement output is nonlinear over the meter's operational range, more sophisticated error correction techniques can be applied.

Equation 1 calculates FWME for calibration data.

Applying a single calibration factor, F, to the meter output reduces the magnitude of the measurement error. Equation 2 calculates F.

Project execution

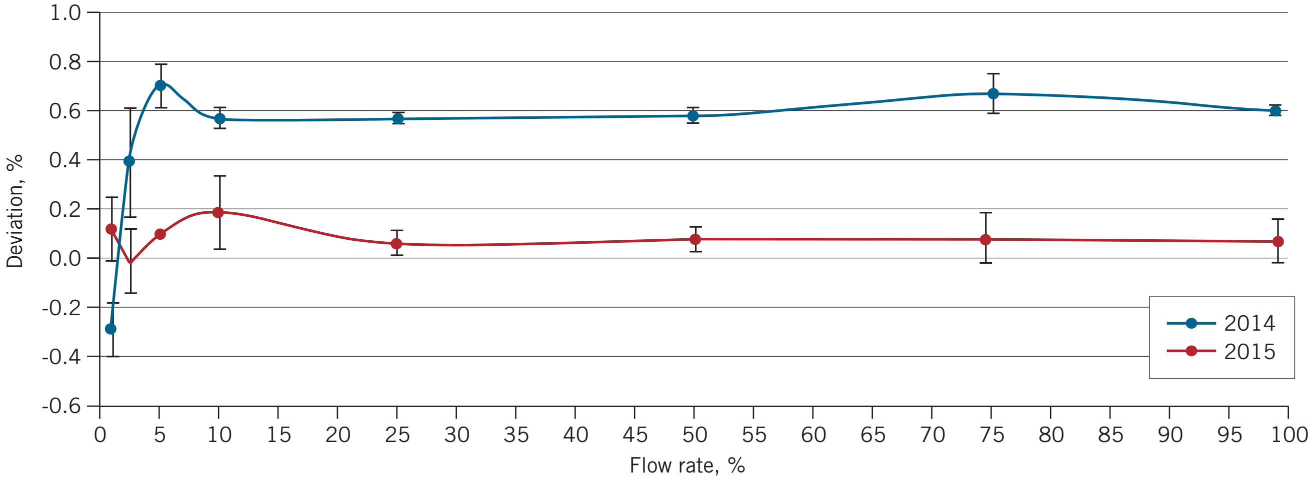
This section identifies issues associated with poor project execution in manufacturing upstream and downstream meter spools for a 720 MMscfd ultrasonic gas metering system. The project's function specification design (FSD) document specified the system consist of three 18-in. meters run in Z-configuration: two duty meters and one check meter for the duty meters.

The FSD stated that each meter run shall have:

- Inlet isolation; double block and bleed valve.
- Two-section upstream meter tubes with total minimum clear length of 20D and a flow conditioning plate installed midway.
- An ultrasonic flow meter.
- A pressure transmitter.
- Downstream meter tubes with minimum clear length of 5D.
- Two thermowells installed 5D downstream of the meter, one for a resistance temperature detector connected to a temperature transmitter and one for checking purposes.
- A 2-in. flanged inspection fitting downstream of the thermowells, mounted at 45° facing the flow.
- Z-configuration installation of the meter run, with double block and bleed valve isolation to allow series operation between the duty meter and check meter.
- Meter-run outlet double block and bleed valve isolation.

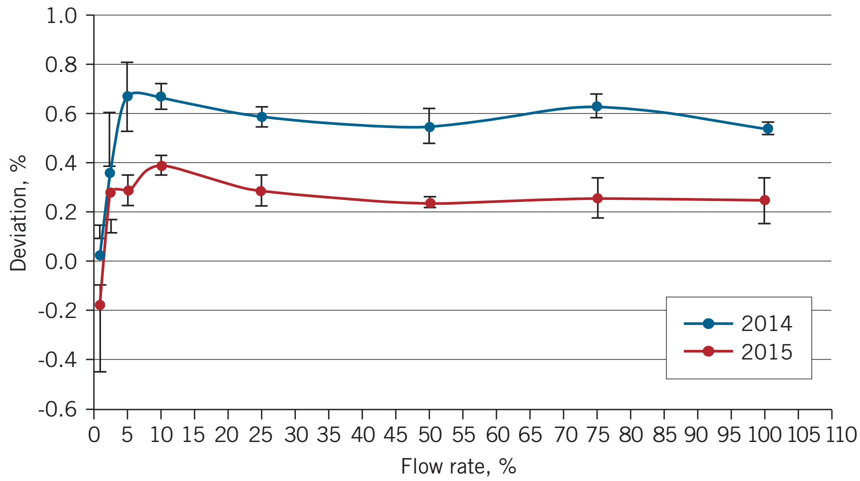
CALIBRATION RESULTS, S/N 06443

FIG. 6



CALIBRATION RESULTS, S/N 06444

FIG. 7



The system integrator responsible for its fabrication also was required to ensure that:

• All meters be flow-calibrated with their meter tubes and flow conditioners.

• The upstream and downstream meter tube sections be constructed of seamless pipe.

• Flanges and fittings welded to meter tubes have internal weld joints ground to a smooth finish, flush with the pipe ID and free of sharp edges or abrupt changes in surface level or diameter.

• Upstream meter tube ends be flanged and equipped with a spacer ring or jack screw so that the tube sections and the flow conditioner can be easily removed for inspection and cleaning.

Inspection

An inspection performed in 2014 on the metering system found non-conformities against the FSD. Longitudinal seam-welded 18-in. pipes had been used both upstream and downstream of all three meter runs. The longitudinal seams were also not ground smooth from inside (Figs. 1-2).

Two of the upstream meter tubes were also found without the flanges required on the upstream end for easy inspection and cleaning (Fig. 3). The branch connection in Fig. 3 is to connect the Z-configuration pipe spool. The arrangement shown, however, prevents removal of the upstream meter tube and flow conditioner for cleaning inspection and calibration.

Inspection could not find the flow conditioning plate's installation marking. This marking is required to ensure the flow conditioner will be installed in the same orientation after dismantling the upstream meter tube for factory flow calibration or whenever the conditioning plate is taken out for inspection or cleaning.

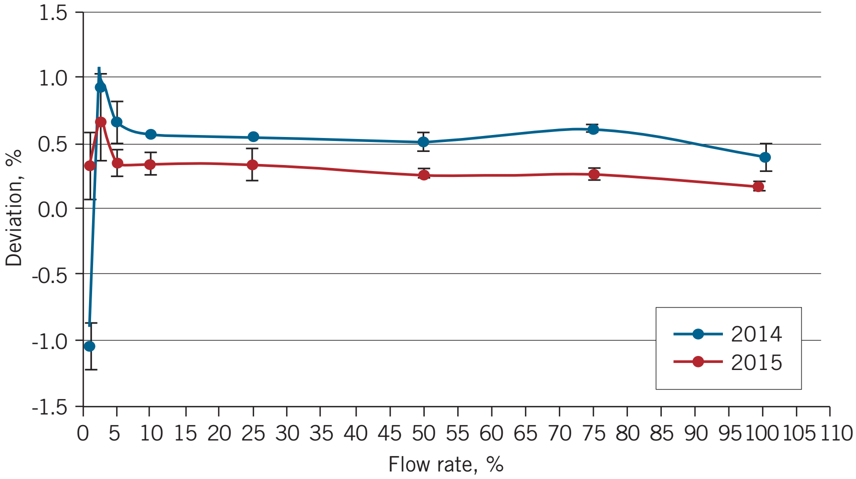
After hydrotesting, the spools were not internally protected by non-toxic vapor phase corrosion inhibitor (Fig. 4). Internal circumferential girth welds were also not grounded and flushed with the pipe wall (Figs. 4-5).

In addition to the inspector's report, the measurement engineer identified non-conformities. Two of the three meter runs were not calibrated with the actual meter tubes installed upstream of the flow conditioner. Two of the three meter runs had also not been calibrated with the actual downstream meter tubes.

The system integrator responded to the inspection report in defense of the services it had supplied. The accompanying

Calibration results, S/N 06445

FIG. 8



CALIBRATION FACTOR (F), FWME

Table 1

Year	S/N:06443 FWME	S/N:06443 F	S/N:06444 FWME	S/N:06444 F	S/N:06445 FWME	S/N:06445 F
2014	0.61	0.9940	0.58	0.9943	0.50	0.9950
2015	0.08	0.9992	0.26	0.9974	0.24	0.9976
Variation, %	—	0.5	—	0.3	—	0.3

F FACTORS

Table 2

	S/N 06443	S/N 06444	Average
2014	0.9940	0.9943	0.9941
2015	0.9992	0.9974	0.9983

SYSTEM FLOW RATES

Table 3

Year	Average F factor	Flowrate (MMscfd)	Corrected flowrate (MMscfd)
2014	0.9941	720	716
2015	0.9983	720	719

SAVINGS, $4.20/MMBTU

Table 4

$/year	$/25 years
4,764,564	119,114,100

SAVINGS, $11.62/MMBTU

Table 5

$/year	$/25 years
13,181,960	329,549,010

box shows the salient portions of this response. The senior UFM engineer also mentioned through an e-mail that the meter's performance in the flow lab is not affected by calibration with different meter tubes upstream of the flow conditioner and downstream of the meter.

Decision taken

Measurement engineers decided to:

- Fabricate new seamless upstream and downstream meter tubes as per the FSD.
- Require the new upstream and downstream meter tube ends be flanged.
- Mandate that all flanges and fittings welded to meter tubes have internal weld joints ground to a smooth finish, flush with the pipe ID and free of sharp edges or abrupt changes in surface level or diameter.
- Recalibrate all three meters with their upstream and downstream meter tubes and flow conditioners.
- Make each meter run's marks show alignment of the flange and flow conditioner tested when each is recalibrated.
- Mandate internal application of non-toxic vapor phase corrosion inhibitor after any hydrotest or flow calibration, as specified in the FSD.

The system integrator implemented these actions in 2015.

Calibration results

Figs. 6-8 show the calibration certificate results obtained from NMi Euroloop Gas Calibration for all meter runs before and after implementation of the measurement engineer's corrective actions. Each chart plots the meter deviation from the calibration standard vs. the percentage of the maximum flow rate.

On all meters the 2015 calibration differences are less than the 2014 differences. The uncertainty bars for given flow rates also do not overlap, indicating a systematic error (bias) due to poor engineering practices in fabricating the 2014 meter tubes (spools).

To better visualize the magnitude of bias introduced by the meter tubes, Table 1 presents the single calibration factor (F) and the flow-weighted mean error (FWME) for each meter by year. The variation presented in Table 1 is the F-factor's percentage variation between 2015 and 2014.

Meters 06643 and 06444 are used for customer billing. Meter 06445 is the check meter used only for verification of the billing meters.

F is a single calibration factor applied to the meter output to reduce the magnitude of the measurement error. Table 2 presents the average F factor for meters 06443 and 06444 by year before and after corrective actions.

Applying the average F factor for the daily flowrate of the metering system, 720 MMscfd, yields the results shown in Table 3. The natural gas seller will charge for an additional 3 MMscfd due to the corrective actions put in place when fabricating the meter tubes.

Using a high heat value (HHV) for the natural gas of 1,036 btu/scf and the European international price of $4.20/MMbtu in place in March 2016,[5] Table 4 shows the money recouped to the seller over the standard 25-year lifetime of a

Recommendations

1. Require a qualified inspector review the metering system manufacturer before the system is delivered to the field. This occurred for the subject project, but the deficiencies found by the inspectors in the field were not detected by the contract inspection company at the manufacturer's site, despite the FSD clearly stating all engineering requirements. As the scope of inspection is large and involves many disciplines including flow metering, either the overseas inspector (or company) should be adequately trained for the system or the project metering engineer should be part of the inspection team.
2. Use newer state-of-the-art gas ultrasonic meter designs. Usually, these newer meters can operate with short inlet lengths and don't need a flow conditioner. These meters can be calibrated in a lab with the lab's pipe spools (upstream and downstream) since the IDs of the upstream calibration spool have the same ID as the inlet of the meter within ±3%. The authors recommend ±1% as good engineering practice. Also, a careful alignment of the meter with its upstream calibration spool is very important. This process will reduce the project's delivery time, logistics, and associated costs.
   These provisions allow the meter's spools to be manufactured in the place or country that the meter will be installed, eliminating the need to send the meter spools (and flow conditioner if required) for meter calibration. This idea approach also applies to the meter's periodic recalibration. Again, the ID of the field upstream meter tube shall be the same as the diameter of the inlet of the meter within ±1%. Careful alignment is required.
   The three meters mentioned in this article were not state-of-the-art and therefore required long inlet lengths and a flow conditioner, demanding calibration of the whole metering package.
3. For an ultrasonic meter requiring a flow conditioner, calibrate the meter with its meter tubes, flow conditioner, and thermowells. After completion of meter calibration, ensure each meter run is marked to indicate alignment of flanges and flow conditioner at the time of calibration.
   Some manufactures specify that only the meter's flow conditioner and the upstream pipe tube between the flow conditioner and the meter itself need to be sent to the lab.
4. Meter tubes with seamed pipe shall have internal longitudinal and circumferential welds machined to a smooth finish, flush with the internal diameter of the pipe and free of sharp edges or abrupt changes in surface diameter.
   If not machined, never agree that the meter has been calibrated with its pipe spools as a single package. This argument has been discredited and an average calibration shift of +0.4% reported. Avoiding this calibration shift represented a large cost savings for the natural gas seller.
5. All flanges and fittings welded to meter tubes shall have internal weld joints ground to a smooth finish, flush with the ID of the pipe and free of sharp edges or abrupt changes in surface level or diameter.

gas metering system: almost \$5 million/year or almost \$120 million over 25 years. Assuming, however, an average European international price for natural gas of \$11.62/MMbtu as observed between October 2011 and October 2013,5 when oil was near \$100/bbl, revenue recouped would have equaled \$13 million/year or almost \$330 million over 25 years (Table 5). OGJ

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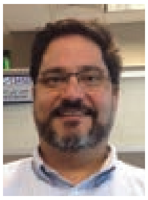
The authors



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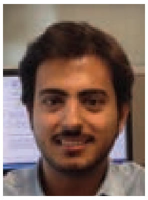

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3-D pipeline spatial data advances design, operation

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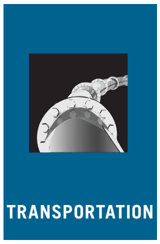


Testing of data provided by the Second Pipeline Construction Co. of China National Petroleum Corp. (PetroChina Pipeline) shows that using a 3D pipeline spatial-data model (PSDM) not only can further pipeline information management but also aid design and operation. The Pipeline Open Data Standard (PODS) provided the data-testing framework.

Pipeline geographic information systems (GIS) provide crucial decision support across a pipeline system's life cycle, including design, construction, and operation. But most pipeline GIS are 2D, limiting their management role. Demand for 3D GIS technology and applications, however, is growing, driven by areas such as pipeline integrity management, visual pipeline design and management, immersive pipeline industry training, online and offline simulating, and remote supervision and control.

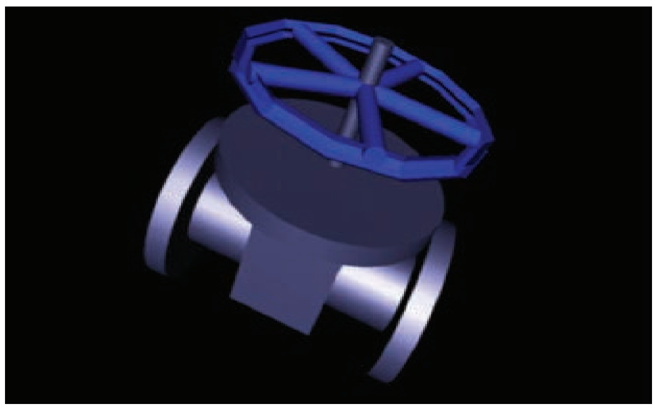
Prospective applications include:

- Design, optimization of new-construction pipeline systems.
- Creation of an interactive virtual pipeline.
- Detailed online and offline simulation.
- Reduction of training cost and time.
- Combining with supervisory control and data acquisition (SCADA) in a networked environment to provide visual remote control.

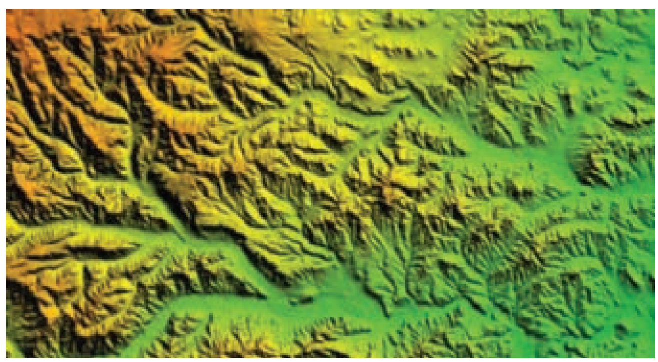
Pipeline data play a fundamental role in pipeline system management. Incomplete data may lead to uncertain or even faulty assessment results. Pipeline data consists of three types generated throughout the pipeline life cycle: survey and design data, construction data, and operational data. These data cover all aspects of pipeline management, including location, geographic features, intelligent in-line inspections, physical inspections, maintenance, operation, cathodic protection, risks, and damage events.

Pipeline data come from multiple sources, are voluminous, and continually increase with time. Most contain geospatial information. Effectively gathering, organizing, and storing these data, while providing GIS support and meeting the needs of different pipeline companies, is an increasingly urgent task.

A pipeline data model formulates the primary structure and behavioral characteristics of pipeline data. It involves behaviors and events that occur during the entire pipeline life cycle as well as information regarding the pipeline's external environment. Most pipeline data models account for the spatial features of pipeline data. The relationship between pipeline spatial data and attribute data is also described in pipeline data models, providing a framework for gathering, organizing, and managing pipeline information.



This 3D valve model combines a 3D hand wheel model and a 3D valve body model (Fig. 1).



Raster data sets run through X3D geospatial components created this 3D terrain model (Fig. 2).

Based on presentation to the Pipeline Technology Conference, May 23-25, 2016, Berlin.

The roles and benefits of data models for pipeline management include:

• Providing a uniform data structure, database, and comprehensive data inventory.

• Improving data accuracy, consistency, and integrity.

• Efficiently managing pipeline data in an ordered, centralized, and interrelated way.

• Easily updating pipeline data.

• Continually providing high quality and reliable data for pipeline management.

• Providing interoperability between pipeline companies and better support of integration activities, and promoting data sharing with industry-standard data models.

• Sharing experiences and practices with other companies.

• Implementing and customizing pipeline systems and problem solutions based on individual needs.

• Providing spatial support for GIS implementation.

• Reducing cost, time, and complexity of GIS implementation.

A robust, industry-standard pipeline data model will benefit the whole pipeline industry. A 3D pipeline spatial-data model should be the first step in developing a 3D pipeline application.

Pipeline data provided by PetroChina Pipeline and implemented through 3D-PSDM created this image (Fig. 3).

Web-based 3D application

Web technology has been an effective means of developing distributed pipeline management systems. With web-based pipeline GIS, pipeline companies are able to distribute, manage, inquire, analyze and share pipeline information. With web-based 3D GIS, a visual oil and gas pipeline management system can be created and deployed on the internet to improve pipeline management efficiency. A well-designed 3D pipeline spatial data model is the first step in developing such pipeline management systems.

Pipeline systems are not isolated. They need to integrate with other information systems. Information integration is driven by data interoperability. After more than 10 years of development, the Pipeline Open Data Standard (PODS) has come to realize the importance of data interoperability. PODS Association and Open Geospatial Consortium (OGC) have signed a liaison agreement to work together to identify enhancement opportunities between the PODS standard and data model and the advanced geospatial interoperability concepts developed within OGC's consensus standards process.[1]

A 3D PSDM as a step towards web application provides an architecture for 3D pipeline data storage and management. It also provides the ability to deploy 3D pipeline GIS on the internet, lowering the cost and time required to implement a 3D pipeline GIS and improving data accuracy, consistency, and integrity.

Model design

Objectives of 3D PSDM include:

• Providing a robust pipeline data architecture for 3D pipeline data storage and management.

• Providing a foundation for developing 3D web-based pipeline GIS.

• Easily integrating with current widely used pipeline data models including PODS, ArcGIS Pipeline Data Model (APDM)—now Utility and Pipeline Data Model (UPDM)—and Integrated Spatial Analysis Techniques.

Design principles of the 3D pipeline spatial data model include:

• Starting with current widely used pipeline data models.

• Supporting linear reference and dynamic segment technology.

• Proving extensibility and flexibility.

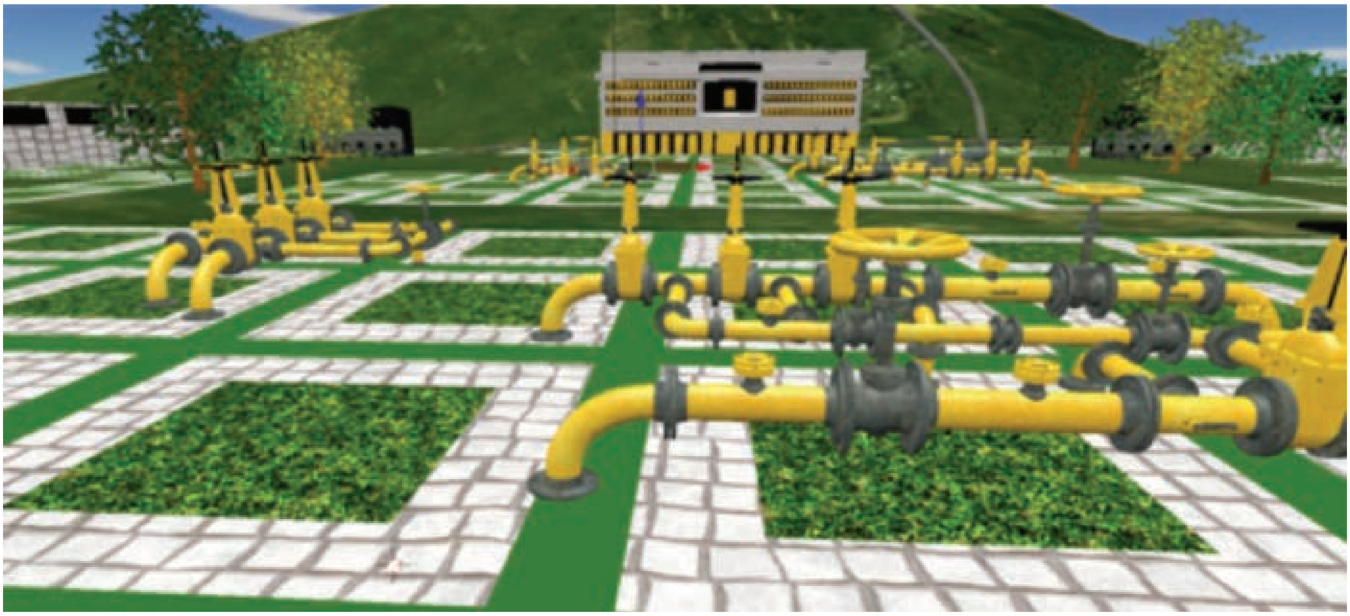
• Supporting 3D data interoperability.

• Being robust, practical, and easy to implement.

Considering wide use of PODS and other pipeline data models, 3D-PSDM design used them as a starting point from which to develop a 3D model both independent of current prevalent data models and able to be integrated with them. Design also used Pipeline Digital Elevation Model (Pipeline-DEM) raster datasets to provide the groundwork for display of visible pipeline elements. Additional raster datasets (DEMImages) provided 3D terrain model texturing.

Web3D toolkits allowed encoding, rendering, and deploying 3D pipeline models on the web. A data field called "3D_description" was appended to the class or table of current geometry-containing pipeline data models.

The 3D_description field stores code segments and descriptions (formatted by a chosen Web3D technology) for



This image used the same PetroChina Pipline data as Fig. 3 but with different textures added (Fig. 4).

pipeline and facilities 3D models according to their actual parameters. For example, centerline is modeled using ID, OD, and length; control points using XYZ coordinates; etc. Pipe-bend modeling uses actual radius, vertical angle, horizon angle, etc. These code segments for 3D models are initially stored in the server for later download to a client.

Another data field called "Texture" contains images used to texture the corresponding pipeline elements.

Current pipeline data models use a horizontal distance to depict the relation between two pipelines, or between other equipment and the pipeline centerline. A 3D pipeline data model is more complex. Several fields will be added to specific tables to describe the direction and relation between two pieces of pipeline equipment.

Fig. 1 shows a hand wheel installed on a valve body, each counted as two distinct pieces of pipeline equipment. Four additional data fields will be added to the Handwheel table for this figure: OffsetX, OffsetY, ZDistance, ValvebodyID.

OffsetX specifies the distance between the hand wheel and valve body's center of mass against the valve body's axis. OffsetY specifies the distance between the hand wheel's center of mass and the valve body along the valve body's axis. ZDistance specifies the vertical distance between the hand wheel's center of mass and the valve body along the Z direction. ValvebodyID specifies with which valve body the hand wheel will be installed. The extra fields allow rendering the 3D hand wheel model in a specific location on the valve body in 3D space.

Implementation

A typical 3D-PSDM implementation roadmap includes:

- Choosing an existing model as the pipeline data framework, and then loading custom pipeline datasets, without necessarily completing full 2D GIS implementation.
- Choose a preferred Web3D technology as a 3D pipeline modeling and rendering tool and an open standard technology if interoperability is a concern.
- Loading PipelineDEM raster datasets with your chosen Web3D technology and selecting the corresponding geographic coordinates system to create the 3D terrain models, preparing a 3D reference space for the 3D pipeline models, texturing them with remote sensing images if necessary.
- Writing codes for the 3D_description field of a pipeline element using chosen Web3D technology, loading this 3D pipeline element model, and rendering it in the created 3D referenced space according to its location information when time to display it, texturing the object with prepared images if necessary.

Working with open standard technologies ensures data interoperability, minimizies data transfer between software applications or multiple databases, promotes data reliability and conciseness, and lowers cost and time, while at the same time allowing for customization.

We chose PODS because it is intended to be a pipeline industry standard and has been widely supported and used. PODS is collaboratively developed and maintained by PODS Association members. PODS Pipeline Data Model provides a highly scalable database architecture to integrate critical records and analysis data with geospatial location for each component of a pipeline system in a vendor-neutral platform. Its pipe-centric approach to managing pipeline data helps operators collect, verify, manage, analyze, update, maintain,

RAW DATA VALUES Table 1

Attribute name	Value
Valve number	16
Name	Pneumatic-hydraulic ball valve
Outside diameter	Ø559
Type	Ball valve
Serial number	L0089237
Model	Class 400
Manufacturer	Chengdu ChengGao Valve Ltd.
Manufactured date	2010.05.01
Installed date	2011.03.16
Specification	Class 400 DN50
Mill test pressure	6.7 MPa
Nominal pressure rating	Class 400
Function	Automatically shut-off in case of emergency
Joint method	Weld
Material	Forged steel
Comments	

and deliver all the information about their pipelines quickly and reliably to applications and end-users.[2]

PODS latest model is modular, organized into functional groups that can be deployed independently.[3] The only required module is the core module that maintains the information necessary to describe the pipeline centerline. Additional modules can be chosen as needed to support specific functional requirements.

This project used Extensible 3D (X3D) as the development toolkit for 3D pipeline modeling, including creating the 3D terrain model, building the 3D pipeline and facilities model, and rendering 3D scenes. There are many options for web-based 3D modeling technology, including WebGL, Collada, XML3D, and ThreeJS. We chose X3D is because it used XML as the encoding format to organize 3D scene graphs, which lay the foundation for 3D pipeline-data interoperability. It can also interact with the external applications needed to create an interactive 3D pipeline GIS.[4]

X3D is a royalty-free open standards file format and runtime architecture to represent and communicate 3D scenes and objects using XML. It is an ISO-ratified standard that provides a system for storage, retrieval, and playback of real-time graphics content embedded in applications, all within an open architecture to support a wide array of domains and user scenarios.[5]

Fields, images

Building the 3D model using PODS required appending the fields "3D_description" and "Texture" to specific data tables. Other fields were optional. Appending PipelineDEM tables and DEMImages to the PODS model, loading raster datasets, and using X3D Geospatial components creates 3D terrain models and textures them with corresponding remote sensing images. Surrounding models such as trees, ground, walls, and buildings were also created in this step. Fig. 2 shows the 3D terrain model created by DEM raster datasets using X3D Geospatial components.

Three-dimensional terrain models commonly contain a huge quantity of geospatial data. This project used a level-of-detail (LOD) algorithm[6] to avoid the storage and transfer-time problems associated with such large files. LOD is a technology used for 3D computer simulation displays. LOD generates several levels of 3D terrain model in the server in advance, using the quadtree algorithm. The multiple levels of detail can then be switched depending on whether the user is closer or further to a specific range.

LOD technology improves render speed, reduces computer resource cost, and achieves an effect approximating the actual visual situation. Figs. 3-4 show a 3D-PSDM implementation done using data from PetroChina Pipeline.

The PetroChina data are for a compressor station and its surroundings. Development tools used included:

- Microsoft Visual Studio 2010.
- Java Development Kit 1.6.
- Microsoft SQL Server 2008.
- Internet Information Servers (IIS).
- ArcGIS for Server 10.2.2, used to create 2D pipeline GIS to verify the 3D-PSDM implementation.
- PODS.
- BS Contact, used as a plug-in to render and display 3D pipeline scenes in the web pages.
- Blender, used to create decorative 3D models, such as trees, which are not a part of the 3D-PSDM.
- Xj3D, used to write application for the interaction between 3D pipeline scenes and external applications.
- Extensible 3D (X3D), used to create 3D models for the elements defined in the 3D-PSDM.
- X3D Edit 3.3.

The pipeline data used for the 3D-PSDM implementation included:

- DEM for the selected area; 1-m resolution, UTM WGS84 coordinate system.
- Dimensions, measures, and locations of trees, lamps, walls, and the only building in the area.
- Attributes of equipment such as launchers, receivers, manifolds, valves, flanges, meters and instruments, tees, taps, elbows, pipes, flow computers, pig pass indicators, and tanks.
- Detailed pictures of the area including terrain, surroundings, building, trees, walls, lamps, and outside facilities (taken from several angles and places).

The accompanying table shows the valve's raw record.

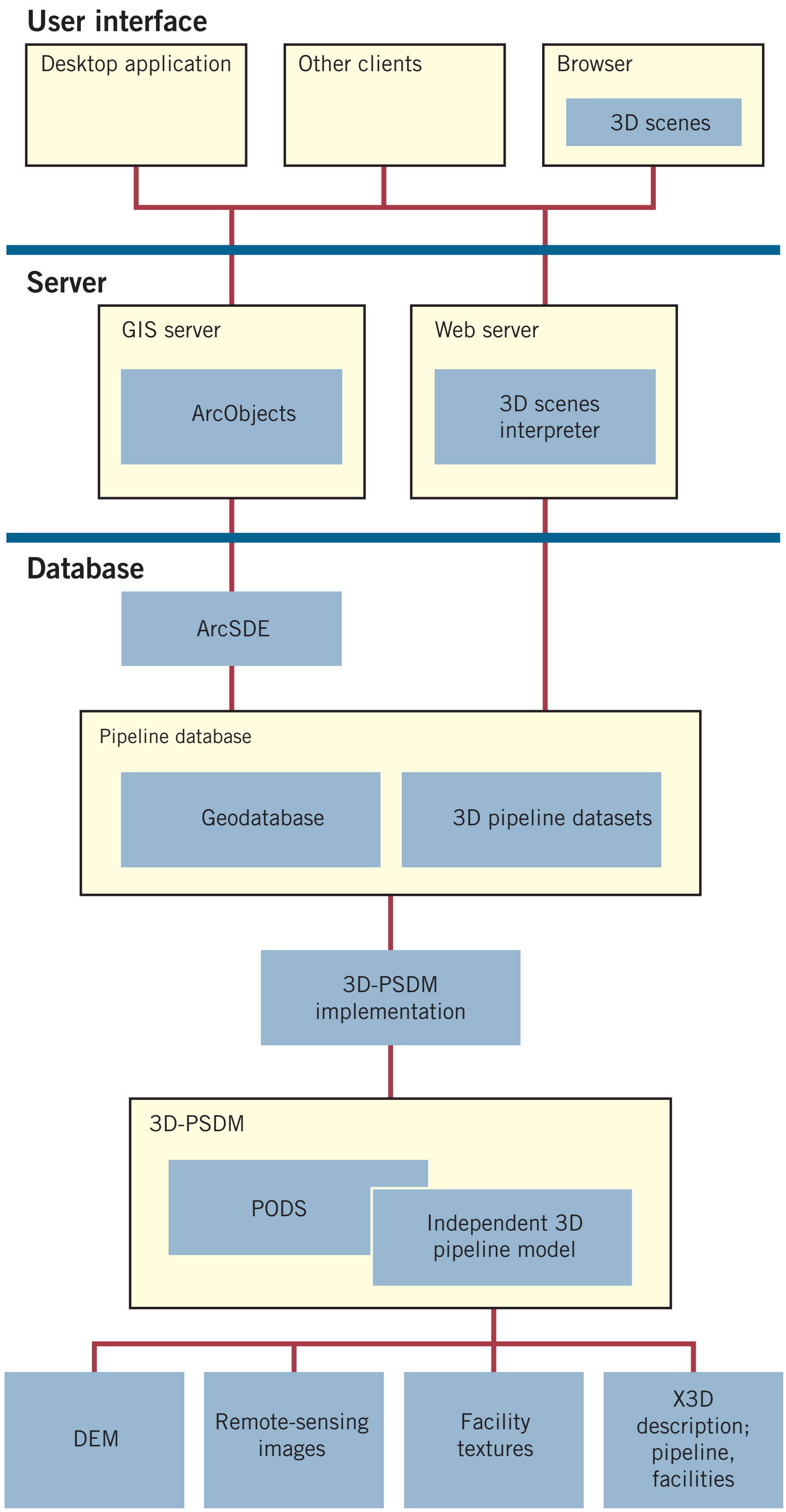
This study's implementation of 3D PSDM used PODS as the starting point, placing data into six separate PODS modules: the core module, the operations module, the offline features module, the offline compression module, the product transport features module, and the attached features module.

The data used can be classified as three types:

- Data that can be targeted into corresponding tables defined in the 3D PSDM; e.g., DEM (corresponding to the PipelineDEM table), parts of pictures (corresponding to DEMImages and the Texture table), and launcher, receiver,

SYSTEM ARCHITECTURE

FIG. 5



elbow, flange, tap, tee, valve, tank, compressor station, and structure data (corresponding to the tables with the same names).

The 3D PSDM is simple for these data, requiring just loading their attributes into the corresponding tables according to pre-defined fields in each. X3D code will be created using each item's actual attributes including size, dimension, shape, model, and specification, then loaded into the 3D_description field.

- Data that cannot be targeted into corresponding tables defined in the 3D PSDM but that still belong to pipeline system elements. These data include manifold, bypass pipe, intake pipe, outlet pipe, flow computer, pressure controller, and pig pass indicator information and use the 3D PSDM's extensibility feature. The design principles and schema of the 3D PSDM were used to design new tables to accommodate these data and append them to the 3D PSDM.
- Data surrounding elements that do not belong to the pipeline system, such as trees, walls, lamps, and a part of pictures. The open-source software Blender used some of the data to create 3D scenes as background and decorated elements for the 3D system. Others verified the 3D pipeline scenes.

Results of implementing the 3D PSDM included:

- An indication that 3D PSDM is a well-designed and easy-to-implement model.
- Uniform, ordered, interrelated, and consistent storage of both 2D and 3D pipeline data.
- An indication that the technical map-making is feasible.
- The ability to see pipeline data in 3D form, providing a completely different way to manage it. For example, system data can be found and checked simply by visually roaming the 3D pipeline scenes, clicking the component in question, and making any changes necessary.
- Reduced errors.
- Easier access. The 3D pipeline system is deployed on the internet. Users

can access the system whenever they connect to the internet.

- A firm foundation for 3D pipeline data interoperability, based on adopting the open-standard Web3D technology, X3D.

The well-designed 3D PSDM provided a uniform architecture for 3D pipeline data storage, organization, and management, in which both 2D and 3D pipeline data could be stored in an interrelated, consistent database. Feasible technical roadmaps allowed raw pipeline data to be turned into the 3D PSDM via a predefined smooth, step-by-step workflow.

Taking PODS as the starting point when implementing the 3D PSDM provided a comprehensive pipeline data inventory that made its implementation much easier. The open-standard Web3D technology X3D enabled deploying 3D pipeline scenes on the internet and laid a firm foundation for 3D pipeline data interoperability.

The extensibility design concept enabled pipeline companies to add new tables to the 3D PSDM to meet custom needs. Applying LOD technology for large 3D pipeline dataset improved display performance of 3D pipeline scenes in a networked environment.

Fig. 5 shows system architecture and implementation roadmaps.

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Haven Technology Solutions LLC: Magnolia TX

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Multi-oil-applicable trunnion ball valves

QuadroSphere Trunnion Ball Valves help prevent oil and gas production, pipeline, and refining valve failure.

Multiple flow paths through the valve and its ball's four recessed surfaces provide self-flushing to prevent clogging and to avoid high scale and solids build-up. QuadroSphere effectively functions where media flowing through it has a tendency to collect and solidify, causing failure in other valve designs.

Val-Matic Valve & Manufacturing Corporation: Elmhurst IL

For FREE Information, select #3 at ogpe.hotims.com

BONUS DISTRIBUTION

Turbomachinery & Pump Users Symposia
Offshore Northern Seas, NAPE South,
SPE Intelligent Energy, POWER-GEN Natural Gas

NEW OIL & GAS PRODUCTS:

Oil-storage-applicable vertical progressing cavity sump pumps

NEMO BT Series vertical progressing cavity sump pumps like this improve oil storage efficiency.

Availability of the series resulted when they recently served a major energy pipeline company's need to streamline its waste oil storage tanks pumping system. A custom 10-stage vertical, semi-submersed PC design was manufactured to lift heavy oil out of a tank. It also delivered 700 psi dp capacity should the system require it in an upset condition.

NEMO BT operates in reverse therefore requiring the seal to be on the discharge side and the entire housing to be pressurized. Its rotor/stator system is located at the lowest point of the pump to avoid potential dry running.

Full NEMO BT application and design details are yours free.

NETZSCH Pumps North America LLC: Exton PA

For FREE Information, select #5 at ogpe.hotims.com

Advantages of using ED-XRF spectroscopy for at-line analysis of sulfur in fuels

This free **application brief** discusses the use of energy dispersive X-ray (ED-XRF) spectroscopy to cut production delays from days to minutes in at-line analysis of sulfur in fuels.

It addresses sulfur content as a key quality determinant for many petroleum products and emphasizes ASTM D4294.

The brief details tests comparing lab and at-line analyses of sulfur in fuels and production samples, the latter using SPECTROSCOUT spectrometer.

SPECTRO, Materials Analysis Division, AMETEK:
Kleve Germany & Mahwah NJ

For FREE Literature, select #250 at ogpe.hotims.com

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3 new predictive maintenance vibration monitoring accelerometers developed

New **ICP accelerometers** with an M12 connector are on the market for predictive maintenance vibration monitoring.

601A92 is a 500-mV/g design with a ±10g measurement range and frequency range of ±3 dB of 0.17 to 10,000 Hz.

602D91 is a 100-mV/g version with ±50g measurement range and ±3 dB frequency range of 0.5 to 8,000 Hz.

603C91 100-mV/g accelerometers offer ±50g measurement range and ±3-dB frequency range of 0.5 to 10,000 Hz.

IMI Sensors Division, PCB Piezotronics: Depew NY

For FREE Information, select #6 at ogpe.hotims.com

Stainless flameproof warning devices

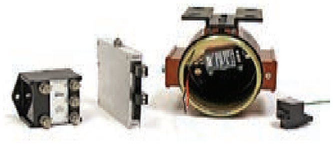
STEx stainless steel flameproof warning devices withstand aggressive onshore and offshore environments.

Specifically developed for use where corrosion is a particular issue, models have ATEX and IEC IECEx approvals. They comprise 117 and 123 dB(A) alarm horn sounders with flared or omni-directional radial horns; 15 and 25-w PA loudspeakers; 21, 15, and 10-Joule Xenon strobe beacons; rotating halogen beacons; LED beacons; and combination units. Complete STEx details are yours free.

E2S Warning Signals: London & Houston

For FREE Information, select #7 at ogpe.hotims.com

Field-installed instruments offered surge suppressor kits



Moore Industries' field-installed instruments enclosed in BH and SB housings are offered newly available **surge suppressor kits**.

They are approved for use in explosionproof applications per USA/Canada sCSAus and Australia/New Zealand ANZEx. The surge suppressors exceed Severity Level 4 of IEC 61000-4,4 providing 3kA (8/20µsec) of surge protection stopping failures due to lightning, spikes, and overvoltage surges while minimizing other electrical noise.

Moore Industries-International Incorporated: North Hills CA

For FREE Information, select #8 at ogpe.hotims.com

Explosionproof cooling products range made to serve in hazardous environments

Petrochem, refining, or oil and gas applications in hazardous environments are served by a line of **explosionproof-designed cooling products**.

Air-cooled condensing units and chillers, remote air cooled condensers, water-cooled chillers, and evaporative condensing chillers are available for indoor or outdoor petroleum uses. All are available in explosionproof design — plus maintain UL and ETL certifications. Full cooling products details are free.

Technical Systems Incorporated (TSI): Pryor OK

For FREE Information, select #9 at ogpe.hotims.com

High-temperature, lightweight carbon fiber composite material

ROCCS 10/40 carbon fiber composite material withstands 2,200°F. for 2+ hours.

The high-temperature-resistant materials weighs 15 kg/sq m and is "priced at less than US $1000 per sq m" to signfiicantly improve safety conditions at an affordable cost, declares the manufacturer. ROCCS 10/40 is available in sheet panel form or in molded net shapes.

10/40 is is produced by this manufacturer's **Rapid Output Controllable Composite Shapes (ROCCS) manufacturing technology** which delivers net shapes with zero waste.

Materials are produced in a 3D fibre matrix with fibres randomly oriented in X, Y, and Z directions and with Fibre Volume Fractions of up to 75%. Materials can be manufactured in a very broad range of basic weights from 800 to 22,000 GSM monoliths.

Carbon Fibre Preforms: Henley, Arden UK

For FREE Information, select #11 at ogpe.hotims.com

New well check valves support weight of up to 1,000 ft of pipe and well pump

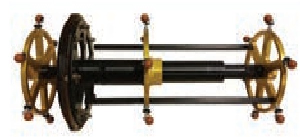
These 2 through 8-in. **Model 80SL Slim Line Well Check Valves** support the weight of up to 1,000 ft of pipe and well pump.

They comprise fusion epoxy coating as standard to protect body materials. Small outside diameter on 80SL's body allows for tight fits in a well. It's made from a strong carbon steel or optionally available 316 stainless steel valve body with corrosion-resistant 316 SS internal valve parts. Full valve details are free.

Flomatic Corporation: Glens Falls NY

For FREE Information, select #12 at ogpe.hotims.com

New waterless riser riser cleaning tool



MUDBUG drilling riser cleaning tool is introduced to be safer, faster, and more cost-effective than other methods.

As an air-activated, self-propelled tool, it uses oscillating brushes to clean debris build-up inside risers. By using only 120 psi air instead of high-pressure water, MUDBUG is said to eliminate water disposal problems and risks of high-pressure washing.

The waterless riser cleaner fits in a 2 x 4-ft job box that takes up little space and is easily transported. It requires two to three crew to operate — instead of the usual five-man team, declares the manufacturer.

Chet Morrison Contractors: Houma LA

For FREE Information, select #13 at ogpe.hotims.com

Metal recovery without waste plus PLC remote connection

Meet EPA limits for heavy metal recovery and effluent polishing — with zero sludge generation: **ENVIRO-CLEAN PROCESS**.

Engineered to reduce water purchases and sewer charges, it recycles metal-free effluent from itself back to a process.

In two steps it recovers such heavy metals as chromium, copper, zinc, lead, cadmium, mercury, nickel, silver, and manganese from groundwater or process and waste streams. It can treat single or multi-component metal bearing streams from 5 to 1,000 gpm.

ENVIRO-CLEAN PROCESS is now optionally available with computer control and internet access with PLC so it can be remotely monitored with process adjustments made from a laptop or mobile device.

Lewis Environmental Services: Pittsburgh PA

For FREE Information, select #14 at ogpe.hotims.com

3m web personal fall limiter

Latchways 3m web personal fall limiter is announced as "the most compact and lightweight self-retracting lanyard in its class using multiple spring radial energy-absorbing technology."

The PFL eliminates the need for an external energy-absorber outside of the housing.

These fall limiter SRLs comprise a highly durable polycarbonate, clear casing to allow for easy visual inspection of critical internal components. Models also provide a fully rotating attachment point, both 360° and 180° for user mobility.

MSA: Berlin

For FREE Information, select #15 at ogpe.hotims.com

UV-A irradiation, visible illumination radiometer/photometer

Apollo 1.0 wireless UV and White Light Dual Meters are on the market with Bluetooth data transmission.

These radiometer/photometer instruments accurately measure UV-A irradiation and visible illumination in nondestructive testing functions. They offer auto ranging and concurrent measuring.

Besides wireless advantages, Apollo 1.0 calibrations need not disrupt operations. You can buy a double kit (1 reader, 2 sensor units) and only send one sensor for calibration while using the other.

Labino AB: Stockholm

For FREE Information, select #16 at ogpe.hotims.com

Heavy-duty, non-metallic safety boots

Tacoma Series heavy-duty non-metallic safety boots are newly introduced.

The series features **Tacoma XT CSA safety boots** with asymmetrical composite toes, puncture-resistant midsole plate, and Barnyard-proof leather to resist damaging effects of a number of substances. These include oleic acid, urea, sodium chloride, and ammonium hydroxide.

Tacoma WP is also part of the introduction. It delivers rugged, durable performance via Goodyear Welt construction and asymmetrical composite safety toes.

Among Tacoma Series features, as with all KEEN utility footwear: "superior comfortable, quality, and fit." A national promotion through October can be viewed on the manufacturer's website including how to win a new Tacoma truck.

KEEN Incorporated: Portland OR

For FREE Information, select #17 at ogpe.hotims.com

Walker = rig operation at lower ground bearing pressures

Super Stomper Walkers allow rigs to operate at much lower ground bearing pressures than other designs.

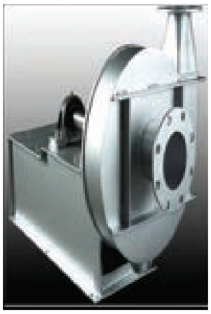
As the next generation of Entro King Pin Walker designs, Super Stomper allows multiple jack cylinders to operate over a single large walking foot. This allows a rig to operate over soft ground while still allowing movement in any direction.

Also announced is a line of heavy haul equipment: **Entro heavy haul jeeps** provide additional capacity for pull trucks to move million-pound trailers. With the available split-axle walking beam, the jeeps offer greater articulation with reduced axles and frame stress. The patented heavy haul jeeps, suspensions, and trailers are specifically engineered to meet rigorous oilfield demands in severest environments, it's noted.

Entro Industries: Hillsboro OR

For FREE Information, select #18 at ogpe.hotims.com

High-temp refinery fans



Garden City high temperature fans function at up to 2,000°F. in refineries. They're offered with complete aftermarket service, support, replacements, parts, and service.

The manufacturer offers site-specific design and customized performance for its durable high-temp configurations which come in various fan designs including radial blade, forward curved, and propeller.

Service technicians provide on-site installation and startup as well as inspections and some repairs at customer facilities.

Howden American Fan Company: Fairfield OH

For FREE Information, select #20 at ogpe.hotims.com

Deep-cycle batteries for oil, natural gas

Trojan OverDrive AGM 31 deep-cycle batteries ruggedly serve oil and gas production or pipeline flow during natural gas extraction.

Deep-discharge-applicable designs handle fluctuating or extreme temperatures. Among features are maintenance that requires no watering, durable polypropylene case, rugged construction for improved vibration resistance, superior recharge efficiency, plus flame arrestor pressure vent for overall safety.

Trojan Battery Company: Santa Fe Springs CA

For FREE Information, select #21 at ogpe.hotims.com

Low-pressure-applicable spoolable pipe product introduced

New **Thermoflex Lite spoolable pipe** is commercialized to transport hydrocarbons at low pressures. It fills the gap between HDPE pipe and the manufacturer's standard Thermoflex.

The new product is designed for long, continuous runs for hydrocarbons or other produced liquids transmission. It uses a proprietary one-step co-extruded production process which includes a Nylon PA-6 liner to protect the HDPE pipe from hydrocarbon contamination. Thermoflex Lite utilizes either a mechanical or electrofusion process to ensure joining, field integrity, and fast installation — for up to 300 psi with hydrocarbons present and in long-term service to 180°F.

Polyflow LLC: Midland TX

For FREE Information, select #22 at ogpe.hotims.com

U-pin-designed terminal loading coupler

LYNX couplers are added to this company's terminal solutions so an operator can disassemble them in seconds.

Of U-pin design, this single coupler might be responsible for the transfer of millions of gallons of fluids — so operators want to shorten the service cycles as much as possible. With a simple pull, LYNX enables access to internal components for maintenance and ability to quickly put the coupler back into service. And this can be accomplished with a flat-head screwdriver.

OPW, a Dover Company: Lebanon OH

For FREE Information, select #23 at ogpe.hotims.com

New compact simple temp calibrators

JOFRA CTC Compact Temperature Calibrators incorporate useful features to extend range and functionality.

Models offer easy-to-read, full-color display with improved navigation for easy access to the instrument's latest features. It now contains an auto step function with up to 12 preset temperature points, an optimized switch test with automatic up and down test runs, assisted manual calibration using predefined temperature points, plus memory to store up to five calibration processes.

The calibrators come in three versions to cover -25° to +660°C. with ±0.2°C. accuracy.

AMETEK Sensor, Test & Calibration: Allerød Denmark

For FREE Information, select #24 at ogpe.hotims.com

Ultra-sensitive industrial trace gas measuring analyzer

LGR-ICOS Model 950 process analyzers are announced as online, continuous laser designs for refining and petrochemical applications. They perform highly sensitive, accurate, precise, and rapid trace gas measurements.

The highly selective, interference-free (with wide dynamic range) instruments use patented Off-Axis Integrated Cavity Output Spectroscopy technology. The cavity enhancement absorption technique extends optical path lengths multiple miles to improve CH_4, CO_2, CO, O_2, H_2S, HCl, NH_3, HF, C_2H_2, and H_2O trace-gas sensitivity.

ABB Measurement & Analytics: San Jose CA

For FREE Information, select #25 at ogpe.hotims.com

Proactive, systematic approach launched for better well integrity

Point system well integrity resource is launched to "focus on integrity dynamics to provide operators with profitable wells and reduced integrity risk."

It combines Archer's proactive and systematic approach to integrity management with its experience in over 4,000 worldwide integrity-related deployments.

Point system is deployed at the surface and downhole to leverage this company's deep understanding of integrity dynamics: "the behavior of the well system in response to its integrity to unravel, decipher, and describe what is happening in the well and locate integrity failures."

Point comprises seven powerful diagnostic programs underpinned by proprietary ultrasound technology.

Complete integrity management details are for the asking.

Archer: Dyce, Aberdeen Scotland

For FREE Information, select #26 at ogpe.hotims.com

Integrated radio and controller chemical management via partnership

In partnership with TXAM Pumps, this oilfield monitoring and optimization company launches **Integrated Radio and Controller for Chemical Management**.

Developing WellAware's hardware offering, used in conjunction with its network and chemical management software, the launch is declared "a critical final step in enabling E&P and chemical service companies to monitor and control production chemical injection through an affordable, subscription-based platform."

A major benefit to operators and service companies is elimination of the up-front barrier that prevents them from streamlining their chemical management processes. Declared a complete "full stack" solution, the integrated radio and controller are compatible with RPMA, cellular, and satellite networks.

WellAware: San Antonio

For FREE Information, select #28 at ogpe.hotims.com

Intervention package cuts subsea well control event cost, deployment time

GRIP: Global Rapid Intervention Package services suite is newly developed to help reduce cost and deployment time in subsea well control events.

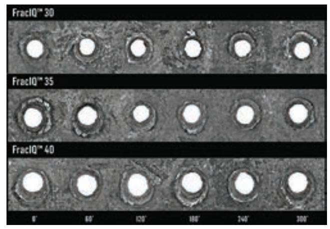
It provides well planning and well kill capabilities facilitated by the developer's global logistics infrastructure and existing product service lines. This includes an inventory of well test packages, coiled tubing units, and relief well ranging tools.

GRIP also feature new high-temperature 15,000-psi RapidCap Air-Mobile Capping Stack. Sourced from Trendsetter Engineering, it incorporates a specially designed gate valve-based system that is a lighter, less expensive, more mobile option than currently available. Full GRIP details are yours free.

Boots & Coots Services, Halliburton: Houston

For FREE Information, select #29 at ogpe.hotims.com

Constant, consistent limited entry perforating system



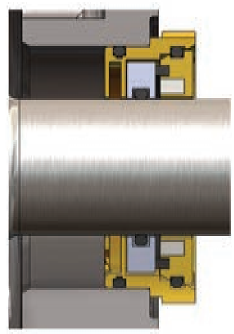
Patent-pending **FracIQ Limited Entry Perforating System** generates constant and consistent perforating entry holes and penetration depths regardless of gun position, well casing, or formation type.

The latest addition to this company's "Plug and Perf" technology, FracIQ's constant-sized casing holes improve fracture planning. It provides optimum pressure diversion while constant rock penetration creates repeatable breakdown pressures. This results in better frac treatments, lower costs, and more productive wells.

GEODynamics Incorporated, Perforating Solutions Division: Fort Worth TX

For FREE Information, select #30 at ogpe.hotims.com

Bearing isolators = positive, liquid-tight seal



Magnetically energized flat faces on this **bearing isolator** create a positive, liquid-tight seal to prevent lubrication leakage or outside contaminants ingress into host equipment bearing housing in dynamic/standby cases.

Its cartridge bearing seal assembly is "easy fit" for installation and removal plus is reusable and field-repairable. Unaffected by axial shaft displacement or thermal growth, models are said to reliably seal at up to 20,000 sfpm.

Designs also deliver proven isolator set and 100,000+ hour cycle life in bath oil, splash oil, flooded, submerged, oil mist, or vertical and horizontal isolator sets.

Isomag Corporation: Baton Rouge LA

For FREE Information, select #31 at ogpe.hotims.com

V1-certified deep-set safety valves designed to function at 12,000+ ft

WUDP-10 deep-set safety valve is certified to V1 standards under API Spec 14A.

The new deepwater valves are effective at depths in excess of 12,000 ft. Because they operate independent of tubing pressure, models can also be set shallow.

The tubing-retrievable safety valves use conventional hydraulic functionality to provide long-term operation not dependent on nitrogen storage. Simple design minimizes leak paths and incorporates a heavy power spring for fail-safe closure. WUDP-10 is one element in a larger V1 and V0-rated completion technologies portfolio for deep water. Together the integrated technologies create a toolbox of modular solutions.

Weatherford International plc: Houston

For FREE Information, select #32 at ogpe.hotims.com

NDT inspection-aiding ultrasound cameras

AcoustoCam i700 ultrasound camera and controller system perform NDT inspections from 0° up to 70° shear.

It improves inspections on not only straight beam pipeline corrosion mapping and composites applications, but also weld and TOFD inspections using new angle beam functionality.

Cameras offer higher resolution C-scan images than automated ultrasonic testing or phased array systems, it's declared. They create images in flat or curved materials up to 6-in. thick and are fully compliant with most industry UT codes.

Imperium Incorporated: Beltsville MD

For FREE Information, select #33 at ogpe.hotims.com

LDPE liner eliminates steel barrel contamination risks

Eliminate contamination risks from rust, condensation, or bacteria in 216-litre steel barrels via **Bag-In-Barrel (BIBA)**.

The strong, pliable LDPE multi-layer inner liner is also specially designed to overcome environmental issues associated with drum disposal.

Patented BIBA sits inside and lines a steel drum. It combines the best properties of both packaging types: the drum's strength along with the liner's flexibility, cleanliness, and chemical resistance, notes the manufacturer.

Liners are cost effective to provide protection to a wide range of products during transportation and storage They meet all current national and international environmental regulations.

Complete Bag-In-Barrel specifics are yours free.

Belgrade Polymer Products: Northamptonshire UK

For FREE Information, select #34 at ogpe.hotims.com

UKAS certification is now standard on non-contact thermometer

Cyclops C100L non-contact thermometer buyers will receive a designated three-point UKAS ISO / IEC 17025:2005 as standard.

These portable petrochemical-applicable instruments provide UKAS certification against three temperature points as specified by its manufacturer: 1,202°F., 2,192°F., and 2,642°F. Temperature points were selected based on the most commonly requested range for UKAS certification of Cyclops C100L. In addition to UKAS certification, thermometers are also supplied with protective jacket.

AMETEK Land: Sheffield UK

For FREE Information, select #35 at ogpe.hotims.com

Continuous, real-time benzene-specific monitors: UL certified

'Titan' continuous, real-time benzene specific monitors have achieved Underwriters Laboratories certification.

Designed to help refineries meet EPA standards, wall-mounted models deliver fast, accurate ambient benzene monitoring along boundary or fence lines. They track exposure in real-time and automatically log data. When a sample is taken, the benzene component is chemically filtered using a robust separation technology.

'Titan' issues an immediate warning alarm when hazardous benzene levels are detected. Further monitors data are free.

Ion Science Ltd.: Cambridge UK

For FREE Information, select #36 at ogpe.hotims.com

Mag-drive blowers boost manufacturing natural gas pressure

Rotron MD101 magnetic-drive regenerative blowers like this are specifically to boost natural gas pressure for a wide range of manufacturing operations.

Three standard (side channel) blowers are offered for chemical processing, environmental, or industrial uses. All employ regenerative air technology to ensure proper air pressures and vacuums for boost function without higher energy and maintenance costs associated with larger, multi-stage or positive, air-displacement blowers and compressors.

AMETEK Dynamic Fluid Solutions: Kent OH

For FREE Information, select #38 at ogpe.hotims.com

Chemical-free sour oil & sour water treatment, process: AMGAS Clear

Without chemicals, **AMGAS CLEAR process** treats sour oil in certain applications especially where treating sour water is also important with reduced disposal and operating costs.

The process also sweetens produced water for well servicing and production re-use. By reusing produced water, the system reduces the amount of water disposal plus eliminates the need for fresh water use. By removing hydrogen sulfide from crude oil, AMGAS CLEAR provides operators greater flexibility and increases economic opportunities via improved oil quality which allows market access to sweet crude oil pipelines and terminals, declares the process developer.

Added benefits include reduced worker safety risks, less equipment corrosion, effective H_2S environmental managing.

AMGAS Services Incorporated: Rockyview Alberta Canada

For FREE Information, select #39 at ogpe.hotims.com

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July "Advertiser Product & Service Followup"

Companies featured here advertised their equipment, products, or services in **July 4 Oil & Gas Journal's OG&PE products section**. These summaries give you an opportunity to receive **free information or literature** on leading manufacturers' and service providers' oil and gas specialties. **Go to OGPE.com — Click "Product Info" (white typeface) at top.** You will receive prompt, complete response from these valued OG&PE media partners.

Optimal filtration for maximum performance: JONELL Filtration Group consistently delivers

Optimize your filtration performance in oil and gas production, refinery and petrochemical, or gas processing and transmission operations with **JONELL Filtration Group products, technologies, and services**.

Specifically JONELL is available to optimize filtration performance in refinery fuel gas, catalyst protection, amine gas treating, compressor protection, final product protection, and glycol dehydration.

JONELL Filtration Group: Houston JonellInc.com

For FREE Information, select #40 at ogpe.hotims.com

QuadroSphere trunnion-mounted ball valves prevent valve failure and reduce clogging

Oil and gas production, pipeline, refining, geothermal, chemical, power, and cryogenic valve failures are prevented by **QuadroSphere Trunnion-Mounted Ball Valves**.

Multiple flow paths through the valve plus four recessed surfaces of the ball deliver self-flushing to prevent clogging as they avoid high scale and solids build-up.

Models are especially applicable where media flowing through them has a tendency to collect and solidify.

Val-Matic Valve & Mfg. Corp.: Elmhurst IL ValMatic.com

For FREE Information, select #41 at ogpe.hotims.com

By any measure — AMETEK knows your petroleum process product needs

AMETEK Chandler Engineering Model 292B portable natural gas chromatographs are compact and lightweight yet include fully integrated sample handling and onboard storage for up to 1,000 sample runs.

Drexelbrook's new total tank level system (TLS) uses the latest magnetostrictive technology to provide unparalleled accuracy when measuring total tank level, interface tank level, and temperature.

AMETEK Process Instruments Model 5100 Gas Analyzers measure moisture in bulk gas or hydrocarbon streams via Tunable Diode Laser Absorption Spectroscopy.

Drexelbrook Impulse wave-guided radar level systems generate total level, distance or volumetric outputs — unaffected by variations in process material electrical characteristics.

AMETEK PMT IDT intrinsically safe pressure transmitters deliver ±0.2% full-scale accuracy for critical applications plus meet FM, ATEX, and IECEx.

AMETEK Thermox WDG-V Combustion Analyzers offer improved control and process safety as they measure excess oxygen, hydrocarbon, and combustibles in flue gas.

AMETEK U.S. Gauge all-welded process gauges comprise integrated seal for lower cost than gauges and seals purchased separately.

AMETEK Grabner MINIVAP ON-LINE process analyzers automatically monitor vapor pressure of gasoline, crude oil, and liquefied or natural petroleum gas.

AMETEK Process Instruments new IPS-4 Spectrophotometers detect and quantify thousands of chemical species — up to eight at once — to verify feedstock, intermediate, and final product quality.

AMETEK: Berwyn PA AMETEK.com For FREE Information, select #42 at ogpe.hotims.com

AFGLOBAL

AFGlobal Corporation has announced that it has agreed to acquire Managed Pressure Operations (MPO), a subsidiary of MHWirth. As a vertically integrated supplier, this acquisition further solidifies the company's position as a specialized original equipment manufacturer (OEM). The resulting combination of companies creates the most complete deepwater managed pressure drilling (MPD) offering currently available in the market, with technology covering both onshore and offshore applications.

The new business group within AFGlobal's oil and gas segment will be known as Advanced Drilling Systems. The complete portfolio will include riser gas management systems, early kick/loss detection, managed pressure drilling, dual gradient drilling and continuous circulation.

One primary benefit to clients is the company's premium in-house design, engineering, and manufacturing capabilities—all managed by a single provider. Blending world-class products and manufacturing with transformational drilling technology will create a new family of the next generation well construction products and services. The new combined offering will create value across a broad client spectrum, targeting both the offshore and land markets.

BOOTS & COOTS SERVICES

Boots & Coots Services, a Halliburton business, announced that it has developed the Global Rapid Intervention Package (GRIP℠), a suite of services to help reduce costs and deployment time in the event of subsea well control events. GRIP℠ provides well planning and well kill capabilities facilitated by the company's global logistics infrastructure and existing product service lines. This includes both an inventory of well test packages, coiled tubing units and relief well ranging tools.

In addition, GRIP℠ features the new high temperature, 15,000 psi RapidCap™ Air-Mobile Capping Stack. Sourced from Trendsetter Engineering, Inc., RapidCap incorporates a specially designed gate valve-based system making it significantly lighter, less expensive, and more mobile than options currently on the market.

Capping stack systems currently available are extremely difficult to deploy due to their size and weight (roughly 220,000 - 300,000 lbs.) and are expensive to transport and reassemble on a job site. It can take weeks to deploy existing systems, especially from locations that lack the infrastructure to timely move the systems into position.

To address the need for a more portable and cost-effective solution, RapidCap aims to reduce deployment time by up to 40 percent over competing systems. Rather than requiring specialized infrastructure, RapidCap can be air transported on a Boeing 747-400F and lifted by a 110 ton or lighter crane. GRIP and the RapidCap Air-Mobile Capping Stack are expected to be ready for deployment by the end of 2016.

CATALYST ARTIFICIAL LIFT

Catalyst Artificial Lift recently decided to bring the honing of sucker rod pump barrels in house, and by doing so the Iola, Kansas-based company increased part quality and expanded its product line with precision barrels, using sound business strategy and a Sunnen HTG tube honing system.

Catalyst Artificial Lift provides sucker rod pump components to U.S. onshore exploration and production companies. The company makes all the parts for the pump assembly, building new pumps and supplying replacement parts. Previously, Catalyst's rod pump barrel products were limited due to reliance on outside sources for pre-honed pipe. The company began searching for options that would allow it to not only gain better control of its production processes, but also refine and enhance its barrels.

Sucker rod pumps are long slender cylinders with both fixed and movable parts. The assembly is inserted in the well to gather fluids and lift them to the surface – a process known as "artificial lift." The barrel, along with the valves and plunger, is one of the key components. Consistent diameter, roundness and straightness are important factors in preventing slippage or leakage past the plunger. The compression ratio is also affected by the fit of the plunger to the pump barrel. Properly fitted parts increase the compression ratio and may reduce the effects of free gas and help prevent gas locking.

Catalyst purchases raw material in 24' to 26' lengths and sells it in this length or cuts it to the customer's requirements after processing. The OD ranges from 1.625" to 2.75" (41.28 mm to 69.85 mm) and ID range from 1.25" to 2.25" (31.75 mm to 57.15 mm).

Prior to acquiring the tube hone, Catalyst produced only soft-pack barrels, which had fairly loose tolerances of -0.002" to +0.006". The hone enables the company to produce a precision barrel line with tolerances as tight as 0 to +0.0002".

Catalyst also expanded its product line to include chrome-plated barrels for heavily abrasive and corrosive well conditions.

For increased speed and accuracy, the HTG uses a new precision hydraulic feed system that combines the brute force of hydraulics with the finesse of a sophisticated control. This includes servo position control of the feed system actuator, electronic pressure control and closed loop feedback. The machine features a 0-100 foot/min (30.48 m/min) stroke velocity and standard 0-300 rpm spindle, though Catalyst's machine is equipped with a 600-rpm spindle option. The machine can produce a tool feed force of up to 2500 lb. (11,200 N).

GOLAR LNG LIMITED

Golar and Schlumberger announced the creation of OneLNG℠, a joint venture to rapidly develop low cost gas reserves to LNG. The combination of Schlumberger reservoir knowledge, wellbore technologies and production management capabilities, with Golar's low cost FLNG solution, offers gas resource owners a faster and lower cost development thereby increasing the net present value of the resources.

Golar and Schlumberger have 51/49 ownership of the joint venture. Golar and Schlumberger have agreed an initial investment commitment to cover the estimated equity needed to develop the first project. In addition, the parties will on a project-by-project basis discuss additional debt capital as required. This future financing will take into account Golar's FLNG intellectual property through an equitable contribution mechanism to be agreed between the parties.

OneLNG℠ will be the exclusive vehicle for all projects that involve the conversion of natural gas to LNG, which require both Schlumberger Production Management services and Golar's FLNG expertise. After reviewing the current market opportunities where 40% of the world's gas reserves can be classified as stranded, both parties are excited at the future prospects of OneLNG℠ and are confident that it would conclude 5 projects within the next 5 years.

FORUM ENERGY TECHNOLOGIES

Forum Energy Technologies has expanded its specialist syntactic foam manufacturing capabilities with the opening of a new plant near Houston.

The six-acre facility in Bryan, Texas, brings Forum's Syntech product line closer to clients in the oil and gas industry and has the capacity to support future growth.

Syntech will share the property with another of Forum's brands, Dynacon, to create a production hub with an enhanced engineering capability and streamlined process.

Forum Syntech is one of world's largest original equipment manufacturers in the niche ROV market for syntactic foam. The product is used to provide buoyancy modules for use in ROVs and other submersible equipment. The new plant not only allows the expansion of Forum's ROV flotation manufacturing capabilities, but also includes the expansion into manufacturing larger installation buoyancy modules, rigging buoyancy and custom/project specific flotation modules.

FUGRO

Fugro is to commence a major program of offshore geotechnical investigations under a contract awarded by ONGC.

Valued at approximately USD 26million, the contract involves site investigation work to gather geotechnical and geohazard data at the field, which is located in the KG-DWN-98/2 block off the east coast of India. The information will support the design and subsequent installation of wellheads, manifolds, platforms, FPSO anchors, umbilicals, pipelines and flow lines.

Fugro will deploy its deepwater geotechnical vessel, Fugro Voyager, which will perform the work in water depths ranging from 50 to 1,500 meters. The fieldwork will be followed by extensive laboratory testing, data analysis, interpretation and integration with other data acquired by Fugro.

NATIONAL OILWELL VARCO

National Oilwell Varco, Inc. and GE Oil & Gas announced the execution of an agreement to collaborate on delivering integrated solutions for Floating Production Storage and Offloading (FPSO) vessels. The agreement brings together the complementary product offerings and engineering capabilities from two industry leaders to optimize engineering design and supply comprehensive topside solutions for FPSO projects.

NOV engineers and manufactures advanced fluids pumping, treatment and processing systems; composite piping systems; cranes and deck machinery; and sophisticated, disconnectable turret mooring systems for FPSOs and related vessels. Additionally, NOV has successfully installed and commissioned equipment on hundreds of vessels in dozens of shipyards for the oil and gas drilling industry.

GE Oil & Gas engineers and manufactures advanced technology solutions for many of the world's most complex power generation and gas compression projects. Also, with its Subsea Production Systems, GE Oil & Gas offers a comprehensive range of solutions including subsea trees, manifold & connection systems, and power & processing technology.

GE Oil & Gas may also involve other GE businesses in the collaboration with NOV.

The new, combined platform will provide industry-leading topside systems with repeatable deliveries, scale economies and standardized interfaces, which are expected to reduce risk of construction delays and cost overruns for deepwater oil and gas customers. Additionally, the new platform will incorporate digital solutions, which will optimize performance and provide predictive analytics through the life of the vessels, enabling FPSOs to efficiently adapt to a wider array of operating parameters.

The industrialized manufacturing supply chain, combined with digital solutions and global service and aftermarket capabilities, is expected to maximize life-cycle efficiencies and drive down the cost of offshore oilfield development.

NOV and GE Oil & Gas expect to complete joint engineering efforts and commence offering topside package solutions to the oil and gas industry by early 2017.

ONESUBSEA

OneSubsea, a Schlumberger company, has been awarded an engineering, procurement and construction contract totaling approximately $300 million from Woodside Energy Ltd. OneSubsea will supply a subsea production system and a dual multiphase boosting system for the Greater Enfield Project, offshore northwest Australia.

The scope of contract includes six horizontal SpoolTree* subsea trees, six horizontal trees for the water injection system, six multiphase meters, a high-boost dual pump station with high-voltage motors, umbilical, topside, subsea controls and distribution, intervention and workover control systems, landing string, and installation and commissioning services.

PK SAFETY SUPPLY

PK Safety Supply announced the addition of real-time gas monitors to the line of products for oil and gas industry. BW Clip Series are reliable, maintenance-free gas detectors, specifically engineered for hazardous environments and extreme temperatures.

This new generation of gas detectors include the real-time digital display of gas levels, the ability to calibrate the device, and the ability to put it into hibernation mode when not in use. H2S and CO models provide up to three years of operation and hibernation capability, and all models are maintenance-free with no need for battery charging or sensor replacement. BW Clip Series Real-Time Gas Detectors are based on Surecell™ and Reflex Technology™. Surecell™ is a unique dual reservoir sensor design that dramatically improves instrument performance, response time, and longevity.

Reflex Technology™ is an advanced automated internal test function that routinely checks the operating condition of the sensor to increase safety, up-time, and overall worker confidence. Specifically, there is an automated self-test of battery, sensor and electronics within the BW Clip Series.

The instrument management option with the IntelliDoX Management System combines smart docking modules, updated Firmware V 7.000, and Fleet Manager II 4.3.31 software. It ensures quick bump tests and calibrations, unmatched configurability, enhanced productivity, and the highest level of protection.

SHAWCOR

Shawcor Ltd. announced that its pipe coating group has received a conditional contract worth approximately $300 million from Infraestructura Marina del Golfo (IMG), to provide pipeline coating solutions to the Comisión Federal de Electricidad (CFE) Sur de Texas - Tuxpan gas pipeline project. The Tuxpan Gas Pipeline project will transport natural gas along an underwater route in the Gulf of Mexico, from the South of Texas, USA to Tuxpan, Veracruz. It will supply natural gas to the CFE's power generation plants in multiple regions of the country. IMG is a Mexican company majority-owned by TransCanada Corporation and partially owned by IEnova

The contract involves coating approximately 690 km of 42" pipe with the application of concrete weight coating in a variety of thicknesses (2.25", 2.752" and 3.5") and supply the installation of 5,000 sacrificial anodes. Coating is expected to commence in the beginning of 2017 and complete by the end of 2017.

The company will execute the work at Shawcor's new coating facility in Altamira, Tampico, MX. The new Altamira facility was strategically developed to serve offshore projects in the Western Hemisphere from Mexico. Development started in January, 2016 and will be fully mobilized and functional by the third quarter of 2016 to serve the Sur de Texas – Tuxpan project requirements. The facility is comprised of a dedicated automated pipe inspection and repair plant and two high capacity concrete weight coating plants capable of coating pipes of up to 48" in diameter. Located with access to substantial adjacent storage areas located within 2km of the commercial port quays for receipt of pipe and raw materials.

SIEMENS

Siemens has won an order from the Trans Adriatic Pipeline consortium for six 15-megawatt SGT-400-driven turbo compressor trains. The Trans Adriatic Pipeline (TAP) will open up the so-called Southern Gas Corridor for Europe. Installation is scheduled for 2017 and the pipeline is expected to begin operating in late 2019.

The pipelines in the Southern Gas Corridor will transport natural gas from the Shah Deniz II field in Azerbaijan in the Caspian Sea to Europe. TAP represents the missing link that will enable this natural gas resource to be exploited. The 878-kilometer-long Trans Adriatic Pipeline will connect with the Trans Anatolian Pipeline at the Turkish-Greek border at Kipoi, crossing Greece, Albania and the Adriatic Sea to come ashore in southern Italy. The landfall in Italy provides multiple opportunities to transport the natural gas to large European markets such as Germany, France, and the UK.

Each of the six gas turbine-driven compressor trains comprises an SGT-400 industrial gas turbine and a Siemens barrel-type STC-SV compressor. Siemens will deliver three compressor trains to the compressor station in Kipoi, Greece. This marks the beginning of the TAP at the border to Turkey. The TAP's landfall in Albania will be 17 kilometers northwest of Fier, up to 400 meters inland from the shoreline. Another three units will be installed in this compressor station. Here, the natural gas will be compressed to up to 130 bar and make its way along the 105-kilometer seabed from the Albanian to the Italian coast.

SUBSEA INDUSTRIES

With an increasing trend for thruster and rudder manufacturers finishing their products with self-cleaning protective hard coatings, Antwerp headquartered Subsea Industries has introduced a filler coating for use with its Ecoshield hard coat system.

Ecofix, specifically formulated to provide ship repairers and OEM's with a cost-effective solution for the repair of corroded or pitted steel surfaces, returns the thruster or rudder to its original state prior to touching up the repaired area with Ecoshield.

Ecofix is an effective alternative to metal facing or very expensive fillers because of its bonding and hardness properties. Since Ecofix uses the same basic resin as Ecoshield, the coating can be applied just one hour after applying the filler.

WEATHERFORD

Weatherford International plc announced that its new model WUDP-10 deep-set safety valve has been certified to V1 standards under the American Petroleum Institute (API) Specification 14A.

The valve is designed for deepwater applications and is effective at depths in excess of 12,000 ft. (3,658 m). Additionally, because it operates independent of tubing pressure, the valve can also be set in shallow applications.

The tubing-retrievable valve uses conventional hydraulic functionality to provide long-term, reliable operation that is not dependent on nitrogen storage. The simple design minimizes leak paths and incorporates a heavy power spring for fail-safe closure.

IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4 7-15 2016	Districts 1-4 7-8 2016	District 5 7-15 2016	District 5 7-8 2016	Total US 7-15 2016	Total US 7-8 2016	Total US 7-17* 2015
	1,000 b/d						
Total motor gasoline	808	761	89	59	897	820	816
Mo. gas. blending comp.	744	645	76	59	820	704	770
Distillate	145	48	45	9	190	57	194
Residual	71	200	147	120	218	320	154
Jet fuel-kerosine	99	28	226	68	325	96	222
Propane-propylene	59	67	24	17	83	84	88
Other	586	893	145	3	733	896	785
Total products	**1,768**	**1,997**	**676**	**276**	**2,446**	**2,273**	**2,259**
Total crude	**6,787**	**6,402**	**1,346**	**1,439**	**8,133**	**7,841**	**7,940**
Total imports	**8,555**	**8,399**	**2,022**	**1,715**	**10,577**	**10,114**	**10,199**

*Revised.
Source: US Energy Information Administration
Data available at PennEnergy Research Center.

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

OGJ CRACK SPREAD

	7-22-16*	7-24-15*	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	55.38	71.57	(16.18)	(22.62)
Brent crude	45.35	55.75	(10.40)	(18.65)
Crack spread	10.03	15.81	(5.78)	(36.56)
FUTURES MARKET PRICES				
One month				
Product value	57.67	75.24	(17.57)	(23.35)
Light sweet crude	44.87	49.26	(4.39)	(8.92)
Crack spread	12.80	25.98	(13.18)	(50.72)
Six month				
Product value	58.00	67.77	(9.78)	(14.43)
Light sweet crude	48.11	52.09	(3.98)	(7.64)
Crack spread	9.89	15.68	(5.80)	(36.96)

*Average for week ending.
Source: Oil & Gas Journal
Data available at PennEnergy Research Center.

EXPORTS OF CRUDE AND PRODUCTS

	Total US 7-15-16	7-8-16	*7-17-15
	1,000 b/d		
Finished motor gasoline	395	395	366
Jet fuel-kerosine	138	138	144
Distillate	1,305	1,305	1,228
Residual	353	353	390
Propane/propylene	661	661	600
Other oils	1,042	1,042	1,013
Total products	**3,894**	**3,894**	**3,741**
Total crude	**598**	**598**	**571**
Total exports	**4,492**	**4,492**	**4,312**
NET IMPORTS			
Total	6,088	5,622	5,888
Products	(1,448)	(1,621)	(1,482)
Crude	7,536	7,243	7,370

*Revised.
Source: Oil & Gas Journal
Data available at PennEnergy Research Center.

CRUDE AND PRODUCT STOCKS

District	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 bbl						
PADD 1	16,668	72,003	66,896	9,671	60,757	10,578	4,367
PADD 2	149,989	53,781	47,111	6,362	30,194	1,340	27,979
PADD 3	269,627	78,853	69,003	16,793	44,665	24,944	52,385
PADD 4	24,652	7,614	5,687	663	3,727	264	[1] 2,705
PADD 5	58,526	28,749	26,019	8,412	13,440	4,950	—
July 15, 2016	**519,462**	**241,000**	**214,716**	**41,901**	**152,783**	**42,076**	**87,436**
July 8, 2016	**521,804**	**240,089**	**213,431**	**40,638**	**152,998**	**41,337**	**87,359**
July 17, 2015[2]	**463,884**	**216,285**	**190,615**	**44,107**	**141,517**	**39,266**	**87,690**

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available at PennEnergy Research Center.

REFINERY REPORT—JULY 15, 2016

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Refinery output Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,104	1,114	3,249	94	362	36	151
PADD 2	3,765	3,764	2,701	201	1,042	46	398
PADD 3	8,909	8,860	2,169	945	2,860	227	988
PADD 4	618	617	338	38	194	8	[1] 197
PADD 5	2,675	2,509	1,669	443	546	95	—
July 15, 2016	**17,071**	**16,864**	**10,126**	**1,721**	**5,004**	**412**	**1,734**
July 8, 2016	**16,905**	**16,544**	**10,179**	**1,727**	**5,034**	**388**	**1,679**
July 17, 2015[2]	**17,161**	**16,870**	**9,822**	**1,721**	**5,073**	**471**	**1,657**
	18,320 Operable capacity		**93.2 utilization rate**				

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available at PennEnergy Research Center.

OGJ GASOLINE PRICES

	Price ex tax 7-20-16	Pump price* 7-20-16	Pump price 7-22-15
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	155.2	204.6	259.3
Baltimore	166.6	217.6	262.4
Boston	163.6	208.6	265.4
Buffalo	157.6	218.6	276.3
Miami	152.7	207.6	269.3
Newark	172.2	205.1	255.2
New York	180.6	241.6	289.7
Norfolk	197.7	238.4	239.7
Philadelphia	147.8	216.6	284.6
Pittsburgh	165.7	234.5	281.6
Wash., DC	189.5	231.4	271.6
PAD I avg	168.1	220.4	268.7
Chicago	224.6	273.2	307.0
Cleveland	174.7	221.1	272.9
Des Moines	173.8	224.2	272.6
Detroit	173.2	222.1	272.9
Indianapolis	174.9	223.2	262.3
Kansas City	175.4	211.1	259.3
Louisville	172.8	217.2	290.9
Memphis	179.4	219.2	261.3
Milwaukee	158.9	210.2	285.3
Minn.-St. Paul	166.2	213.2	276.8
Oklahoma City	158.3	193.7	243.8
Omaha	165.1	211.2	260.3
St. Louis	167.5	203.2	276.8
Tulsa	165.5	200.9	257.0
Wichita	165.7	208.1	261.3
PAD II avg	173.0	216.8	270.7
Albuquerque	154.8	192.1	255.7
Birmingham	166.7	206.0	246.7
Dallas-Fort Worth	161.7	200.1	247.6
Houston	163.3	201.7	247.7
Little Rock	161.8	202.0	252.7
New Orleans	162.3	200.7	251.7
San Antonio	161.7	200.1	250.8
PAD III avg	161.8	200.4	250.4
Cheyenne	174.6	217.0	273.3
Denver	186.6	227.0	283.6
Salt Lake City	181.1	229.0	290.2
PAD IV avg	180.8	224.3	282.4
Los Angeles	254.9	313.9	412.8
Phoenix	191.5	228.9	297.0
Portland	188.4	237.9	302.0
San Diego	228.9	287.9	400.1
San Francisco	234.9	293.9	420.9
Seattle	208.0	270.9	328.7
PAD V avg	217.8	272.2	360.2
Week's avg.	**176.8**	**223.5**	**280.4**
June avg.	**188.3**	**234.9**	**276.9**
May avg.	**176.1**	**222.8**	**267.0**
2016 to date	**160.0**	**206.7**	—
2015 to date	**201.7**	**249.0**	—

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

BAKER HUGHES RIG COUNT

	7-22-16	7-24-15
Alabama	1	1
Alaska	6	11
Arkansas	—	4
California	7	11
Land	7	11
Offshore	—	—
Colorado	20	39
Florida	—	1
Illinois	3	2
Indiana	—	—
Kansas	—	11
Kentucky	1	3
Louisiana	44	76
N. Land	15	25
S. Inland waters	3	4
S. Land	8	17
Offshore	18	30
Maryland	—	—
Michigan	—	—
Mississippi	2	2
Montana	—	1
Nebraska	—	2
New Mexico	26	51
New York	—	—
North Dakota	27	69
Ohio	12	20
Oklahoma	59	107
Pennsylvania	14	44
South Dakota	—	—
Texas	217	374
Offshore	—	1
Inland waters	—	—
Dist. 1	15	48
Dist. 2	16	41
Dist. 3	5	16
Dist. 4	10	20
Dist. 5	2	4
Dist. 6	9	23
Dist. 7B	5	4
Dist. 7C	25	35
Dist. 8	110	148
Dist. 8A	8	13
Dist. 9	—	4
Dist. 10	8	17
Utah	3	7
West Virginia	10	18
Wyoming	8	21
Others ID-INV-1	2	1
Total US	**462**	**876**
Total Canada	**102**	**200**
Grand total	**564**	**1,076**
US oil rigs	371	659
US gas rigs	88	216
Total US offshore	19	31
Total US cum. avg. YTD	**486**	**1,116**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 46.
Source: Baker Hughes Inc.
Data available at PennEnergy Research Center.

OGJ PRODUCTION REPORT

	[1]7-22-16	[2]7-24-15
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	27
Alaska	445	450
California	540	564
Colorado	296	337
Florida	6	6
Illinois	19	26
Kansas	95	123
Louisiana	1,278	1,413
Michigan	13	17
Mississippi	50	68
Montana	54	77
New Mexico	344	412
North Dakota	1,036	1,199
Ohio	67	73
Oklahoma	340	425
Pennsylvania	15	20
Texas	3,529	3,759
Utah	82	101
West Virginia	19	22
Wyoming	184	239
Other states	49	53
Total	**8,479**	**9,411**

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

US CRUDE PRICES

	7-22-16 $/bbl*
Alaska-North Slope 27°	22.77
Light Louisiana Sweet	39.56
California-Midway Sunset 13°	34.75
California Buena Vista Hills 26°	42.94
Wyoming Sweet	40.44
East Texas Sweet	38.75
West Texas Sour 34°	35.75
West Texas Intermediate	40.75
Oklahoma Sweet	40.75
Texas Upper Gulf Coast	34.50
Michigan Sour	32.75
Kansas Common	39.75
North Dakota Sweet	34.75

*Current major refiner's posted prices except N. Slope lags 2 months. 40° gravity crude unless differing gravity is shown. Source: Oil & Gas Journal. Data available at PennEnergy Research Center.

WORLD CRUDE PRICES

		$/bbl
OPEC reference basket	**Wkly. avg. 7-22-16**	**42.68**
	Mo. avg., $/bbl	
	May-16	June-16
OPEC reference basket	43.21	45.84
Arab light-Saudi Arabia	43.48	46.28
Basrah light-Iraq	42.05	44.63
Bonny light 37°-Nigeria	46.85	48.48
Es Sider-Libya	45.83	47.28
Girassol-Angola	46.58	48.30
Iran heavy-Iran	41.67	44.68
Kuwait export-Kuwait	41.60	44.50
Marine-Qatar	44.13	46.37
Merey-Venezuela	34.28	38.22
Minas 34°-Indonesia	48.64	51.56
Murban-UAE	47.12	49.28
Oriente-Ecuador	41.96	44.03
Saharan blend 44°-Algeria	47.73	48.98
Other crudes		
Fateh 32°-Dubai	44.29	46.25
Isthmus 33°-Mexico	44.76	47.51
Brent 38°-UK	46.83	48.28
Urals-Russia	45.08	46.60
Differentials		
WTI/Brent	0.01	0.46
Brent/Dubai	2.54	2.03

Source: OPEC Monthly Oil Market Report.
Data available at PennEnergy Research Center.

REFINED PRODUCT PRICES

Spot market product prices

	7-15-16 ¢/gal
Motor gasoline (Conventional-regular)	
New York Harbor	138.70
Gulf Coast	137.90
Motor gasoline (RBOB-regular)	
New York Harbor	148.20
No. 2 heating oil	
New York Harbor	128.80

	7-15-16 ¢/gal
No. 2 Distillate	
Low sulfur diesel fuel	
New York Harbor	137.60
Gulf Coast	133.80
Los Angeles	138.80
Kerosine jet fuel	
Gulf Coast	125.10
Propane	
Mont Belvieu	48.30

Source: EIA Weekly Petroleum Status Report.
Data available at PennEnergy Research Center.

IHS PETRODATA RIG COUNT

JULY 22, 2016

	Total supply of rigs	Marketed supply of rigs	Marketed contracted	Marketed utilization rate (%)
US Gulf of Mexico	109	53	40	75.5
South America	55	51	41	80.4
Northwest Europe	109	88	70	79.6
West Africa	69	57	29	50.9
Middle East	166	156	123	78.9
Southeast Asia	95	80	39	48.8
Worldwide	835	698	501	71.8

Source: IHS Petrodata
Data available in PennEnergy Research Center

US NATURAL GAS STORAGE[1]

	7-15-16	7-8-16	7-15-15	Change, %
	bcf			
East	697	678	622	12.1
Midwest	801	785	629	27.3
Mountain	210	208	166	26.5
Pacific	318	319	336	(5.4)
South Central	1,251	1,253	1,053	18.8
Salt	349	355	304	14.8
Nonsalt	901	898	748	20.5
Total US	**3,277**	**3,243**	**2,806**	**16.8**
	Apr.-16	**Apr.-15**	**Change, %**	
Total US[2]	**2,653**	**1,805**	**47.0**	

[1]Working gas. [2]At end of period.
Source: Energy Information Administration
Data available at PennEnergy Research Center.

PACE REFINING MARGINS

	Apr. 2016	May 2016	June 2016	June 2015	Change	Change, %
			$/bbl			%
US Gulf Coast						
Composite US Gulf Refinery	11.48	11.11	11.32	15.87	(4.55)	(28.7)
Mars (Coking)	12.86	12.09	12.22	16.74	(4.52)	(27.0)
Mars (Cracking)	8.99	8.29	8.40	13.55	(5.15)	(38.0)
Bonny Light	6.83	7.63	7.71	13.68	(5.97)	(43.6)
US PADD II						
Chicago (WTI)	14.59	15.89	19.05	19.84	(0.79)	(4.0)
US East Coast						
Brass River	8.36	9.22	11.31	17.62	(6.30)	(35.8)
East Coast Comp	10.04	11.03	14.90	21.63	(6.73)	(31.1)
US West Coast						
Los Angeles (ANS)	14.59	10.81	14.21	16.46	(2.25)	(13.7)
NW Europe						
Rotterdam (Brent)	3.14	1.76	2.45	5.79	(3.35)	(57.7)
Mediterranean						
Italy (Urals)	4.30	4.06	4.37	6.64	(2.27)	(34.2)
Far East						
Singapore (Dubai)	3.07	2.49	2.52	5.67	(3.16)	(55.6)

Source: Jacobs Consultancy Inc.
Data available at PennEnergy Research Center. **NOTE: No new data at press time.**

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	Mar. 2016	Feb. 2016	Mar. 2015	Mar. 2016–2015 change	Total YTD 2016	Total YTD 2015	YTD 2016–2015 change
				bcf			
DEMAND							
Consumption	2,375	2,697	2,617	(242)	8,201	8,699	(498)
Addition to storage	215	111	182	33	392	314	78
Exports	196	164	164	32	530	454	76
Canada	81	62	90	(9)	213	240	(27)
Mexico	105	99	74	31	304	208	96
LNG	10	3	—	10	13	6	7
Total demand	**2,786**	**2,972**	**2,963**	**(177)**	**9,123**	**9,467**	**(344)**
SUPPLY							
Production (dry gas)	2,294	2,183	2,291	3	6,773	6,607	166
Supplemental gas	5	5	5	—	16	16	—
Storage withdrawal	274	515	376	(102)	1,583	1,974	(391)
Imports	240	251	258	(18)	763	790	(27)
Canada	231	241	243	(12)	733	752	(19)
Mexico	—	—	—	—	—	—	—
LNG	9	10	15	(6)	30	38	(8)
Total supply	**2,813**	**2,954**	**2,930**	**(117)**	**9,135**	**9,387**	**(252)**

NATURAL GAS IN UNDERGROUND STORAGE

	Mar. 2016	Feb. 2016	Jan. 2016	Mar. 2015	Change
			bcf		
Base gas	4,354	4,361	4,361	4,360	2,477
Working gas	2,492	2,544	2,948	1,483	1,009
Total gas	**6,846**	**6,905**	**7,309**	**5,843**	**3,486**

Source: DOE Monthly Energy Review.
Data available at PennEnergy Research Center. **NOTE: No new data at press time.**

WORLDWIDE NGL PRODUCTION

	Apr. 2016	Mar. 2016	4 month average production 2016	4 month average production 2015	Change vs. previous year Volume	Change vs. previous year %
			1,000 b/d			%
Brazil	99	93	93	106	(12)	(11.6)
Canada	760	760	791	708	83	11.7
Mexico	301	290	303	337	(34)	(10.2)
United States	3,504	3,509	3,411	3,144	268	8.5
Venezuela	193	193	195	213	(18)	(8.3)
Other Western Hemisphere	226	223	213	237	(24)	(10.1)
Western Hemisphere	**5,083**	**5,068**	**5,007**	**4,744**	**262**	**5.5**
Norway	374	382	382	345	38	11.0
United Kingdom	76	76	75	57	17	30.3
Other Western Europe	13	13	13	12	1	6.1
Western Europe	**463**	**471**	**470**	**414**	**56**	**13.5**
Russia	792	823	829	705	124	17.6
Other FSU	170	170	170	156	14	9.0
Other Eastern Europe	15	15	15	15	—	(1.6)
Eastern Europe	**977**	**1,008**	**1,014**	**876**	**138**	**15.7**
Algeria	521	521	521	529	(8)	(1.4)
Egypt	202	202	202	201	1	0.5
Libya	50	50	50	50	—	—
Other Africa	154	147	148	131	17	13.2
Africa	**927**	**920**	**921**	**910**	**11**	**1.2**
Saudi Arabia	1,820	1,820	1,820	1,810	10	0.6
United Arab Emirates	641	641	641	641	—	—
Other Middle East	741	737	737	717	20	2.8
Middle East	**3,202**	**3,198**	**3,198**	**3,168**	**30**	**1.0**
Australia	51	51	51	49	2	3.6
China	12	12	12	12	—	—
India	122	122	122	102	20	19.6
Other Asia–Pacific	315	316	315	318	(3)	(0.9)
Asia–Pacific	**500**	**501**	**500**	**481**	**19**	**4.0**
TOTAL WORLD	**11,152**	**11,166**	**11,109**	**10,593**	**516**	**4.9**

Totals may not add due to rounding.
Source: Oil & Gas Journal.
Data available at PennEnergy Research Center.

OXYGENATES

	Apr. 2016	Mar. 2016	Change	YTD 2016	YTD 2015	Change
			1,000 bbl			
Fuel ethanol						
Production	28,059	30,812	(2,753)	117,868	113,942	3,926
Stocks	20,992	22,301	(1,309)	20,992	20,787	205
MTBE						
Production	1,623	1,649	(26)	5,768	3,708	2,060
Stocks	1,022	1,183	(161)	1,022	704	318

Source: DOE Petroleum Supply Monthly.
Data available at PennEnergy Research Center.

US HEATING DEGREE–DAYS

	Mar. 2016	Feb. 2016	Mar. 2016	% change	Total degree days YTD 2016	Total degree days YTD 2015	% change
New England	755	956	1,103	(31.6)	2,839	3,853	(26.3)
Middle Atlantic	648	900	1,001	(35.3)	2,665	3,581	(25.6)
East North Central	670	956	951	(29.5)	2,865	3,690	(22.4)
West North Central	652	935	802	(18.7)	2,890	3,374	(14.3)
South Atlantic	241	483	359	(32.9)	1,385	1,671	(17.1)
East South Central	323	574	445	(27.4)	1,756	2,145	(18.1)
West South Central	180	310	277	(35.0)	1,055	1,400	(24.6)
Mountain	542	617	481	12.7	2,072	1,898	9.2
Pacific	390	342	283	37.8	1,298	1,083	19.9
US average*	**450**	**627**	**583**	**(22.8)**	**1,947**	**2,340**	**(16.8)**

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review.
Data available at PennEnergy Research Center. **NOTE: No new data at press time.**

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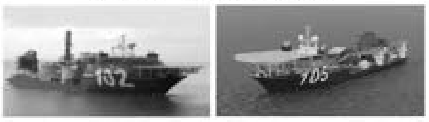

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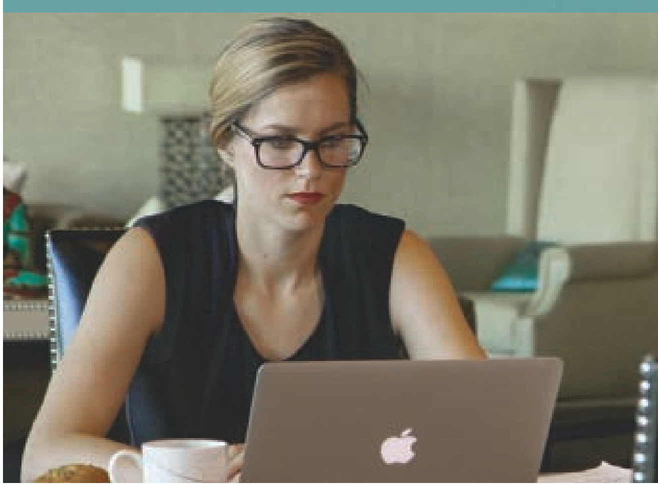

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THE EDITOR'S PERSPECTIVE

Colorado initiatives would foreclose oil and gas development

by **Bob Tippee**, Editor

Initiatives in constitutionally pliant Colorado need attention from oil and gas professionals everywhere.

In an effort to get two measures on a fall state ballot, activists have until Aug. 8 to collect 98,492 signatures of Colorado voters.

Both initiatives can seem benign. But they'd foreclose oil and gas development.

That, of course, is what activists want. If they succeed in Colorado, accommodating as it is to citizen initiatives, they'll expand the campaign.

Initiative 75 would transfer from the state to local governments authority over oil and gas development when the outcome would be toughened regulation.

In a letter to members, Colorado Oil & Gas Association Pres. and Chief Executive Officer Dan Haley warns of "a patchwork of regulations across the state, making development difficult."

Initiative 78 would require a 2,500-ft setback between oil and gas facilities and occupied structures or areas of "special concern." Those areas include drinking-water sources, lakes, rivers, perennial or intermittent streams, creeks, irrigation canals, riparian areas, playgrounds, permanent sports fields, amphitheaters, public parks, and public open space.

"It is essentially a ban on new oil and gas development, cutting off 90% of the state from new development," Haley says.

That estimates comes from data collected by the Colorado Oil & Gas Conservation Commission.

The setback requirement, Haley adds, "shreds the private property rights of 600,000 mineral owners," who probably would sue the state if it passed.

In a study published last month for three business groups, the Business Research Division at the University of Colorado Leeds School of Business estimates business consequences of the setback requirement, based on the conservation commission's estimate of affected acreage: state gross domestic product, down by an average $7.1 billion in the first 5 years and $14.5 billion between 2017 and 2031; jobs, down 54,000 in the first 5 years and up to 104,000 over 15 years; and personal income, down $10.9 billion over 15 years.

For activists phobic about oil and gas, of course, no cost is too high.

(From the subscription area of www.ogj.com, online July 22, 2016; author's e-mail: bobt@ogjonline.com)

WATCHING GOVERNMENT

Nick Snow
Washington Editor

Can Iraq tackle its problems?

Iraqis generally recognize that their country sits on some of the world's largest oil and gas supplies that could provide substantial benefits. But depressed commodity prices aggravated mismanagement imposed by outsiders as well as internally in a nation that's in the middle of one of the world's most politically unstable neighborhoods, an expert observed.

Part of this has resulted from Iraq's having been a country for only 95 years, and having 12 successful uprisings since 1923 amid growing sectarianism, Luay J. Al-Khatteeb, founder and director of the Iraq Energy Institute and a senior energy policy and economic reform advisor to Iraq's parliament, said during a July 19 discussion at the Middle East Institute in Washington, DC.

"It was forced to move from a monarchy underpinned by tribal structures to a republic with a strong military basis," Al-Khatteeb explained. "When politics moved from centralism to federalism, it created 'shock and awe' on the regional level. The people basically weren't that well prepared. Negotiations over hydrocarbons law, heads of court, finance, and other issues were difficult."

Al-Khatteeb said Iraq survived all this by sheer luck—in the form of high oil prices that quadrupled its revenue over 10 years. "Consensus, not democracy, defined its politics. Everyone agreed to split the pie, with all the political parties having one leg in the government and the other in the opposition. Everybody dealt with this as their own personal supermarket," he said.

Matters might improve if outsiders quit interfering, Al-Khatteeb suggested. Iraq is surrounded by six countries, each with its own foreign policy that sometimes is only interested in exploiting Iraqi factions. But recent administrations made bad choices when they increased the national payroll from $2 million in 2003 to $7 million just 10 years later when oil and gas prices were high, he added.

Gas imports amid flaring

"Corruption and mismanagement are serious problems," Al-Khatteeb said. "International Monetary Fund conditions for further assistance are valid, particularly when it comes to subsidies and wasting resources. Iraq produces 2 bcf of natural gas and flares another 1.6 bcf—about equal to what it's talking about importing from Iran."

As oil and gas prices stay relatively low, Iraq's national government needs to slash salaries at every level, he said.

"I can't understand how a member of Parliament makes a $20,000/month base salary or an administrator makes $1 million/year. Teachers and healthcare workers should be getting more of this money," Al-Khatteeb said.

Essentially, he maintained, "Iraq is rich in people-resources, but has been poor in leadership. Without radical economic reform to address giant government payrolls in Baghdad and up north, its problems won't begin to be solved." OGJ

Chevron

Jack/St. Malo

Expanding Chevron's Reach in the deepwater U.S. Gulf of Mexico

A SUPPLEMENT TO

OIL&GAS JOURNAL · Offshore · OIL&GAS FINANCIAL JOURNAL

Contents

Jack/St. Malo

Expanding Chevron's Reach in the Gulf of Mexico

"Jack/St. Malo is the result of the collaboration of hundreds of suppliers and contractors and many thousands of people across nine countries over a ten-year period. This project highlights our long-term commitment to safely developing the natural resources of the U.S. Gulf of Mexico, where Chevron is one of the top leaseholders. For the life of the fields, operating and maintaining Jack/St. Malo will continue to contribute to the nation's economy and support hundreds of local jobs."

— Jeff Shellebarger, president,
Chevron North America Exploration and Production Company

The Project

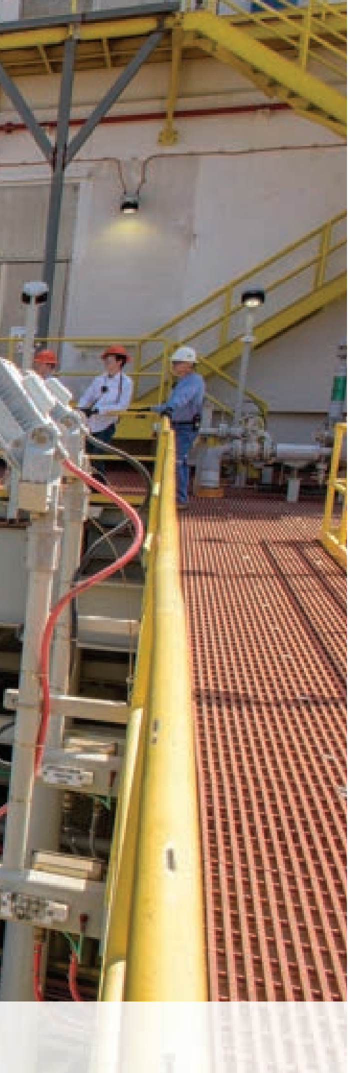
Two of the Gulf's largest fields

The Jack/St. Malo development, which includes the Walker Ridge Regional host facility, in the deepwater U.S. Gulf of Mexico is a key part of Chevron's plan to boost its global production. Along the way, the project has safely extended the industry's deepwater capability well beyond what it was when the St. Malo field was discovered in 2003, and the Jack field the following year.

The reservoirs are 25 miles apart, some 280 miles southwest of New Orleans, Louisiana. Water depths in both fields are around 7,000 feet (2,134 meters). The reservoirs lie some five miles below the water surface. With today's technology about 500 million barrels of oil is recoverable, but that estimate may increase as we continue to improve our tools and learn more about the resource.

Jack and St. Malo are being developed simultaneously with subsea completions flowing back to a single semi-submersible floating production host platform located between the two fields. Electric seafloor pumps boost the produced fluids to the host.

The Walker Ridge Regional host production platform can handle as much as 170,000 barrels of oil and 42 million cubic feet (1.2 million cubic meters) of natural gas per day, and there is room onboard for expansion. The platform—built for an operating life of more than 30 years—is the largest semi-submersible floating production unit in the Gulf of Mexico. It also serves as the host production facility for the Julia field and has excess capacity for other nearby operators.



The Co-owners

Financial and technical strength

Chevron, through its subsidiaries, Chevron U.S.A. Inc. and Union Oil Company of California, owns 50 percent of Jack, 51 percent of St. Malo, and is the operator of both fields. Maersk Oil Gulf of Mexico Four LLC and Statoil Gulf of Mexico LLC are the co-owners in the Jack field, with 25 percent working interest each. The St. Malo field co-owners are Petrobras America Inc. (25 percent), Statoil (21.5 percent), ExxonMobil Corporation (1.25 percent) and Eni Petroleum US LLC (1.25 percent).

Chevron U.S.A. Inc. and Union Oil Company of California also own 40.6 percent of the host facility, with co-owners Statoil (27.9 percent), Petrobras (15 percent), ExxonMobil (10.75 percent), Maersk Oil (5 percent), and Eni (0.75 percent). The combined Jack/St. Malo investment, sanctioned in 2010, had an initial development budget of $7.5 billion.

Exploring the Lower Tertiary

Back-to-back successes at the edge of the deepwater frontier

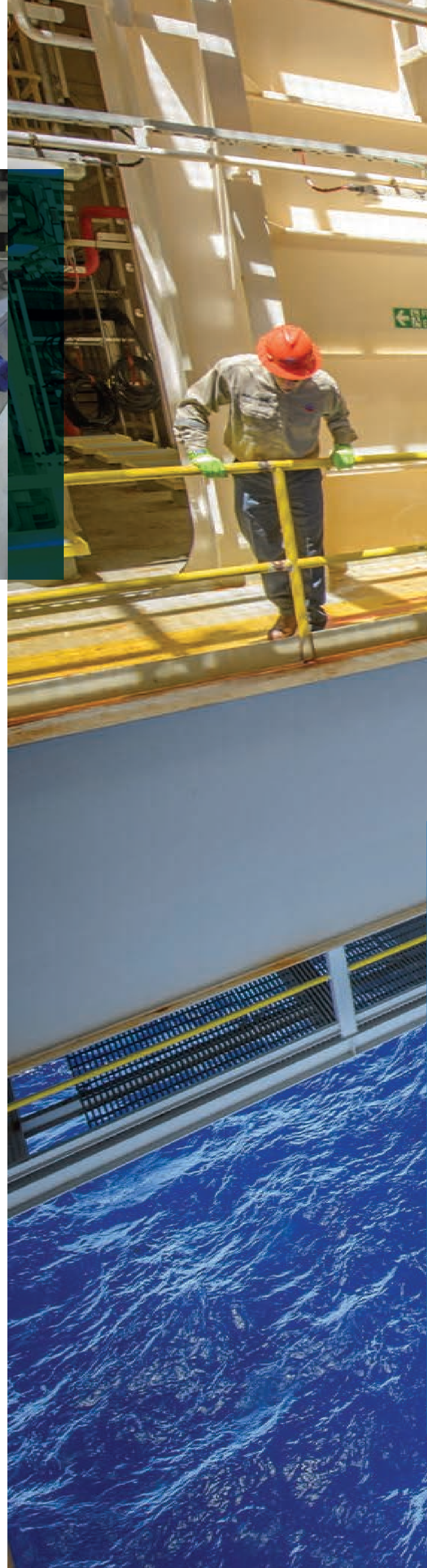
Since the world's first modern offshore platforms began appearing in the U.S. Gulf of Mexico in the late 1940s, the petroleum industry has delivered the energy equivalent of more than 40 billion barrels of oil from the continental shelf, and another nine billion from the Gulf's deepwater basins. Analysts say production from deepwater wells will likely eclipse the total production from shallow-water fields in the coming decades. One of the most prolific systems is what geologists call the Paleogene—more often referred to as the Lower Tertiary. Still others call it the "final frontier" of deepwater drilling.

Industry's greatest challenge

Some analysts estimate that the Lower Tertiary in the Gulf of Mexico holds as much as 40 billion barrels of oil equivalent (boe). The challenge is that most of it lies some five miles deep, below as much as 10,000 feet (3,048 meters) of water and hidden from seismic sensors by thick layers of salt.

Compared to Miocene plays, most of the reservoirs found in the Lower Tertiary are relatively low permeability. In other words, even though the great depth means the reservoir pressures and temperatures are high, the rock's ability to flow fluids is much lower than the Miocene reservoirs. Without additional assistance from improved completions, artificial lift, and possibly gas or water injection, oil recovery rates may be less than 10 percent. The good news is that what industry is learning today about the Lower Tertiary in the Gulf of Mexico applies to other subsalt deepwater prospects, including those off the coasts of Brazil

Steve Thurston, vice president of Deepwater Exploration and Projects Business Unit.



and West Africa. Through the end of 2015, Chevron had drilled more than 30 percent of all the industry's new wells in the Lower Tertiary.

"Our success rate for wildcat wells has been great, resulting in many fields with commercial potential," says Steve Thurston, Chevron's vice president of Deepwater Exploration and Projects Business Unit (DWEP). "These discoveries do not come easy. Overall, the Lower Tertiary trend requires some of the most challenging wells and development technologies in the world."

Chevron was one of the early pioneers, Thurston notes. "We started buying leases in the late 1990s. By the time we discovered the Jack field, we knew we were on to something big."

Two of Chevron's biggest deepwater discoveries, St. Malo and Jack, were made in 2003 and 2004 in the Lower Tertiary Wilcox trend. At the time, the technology to develop them didn't exist, and there are still significant technical challenges.

"Wells in the Lower Tertiary have to be drilled in water depths down to 8,000 feet (2,438 meters), and each well extends from 26,000 feet (7,925 meters) to as much as 36,000 feet (10,973 meters)," Thurston says. "The good news is the reservoir intervals are typically more than 1,000 feet (305 meters) thick, which means there is a tremendous amount of oil in place."

The Jack-2 appraisal well reached a total depth of 28,175 feet (8,588 meters) in the second quarter of 2006. A subsequent production test, which delivered a sustained flow of more than 6,000 barrels of crude oil per day, was the deepest ever performed in the Gulf of Mexico. It was also an industry milestone for understanding the potential of the Lower Tertiary, where Chevron is the largest leaseholder.

"Since the mid-2000s, with Chevron's installation of major developments such as the Tahiti field in the Gulf of Mexico, key technologies have enabled our deepwater developments," Thurston explains. "We are also committed to project safety, and Jack/St. Malo is a prime example."

The Chevron Way

Built on a philosophy developed in the 1990s, The Chevron Way gives every employee and contractor a concise definition of the company's corporate vision, values and strategies. It establishes a common understanding for all of those who work for and interact with Chevron. It can be summed up in the phrase: Get results the right way.

At the heart of The Chevron Way is the vision to be the global energy company most admired for its people, partnership and performance. This vision means that Chevron:

- Safely provides energy products vital to sustainable economic progress and human development throughout the world
- Is an organization with superior capabilities and commitment
- Is the partner of choice
- Earns the admiration of their stakeholders — their investors, customers, host governments, local communities and employees —not only for the goals achieved but how the company achieves them
- Delivers world-class performance

Photo courtesy of McDermott International, Inc.

McDermott's *North Ocean 102* fast-transit construction vessel transported and installed some 65 miles (105 kilometers) of control and power umbilicals in waters as deep as 7,200 feet (2,195 meters).

Building the Fields

Advanced technology trims cost per well

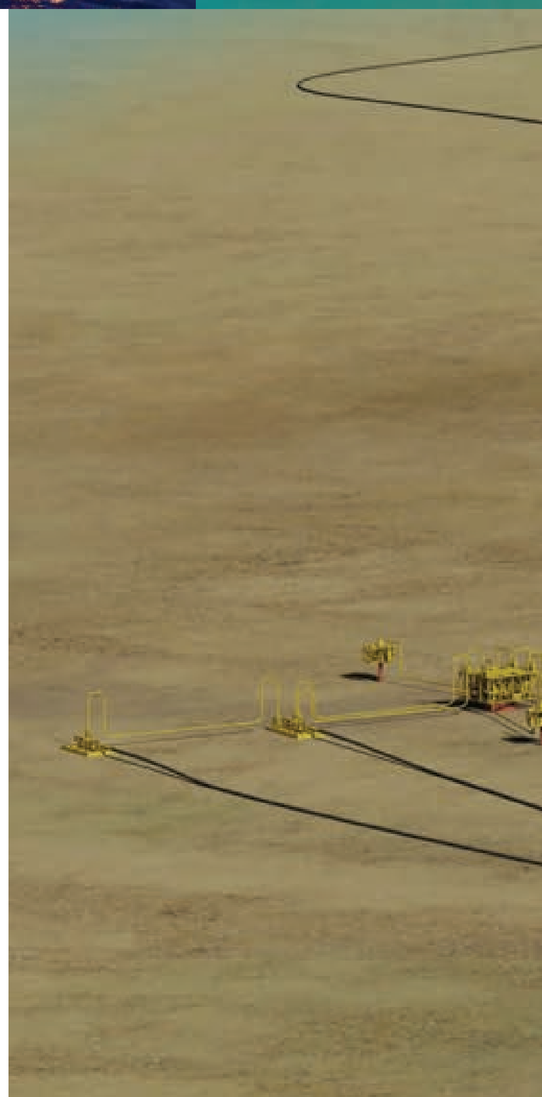
Through the first quarter of 2016, Chevron had drilled seven exploration wells and nine production wells in the Jack/St. Malo development. Daily hydrocarbon production from the fields reached 75,000 barrels of oil equivalent per day in March 2016.

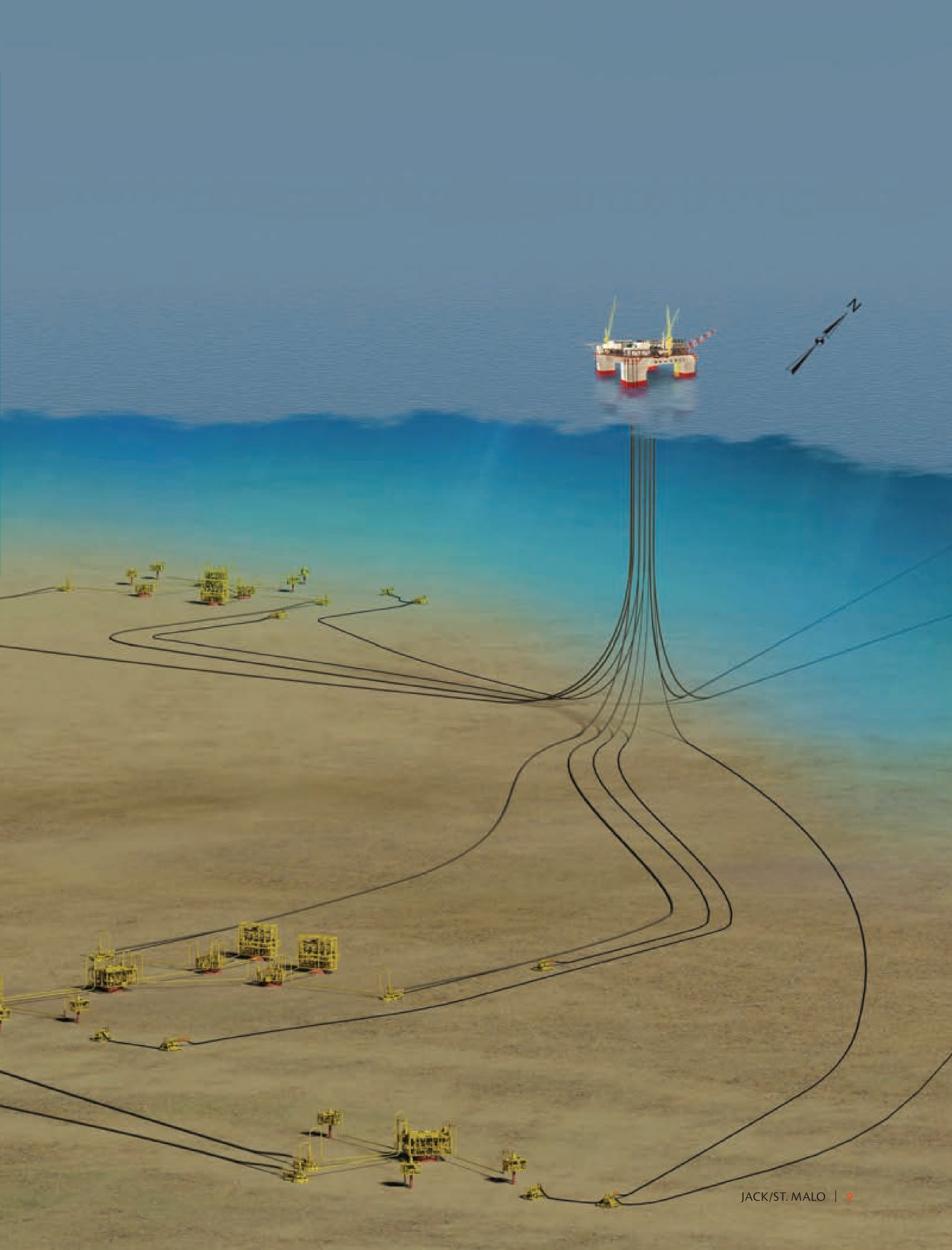
Phase 1 development drilling started in November 2011, resulting in nine production wells: four at Jack and five at St. Malo. Development drilling resumed after the production hub logged its first oil in December 2014.

Phase 2 of the JSM development plan includes four additional wells: two each at Jack and St. Malo. The front-end engineering and design (FEED) activities for Stage 2 were completed in September 2015. The drilling that began in October 2015 will continue into 2017. First oil from Stage 2 is expected in 2017.

Expected production levels

The fields have an estimated remaining production life of at least 30 years, with recoverable oil-equivalent resources estimated to exceed 500 million barrels. Beyond that, new drilling and completion techniques and advanced production technologies developed in coming years

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have the potential to substantially increase incremental recovery from these fields.

Picking the right target, first time

With the enormous cost of drilling and completing wells in ultra-deep water, operators demand a high degree of certainty before they commit. One of the toughest challenges is creating seismic images that are sharp and accurate enough to make good decisions.

"At these depths, nearly 30,000 feet, the seismic image is quite limited," says Matt Richards, subsurface geoscience team leader for Jack/St. Malo. "That's not abnormal, but it takes a lot of work to bring those images up to a level where you feel like you understand the field. We had to acquire multiple generations of seismic. Fortunately, the technology was advancing rapidly during this time, which ultimately worked to our benefit."

Sensors on the seabed

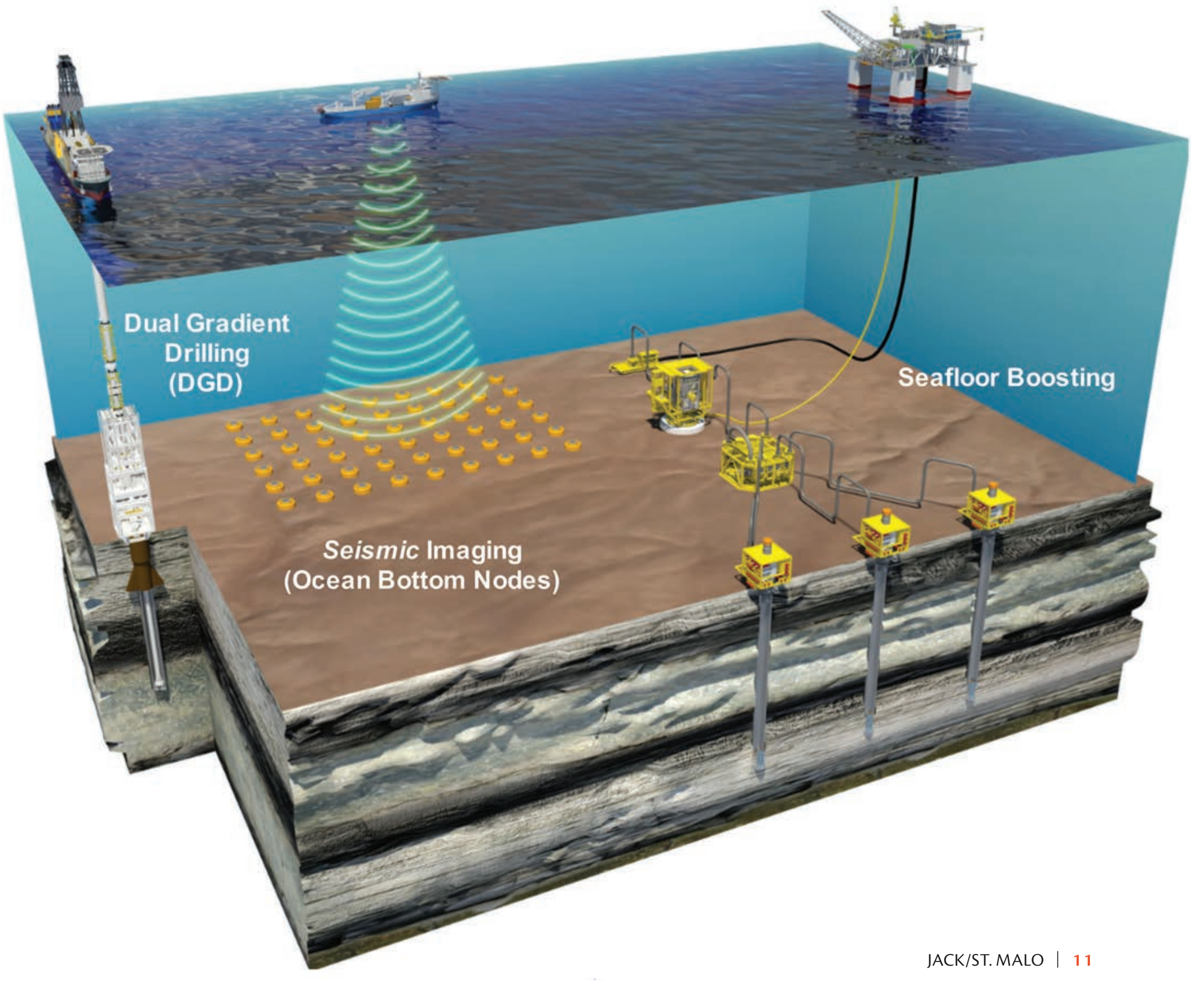
In conventional offshore seismic surveys, ships pull long streamers of acoustical sensors that record the digital echoes of sound waves as they penetrate subsea layers. The deeper the water, the harder this process becomes, since seawater itself muffles the signal. To improve chances of producing high quality seismic models at JSM, the team put seismic sensors on the ocean floor rather than towing them behind a boat. That costs more initially, but the system is safer, more versatile, and it yields better results.

With ocean bottom node (OBN) technology, remotely operated vehicles deploy a grid of 100-pound receivers (nodes) directly on the seabed. Each autonomous suitcase-sized device—which contains a battery, clock, geophone and other gear—can remain on the bottom for as long as 120 days, allowing for survey acquisition over large areas. There are several advantages. First, placing sensors on the seabed eliminates any signal degradation caused by the water column above.

Equally important, these stable ocean bottom nodes catch reflected waves in an orderly grid, enabling the gathering of clean, high-fidelity data without gaps in coverage. They also improve the repeatability of 4-D seismic, which compares surveys made years apart to see how reservoir fluids have moved over time, during development. Over the life of the field, this information helps us decide where to place new wells and how to optimize our facilities. The bottom line is that OBN data gives Chevron a clearer structural image without the noise of conventional data. It helps Chevron see past barriers of complex geology to better estimate a reservoir's potential.

"The Wilcox Reservoir is very thick here," Richards adds. "It's up to 1,400 feet thick in some places with a lot of oil in place, suggesting very long field lives."

Yet another advantage of OBN technology is that it can be carefully deployed in congested waters and fields where there is already a lot of equipment on the sea floor. In areas where complex geological features such as salt or volcanic layers hide oil and gas deposits, the source boat may sweep outside the boundaries of the field to collect wide and full azimuth seismic data. OBN technology allows them to safely pass closer to the field's existing facilities than a conventional streamer vessel could with its wide swath of receivers in tow.



Ocean bottom node technology is one of several enabling tools that did not exist when the St. Malo and Jack fields were discovered in 2003 and 2004. To help delineate Jack/St. Malo, 1,100 nodes were placed on the seabed in each field in 2013. The back-to-back surveys lasted 10 months, involving 100 people and two ships. The surveys broke several industry records, including the number of nodes, the longest acquisition schedule, the deepest water, and the largest source area. Besides their use at Jack/St. Malo, Chevron has completed similar ocean bottom node surveys in the North Sea, and off the coasts of West Africa, Brazil and Northwest Australia.

Single-trip, multi-zone completions

With low-permeability reservoirs like Jack and St. Malo, engineers typically pump a high-pressure slurry of sand, water and treating chemicals into isolated zones to create fractures in the reservoir rock. Pressure drives the sand deep into the newly formed cracks, and the sand grains (or similar manmade material) prop the cracks open once the pressure is released.

This process, called frac-packing, historically represented as much as one-third the total cost of a deepwater production well, and a good bit of the risk. Part of the expense was the time it took—as much as five days to treat one zone. The risk came from running miles of pipe in and out of the hole over and over again. One well, for example, had five zones to complete. With the technology that was available when Jack and St. Malo were first discovered, the job would have required 14 trips in and out of the well to plug, perforate and fracture. The cost was prohibitive.

Chevron and Halliburton engineers joined forces in 2007 to develop a new single-trip, multi-zone system that could stimulate multiple zones in one operation. Their goals were to increase the maximum pump rate and pressure differential, and to boost the volume of proppant. They got it right. Instead of four or five days, it now takes as little as 18 hours to stimulate each zone. One result is a much safer work environment, since crews now spend less time running pipe in and out of the well. The other benefit is a tremendous reduction in cost.

"This technology is really going to help the development of deepwater Gulf of Mexico," says Aaron Conte, senior drilling superintendent. "With spread rates well over $1 million per day, every hour saved is significant. It has delivered more than $200 million in savings across the Gulf of Mexico."

At one well in the Jack field, Chevron stimulated a record-breaking six zones and pumped more than 2 million pounds of proppant (sand) in just a few days instead of several weeks. The first of the three wells tested at more than 13,000 barrels of oil per day.

Chevron also successfully tested the technology that Halliburton calls the Extended Single-Trip Multizone (ESTMZ™) Frac-Pack system.

"ESTMZ™ allows more reservoirs to be stimulated in a shorter amount of time," says Ron Shuman, senior vice president of Halliburton's Southern and GOM regions. "This system allows us to deliver a very aggressive stimulation with rates up to 45 barrels per minute and volumes greater than 400,000 pounds of high-strength proppant. We deliver this with 10,000 horsepower per interval for up to five intervals, providing a total cumulative proppant volume of more than 2 million pounds per well with one service tool."

The multizone system was developed for use in the Gulf of Mexico, but has since been deployed in Indonesia, Brunei and elsewhere.

Subsea boosting

The naturally high reservoir pressures driving Jack and St. Malo during the early stages of development will decrease over time as the fields are

produced. To compensate and maintain production levels, Chevron called on OneSubsea (a Cameron and Schlumberger company) to install three powerful subsea pumps on the seabed to boost fluids from the wells to the host platform. Each pump can withstand pressures up to 13,000 pounds per square inch. The working depths and power consumption—some 3 megawatts each—represent a significant improvement over previous subsea boosting systems. As part of the subsea production and processing systems for the combined fields, OneSubsea also installed a dozen 15,000 psi subsea wellhead trees, the production controls, four manifolds and their associated flowlines. At the time the work was done in 2011, it included the deepest, longest and highest-pressure tieback in the Gulf of Mexico.

Developing the subsea infrastructure and boosting system for Jack/St. Malo was one of the biggest challenges for the facilities team. Because of their experience with subsea boosting systems on the Norwegian continental shelf, technical experts from Statoil—Chevron's co-owners in both fields—were seconded to the Jack/St. Malo team.

"Subsea boosting is not new," says facilities engineer Chris Hey, "but on Jack/St. Malo, in terms of the water depth, the pressure rating and the power of the pumps, there's nothing else like this in the industry."

Many of the technical advances were developed specifically for this project. Some addressed the challenge

Photo courtesy of McDermott International, Inc.

of working in water more than a mile deep. Others supported the building of JSM's complex infrastructure and improved the recovery of its oil and natural gas.

McDermott International installed the jumpers, flying leads, subsea pumps and umbilicals. Much of the heavy equipment, including three pump stations weighing 209 tons each, was installed by McDermott's *Derrick Barge 50*. A second McDermott vessel, *North Ocean 102*, installed the control and power umbilicals.

An extra level of safety

As the largest leaseholder in the U.S. Gulf of Mexico, Chevron is a principal sponsor of the Marine Well Containment Company LLC (MWCC), a company which was established in 2011 to respond to deepwater well containment emergencies. Available to all deepwater operators, MWCC maintains a system that can stop or cap and flow a runaway well in water depths from 500 to 10,000 feet, temperatures as great as 350 degrees Fahrenheit, and pressures up to 15,000 pounds per square inch.

With the assistance of experts from Chevron and other major energy producers, MWCC upgraded its interim containment system in 2015 to provide increased capacity and compatibility with a wider range of well designs, flow rates and environmental conditions. The company maintains two shore bases on the U.S. Gulf Coast. Regular training exercises keep MWCC's equipment and personnel ready to respond to a well control emergency at any time.

The Production Hub

Largest in the Gulf of Mexico

With a nameplate capacity of 170,000 barrels per day, the Walker Ridge Regional host floating production unit is the largest such facility that Chevron operates in the Gulf of Mexico. Indeed, it is one of the largest in the world. Building the host platform and moving it around was no easy job.

Fabricating the hull

The front-end engineering and design (FEED) for JSM's topsides facilities began in the second quarter of 2009. The principal contractor for this part of the job was Houston-based Wood Group Mustang. Wood Group also managed the commissioning of the production platform. Construction began on the hull at the Samsung Heavy Industry yard in Geoje, South Korea in early 2011. At the time, JSM was the largest semi-submersible hull constructed in terms of displacement, as it displaces 146,168 metric tons (161,122 short tons) of water.

KBR performed the detailed engineering for the floating production unit's hull, deck box, crew quarters, equipment foundations, mooring system and the anchor suction piles.

GVA Consultants, a subsidiary of KBR, worked exclusively on the hull configuration. The deep draft hull design minimizes the motion of the vessel, which in turn reduces stress on the vessel's risers, umbilicals and more than 164,000 feet (50,000 meters) of polyester mooring lines.

Transporting the hull

The hull was completed in February, 2013. Soon after, it left South Korea aboard the new *Dockwise Vanguard*—the world's largest heavy lift transport vessel—on the ship's inaugural run. The *Dockwise Vanguard* took its 56,000-ton cargo safely around Southern Africa and the Cape of Good Hope to arrive at Kiewit Offshore Services' Ingleside yard near Corpus Christi, Texas, in mid-April.

Topsides

The host topsides facilities were fabricated and assembled at Ingleside. There are three main topsides modules for production, power generation and gas compression. The completed modules were lifted onto the hull and deck box in May 2013. Most of the integration and commissioning was completed before the facility was towed to the field. Kiewit also fabricated the host's mooring piles. For efficiency and worker safety, most of the integration and commissioning of the mooring piles was also completed before the facility was towed to the field.

The integrated semi-submersible platform left Ingleside in November, 2013, and was moored offshore and in place by early January, 2014. Offshore commissioning began while the hull was being towed to the field, and the installation of the subsea infrastructure continued through 2014.

Project economics

Chevron holds a 50 percent interest in Jack, a 51 percent interest in St. Malo, and is the operator of both fields. The company also has a 40.6 percent interest in the production facility, which is designed to accommodate production from the Jack/St. Malo development and third-party tiebacks. Chevron's other co-owners for the hub facility are Statoil, Maersk Oil, Petrobras, ExxonMobil and Eni. The total daily production from the Jack and St. Malo fields in 2015 averaged 61,000 barrels of liquids and 10 million cubic feet of natural gas. Although the project delivered first oil in December 2014, ramp-up and development drilling for the first phase of the development continued into 2015. Production for the Julia field, which is also serviced by the host, began in April 2016.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The Export Pipelines

Planning for growth in the region

Crude oil from the regional host travels 136 miles to the Shell-operated Green Canyon 19 platform via the Jack/St. Malo Oil Export Pipeline. From there it enters the larger network that delivers crude oil to refineries all along the Gulf Coast. To handle the natural gas, Chevron and Enbridge, Inc. signed an agreement in 2009 for a 170-mile (274-kilometer) southern extension of the Enbridge central Gulf of Mexico natural gas gathering system. The 8- and 10-inch pipeline includes bi-directional points at Jack and St. Malo and similar links to other nearby fields. For the oil and gas export pipelines alike, the combination of extreme water depths, large diameter, high-pressure design, and the system's flexibility for future development have set new milestones for the Gulf of Mexico.

Largest pipeline at this depth

The JSM oil export pipeline is the first of its kind to address the challenges of installing high-pressure, large diameter pipe in ultra-deep water. The 24-inch (61-centimeter) export pipeline, with a pressure rating of 4,500 psi, was installed in 2014 at water depths greater than 7,000 feet (2,134 meters).

The pipeline's innovative design includes two 92-ton inline modules that allow Chevron or future operators in the Walker Ridge area to connect their development projects to the main export line. The oil export pipeline was designed, built and installed by Amberjack Pipeline Company LLC, a joint venture between Chevron Pipe Line Company and Shell Pipeline Company.

"It was a first for us, especially in dealing with a 24-inch diameter pipeline in 7,000 feet of water and operating at 4,500 psi," says Edward LaCour,

Chevron Pipe Line's asset manager, Gulf Coast Area. "Safety and reliability were our primary concerns, but another feature is that the pipeline includes inline sleds for future tie-ins. It links our upstream and downstream businesses in a supply chain that will also provide competitive solutions for other leaseholders in the transport of crude to the market."

Installing the crude oil export line

For this project, even the pipe-lay vessel was new. At the time, the *Castorone* was the largest such vessel in the world. The vessel and its crew installed up to 1.5 miles (2 kilometers) per day, which translates to more than 120 joints of pipe being laid off the back of the vessel.

"The pipe is brought out in 40-foot segments," explains Jerry Hoose, Chevron Pipe Line's installation engineer for the JSM export pipeline. "Within the vessel's triple-joint factory, sets of three 40-foot lengths of pipe were welded into 120-foot segments. They were then brought up to the main firing line where the segments were welded together to form a continuous pipe."

The pipe is fed in a gentle curve off the back of the vessel and down to the seabed. All the while, a constant tension on the pipeline keeps it from buckling. At the seabed, the pipe curves again until it is lying flat on the bottom.

"A project this size takes years of planning by teams from around the world," Hoose adds. "What we delivered was the largest pipeline ever laid in these water depths."

The success was noted throughout the industry, according to Al Williams, the president of Chevron Pipe Line during the installation and the current vice president of Chevron's San Joaquin Valley Business Unit. "Completing this project demonstrated to our co-owners that Chevron Pipe Line has the ability to perform in this challenging environment and can deliver these critical resources to the market. Every Chevron employee can take pride in the way individuals and teams came together to develop one of the company's most technologically challenging and commercially rewarding projects."

Al Williams, the former president of Chevron Pipe Line and current vice president of Chevron's San Joaquin Valley Business Unit.

The gas export line

All of the natural gas produced from Jack and St. Malo is sold into a pipeline system built and operated by Enbridge, Inc. To reach the host, Enbridge spent some $500 million to extend its southern reach into the deepwater Gulf of Mexico.

The Walker Ridge gathering system is a new supply source for the Enbridge Manta Ray and Nautilus offshore pipeline systems, which enhances the company's existing offshore pipeline business and establishes a strategic base for future growth by Chevron and other operators in the ultra-deep Gulf of Mexico. The new line has the capacity to carry 100 million cubic feet of natural gas per day.


LIQUID HYDROCARBON
FROM KAU-1830 OIL BUY BACK METER


WR 718A
CHEVRON
JSM SOUTH
WR 718A
H
CHEVRON
JSM EAST

First Oil

The start of a long run

"There's nothing more exciting than the startup of a new oil field in the deepwater," says Steve Thurston, vice president of Deepwater Exploration and Projects. "With the startup of the Jack and St. Malo fields, we were finally able to see what these wells could produce."

Jack/St. Malo is a showcase of Chevron's focus on safety and operational excellence, yet for all of the exploration success so far, the Wilcox remains a challenging reservoir. Many questions remain. In the next few years, development drilling at Jack/St. Malo will teach the industry a great deal. One thing that is known is that the Wilcox reservoir is very thick in this area, as much as 1,400 feet (427 meters). There is a lot of oil in place in both fields, which means they should be productive for a very long time.

Safely delivered on time and on budget

The Jack/St. Malo project was completed on a timeline that began with the discovery of St. Malo in 2003. First oil occurred on schedule on December 1, 2014. Soon after, Chevron's Gulf of Mexico business unit took over the daily operation of the fields. Within a few months, the project was producing a steady 70,000 barrels per day from five wells. Stage 1, which will continue into 2017, includes nine production wells. Four additional wells are planned in the second stage of the development. Stage 2 development drilling will continue through 2017.

Stage 1 of the investment, which included more that 20 million hours of work, was accomplished with only three lost-time incidents.

"While working on Jack/St. Malo, some of our contractors posted the best safety records they've ever had," says Billy Varnado, the Jack/St. Malo project director. "I think that is good evidence of all the effort everyone put in."

Billy Varnado, the Jack/St. Malo project director.

Continuing Operations

Innovation, safety and efficiency are the keys

It's only natural for a project as large and important as Jack/St. Malo to become a showcase for the industry's most advanced technology. Given the anticipated life of the fields—more than 30 years—we've also planned for years of expansion and growth.

Decision Support Center

In 2015, Chevron expanded the capabilities of its Drilling & Completions Decision Support Center. The center is a combination of technology, processes and people designed to help eliminate serious well-control incidents and improve operational efficiency. Working as a team, Chevron specialists monitor in real time our most complex wells around the world. They are called upon any time Chevron is drilling a complex well. This state-of-the-art center can support as many as 15 drilling rigs on a continuous basis, providing expert backup and advice to ensure safe, reliable and efficient operations.

Monitoring equipment performance

Within Chevron's Energy Technology Company, the Machinery and Power Support Center (MPSC) uses predictive analytics to monitor machinery performance at a centralized and local level. There, and in several of the business unit


WORLD CLASS PROJECT
WORLD CLASS SAFETY
WORLD CLASS FACILITY
CONGRATULATIONS ON
3,000,000 INJURY FREE HOURS
Jack St. Malo
FIREWATER

Equipment Decision Support Centers (EDSC), experts remotely monitor rotating equipment to evaluate its performance and safety, ensure the proper maintenance, and to avoid unplanned shutdowns.

Rather than waiting for equipment to fail, the MPSC and EDSC teams feed data into a model that gives advance notice of potential failures or maintenance needs.

This process reduces unplanned downtime, couples work-orders and identifies what spare parts are needed.

Ready for the next big storm

Chevron and its legacy companies have been exploring for and developing oil and gas resources in the Gulf of Mexico for more than 75 years. As of early 2016, Chevron has an interest in 466 leases in the Gulf of Mexico, 347 of which are located in water depths greater than 1,000 feet. At the end of 2015, Chevron was the Gulf's largest leaseholder. Over the decades, Chevron brought their people safely through numerous tropical storms and hurricanes, including mega-storm Katrina, when the company evacuated more than 1,000 employees and contractors without a single injury. Offshore installation manager Tommy Boepple knows the drill first hand.

"Jack/St. Malo is more remote than most of our offshore facilities, so we allow extra time to initiate the systems that will ensure the safety of our people and assets," Boepple says. "We rely on a number of resources. Chevron maintains its own Gulf of Mexico helicopter fleet, for example, which gives us greater flexibility if we need to evacuate a platform prior to a storm."

Jack/St. Malo is also equipped with technology to track a storm's progress and trajectory, as well as detailed computerized crew manifests to keep tabs on who is offshore and where they are.

"Like other fields, Jack/St. Malo is connected to our onshore Decision Support Center (DSC) in Covington, Louisiana," Boepple says. "Covington serves as our 'mission control' during severe weather. To make sure we're ready, we conduct periodic drills that reinforce each individual's role and responsibilities in a weather emergency."

Chevron's tasks and timelines during severe weather are guided by the company's hurricane action plan. Storms are monitored as soon as they develop. If they have the potential to impact the Gulf of Mexico, the hurricane evacuation team is activated, and the DSC is staffed 24 hours a day.

"Assets in the Gulf are evacuated and production is curtailed in phases, based on the track of the storm and information provided by the National Weather Service," Boepple adds. "The facilities closest to the tropical weather's most immediate path are cleared first. All available marine and aviation assets are directed and monitored by the DSC throughout the entire evacuation and remobilization process."

The role of information technology

Chevron information technology (IT) teams from around the world put their stamp on Jack/St. Malo, providing the technical support that helped this major capital project achieve first oil. Chevron IT experts delivered telecommunications and the infrastructure needed to support


ZZZ-1800

operations at Jack/St. Malo as well as network connectivity on the floating production unit, the pipe-laying vessel, floating accommodation vessel and the drillships.

"One of the big wins was the great collaboration we had," says Keith Breaux, Chevron's DWEP Information Technology manager. "We were aligned not only in transition from the project team to the Gulf of Mexico business unit, but on the facility itself. The IT teams from Jack/St. Malo, DWEP and GOM business units were phenomenal. They worked together seamlessly."

Over the course of the project nine "digital oil field" solutions were also implemented, including new operator workflows and Chevron's Production Reliability and Efficiency Program.

"These solutions helped the GOM business unit increase the reliability of the facility, reduce health, safety and environmental risks, and decrease costs," says GOM Information Technology manager Jennifer Scriabine. "Real-Time Reservoir Management is also providing engineers with the information they need to make faster, better decisions to bring wells on line sooner, reduce downtime and maximize production."

Linking the facilities required 88 miles (142 kilometers) of new network subsea fiber optic cable on the ocean floor. The cable runs from Jack/St. Malo to a high-performance network connectivity system made available by BP to oil and gas producers in the Gulf of Mexico. The host also boasts more than 137 miles (220 kilometers) of telecommunications cabling onboard for fast, reliable access to data and systems.

Eric Sirgo, DWEP's general manager of Major Capital Projects.

Design, construction and regulatory approval required the processing of more than 200,000 documents and drawings, including regulatory and specifications documentation, process safety, personal safety and environmental management system documentation, as well as operating and installation manuals. The team migrated construction data to a document management system for use during handover and operations and developed a central document archive.

"The IT challenge for a major capital project is staggering," explained Eric Sirgo, DWEP's general manager of Major Capital Projects. "IT is integral to all aspects of the project, including document management, telecommunications, security, operational data gathering and control and reservoir management. IT's role and contribution were critical to the project's overall success."

Operational Excellence

Chevron's values and vision

To achieve and sustain projects like Jack/St. Malo, Chevron has developed world-class capabilities and a company-wide culture of operational excellence. It is a process that requires active leadership and the engagement of the entire workforce, employees and contractors alike. At its core is the belief that all incidents are preventable and that "zero incidents" is an achievable goal.

Workforce health and safety

Every job involves risk. Chevron identifies and mitigates those risks by enhancing technology, tools and competency at all levels. The company gives its employees and contractors the authority and responsibility to stop work if they believe that conditions are unsafe. Chevron is also an industry leader in providing health awareness and educational programs to its employees and their families, as well as to the residents of their host communities.

The View from Here

A solid foundation for future deepwater developments

"Jack/St. Malo is the fourth deepwater facility that we operate in the Gulf of Mexico," says Mike Illanne, vice president of Chevron's Gulf of Mexico Business Unit. "Chevron is a big operator in the Gulf and the number one leaseholder overall. Our top priorities are protecting people, being good stewards of the environment, and good business partners in the communities where we operate."

With its numerous technical advancements, Jack/St. Malo serves as an example of what Chevron can achieve and a foundation for its future deepwater developments. To that end, we place the highest priority on the health and safety of our workforce and protection of our assets and the environment. We aim to be admired for world-class performance through disciplined application of our Operational Excellence Management System.

"I believe that the work we've done on process safety and environmental protection—ensuring that we had the right design and procedures in place to operate this project reliably—has been outstanding," Illanne adds. "I am very confident that Jack/St. Malo will have a great record of safety and success going forward."

Mike Illanne, vice president of Chevron's Gulf of Mexico Business Unit.

COMPANY PROFILES

Jack/St. Malo—a collaborative success

A winning formula

As with any major development, success hinges on close and continuous collaboration between all parties involved. Chevron's Jack/St. Malo prospect is no exception. This ongoing deepwater frontier development in the Gulf of Mexico began following discovery of the two fields in 2003–2004. With such a major project, Chevron elected to benefit from the 'chain of accountability' for mission-critical services, whereby responsibility for key, linked services was assigned to a single provider.

For Chevron, collaborating with Schlumberger to develop several of these service solutions was a natural choice based on the companies' shared positive experience developing the Tahiti prospect in 2004. Learnings from the Tahiti prospect proved invaluable as it set the record for water depth for a producing well.

The decision to collaborate had dual benefits: first, communication between Schlumberger and Chevron was greatly facilitated by all parties having a common purpose—working with Chevron to construct wells in challenging geology and landing them precisely in reservoir sweet spots. Second, technical expertise was available to all participants up and down the chain of operations. Learnings experienced by operational planning and implementation teams was seamless, resulting in major efficiencies as the project proceeded. Close collaboration ensured that data required for life-of-reservoir decisions was acquired at the most opportune time.

To illustrate, flow assurance, which is typically a completions concern, requires field designers to know precisely where the asphaltenes threshold will be reached. The information required to make this calculation is provided by sophisticated logging tools run many months earlier in the development process. Coordination between the information providers and data users fast-tracked resolution of this critical task.

The challenge

The Jack/St. Malo prospect presented numerous technical challenges in terms of water depth that ranged from 2,100 ft (640 m) to more than 7,000 ft (2,134 m). Reservoir targets were estimated at more than 20,000 ft (6,096 m) beneath the seabed. They were characterized as low permeability, 30,000-psi ultra-high pressure reservoirs that would require a full portfolio of suitable and reliable technologies to enable Chevron to assess the reservoirs' economic potential toward reaching production goals of 94,000 b/d of oil and 21 MMcf/d of natural gas in the coming years.

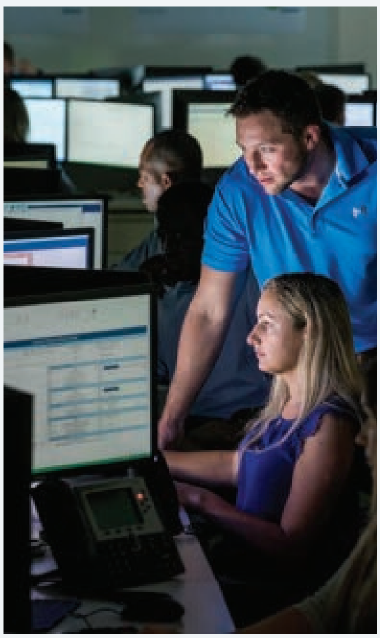


Figure 1: A collaborative environment between Chevron and Schlumberger teams enables optimal data integration and management throughout operations at Jack/St. Malo.

Valuable information for exceptional planning

Chevron's planners were already applying their foreknowledge based upon seismic surveys and other exploration techniques to build dynamic models. These could be easily updated as additional information became available. The early models were promising; nevertheless, each new bit of information helped to clarify and improve Chevron's ability to estimate costs and profits.

In 2006 Chevron commissioned a 3D seismic survey conducted with the Q-Marine* point-receiver marine seismic system to image the St. Malo reservoir. Information from this survey enabled Chevron to high-grade initial reservoir models and optimize early appraisal and development targets. The positive results of this survey led Chevron to sponsor a multiclient wide-azimuth (WAZ) project in 2008. The new survey provided better illumination under complex salt bodies and improved structural definition. During 2011 and 2012, Chevron employed a combination of Chevron and

WesternGeco imaging technologies to improve the seismic imaging, which then served as the foundation for a collaborative uncertainty analysis study that integrated Chevron's knowledge of the Earth Model with the WesternGeco WAZ data. Results from the study were integrated into Chevron's static model for St. Malo reservoir management and used for scenario testing and risk mitigation.

Drilling technology evolution

The Jack/St. Malo project benefited from application of the industry's technology advancements. Drilling tools and techniques, drilling fluid development, and logging and well-testing technology were all evolving rapidly at this time to deliver higher efficiency, more precise information, and greater safety.

For drilling at Jack/St. Malo, the PowerDrive Orbit* rotary steerable system (RSS) efficiently drilled up to 8,000 ft (2,439 m) of complex, salt, shale and abrasive sandstone strata that would have greatly affected the run-life of previous-generation equipment. The highly reliable push-the-bit pad actuation of the PowerDrive Orbit RSS utilizes metal-to-metal seals for enhanced drilling performance, efficiency, and trajectory control, even when high shock and vibration and other harsh drilling conditions are present.

The system enabled accurately steering through the overlying strata to hit reservoir targets and to achieve Chevron's ambitious development plan while reducing shock and vibration issues that are anathema for bottomhole assemblies. The drilling system delivered an unprecedented 24% improvement in salt penetration rates, and 208% improvement in the sediment.

Compared with earlier St. Malo wells, Chevron saved 15.9 days of deepwater drilling vessel time, which is equivalent to a 55% drop in estimated costs and savings of more than USD 14 million.

One application where innovation directly addressed Chevron's concerns was underreaming while drilling. Previously numerous trips were required to achieve desired hole diameter, with the costs not in line with the marginal value. Because the Rhino XC* on-demand hydraulically actuated reamer can be quickly adjusted via flow activation, 48 hours of trip time was saved.

Figure 2: The newly designed pad actuation system, combined with real-time three-axis shock-and-vibration measurements, allows the PowerDrive Orbit RSS to withstand the most difficult drilling conditions and operate at higher rotational speeds than conventional systems.

Continuous measurements transmitted in real time while drilling enabled M-I SWACO, a Schlumberger company, to customize its drilling and completion fluids as needed. Chevron drilling engineers worked with Schlumberger fluids experts to model each section to minimize equivalent circulating density (ECD) and reduce lost returns. Conventional fluid systems were compared with M-I SWACO's WARP* advanced fluids technology. This micronized-barite drilling fluid was selected in consideration of its ability to maintain ECD within a narrow band, with a subsequently reduction in overall fluid losses to 144 bbl.

Reducing risk

Chevron's mission-critical objectives for wireline logging addressed reservoir compartmentalization and communication, relative position of reservoirs for designing well paths, prospective production potential, and, most importantly, early identification of any production impediments.

Although wireline logging tools provide the most accurate geological and petrophysical information needed to characterize the reservoir, the risk of tool sticking with its subsequent fishing costs concerned Chevron engineers. Accordingly, Schlumberger deployed the logging toolstrings on the MaxPull* high-tension wireline conveyance system using TuffLINE* torque-balanced composite wireline cable to provide 40% greater pulling capacity than conventional ultra-strength logging cable systems. The MaxPull system also delivers higher bottomhole wattage to run complex tool combinations that reduce the number of logging runs.

Workflows were developed to efficiently acquire and analyze the data needed to address Chevron's immediate concerns, but Schlumberger understood that more insight would be required as development progressed. Perhaps the most valuable information was derived from measurements acquired with the MDT* modular formation dynamics tester equipped with Quicksilver Probe* focused fluid extraction and the InSitu Fluid Analyzer* real-time downhole fluid analysis (DFA) system because it enabled real-time decision making by Chevron engineers. The previously mentioned asphaltenes threshold is but one of the critical parameters revealed by DFA conducted with specialized sensors on the fluid at reservoir conditions.

As its name implies, Quicksilver Probe extraction speeds the acquisition of uncontaminated formation fluid. In addition to the real-time insights provided by DFA, fluid samples can be retrieved for laboratory analysis. Both the shorter station time for Quicksilver Probe extraction and the critical reservoir information obtained enable reducing the risk of sticking to save valuable rig time. Where closely spaced fluid samples are not required, the MDT tool is augmented with PressureXpress* reservoir pressure while logging service to determine pressure gradients that identify gas/oil and oil/water contacts, which is vital knowledge for completions specialists and reservoir engineers.

The gold standard

Recognized by petroleum engineers as the "gold standard" of reservoir data, the final step in the well evaluation is the well test, a temporary completion of the well achieved by a string of downhole test tools. Pressure transients, measured by precise downhole gauges, are used by reservoir engineers to calculate reservoir volume and connectivity and place boundaries. These data give critical input to Chevron's 3D reservoir model for economic decisions.

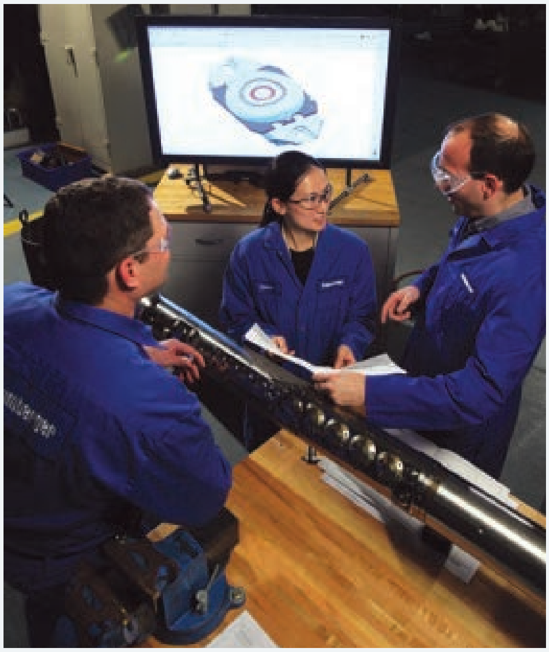


Figure 3: Engineers discuss the Quicksilver Probe focused extraction which drains off contaminated filtrate from the outer ring while sampling uncontaminated formation fluid from the center port.

> *Well testing at Jack/St. Malo determined that commercial production rates were indeed achievable and, in the process, set a world record for well test depth at more than 28,000 ft (8,537 m).*

As part of the dynamic underbalance management program, wells were prepared for optimal flow using the latest-generation innovation in HP high-shot-density gun systems—the INsidr* perforating shock and debris reduction technology. Chevron used the technology to minimize debris fallout and manage the dynamic underbalance effects in their HP wells, enabling a best-fit completions design.

The development of Jack/St. Malo remains on target due to the continuous collaboration between Chevron and Schlumberger. As the program continues, knowledge of the reservoir—from data integration and management by Chevron experts in the 3D dynamic reservoir model—will benefit future decisions as well as provide backbone information for completion and production engineers, extending all the way to final abandonment.

Perhaps the ultimate achievement is that the development of the Jack/St. Malo blueprint will guide geoscientists and engineers as they tackle future challenges.

*Mark of Schlumberger

Lower Tertiary success with leading-edge completion and production technologies

The Lower Tertiary trend in deepwater Gulf of Mexico is characterized by older sediments with low porosities, ultra-deepwater depths, and high bottomhole pressures. At the outset, Chevron realized that production from the Jack/St. Malo discoveries was not economically feasible without significant advances in completion and production technologies. To develop the critical solutions, Chevron teamed up with Halliburton to push the technology frontier.

The *Stim Star IV* has the frac fluid and proppant storage capacity, blending on the fly and high-volume pressure pumping capabilities needed for Lower Tertiary wells in deepwater Gulf of Mexico.

Enhanced completions

For optimum results in the Lower Tertiary, Halliburton developed the ESTMZ™ Enhanced Single-Trip Multizone system in 2007, based on its highly successful single-trip multizone system. Chevron depended on the ESTMZ system's full 10,000 psi differential pressure rating, which increases the operating envelope for deeper wells and allows frac design optimization.

Halliburton's Integrated Completions Center in New Iberia, Louisiana, provides comprehensive resources for deepwater completions throughout the Gulf of Mexico region.

The industry's highest frac and proppant ratings enabled pressure pumping to be increased to 45 bbl/min. The volume for 16/30 high-strength proppant increased from 300,000 lb to 3.75 million lb per well with the use of special alloys that have greater erosion resistance. These capabilities enabled the Chevron-Halliburton team to perform single-trip completions on a six-zone well, saving 14 trips. Compared to conventional completions, Chevron estimates the ESTMZ system saved up to 25 days on average and approximately $22 million per well.

State-of-the-art stimulation

During the first completions for the Jack/St. Malo fields, Halliburton used two stimulation vessels in order to meet the high volume stimulation requirements. Through innovative solutions, such as the Offshore Proppant Transfer System, and through the launching of the Stim Star IV in 2015; Halliburton can accomplish these same tasks with just one stimulation vessel.

The Offshore Proppant Transfer System has blown proppant offshore, vessel to vessel, at 1,000 lb/min. The Stim Star IV has storage capacity for 14,374 bbls of frac fluid and 4 million lb of proppant. With 21,500 hhp of high pressure pumps, redundant 75 bpm blenders, redundant power units, and redundant proppant movers, the Stim Star IV is capable of providing more quality assurances than any vessel to date. These technological advances make it possible to place over 4 million lb of proppant in a single trip.

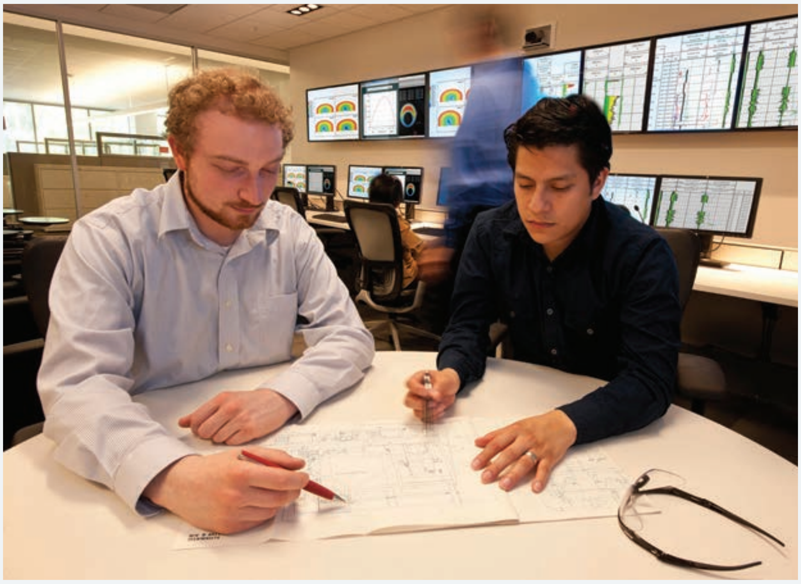
Real-time visualization service (RTVS)

Halliburton's completion crews can access the InSite® system for real-time visualization of the entire sandface assembly, including the service string. This helps save significant time and money, while increasing the reliability of service tool positioning. During pre-job analysis, the crews can validate the interaction between the completion string and the service tool by simulating the job using the proposed operational steps. As the job is underway, it is possible to track, in real time, the service tool's movement, position and status. For post-job analysis, the crew is able to use the visualization tools to review all or portions of the job data using the replay feature or log plots.

Wellbore assurance, provided through various critical operations such as wellbore cleanout, completion services, pumping and fluids, also contributes to the success of the wells. This integrated approach in planning and execution mitigates risks, while promoting efficiency, and providing an optimal conduit for the reservoir to flow.

Collaboration success

The Jack/St. Malo project is a remarkable example of how collaboration between an operator and a service company can achieve step-change advances in oilfield technologies. The technical innovations and lessons learned during the Jack/St. Malo project have made deepwater economics more favorable by reducing the number of trips needed to complete a well from Lower Tertiary formations.



Real-time visualization/collaboration centers provide technological elements that facilitate access to information and effective team decision making.

Advancing the industry frontier

Halliburton is committed to working with Chevron to reduce completion and production costs for successive phases of the Jack/St. Malo project and apply the efficiency gains to other deepwater and ultra-deepwater E&P projects in the Gulf of Mexico and throughout the world. In fact, Halliburton has worked on more than 90% of deepwater operations worldwide, including every project in the Lower Tertiary.

Integrated completion resources

In February 2015, Halliburton opened its new Integrated Completions Center (ICC) in New Iberia, Louisiana. Located on 103 acres, the 275,000-sq-ft climate-controlled facility includes a 30,000-sq-ft administration building, an operations command center and several learning auditoriums for training. The ICC will increase the company's resources for deepwater completions, align services, ease equipment maintenance, preparation and job execution for its Gulf of Mexico area customers, all aimed at delivering the highest level of service quality.

Enbridge WRGS provides gas gathering services for Jack/St. Malo

Enbridge constructed, owns and operates the Walker Ridge Gathering System (WRGS). WRGS currently serves the Jack/St. Malo fields, and will also provide the gas portion of the Big Foot field when it is connected. With an estimated capital cost of $400 million, the WRGS has a capacity of 120 million cubic feet per day (MMcf/d) and includes 170 miles of 10-inch and 8-inch diameter pipeline at water depths of up to 7,000 feet. The WRGS ties into Enbridge's Manta Ray and Nautilus offshore pipeline systems. The first phase of the system, serving Jack/St. Malo, went into service in December 2014.

Integrated Project Team

Soon after the Jack/St. Malo discoveries, Enbridge engaged with Chevron and its project co-owners to understand the requirements of a gas gathering system for the Walker Ridge area.

"It's important for us to always focus on the needs of the customer," said Enbridge's Allan Schneider, vice president of engineering and project execution. "Having a clear understanding of their needs and working with our customer every step of the way ensures a good outcome."

Once definitive agreements were signed in December 2010, Enbridge and Chevron formed an integrated team, with defined roles and responsibilities, to design and implement the WRGS project.

The 20-person team had members from all aspects of the project including procurement, project controls, quality control, engineering and project management. Chevron team members participated in technical, commissioning coordination and risk management roles on the Enbridge Project Team. Representatives from Jack/St. Malo and Big Foot, as well as a commercial representative were actively monitoring the project and officially represented Chevron and its project co-owners on interface issues and decisions.

The team conducted biweekly meetings to discuss ongoing issues, make decisions, and carefully document every step of the project. The team consulted with groups working on the Jack/St. Malo floating production unit (FPU) to understand all requirements and develop procedures to tie the pipeline into the FPU in 7,000 feet of water. In addition, the team worked with Chevron to provide a comprehensive progress report annually to the project co-owners on Jack/St. Malo. The integrated team approach worked well and kept the project on schedule.

Unique Requirements for WRGS

The Walker Ridge Gathering System was designed to meet a number of unique requirements. The WRGS had to transport up to 120 MMcf/day of high pressure gas 150 miles from Walker Ridge 718 to Ship Shoal 332. The system had to safely tie into the Jack/St. Malo FPU in 7,000 feet of water using steel catenary risers (SCR) and terminate in the crowded infrastructure on the shelf around Ship Shoal 332.

(Below) Ship Shoal 332 platforms (A & B) in the U.S. Gulf of Mexico, (left) Technip's Deep Blue performed the pipelay work. Photo courtesy of Technip.

The Jack/St. Malo FPU was designed to be powered by natural gas, so the WRGS pipeline had to be bi-directional, providing import gas for FPU startup operations, and for times when produced gas became insufficient to meet fuel needs during the life of the platform. In order to provide suitable pressure and quality for gas used during import operations, a compressor and dehydration station were installed at the Ship Shoal 332 platform.

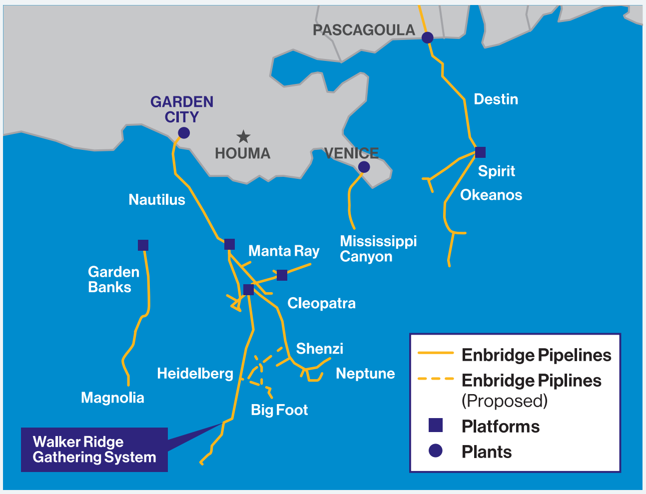
The WRGS design also had to accommodate the subsequent tie-in of gas production from other deepwater fields, so the project included installation of several large subsea sled structures with Y connection points.

In addition, by terminating at Ship Shoal 332, the WRGS gave the Jack/St. Malo owners an alternate route to ship gas to market. In the unlikely event of problems on Enbridge's Nautilus pipeline, gas from WGRS could be directed to the nearby Kinetica Energy Express pipeline, assuring reliable gas delivery.

During the front-end engineering and design (FEED) process, the team developed a comprehensive design for the WRGS to address all of these requirements.

WRGS Implementation

While the Jack/St. Malo FPU was being assembled in Ingleside, Texas, Enbridge began construction of the WRGS, with Technip as the pipelay contractor. Technip's Deep Blue and Deep Energy vessels, which are capable of installing up to 33 miles of 10-inch diameter pipe in a single voyage, were selected to perform the work.



The WRGS was constructed during peak activity in the Gulf of Mexico. At the time, pipeline contractors were working at full capacity, and Enbridge had to coordinate with suppliers and several producing groups to schedule WRGS construction and keep the project on schedule. Work proceeded without weather delays, completing the 170 miles of the gas pipeline system in five segments.

As the pipeline was installed, the project team focused on equipment inspection and quality control of system components. Extensive pigging tests were performed on the bi-directional Y connections (provided by Quality Connector Systems, now part of Oil States International), and additional tests were performed to assure pig-ability of the entire system.

Chevron and other project co-owners required the WRGS to have a very robust emergency pipeline repair system (EPRS) in place to minimize downtime in the event of pipeline damage. To comply with the requirement, Enbridge acquired and tested a complete EPRS package, including lifting frames, clamps, connectors and remotely operated vehicle tools for coating removal, cutting and beveling.

At Ship Shoal 332, Technip's Uncle John vessel was used for spool and riser installation in 435 feet of water. For redundant protection, installation included a subsea safety shutdown system for the high pressure gas line in addition to the standard surface emergency shutdown system.

At Jack/St. Malo, the gas export line was successfully connected to the FPU through a steel catenary riser, and during initial startup, Enbridge delivered gas to the platform, demonstrating the bi-directional operation of the pipeline system.

The WRGS delivered first gas from Jack/St. Malo in December 2014. Enbridge completed the project on time and under budget.

The WRGS system is designed for reliable operation, and provides options for Chevron and its project co-owners to keep oil flowing and deliver gas to market.

ENBRIDGE
Life Takes Energy™

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COMPANY PROFILE ■ **AKER SOLUTIONS INC.**

Early delivery of complex production control umbilicals

Over the past 20 years, Aker Solutions has delivered more than 550 umbilicals for some of the world's most challenging fields, from harsh environment to ultra-deep, high-pressure water conditions.

For the Jack/St. Malo fields, Aker Solutions supplied five subsea production control umbilicals, which provide hydraulic, electrical and fiber-optic service. Totaling 112,403 m, these steel-tube umbilicals have been deployed at 7,000-ft water depth.

Engineering, project management, and manufacturing took place at the company's state-of-the-art umbilical facility in Mobile, Alabama. "The JSM umbilical project required extensive coordination with suppliers, the deployment contractor and Chevron's JSM team," explained Aker Solutions' project manager Graham Jones. "Despite the logistical challenges and complex umbilical construction, which included UV protection for the dynamic portions of the umbilicals that are above the water line and a double closing process to incorporate additional fiber-optic cables and hydraulic lines, Aker Solutions achieved early delivery, before the contractual date."

Aker Solutions' umbilical facility in Mobile, Alabama, with its high-capacity horizontal cable, is specially designed to meet the challenges of demanding deepwater applications.

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COMPANY PROFILE ■ **DNV GL**

Success through project performance forecasting and technology qualification

The Jack/St. Malo project posed numerous challenges in terms of performance forecasting, technical risk assessment and qualification of innovative E&P technologies. "DNV-GL is proud to have contributed to the success of this deepwater milestone through our technical advisory services," explained Graeme Pirie, Vice President DNV-GL – Oil &Gas.

Performance forecasting. A DNV-GL team performed an asset risk study, assuring that the Jack/St. Malo facility will meet its intended production targets based on the engineering design and system configuration. The study

included technical risk assessments to ensure that the topsides and loads were within design specifications.

Technology qualification. In Bergen, Norway, DNV-GL performed testing on umbilicals and polyester ropes. Laboratory testing was also performed at DNV-GL's facility in Columbus, Ohio, to ensure that materials under test were fit-for-purpose in the downhole Lower Tertiary environment.

Chevron has endorsed DNV-GL's recommended practice (RP 8203) for its Technology Qualification Program (TQP). The TQP is used to qualify any novel or unproven technology that is under consideration.

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Bevel Tech Group Inc. provides ID Machining of JSM Riser and FSFL pipe joints

Bevel Tech Group Inc. (BTG) provides critical, precision machining on the ID and OD of deepwater pipe and components from 3" to 28" onsite, with CNC precision, in the U.S. and internationally. In 2006 BTG completed the machining on Chevron's Tahiti Project steel catenary risers (SCR), FSFLs, Flow-lines and J-Collars, machining over 6,000 ends to project specifications using our manual counter boring systems.

Bevel Tech Group Inc.'s machining system provides CNC quality products in virtually any location, no matter how rugged or remote.

Proprietary CNC Machining

Developed in 2006, BTG's CNC machining system was designed to provide CNC quality machined products in virtually any location, no matter how rugged or remote. The system can operate under generator power, is adjustable to compensate for uneven landscapes, and is containerized for shipping overseas. However, BTG's main goal in developing the concept was to provide our fully trained staff a safe operating system for use in any set up location.

For the Jack/St. Malo Project BTG's automated CNC system performed the ID machining on the FSFL and SCR pipe joints on location. More than 3,500 ends were machined to exact ID and WT specifications needed on time, safely.

Entering our 10th year of operating our CNC systems, we have completed more than 50 deepwater machining projects without any safety or quality incidents.

About Bevel Tech Group Inc.

Bevel Tech Group Inc. was established in 1998 as a specialty field and shop machining company with heavy emphasis on deepwater pipe and products. Since then, BTG has become a leader in counter boring SCR pipe and components needed for deepwater projects. Bevel Tech Group Inc. partners with major oil companies and their EPC contractors to develop and provide unique services for the deepwater industry:

- Counter boring (OD and ID) for SCR and flow line piping or other applications
- Specialized coating machining removal / modifications
- Pipe End Measurement Services (PEMS) Laser Metrology
- Pipe cutting and beveling services for all sizes of pipe.
- Bolting/ Torqueing
- Isolation Testing
- Millwrights
- Field Machining of all Types

BTG provides proven project management, equipment, and technicians while achieving high standards in Safety and Quality.

Danos Supports Jack/St. Malo Platform Commissioning

Danos provided mechanical hook-up and commissioning support for the Jack/St. Malo floating production unit (FPU). The company also closed out or mitigated more than 2,000 punch-list items to enable Chevron to produce first oil on schedule.

Danos owners, from left: Paul Danos, Executive Vice President; Garret"Hank" Danos, President & CEO; Mark Danos, Vice President of Project Services; and Eric Danos, Executive Vice President.

Onshore and Offshore Support

Danos provided onshore logistics, materials management, fabrication and construction support throughout the topsides integration. Mechanical walkdowns began 90 days before the FPU was towed from the integration yard in November 2013.

Once the FPU was moored at Walker Ridge 718, Danos continued to provide installation, testing and remediation services through January of 2015. One of the challenges of the Jack/St. Malo project was that many operations typically performed onshore— adjustable speed drive (ASD) transformer removals, large valve replacements, and hydrostatic testing — had to be carried out in the offshore environment. Danos managed difficult logistics, as well as limitations for personnel on board, to successfully perform these complex operations on the FPU moored 250 miles from the nearest port.

Project Highlights

Danos contributed to the success of the Jack/St. Malo project:

- Fabricated and installed a temporary oil export system with two pumps and 500 linear feet of pipe, requiring over 300 shop welds.
- Removed and reinstalled five large ASD skids in two buildings, and designed and performed infrastructure modifications needed to complete the task.
- Removed, repaired and reinstalled 106 PetrolValves and actuators, including 52 large, high-pressure valves (rated at 15,000 psi).
- Installed a 66,000-pound H_2S removal skid below the platform's north bridge. Danos project managers designed a skid-in plan to install the unit from the platform's moonpool, eliminating the need for derrick barge support.
- Completed 160 pressure tests of 34 systems at pressures up to 22,500 psi. Issues found during 14 flow line tests were successfully repaired without delaying line commissioning.

About Danos

Founded in 1947, Danos is a family-owned and managed oilfield service provider. In addition to project management and construction services, Danos offers production workforce, environmental, instrumentation and electrical, fabrication, coatings, materials management, scaffolding, shorebase and logistics solutions.

danos

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Heerema transports, installs Jack/St. Malo FPU

Heerema Marine Contractors (HMC) transported the Jack/St. Malo floating production unit (FPU) from the Kiewitt Offshore Services (KOS) shipyard in Corpus Christi 425 miles to Walker Ridge 718. HMC installed mooring lines and steel catenary risers (SCR) to the FPU. In addition, HMC managed design, fabrication and testing of the SCR pull-in equipment, and marshaled chains, ropes and connectors needed to install the FPU in 7,000 ft of water. This large-scale installation required subcontracting with 18 suppliers, as well as deployment of the Balder Deepwater Construction Vessel, a support vessel, a smart buoy, two barges and a total of 14 tugs.

Suction Pile Installation

First, Heerema transported 16 suction piles and installed them in the ocean floor to secure the mooring lines. Each pile was 120 ft long and 19 ft in diameter, with a dry weight of 353 short tons. The piles were towed on barges from the KOS facility to Walker Ridge block 718. The Balder vessel, which is equipped with two cranes and can lift up to 6300 tons, unloaded the piles from the barge and lowered them to the seabed. Suction pumps were used to drive them into the sea floor. This operation took two weeks, from May 8 to May 22, 2013.

Marshalling Materials

At its facility in Port Fourchon, La., HMC gathered and organized 13,000 m of chains with associated shackles; 43 reels containing more than 72,000 m of polyester rope; and a variety of subsea mooring connectors and rope connectors.

DCV Balder lifting a Jack/St. Malo suction pile.

Tow-out and Installation of Mooring Lines

In November 2013, HMC towed the Jack/St. Malo FPU from the KOS facility. The massive FPU, which weighs 55,000 mT, was towed by 11 tugs to a holding area where the push fenders were removed and bunkering took place to increase its draft. Then the FPU was towed to its operating location.

Next, HMC installed the 16-line mooring system to secure the FPU in place. Each of the mooring lines was secured to a mooring pile, and was comprised of an anchor chain, multiple polyester rope segments joined by H-link connectors, and an upper chain connected to the FPU.

Custom SCR Pull-in System

HMC managed the design, procurement, fabrication and testing of the custom-engineered SCR Pull-in equipment. The system, which includes an SCR module (SCRM), specially manufactured chain, chain locker and work wire winch, has the capacity to pull 1250 mT of riser.

Once the FPU was moored on location, six SCRs were laid down on the seabed in proper orientation, and so their installation would not interfere with the mooring lines. Then the SCRs were recovered in sequence and pulled up by the SCRM. This operation was completed in January 2014.

About HMC

Heerema Marine Contractors (HMC) is a world leading marine contractor in the international offshore oil and gas industry. HMC transports, installs, and removes fixed and floating structures, subsea pipelines and infrastructures in all water depths. The company is a fully-owned subsidiary of the Heerema Group.

MARINE CONTRACTORS

HEEREMA MARINE CONTRACTORS
Vondellaan 47
2332 AA Leiden
The Netherlands

Self-supporting, open-water umbilical systems for rigless, riserless well control

Comprehensive pre-deployment inspection and testing ensured successful installation of the IWOC umbilicals for the Jack/St. Malo project.

A world-class provider of subsea technologies, JDR Cables plays a key role in the design, development and delivery of self-supporting, open-water intervention workover control (IWOC) umbilical systems.

Self-supporting open-water umbilicals. Custom-engineered, patented and manufactured by JDR, this class of open-water umbilicals utilizes high strength materials and innovative component configuration to support its own weight—and that of the subsea termination assembly. The JDR umbilicals are suitable for riserless, rigless open-water applications. They can be spooled rapidly and immediately upon arrival at the site, and may be deployed through the moonpool or "over the side" from a vessel of opportunity. The Umbilical Termination Assembly (UTA) can be deployed via the umbilical as well. JDR umbilicals have a smaller footprint and reduced need for topside equipment. Risk of exposure for personnel is reduced as well.

Workscope. For the Jack/St. Malo project, JDR developed two high-strength, self-supporting, open-water umbilical systems, designed to operate in water depths of 7,000 ft. With patented terminations, the umbilicals enable an extensive range of well control packages to be rapidly deployed from a vessel of opportunity, without the need to clamp the umbilical to a wireline or riser.

The umbilical packages featured JDR's high-capacity subsea terminations and custom-engineered hydraulic reelers for open-water operations. Designed and manufactured in Littleport (UK), the umbilicals were integrated with the reelers before field shipment.

Comprehensive testing. In addition to a full API17E qualification program, JDR undertook a series of tests to evaluate and verify the strength and compatibility of the umbilical design under a variety of operational and environmental workloads.

The umbilicals were load tested at 2.5 x SWL with no failure. There was 95% retention in strength of umbilical after fatigue due to continuous reeling (employing a solid turning wheel for uniform load distribution). The umbilicals were suitable for continued operation at its safe working load (SWL) of 30,000 lb for >50 deployment cycles. The subsea termination exceeded the specified minimum break load (MBL) of 72,500 lb.

JDR's dynamic and agile approach delivers industry-leading solutions; building long-term partnerships and increasing asset productivity. New technologies, such as JDR's self-supporting, open-water umbilical systems, have been developed to enable Operators to realize significant cost savings for their intervention operations in deepwater applications.

JDR CABLE SYSTEMS LTD
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KBR is Pleased to Have Collaborated with Chevron on Successful, Ground-Breaking Jack/St. Malo Project

The opportunity to participate on the Jack/St. Malo floating production unit (FPU) for Chevron positioned KBR at the forefront of deep water field development.

One of the largest semi-submersible production platforms in the world and the first semi-submersible floating production unit designed and built as a low-motion unit for the Gulf of Mexico, the Jack/St. Malo FPU is an example of KBR's ability to offer integrated solutions through combined expertise across all of KBR and our subsidiaries.

Jack/St. Malo's hull arrives in Port Aransas, TX on its way to the fabrication yard in May of 2013

KBR performed conceptual engineering and design, pre-front-end engineering design (FEED) and FEED services and KBR subsidiaries Granherne and GVA collaborated on the execution of the design and engineering support through fabrication for the deep draft semi-submersible including: hull, deck box, accommodations, appurtenances, equipment foundations, mooring system design, and anchor suction piles. The semi was designed to minimize vessel motion and allow acceptable fatigue lives of the moorings, risers and umbilicals.

With the Jack/St. Malo FPU, Chevron has expanded the possibilities of offshore exploration and production and KBR is pleased to have collaborated with Chevron on this successful and ground-breaking project.

Jack/St. Malo is the largest semi-submersible in the Gulf of Mexico based on displacement. With a planned production life of more than 30 years, current technologies are anticipated to recover in excess of 500 million oil-equivalent barrels

KBR

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Oil States technology gets SCRs on board at Jack/St. Malo

Oil States Industries, Inc. collaborated on the Jack/St. Malo project, providing pull-in technology for the installation of multiple SCRs as well as FlexJoint™ HPHT SCR flexible joint assemblies.

A cooperative effort between Oil States–Houma and Bardex, the SCR Pull-In System was used to transfer the flow-lines and risers from the installation vessel to the FPU. The Oil States team designed, manufactured, and tested the system's SCR Pull-In Module; the chain windlass and chain locker assembly; and the work wire and auxiliary winches.

The system offered the ability for the entire system and components to translate 360° around the moon pool on rails and for the SCR module to rotate 360° under load. These capabilities were vital to achieving precise installation into the hang-off porches integral to the FPU hull.

The modules included:

- SCR Pull-In Module with chain jack designed for a 1250 Te nominal capacity and 147mm chain for lifting and positioning the SCRs
- Chain Locker Module for storage of 600m of 147mm chain, including a 40 Te auxiliary winch to manage and store slack
- Work Wire Winch Module designed for 700m of 3" wire with a line pull of 175 Te on all layers; used to install the chain onto the FPU from the support barge

Oil States completed a full-scale dynamic test of the system at its facility in Houma, Louisiana. The installation was completed on time and without incident.

Oil States also designed, qualified and manufactured four 10 ¾" production, one 10 ¾" gas export, and one 20" oil export FlexJoint™ HPHT SCR flexible joints for the Jack/St. Malo project. The flexible joints provide the required storm safety and fatigue resistance for the SCRs connected to the Jack/St. Malo FPU.

Acute Technological Services (ATS), owned by Oil States, provided specialty welding services for the project and qualified three first-joint girth weld procedures and NDE. ATS also fabricated the first girth welds for each of the six top-of-riser assemblies.

Oil States Houma provided 16 Model UCF-104 7-pocket Underwater Chain Fairleads sized for 165mm chain.

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SCR Pull-in system on board the Chevron Jack/St. Malo FPU

Subsea Boosting Systems Contribute to Jack/St. Malo's Success

Seabed boosting technology from OneSubsea, a Schlumberger company, is making an important contribution to Chevron's Jack/St. Malo project by providing the necessary lifting required to produce from the two deepwater fields and enable long tiebacks to the development's Floating Production Unit (FPU).

To date, Chevron has drilled 12 wells in three clusters (one in the Jack field and two in the St. Malo field), which are served by three subsea pumps.

The OneSubsea boosting pumps are rated for 13,000 psi design pressure and differential pressures up to 4,500 psi.

Importance of Seabed Boosting

The prolific Lower Tertiary reservoirs tapped by Jack/St. Malo's 28,000-ft wells naturally provided enough pressure to lift the hydrocarbons from the reservoir to the seabed, and carry them through the long tiebacks and to the production platform. However, as the original reservoir pressure declined, Chevron chose to deploy subsea pumps on the seafloor to boost the production to the topsides facility. Chevron has stated that by reducing the back-pressure on the reservoir, the boosting pumps have the potential to improve the recovery factor by 10% to 30%. This translates to between 50 and 150 million barrels of additional oil recovery resulting from this leading-edge subsea boosting technology.

The OneSubsea Solution

OneSubsea, through its Schlumberger and former Cameron roots, has implemented 30 subsea projects over the last 25 years and has unmatched experience in meeting the challenges of deepwater production. After rigorous evaluation, Chevron chose OneSubsea as its supplier for the subsea boosting system on the Jack/St. Malo project.

OneSubsea provided a broad scope of services and products for Jack/St. Malo, including engineering, project management, 12 subsea trees, production controls, and four manifolds. Subsea boosting technology was the most advanced contribution from OneSubsea, including three pump stations with 3.0MW single-phase pumps, subsea transformers, and pump control modules; associated controls and instrumentation; and a complete topside power and control system.

Installed in 2,100 m (7,000 ft) of water, the 3.0MW pumps are the most powerful subsea pumps ever deployed, and are rated for 13,000 psi design pressure and differential pressures up to 4,500 psi. The powerful pumps convey production through two 20-km (12.5-mile) tie-backs and the risers to the topside processing system on the FPU.

Booster Systems Installed and Commissioned

The subsea boosting systems were installed and tested in 2014, and Jack/St. Malo's first oil was produced in December of that year. In early 2016, the systems were fully operational, lifting 70,000 bopd. Jack/St. Malo production is expected to ramp up to 94,000 bopd and 21 MMCF/day in the coming years.

OneSubsea
A Schlumberger Company

4646 W Sam Houston Pkwy N
Houston, Texas 77041
www.onesubsea.slb.com

Data-driven solutions across the entire oil and gas value chain

Buzzwords such as “analytics”, “data-driven solutions” and “business intelligence” have entered the lexicon of the oil and gas industry for some time now. With the implementation of oil and gas apps on the TIBCO Spotfire platform, Ruths.ai has transformed these buzzwords from promises to best practices.

Ruths.ai

An oil and gas data analytics company, Ruths.ai specializes in building solutions that handle the messy reality of today’s data. These solutions enable scientists and engineers make informed decisions across the entire oil and gas value chain. Ruths.ai leverages the TIBCO Spotfire platform as the visual analytics and interactive exploratory analysis engine of delivered solutions. Ruths.ai has over eight years of experience in applying Spotfire to both common workflows and in-depth analyses in the oil and gas domain. Based in Houston, the Ruths.ai team works with technical end users and IT departments to gain valuable insights for some of the largest and most complex oil and gas fields in the world.

The Ruths.ai team is led by Troy Ruths, who is the founder and Chief Data Scientist. Troy earned his BEng in Computer Science from Washington University in St. Louis in 2008. Subsequently, Troy graduated with a PhD, also in Computer Science, from Rice University. He gained his first insights into the oil and gas industry as an intern for Chevron. In recent years, through Ruths.ai, Troy has worked closely with Chevron’s technical and IT teams to design and implement sophisticated analyses for a growing set of global applications.

Data analytics resources

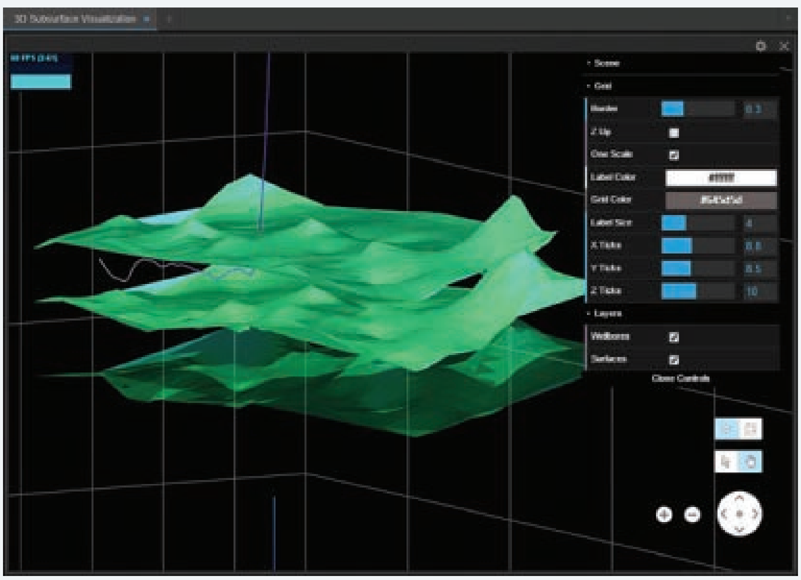
Ruths.ai works with its clients through an analytics retainer. This arrangement provides a comprehensive set of services for an organization to help mature and support its growth in data sciences and data-driven solutions. Specifically, the retainer offers:

1) **Exchange.ai Premier Membership** for privileged access to Exchange.ai, a multi-vendor analytics app store,
2) **Onsite and Web Support** for day-to-day data analysis questions,
3) **Advisement** for access to a Community of Excellence and data science advisors,
4) **Training** consisting of a deep course catalog of classes provided at regular intervals.

An exciting part of the Ruths.ai ecosphere is **DataShopTalk**, a collection of curated articles about Spotfire, data, data science, and messages about how the data analytics community lives, works, and plays.

Oil and gas apps at Exchange.ai

Exchange.ai is the only multi-vendor analytics app marketplace that allows users to browse solutions and download a growing array of templates and extensions across the oil and gas value chain. Templates are guided analytic workflows that provide the users a launching



Ruths.ai’s 3D Subsurface Visualization extension adds surfaces, trajectories and seismic volumes for a true, 360°, interactive view of the subsurface environment, bringing together the best data science interface for 3D analytics.

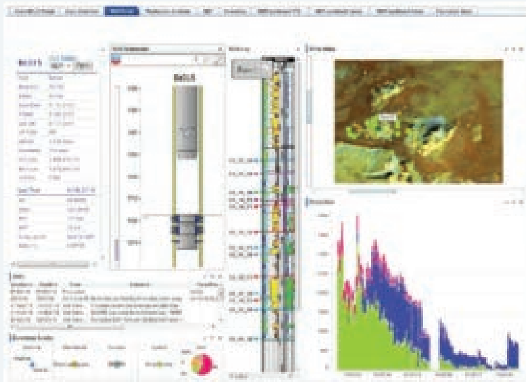
point for their Spotfire analysis. The templates are designed to solve common oil and gas workflows. Extensions provide new functionality to Spotfire by adding visualizations, data connectors, and tools.

Ruths.ai provides modular templates and extensions that can be combined to make powerful workflows. Some of the Ruths.ai products, available through Exchange.ai, include:

- **3D Subsurface Visualization** – an extension for visualizing 3D surfaces, well paths, variables on well paths, wellbore features, geobodies, and seismic within Spotfire,
- **Basic Type Curve Analysis** – an extension for aggregating well declines to determine typical behavior of a well ensemble,
- **Workover Candidate Analysis** – a workflow for identifying potential workover candidates using past field performance,
- **Well Log Visualization** – an extension to create, visualize, and interact with log data.

Data analysis partnership with Chevron

Ruths.ai and Chevron have had an enduring data analytics collaboration. A recent example is a reservoir management application that Troy Ruths and John Pederson, production manager of a Chevron asset, designed to analyze and monitor oil fields. The software's goal is to integrate and expose



A visual, interactive experience enables scientists and engineers to discover new and actionable insights into their oil and fields to increase production and reduce costs.

relevant, oilfield-related data sources to improve the efficiency and quality of decision-making, communication, and data mining in a friendly, visual analytics environment. The application is stable, tested, and deployed across Chevron's global assets.

Startup monitoring for JSM wells

Ruths.ai delivered several analytics tools that provided advanced Spotfire capability for the JSM engineering team. Specifically, these tools enabled the JSM team to build dynamic plots necessary for startup monitoring. This extension improved the existing toolset for the JSM startup workbench in terms of performance and content, built additional analyses that target tactical workflows, and is supporting ongoing reporting requirements.

"Our application enabled the Chevron engineers to monitor real-time data feeds from the JSM wells as well as to discern how parameters, such as the productivity index (PI) and reservoir pressure, for the wells compare with simulation data as they were ramping them up," explained Troy Ruths. "We were able to bring up the simulation data side-by-side with the field data for a real-time comparison.

We also ran predictive well integrity models against PI degradation and pressure loss." The JSM stage 1 producing wells data will be utilized in the analysis to provide insights and information to support future JSM wells.

Analyst Recognition

Gartner has named Ruths.ai as one of the Cool Vendors in Oil and Gas, 2016 for its custom developed data science solutions.

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Technip leverages its products and services to deliver an integrated subsea system

Technip is a world leader in project management, engineering and construction for the energy industry. From the deepest subsea oil and gas developments to the largest and most complex offshore and onshore infrastructures, our 34,400 people are constantly offering the best solutions and most innovative technologies to meet the world's energy challenges. Present in 48 countries, Technip has state-of-the-art industrial assets on all continents and operates a fleet of specialized vessels for pipeline installation and subsea construction.

The *Deep Blue* is one of the most advanced pipelay and construction vessels of the subsea industry and the flagship of the Technip fleet.

Jack/St. Malo (JSM) subsea project

Technip was responsible for subsea installation services, using the *Deep Blue*, one of the world's largest ultra-deepwater pipelay and subsea construction vessels, to install 55 miles of flowlines and SCRs, eight PLETS, and eight heavy-lift structures over four, continuous offshore campaigns.

Stalk fabrication for the flowlines and SCRs took place at Technip's spoolbase in Theodore, Alabama, which also served as the mobilization site for the *Deep Blue*. Fatigue-sensitive flowline sections required buoyancy modules. Strakes and anodes were also part of the flowlines installation. The Technip-designed pipeline end terminations (PLETs) were fabricated in Houston, Texas. Six stab and hinge-over PLETS were fabricated to initiate flowlines, and two gravity-base, second-end PLETs were supplied for terminations. All stab and hinge-over PLETS were stabbed into pre-installed piles and hinged over to land on the pile top.

The Technip-designed stab and hinge over PLETS were the first of their kind for rigid pipelay applications with the *Deep Blue*. The heavy-lift structures, four manifolds and four tie-in skids, were free-issued by Chevron and loaded out by inland barge, transferred to an offshore barge and transported to the field for offshore installation. All structures were installed onto pre-existing piles. The heaviest of the manifold structures installed weighed 200 tonnes.

HSE milestones

Consistent with our HSE Pulse program, the health and safety of our employees is a core value and an absolute commitment for Technip. The JSM project completed over one million man-hours without a recordable injury (LTIR=0.00 and TRIR=0.00).

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Wood Group Mustang Puts Experience to Work with the Jack/St. Malo Topsides Design

Since its inception more than 25 years ago, Wood Group Mustang has developed a global reputation for its innovation, technical excellence and project management expertise on many of the industry's most notable floating deepwater projects. As testimony, it has designed and engineered more than 60% of the topsides for floating production facilities currently operating in the U.S. Gulf Mexico (GOM). In just the past decade alone, Wood Group Mustang has designed more than 500,000 metric tons of topsides representing production of over 1.5 million BOPDE.

The complexity of the Jack/St. Malo design was complicated by the need for the facility to host the two co-developed fields, 25 miles (40 km) apart and in ultra-deep 7,000-foot water depths. The design also needed to incorporate additional provisions to accommodate future subsea tie-backs to additional fields. Jack/St. Malo is one of the largest semi-submersible facilities in the world and the largest by displacement in the GOM, with a final topsides weight of 33,000 tons. The initial design throughput was for 170,000 BOPD and 43 mmscf gas. The hub supports 43 subsea wells and is the first such facility to operate in the gulf's high-pressure Lower Tertiary trend.

Wood Group Mustang first completed the front-end engineering design (FEED) phase for the production facilities. Following the project's sanctioning in 2010, Wood Group Mustang was further awarded the detailed design for the topsides.

Utilizing its very experienced project team, Wood Group Mustang found innovative ways to keep the project on schedule while assuring the necessary quality standards were met. Wood Group Mustang performed process and mechanical designs for the many equipment packages; procured valves, instruments and other equipment for the topsides, as well as some hull and subsea packages; then provided construction management for the topsides assembly by the selected fabricator. This procedure allowed the detailed piping design to be expedited, greatly reducing the time normally allotted for packaged equipment vendor data. An example was a highly complex subsea chemical distribution module that had to fit in a compact deck footprint. Wood Group Mustang's experienced designers provided the layout for the equipment, which was installed without incident.

The project was delivered safely, within budget and on schedule.

Wood Group Mustang's sister companies also made significant contributions to the success of the Jack/St. Malo project. Wood Group Kenny performed detailed design for the 137-mile oil export pipeline and Wood Group PSN provided services relative to the planning, management and execution of onshore and offshore hook-up and commissioning services.

WOOD GROUP MUSTANG

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McDermott delivers integrated subsea solutions

The ability to fabricate jumpers in house, and the combined strengths of its offshore construction vessels, enables McDermott to deliver integrated subsea solutions for challenging deepwater projects.

McDermott's *North Ocean 102* installed umbilicals totaling 65 miles.

For Jack/St. Malo's first-stage development, McDermott completed in September 2014 the installation of jumpers, flying leads, subsea pump stations and umbilicals, and achieved subsea landings for some of the industry's largest and most complex umbilical-end terminations. McDermott performed in-house fabrication of 21 high-specification rigid flowlines, manifold and pump jumpers, and installed the structures using the *Derrick Barge 50*, with its specialized deepwater lowering system.

Three control and two power umbilicals, totaling 65 miles, were installed by the subsea construction vessel, *North Ocean 102*.

In March 2015, Chevron awarded the company a contract to support the brownfield expansion of the Jack/St. Malo fields. The transportation and installation of 30 miles of umbilicals is expected to commence in the second quarter of 2016.

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