UKRAINE OFFERS NEW PSAS
IEA UPDATES EOR PROJECTS, OUTPUT
IMPROVING NAPHTHA CRACKING
MARCELLUS-UTICA OPTIONS
Since 1862, a diverse legacy of quality companies has gathered strength and now stands as the single global source for energy industry products, market-focused applications and total supply chain solutions. DNOW has the unmatched scope and scale to never stop delivering value so clients can accelerate their businesses and surpass their goals.
GENERAL INTEREST

IEA: Crude oil quality matters amid lower supply
26

Queensland’s CSG-LNG plants unlikely to reach full capacity
Rick Wilkinson 27

BP lets rig contract for Ironbark wildcat off Western Australia
Rick Wilkinson 28

APLNG to buy Ironbark coal seam gas prospect from Origin Energy
Rick Wilkinson 28

Aramco forms combine for $10-billion Chinese refining complex
Robert Brelsford 29

Meridian Energy plots grassroots refinery for Permian basin
Robert Brelsford 29

NAPE: Croatia opens licensing round in Dinarides onshore area
Paula Dittrick 30

COVER
Devon Energy Corp. plans by yearend to sell or spin-off its heavy oil properties in Canada and gas production in the Barnett shale to focus on US oil. The moves will help Devon meet a cost-cutting target of at least $780 million/year by 2021. Concentrating on US oil, Devon expects to achieve production growth of 13-18% in 2019 with 10% less upstream capital than in 2018, self-funded at an oil price of $46/bbl if service and supply prices don’t increase. Photo from Devon Energy.
DEVELOP DEEPER TIES

MARCH 5–7, 2019 | SAN ANTONIO, TX USA
HENRY B. GONZALEZ CONVENTION CENTER | WWW.SUBSEATIEBACKFORUM.COM
TECHNOLOGY...

EXPLORATION & DEVELOPMENT
Ukraine outlines latest concessions, production-sharing agreements
Roman Opimakh
31

DRILLING & PRODUCTION
IEA updates EOR project data, doubling output forecast
34

PROCESSING
US olefins industry turns to face global market
Dan Lippe
36
In-depth phase characterization improves naphtha cracker emulsion breaking
Fabrice Cuoq
Jérôme Vachon
44

TRANSPORTATION
US DOE details Marcellus-Utica ethane, petrochemical options
49
HRM FOR THE OIL & GAS INDUSTRY

An in-depth look at human resource management for all aspects of the oil and gas sector. Managing Human Resources in the Oil & Gas Industry will help:

- Guide managers in the oil and gas sector on how to better manage their employees
- Explain ways to deal effectively with the complexities of globalization
- Describe numerous ways to foster a safety culture
- Show how effective management of human resources can improve project success
- Explain how human resources will recruit and train the next wave of industry workers and leaders during the “Great Crew Change”

Order Your Copy Today!

410 Pages/Hardcover/2016

www.pennwellbooks.com
800-752-9764

In Houston
Vice President and Group Publisher
Paul Westervelt, pwesterveltpennwell.com
Editor Bob Tippee, bob@ogjonline.com
Managing Editor-News Steven Fortner, stevenf@ogjonline.com
Managing Editor Technology Christopher E. Smith, chrisOGJ@ogjonline.com
Upstream Technology Editor Paula Dittrick, paulad@ogjonline.com
Downstream Technology Editor Robert Brelsford, rbrelsford@ogjonline.com
Senior Editor-Economics Conglin Xu, conglinx@ogjonline.com
Editor News-Midstream Kevin Athane, mkaia@pennwell.com
Editorial Assistant Vannetta Dibbles, vannettad@ogjonline.com

In Tulsa
Statistics Editor Laura Bell, laurab@ogjonline.com
Art Director Clark Bell, clarkb@pennwell.com
Creative Director Jason Blair, jasonb@pennwell.com
Senior Illustrators Chris Reeder, Chris Hipp
Production Director Charlie Cole
Production Manager Shirley Gamboa
Ad Services Manager Gary Shipley

In Washington
Washington Editor Nick Snow, nicks@pennwell.com Tel 703.533.1552

Editorial Advisory Board
Pat Dennyer Motiva Enterprises LLC, Port Arthur, Tex.
Douglas Elliot Bechtel Hydrocarbon Technology Solutions (Advisor), Houston
Fernando Feitosa de Oliveira Pasadena Refining System Inc., Pasadena, Tex.
Andy Flower Independent Consultant, Caterham, UK
Michelle Michot Foss Bureau of Economic Geology’s Center for Energy Economics, The University of Texas (Houston)
Tom Miesner Pipeline Knowledge & Development, Houston
Ralph Neumann Badger Midstream Energy LP
Kent F. Perry RPSEA, Houston
Ignacio Quintero Chevron Pipe Line Co., Houston
Andrew J. Slaughter Deloitte Services LP, Houston
John Thorogood Drilling Global Consultant LLP, Insh, Scotland

Steven Tobias Hess Corp., Houston
Shree Vikas ConocoPhillips Co., Houston
Clark White Targa Resources Inc., Houston
Colin Woodward Woodward International Ltd., Durham, UK

Editorial Offices
Oil & Gas Journal
1455 West Loop South, Suite 400, Houston, TX 77027
Tel 713.621.9720; Fax 713.963.6285
www.ogjonline.com

Corporate Officers
President and Chief Executive Officer
Mark C. Wilmuth
Executive Vice President, Corporate Development and Strategy,
Jaye A. Gilsgier
Chief Operations Officer PennWell Media, Robert Brighouse

Subscriber Service
Knowledge Marketing, PO Box 47570, Plymouth, MN 55447 USA
USA inquiries: 800-869-6882
International inquiries: 512-982-4277
Email: OGJ@kmpsgroup.com

Senior Audience Development Manager
Emily Martin, emilym@pennwell.com

Custom Article Reprints
Rusty Vanderpool
rustylv@pennwell.com
Office (918) 831-9144

PennWell Corporate Headquarters
1421 S. Sheridan Rd., Tulsa, OK 74112

PennWell
Member Alliance for Audited Media & American Business media

PENNWELL

www.ogjonline.com
Tel 713.621.9720; Fax 713.963.6285

Member Alliance for Audited Media

Reproduced in whole or in part without permission is prohibited. We make portions of our subscriber list available to carefully screened companies that offer products and services that may be important for your work. If you do not want to receive these offers and/or information via direct mail, please let us know by contacting us at List Services Oil & Gas Journal, 1421 S. Sheridan Road, Tulsa OK 74112. Printed in the USA. GST No. 135883153. Publications Mail Agreement no. 4013696.
SMALL PARTICLE BIG ROLE

SINOPEC CATALYST CO., LTD

— One of the world’s leading manufacturers, suppliers, and service providers for oil refining and chemical catalysts
— Dedicated to supplying premium quality products and excellent customer service to refining and chemical enterprises
— Products including oil refining catalysts, polyolefin catalysts, catalysts for basic organic raw materials, coal chemical catalysts, environmental protector catalysts, additives, and absorbents.
— Nearly 70% of China’s refining and chemical enterprises and a considerable part of the world’s oil and gas companies are clients

Contact Information
Phone: +17138408499 Xuej.chji@sinopec.com
http://scc.sinopec.com
**GENERAL INTEREST**

**QUICK TAKES**

**Court nixes challenge to Alberta export bill**
The government of British Columbia has received a setback to its challenge of legislation that would empower the Alberta energy minister to require licenses for the transport of energy away from the province (OGJ Online, May 23, 2018).

Because the bill has not become law, BC’s claim is “premature and inappropriate for consideration by the court,” a Calgary justice ruled.

The Alberta General Assembly passed the legislation last May in response to BC opposition to the expansion by Kinder Morgan of the Trans Mountain Pipeline between Edmonton and Burnaby, BC. Since then, the Canadian government has acquired the Trans Mountain system and expansion project.

**Targa divests Badlands assets for $1.6 billion**
Targa Resources Corp., Houston, agreed to sell a 45% interest in Targa Badlands LLC, the entity that holds Targa’s North Dakota oil and gas assets, to funds managed by GSO Capital Partners and Blackstone Tactical Opportunities for $1.6 billion in cash. Targa will continue to operate and hold majority rights.

The Badlands assets and operations, in the Bakken and Three Forks shale plays of the Williston basin, include some 480 miles of oil gathering pipelines, 125,000 bbl of operational oil storage, about 260 miles of gas gathering pipelines, and the Little Missouri gas processing plant with a current gross processing capacity of 90 MMcfd. Additionally, Badlands owns a 50% interest in the 200 MMcfd Little Missouri 4 Plant anticipated to be completed in this year’s second quarter.

Future growth capital is expected to be funded on a pro rata basis. Badlands will pay a minimum quarterly distribution to Blackstone and to Targa based on their initial investments, and Blackstone’s capital contributions will have a liquidation preference upon a sale of Badlands.

**RockRose Energy to buy Marathon Oil’s UK business**
Marathon Oil Corp. will exit the UK with a sale of its UK businesses Marathon Oil UK LLC (MOUK) and Marathon Oil West of Shetland Ltd. (MOWOS) to RockRose Energy PLC to further concentrate on its high margin, high return US resource plays.

MOUK holds a 37-40% operated interest in fields in the Greater Brae Area, and MOWOS holds a 28% interest in the BP PLC-operated Foinaven field unit and 47% in Foinaven East. The deal includes interests in the SAGE, Brae-Forties, and WASPS infrastructure. At yearend 2018, Marathon Oil carried 21.4 million boe/d of proved reserves in the UK. Anticipated production is 13,000 boe/d in 2019, taking RockRose’s total net anticipated production to 24,000 boe/d for the year.

Subject to adjustments, closing consideration payable to Marathon Oil will be $140 million, which reflects the assumption by RockRose of MOUK and MOWOS working capital and cash equivalent balances of some $350 million as of Dec. 31, 2018.

The MOUK and MOWOS assets and teams in Aberdeen, Peterhead, and offshore will transfer with MOUK and MOWOS to RockRose upon the deal’s completion—expected in this year’s second half with an effective date of Jan. 1.

**Devon to shed assets, focus on US oil**
Devon Energy Corp. plans by yearend to sell or spin off its heavy oil properties in Canada and gas production in the Barnett shale to focus on US oil. The company has hired advisors for each group of assets to be separated. It will open data rooms by this year’s second quarter.

In Canada, Devon in 2017 produced 131,000 boe/d net to its interests (98% liquids) via steam-assisted gravity drainage in the Athabasca region of Alberta and cold flow in Saskatchewan.

Its average 2017 net production from the Barnett shale of North Texas was 153,000 boe/d, of which 27% was liquids.

The moves will help Devon meet a cost-cutting target of at least $780 million/year by 2021. Concentrating on US oil, Devon expects to achieve growth of 13-18% in 2019 with 10% less upstream capital than in 2018, self-funded at an oil price of $46/bbl if service and supply prices don’t increase.

The company’s core properties in the Delaware basin and Eagle Ford play of Texas, STACK play in Oklahoma, and Powder River basin of Wyoming produced an average 296,000 boe/d of oil and gas in the fourth quarter last year.

**QEP reviews options after Williston deal falls through**
QEP Resources Inc., Denver, has started a comprehensive review of strategic alternatives that could result in a merger or sale of the company or its assets and intends to engage in discussions with parties that have expressed interest, including...
As the industry leader in compression, Ariel offers design innovations inspired by our deep-rooted commitment to our customers. Our engineers have listened to partners in the field for over half a century, and the result is unrivaled quality.
US INDUSTRY SCOREBOARD — 3/4

<table>
<thead>
<tr>
<th>Latest week 2/15</th>
<th>4 wk. average</th>
<th>4 wk. avg. year ago</th>
<th>Change, %</th>
<th>YTD average</th>
<th>YTD avg. year ago</th>
<th>Change, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Product supplied, 1,000 b/d</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Motor gasoline</td>
<td>9,021</td>
<td>9,054</td>
<td>(0.4)</td>
<td>8,907</td>
<td>8,920</td>
<td>(0.1)</td>
</tr>
<tr>
<td>Distillate</td>
<td>4,195</td>
<td>4,139</td>
<td>1.4</td>
<td>4,225</td>
<td>4,143</td>
<td>2.0</td>
</tr>
<tr>
<td>Jet fuel</td>
<td>1,600</td>
<td>1,636</td>
<td>(2.2)</td>
<td>1,609</td>
<td>1,661</td>
<td>(3.1)</td>
</tr>
<tr>
<td>Residual</td>
<td>253</td>
<td>309</td>
<td>(18.1)</td>
<td>266</td>
<td>285</td>
<td>(6.7)</td>
</tr>
<tr>
<td>Other products</td>
<td>5,553</td>
<td>5,508</td>
<td>0.8</td>
<td>5,725</td>
<td>5,660</td>
<td>1.1</td>
</tr>
<tr>
<td>TOTAL PRODUCT SUPPLIED</td>
<td>20,622</td>
<td>20,646</td>
<td>(0.1)</td>
<td>20,732</td>
<td>20,669</td>
<td>0.3</td>
</tr>
</tbody>
</table>

Supply, 1,000 b/d

| | | | | | | |
| Crude production | 11,925 | 10,178 | 17.2 | 11,902 | 10,007 | 18.9 |
| NGL production | 4,576 | 4,033 | 13.5 | 4,581 | 4,007 | 14.3 |
| Crude imports | 6,990 | 7,808 | (10.5) | 7,318 | 7,852 | (6.8) |
| Product imports | 2,066 | 2,237 | (7.6) | 2,127 | 2,113 | 0.7 |
| Other supply¹ | 2,429 | 2,374 | 2.3 | 2,434 | 2,273 | 7.1 |
| TOTAL SUPPLY | 27,986 | 26,630 | 5.1 | 28,362 | 26,252 | 8.0 |
| Net product imports | (2,961) | (2,508) | — | (2,825) | (2,729) | — |

Refining, 1,000 b/d

| | | | | | | |
| Crude runs to stills | 16,144 | 15,673 | 3.0 | 16,630 | 16,282 | 2.1 |
| Input to crude stills | 16,400 | 16,619 | (1.3) | 16,909 | 16,639 | 1.6 |
| % utilization | 88.2 | 89.5 | 90.9 | 89.6 | 89.6 |

Latest week 2/15

| | Latest week | Previous week¹ | Change | Same week year ago¹ | Change | Change, % |
| Stocks, 1,000 bbl | | | | | | |
| Crude oil | 454,512 | 450,840 | 3.672 | 423,498 | 31,014 | 7.3 |
| Motor gasoline | 256,847 | 258,301 | (1.454) | 251,817 | 5,030 | 2.0 |
| Distillate | 138,688 | 140,200 | (1.517) | 137,985 | 606 | 0.5 |
| Jet fuel–kerosine | 43,365 | 42,113 | 2.625 | 43,068 | 297 | 0.7 |
| Residual | 29,411 | 30,305 | (894) | 32,056 | (2,645) | (8.3) |

Stock cover (days)²

| | | | | | | |
| Crude | 28.2 | 27.4 | 2.9 | 26.0 | 8.5 |
| Motor gasoline | 28.5 | 28.6 | (0.3) | 27.5 | 3.6 |
| Distillate | 33.1 | 32.5 | 1.8 | 33.6 | (1.5) |
| Propane | 31.1 | 34.7 | (10.4) | 25.6 | 21.5 |

Futures prices² 2/22

| | Change | Change Change, % |
| Light sweet crude ($/bbl) | 56.81 | 53.88 | 2.93 | 62.48 | (5.67) | (9.1) |
| Natural gas, $/MMBtu | 2.68 | 2.62 | 0.06 | 2.63 | 0.04 | 1.7 |

¹Based on revised figures. ²Includes other liquids, refinery processing gain, and unaccounted for crude oil. ³Stocks divided by average daily product supplied for the prior 4 weeks. ⁴Weekly average of daily closing futures prices.

Source: US 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

Oil & Gas Journal | Mar. 4, 2019
Thailand will open its 21st round of bidding for offshore oil

Official: Thai licensing round due in June

Thailand will open its 21st round of bidding for offshore oil and gas licenses in June, according to Energy Minister Siri Jirapongphan. The official said terms will be production-sharing with 25% ownership reserved for Thai state enterprises, the Bangkok Post reported.

Jirapongphan spoke at the signing by PTTEP Energy Development Co. Ltd. of PSCs covering Erawan and Bongkot natural gas fields in the Gulf of Thailand.

Those contracts became available as concession expirations approached for Erawan in 2022 and Bongkot in 2023 (OGJ Online, Dec. 14, 2018).

PTTEP is the current Bongkot operator and will be sole stakeholder. It will replace a Chevron Corp. subsidiary as Erawan operator with a 60% interest. Mubadala Petroleum holds the remaining Erawan interest.

The Thai company has committed to holding production at 800 MMcfd at Erawan and 700 MMcfd at Bongkot.

The 21st licensing round had been scheduled in 2014 but was delayed by an economic lull and political instability. Thailand closed its 20th licensing round in 2008.

**Contracts let for gas fields off Sarawak**

Sarawak Shell Bhd. and Sapura Exploration & Production have let contracts to McDermott for work related to the linked development of three natural gas fields offshore Malaysia.

The Shell unit’s contract covers transportation and installation of jackets, topsides, and pipelines for Gorek field. The Sapura contract is for the same work for Larak and Bakong fields. McDermott also will fabricate risers and spools under both contracts.

The fields are on the 4,400-sq-km SK408 production-sharing contract area in the Central Luconia Gas Province in shallow water of Sarawak. The area is 130 km northwest of Miri.

Each field will have a wellhead platform tied back to an existing processing facility.

Shell, with a 30% interest in the PSC, is development and production operator for Gorek field. Sapura, with 40%, is development and production operator for Larak and Bakong fields. Petronas Carigali holds the remaining SK408 interest.

Sapura discovered the fields in Late Miocene carbonate build-ups during a drilling campaign that began in 2014.

**EXPLORATION & DEVELOPMENT QUICK TAKES**

**ExxonMobil makes gas discovery offshore Cyprus**

ExxonMobil Corp. announced a natural gas discovery offshore Cyprus in the Eastern Mediterranean on Block 10. The Glaucus-1 well cut 436 ft of reservoir rock. Evaluation of the potential of Block 10 continues. The well was drilled to 13,780 ft in 6,769 ft of water. ExxonMobil said preliminary interpretation of the well data indicates gas resources of 5-8 tcf although additional analysis will determine resource potential.

Glaucus-1 was the second well drilled on Block 10. The first well, Delphyne-1, did not encounter commercial quantities of hydrocarbons. Block 10 covers 635,554 acres. ExxonMobil Exploration & Production Cyprus (Offshore) Ltd. operates the block with 60% interest. Qatar Petroleum International Upstream holds the remaining interest.

**Official: Thai licensing round due in June**

**Woodside-led group lets Senegal SNE field contract**

The Woodside Energy Ltd.-operated development phase of the SNE oil field offshore Senegal has let the front-end engineering and design contract for the floating production, storage, and offloading facility to MODEC International Inc.

This follows award of the subsea FEED scope to Subsea Integration Alliance last December. Woodside said that following FEED and subject to necessary government and joint venture approvals, it anticipated that further contracts will be awarded to MODEC to supply, charter, and operate the FPSO facility.

CEO Peter Coleman said securing an FPSO facility is a huge step for the joint venture and will allow the project team to complete the technical and commercial activities required to...
support a final investment decision, targeted for midyear.

The development concept is a stand-alone FPSO facility with 23 subsea wells comprising 11 producers, 10 water injectors, and 2 gas injectors plus supporting subsea infrastructure.

The FPSO is expected to have a capacity of about 100,000 b/d to be brought on stream in 2022.

The FPSO will be designed to allow for the integration of subsequent SNE development phases, including gas export to shore and future subsea tie-backs from other reservoirs and fields.

Phase 1 of the SNE development is targeting an estimated 230 million bbl of oil reserves.

**Equinor lets contract to boost Vgidis field output**

Norway’s Equinor has let a $1.3-million engineering, procurement, construction, and installation contract to Wood for the boosting station to increase production from Vgidis subsea field in the Tampen area on Block 34/7 in the Norwegian North Sea.

Under the contract, Wood will provide topside modifications to enable the tie-in of subsea equipment to the Snorre A and B oilfield platforms, which process oil from Vgidis.

This contract follows Wood’s completion of the front-end engineering design and concept study for the asset. Wood currently provides maintenance, modification, and operations services on Snorre A and B under a framework agreement with Equinor.

In late 2018 Equinor and its partners reported plans to invest some 1.4 billion kroner in the boosting station for the field, which has been producing oil through Snorre field for more than 20 years (OGJ Online, Dec. 5, 2018). Equinor expects to bring the station online in first-quarter 2021.

On completion of the project, production from Vgidis field will be increased by almost 11 million bbl.

Vigidis field came on stream in 1997 and it was estimated at the time that the field would produce 200 million bbl of oil.

The field has now produced 394 million bbl and recoverable resources have been increased to 455 million bbl of oil.

**Neptune plans Gjoa tie-back developments**

Neptune Energy and partners plan to develop in parallel Duva oil and gas field and an extension designated P1 of Gjoa oil and gas field in the Norwegian North Sea with subsea completions tied back to the Gjoa platform on PL153 (OGJ Online, Oct. 2, 2019).

Neptune Energy Norge operates both fields, where water depth is about 360 m.

It seeks to develop Gjoa P1 under the plan for development and operation (PDO) covering the Gjoa license, for which it is operator, as a northern extension. Neptune said in a news release it plans to install a subsea template but didn’t specify drilling. An image with the news release indicates two oil and one gas well.

Neptune estimates Gjoa P1 recoverable resources at 32 million bbl and expects the extension to produce at a maximum rate of 24,000 boe/d.

Neptune has applied for a PDO for Duva field, formerly Cara, on PL636, 6 km northeast of Gjoa field and 12 km northeast of the Gjoa platform.

It plans to install a flour-slot subsea template and drill two oil production wells, one gas producer, and possibly another oil producer.

Duva is to produce at a peak rate of 30,000 boe/d from recoverable resources of 88 million boe.

**Algeria’s Touat gas project on track for exports**

Neptune Energy Group, London, and Algeria’s Sonatrach have started natural gas production as part of the commissioning of the partnership’s Touat project in the Shaa basin, 1,500 km southwest of Algiers, near Adrar.

The development, which will produce about 450 MMcfd of gas at plateau, remains on track to begin gas export production by the end of this year’s first half, Neptune Energy said.

Touat comprises eight gas fields and a gas processing plant.

Project development involved drilling 18 development wells, along with building a road, aircraft runway, living quarters, gathering network, and gas treatment complex, as well as installation of a connection to the main GR5 pipeline, built by Sonatrach, to collect the gas from southwest Algeria to bring to Hassi R’Mel, about 800 km north.

**Aramco lets contracts for Marjan oil field work**

Saudi Aramco has let two contracts to McDermott International Inc. for engineering, procurement, construction, and installation services for Marjan oil field offshore Saudi Arabia. Aramco is expanding production capacity of Marjan field, now 500,000 b/d, by 300,000 b/d.

One contract—valued at $50-100 million—is for services for the upgrade of two existing platforms related to the installation of associated equipment for electrical submersible pumps and space for a future high integrity pressure protection system, subsea composite cable lay, and topside cable tie-ins.

The project is scheduled to be fully executed from McDermott’s Al Khobar office and Dammam fabrication facility.

A second contract—valued at $500-700 million—includes the design, procurement, fabrication, and installation, testing and precommissioning of the TP-10 tie-in platform, six gas lift topside modules, and associated pipeline and subsea cables.

The total weight of the structures will exceed 27,000 tonnes and pipelines totaling more than 65 km.

**IOC inks term contract for US crude supplies**

Indian Oil Corp. Ltd. has finalized a term contract to import as much as 3 million tonnes/year of crude oil from the US as part of the operator’s strategy to diversify its term crude sources.

IOC finalized the contract—valued at $1.5 billion—on Feb. 15, the company said. This is the first term contract for US crude grades secured by any Indian state-run refining company.

IOC did not confirm a duration of the contract or the producers from which it has secured the term shipments.

With an overall group refining capacity of more than 1.6
million b/d, IOC controls 11 of India's 23 refineries to account for a 35% share of total national refining capacity.

**ADNOC Refining lets contract for Ruwais refinery**

Abu Dhabi National Oil Co. (ADNOC) subsidiary ADNOC Refining (formerly Takeeet) has let a contract to John Wood Group PLC to deliver preliminary front-end engineering and design (pre-FEED) for a refinery to be built in Ruwais, in the western region of Abu Dhabi (OGJ Online, May 14, 2018).

With a proposed nameplate capacity of 600,000 b/d, the new refinery will be designed to have full-conversion capability as well as the ability to be integrated with existing petrochemical infrastructure in Ruwais, Wood said.

As part of the contract—valued at $8 million—Wood will also provide services, including licensor selection, site master-plan development, scope of work for the FEED phase, as well as a schedule and cost estimate for the engineering, procurement, and construction phase.

Wood said it expects to complete the pre-FEED phase by yearend. Once completed, the new refining and petrochemicals complex will become the world's largest.

The latest contract follows ADNOC's May 2018 announcement that it would expand refining capacity at Ruwais, now a combined 817,000 b/d, with the addition of a 600,000-b/d refinery and to expand petrochemical capacity at the complex as part of its broader $43-billion program to become a global downstream leader under a new combined model of strategic partnerships and investments (OGJ Online, Jan. 28, 2019).

A cornerstone of the downstream investment plan is expansion of the company's existing refining capacity by more than 65% to 1.5 million b/d by 2025, ADNOC said.

**Aramco, Total form Saudi retail venture**

Saudi Aramco and Total SA have signed an agreement to form a 50-50 joint venture that will invest $1 billion to develop a network of fuel and retail services in Saudi Arabia.

Total will be the first major international oil company to invest in the kingdom's fuel retail network.

The companies also agreed to acquire Tas'helat Marketing Co. and Sahel Transport Co., owners of 270 service stations and a fuel tanker fleet.

**NEB recommends approval of Trans-Mountain pipeline**

Canada's National Energy Board recommended the approval of the Trans-Mountain Pipeline expansion project as it delivered its reconsideration report with 156 conditions and 16 new recommendations to the federal government on Feb. 22. NEB's recommended approval came despite the board's conclusion that project-related marine shipping would likely cause adverse environmental effects on the southern resident killer whale and on indigenous cultural uses associated with the animal. It also found that greenhouse gas emissions from project-related marine vessels would be substantial.

NEB carried out the reconsideration and met a 155-day deadline after a federal appeals court cancelled the crude oil and products pipeline project's 2016 authorization last year (OGJ Online, Aug. 31, 2018). The proposed $7.4-billion (Can.) crude oil and products pipeline would be near one that was built in 1953 and increase capacity to 890,000 b/d from 300,000 b/d.

While a credible worst-case spill from the project or a related marine vessel is not likely, environmental effects would be weighty if one occurred, the report said. “While these effects weighed heavily in the NEB's consideration of project-related marine shipping, the NEB recommends that the government of Canada find that they can be justified in the circumstances, in light of the considerable benefits of the project and measures to minimize the effects,” it said.

These benefits include increased access to diverse markets for Canadian oil; jobs created across Canada; the development of capacity of local and indigenous individuals, communities, and businesses; direct spending on pipeline materials in Canada; and considerable revenues to various levels of government.

**ADNOC completes pipeline system investment deal**

Abu Dhabi National Oil Co. (ADNOC) entered into a landmark multibillion-dollar midstream pipeline infrastructure partnership with institutional investors KKR and BlackRock. Newly formed ADNOC Oil Pipelines will lease ADNOC's interest in 18 pipelines transporting stabilized crude oil and condensate across ADNOC's offshore and onshore upstream concessions for a 23-year period. The entity will, in turn, receive a tariff payable by ADNOC, for its share of volume of crude and condensate that flows through the pipelines, backed by minimum volume commitments.

The 18 pipelines leased by ADNOC Oil Pipelines have a total length of more than 750 km and a total aggregate capacity of about 13 million b/d. These assets move most of Abu Dhabi's crude oil production to sites for either conversion to other products or shipment to global energy markets. The pipelines have underlying long-term minimum volume commitments and are supported by stable crude oil production from ADNOC Onshore and ADNOC Offshore with global international oil companies as joint-venture partners, each with an average remaining concession life greater than 35 years.

**ADNOC plans oil storage in Fujairah**

Abu Dhabi National Oil Co. plans to build in Fujairah what it calls "the world’s largest single underground project ever awarded for oil storage." It let an engineering, procurement, and construction contract to 5K Engineering & Construction Co. Ltd., Seoul, for three underground storage caverns with capacities of 14 million bbl each.

ADNOC said the $1.21-billion contract is "the largest for a single project award for underground crude oil storage in the world."

Completion is due in 2022.
2019-2020 EVENT CALENDAR

MARCH 2019


International Conference on Oil & Gas, Singapore, web site: https://oil-gas.pulsusconference.com 11-12.


APRIL 2019

International Conference & Exhibition on Liquefied Natural Gas, Shanghai, web site: www.lng2019.com/ 1-5.


Lebanon International Oil & Gas Summit (LIOG), Beirut, web site: lio-g-summit.com/2-4.


Mexico Energy Assembly, Mexico City, web site: oilandgascouncil.com/event-events/mexico-energy-assembly 3-4.


Denotes new listing or a change in previously published information.
FRAC FUEL SOLUTIONS IS CHANGING THE WAY FRAC PUMPS ARE FUELED.

SAFETY: our system keeps employees AND large amounts of fuel out of the hot zone—significantly reducing the risk of fire.

DIRECT FUELING: our system delivers diesel directly to frac pumps, which keeps your site running uninterrupted.

COST SAVINGS: our system reduces day rate and increases operational efficiencies—adding up to substantial cost savings.

THE ONLY DIRECT ENGINE FUELING SYSTEM, PATENTED TECHNOLOGY

WWW.FRACFUELSOLUTIONS.COM  713-907-4371
IT ALL STACKS UP

Driving results through continuous improvement is one of the values on which our company was built.

With focused operations in Oklahoma’s fast-growing STACK Play, our team of oil and natural gas experts is Energizing America’s Heartland™ and delivering safe, cost-efficient ways to unlock the vast potential of our almost 127,000 STACK acres.

Chaparral Energy

405-693-5400

www.chaparralenergy.com

Chaparral Energy Listed NYSE

2019-2020 EVENT CALENDAR


JULY 2019


SEPTEMBER 2019


SPE Offshore Europe 2019 Oil & Gas Conference & Exhibition, Aberdeen, web site: www.offshore-europe.co.uk 3-6.


OCTOBER 2019

MSGBC Basin Summit & Exhibition, Dakar, web site: https://oilandgascouncil.com/event-events/msgbc-basin-summit/7-9.


Oil & Gas Journal | Mar. 4, 2019


NOVEMBER 2019


DECEMBER 2019


MARCH 2020


TO EXACTING STANDARDS

API 676 PUMP

The new BNA pump ensures compliance with API 676 and API 682 while reducing costs in petrochemical applications. Act now to experience the benefits of this API pump for yourself.

YOUR BENEFITS

- API 676 and API 682 compliant
- Extremely robust design
- High containment pressure and corrosion resistance
- Simple integration into piping systems
- Non-welded casing means reduced documentation and fewer inspections
- Shorter lead time, high operational safety

SEEPEX GmbH
T +49 2041 996-0
www.seepex.com
UKCS volcanoes questioned

Researchers said recent study results suggest the possibility of oil and natural gas discoveries in a 7,000-sq km area of the UK North Sea because of “phantom” volcanoes.

Geologists said a large swathe of the UK Continental Shelf was unexplored for more than 50 years because of beliefs about the existence of volcanoes based upon what researchers now call “incorrect geological models.”

Scientists from the University of Aberdeen led a study resulting in an article entitled “Phantom volcanoes discovery signals new hope for North Sea oil and gas exploration” that was published in November 2018 in the Journal of the Geological Society.

Previously, scientists believed the Middle Jurassic Rattray volcanic province off northwest Scotland contained three volcanoes that erupted 165 million years ago. The notion that the area contained empty magma chambers ruled out possible oil and gas discoveries.

The volcanoes were believed to have been formed millions of years ago during seismic activity under the North Sea that almost created an ocean between Britain and Europe—a rifting episode geologists have described as a failed ‘Jurassic Brexit’ attempt.

**Assumption overturned**

Nick Schofield and Ailsa Quirie from the University of Aberdeen along with colleagues from Heriot-Watt and the University of Adelaide have questioned this assumption.

Schofield said reinterpretation using 3D seismic data and well data shows no volcanic centers are present, and the Rattray volcanics were instead sourced in fissure eruptions from linear vents.

Norway’s Petroleum Geo-Services provided the 3D seismic.

The fissures run parallel to the Highland Boundary Fault, which intersects the Rattray volcanics at the Buchan-Glenn Fissure System.

“What we found has completely overturned decades of accepted knowledge,” Schofield said. “Our study has shown these volcanoes never existed at all. Essentially this gives us back a huge amount of gross rock volume that we never knew existed.”

Schofield added: “There is a huge area under there that hasn’t been looked at in detail for a long time” because of an incorrect geological model. Meanwhile, discoveries still are being made in the North Sea, such as the Central Graben and Viking Graben areas.

**UKCS discoveries**

Wood Mackenzie Ltd. said the UK Central Graben basin is in less than 100 m of water. The Mesozoic high-pressure, high-temperature play remains of interest following the large Culzean discovery in 2008, which is expected on stream late this year.

In January, CNOOC Petroleum Europe Ltd. discovered natural gas and condensate pay in the Glengorm prospect in the Central Graben area. The CNOOC subsidiary drilled an exploration well to 5,056 m TD in 86 m of water, encountering net gas and condensate pay with a total net thickness of 37 m in a Upper Jurassic reservoir.

Recoverable resources are estimated at about 250 million boe, said partner Total E&P UK North Sea Ltd.

Further drilling and testing will be carried out to appraise resources and the productivity of the reservoir, Total said.

The discovery was in the P2215 license, previously part of the Maersk Oil portfolio, and close to existing Total-operated infrastructures offering tie-back possibilities, such as the Elgin-Franklin platform and the Culzean project.

CNOOC is operator with 50% working interest. Partners include Total and Euroil, a wholly owned subsidiary of Edison E&P SPA, each with 25% working interest.
DO NOT CLOSE
this magazine until you’ve seen it all!

Published every month in print and online, check out the OGJ Market Connection for the latest in product and service offerings!

• EMPLOYMENT OPPORTUNITIES
  Want to start a career in the oilfield? Use Market Connection to find available jobs to get your foot in the door.

• EQUIPMENT
  Looking to purchase equipment? This section connects buyers and sellers with generators, tanks, gauging systems, refining equipment, etc. You can find just about anything here.

• PRODUCTS
  View the latest and greatest new products and services and expand your knowledge of what’s available in the marketplace!

• REAL ESTATE / LEASES
  Be the first to find out about land leases up for bid and potential partnerships. The movers and shakers are looking for a partner like you, so find out about the latest opportunities with Market Connection!

THINK YOU’VE SEEN IT ALL?
Turn to the back of this issue to be hired, acquired, buy or sell in the Market Connection. Also be sure to visit us online for weekly updates www.ogj.com.market-connection
FERC’s breakthrough

Breakthrough came to more than a queue of LNG export projects when the US Federal Energy Regulatory Commission approved Venture Global LNG’s Calcasieu Pass venture on Feb. 21. Compromise enabling this welcome move shows hope for progress away from the all-or-nothing approach that frequently mires regulation addressing climate change.

Approval of a 12 million-tonne/year gas liquefaction project by a commission split 2-2 over a crucial topic of regulation is important by itself. Twelve other LNG export plants await FERC approval, and five more are in prefiling stages. Not all those ventures will advance to construction. But LNG is a rapidly growing export commodity as gas production increases from unconventional resources. Liquefaction projects are vital to realization of this economic promise and must be ready when the market needs them.

A ‘new approach’

Just as important as buildout of export capacity, though, is the way commissioners eased political deadlock. FERC “applied a new approach for consideration of direct greenhouse gas [GHG] emissions from LNG facilities,” reported Chairman Neil Chatterjee in a press statement. “I anticipate we’ll be able to use the framework developed in this order to evaluate the other LNG certificates that the commission is considering.”

For Calcasieu Pass, the commission assessed direct emissions of GHGs—3.9 million tpy of carbon dioxide-equivalent, according to the environmental impact statement—as a share of total US emissions in 2016—0.07%. Under a 2016 court ruling, FERC doesn’t review indirect GHG emissions upstream and downstream of projects. The Department of Energy accounts for indirect emissions in its public-interest decisions about LNG exports, which precede FERC review of project facilities.

The new approach cited by Chatterjee didn’t fully satisfy Commissioner Cheryl A. LaFleur, a Democrat, but enabled her to join the commission’s Republicans, Chatterjee and Bernard L. McNamee, in support of the project. The other Democratic commissioner, Richard Glick, dissented. FERC has been politically balanced since the Jan. 3 death of former Chairman Kevin McIntyre, a Republican.

Glick disagreed with FERC’s finding that Calcasieu LNG’s fractional contribution to national GHG emissions was environmentally insignificant. “The result is that climate change plays no meaningful role in the commission’s public-interest determination,” he wrote.

His conclusion suffers from overstatement but nevertheless identifies a genuine problem. FERC has no framework within which to distinguish between environmentally significant and insignificant levels of GHG emissions from individual projects. This indicates no procedural lapse. It instead reflects the core vexation of climate regulation and the futility of applying it project by project.

Climate change is a global phenomenon. No one project can affect it much. Activists therefore try to block as many CO2-emitting activities as they can, hoping to make a collective difference. Yet, even if they were to succeed in foreclosing projects that would have accounted for, say, one third of global GHG emissions, what would the effect be on globally averaged temperature? The answer depends on equilibrium climate sensitivity, the long-term temperature response to a doubling of CO\textsubscript{2} in the atmosphere. About that, the generally accepted scientific estimate varies by a factor of three. With such a wide range of uncertainty, warming—the core concern of climate change—from incremental CO\textsubscript{2} loading of the atmosphere under reasonable assumptions might or might not be significant. It thus might threaten human welfare, or it might not.

Skirting myopia

Glick and LaFleur wish for some way to condense these perplexities into manageable quanta convenient for regulation. Both extol the social cost of carbon (SCC), which estimates costs attributable to CO\textsubscript{2} emissions. But the SCC is arbitrary and subject to political manipulation. Given the complexity of climate phenomena and uncertainty about the CO\textsubscript{2}-temperature relationship, it is, at best, guesswork.

Regulation of GHGs is prudent and necessary. To be effective, however, it must apply at meaningful scale, avoid unreasonable precision in performance metrics, and work within broader environmental programs with clearer benefits in relation to cost. By skirting project-level climate myopia, the FERC decision moves constructively in that direction.
PennWell Books publishes technical & nontechnical books for the petroleum industry. Written by selected industry experts, PennWell Books will help you broaden your expertise in the petroleum industry, understand other related disciplines, provide quick-glance references as topics arise in your daily routine, and make excellent classroom and training texts.

ORDER TODAY!

Visit www.pennwellbooks.com or call 800-752-9764
Growth of US upstream spending to decelerate in 2019

Conglin Xu
Senior Editor-Economics

Upstream oil and gas capital expenditures in US this year will increase only 2%, following an 23% increase last year, as independent producers focus on capital discipline and cashflow neutrality.

Total spending for exploration, drilling, and production will total almost $152 billion, OGJ forecasts. Firms’ spending plans show a divergence between US independents and international oil companies (IOC). Combined spending of the US independent group could drop 6-8% from a year ago, while IOCs will expand their activities.

In 2018, upstream spending surged 23% compared with an original guidance of 9% because of increased activity and higher costs as oil prices held firm for most of the year.

Capital expenditures on the other categories—including refining, petrochemicals, and pipelines—continue to increase this year.

Meanwhile, E&P capital spending in Canada will decline this year, partly because of production curtailments announced by the Albertan government. However, spending for oil sands development there will climb.

International upstream spending outside North America is expected to increase. According to the latest Barclays E&P survey, growth will reach at least 8% from almost every international region, with the exception being Russia and the former Soviet Union. International spending is forecast to reach $286 billion in 2019.

All dollar amounts reported are in US dollars unless otherwise indicated.

**US upstream spending**

The growth of US independents takes a back seat. Consistent with the commitment to capital discipline and in response to recent volatile commodity price trends, most US E&P companies have announced reductions in rig and frac spread counts and intend to reduce 2019 capital spending.

Most companies made their 2019 budgets assuming a West Texas Intermediate oil price of $50-55/bbl and a Henry Hub natural gas price of $3/MMbtu.

Combined spending of US independents could decline 6-8% this year, based on estimates from their budget releases. Despite the overall capex decline, producers are forecasting strong production gains, as they will decrease the inventory of drilled but uncompleted (DUC) wells.

Meanwhile, IOC activities will expand rapidly this year. IOCs have been building out supply chain and infrastructure to support large, multiwell pad developments in the Permian basin. IOCs’ spending plans are usually with lower commodity price sensitivity.

According to preliminary company data and OGJ estimates, Chevron Corp., ExxonMobil Corp., ConocoPhillips, Royal Dutch Shell PLC, and BP PLC will all increase their US onshore capital spending. BP just completed its $10.5-billion purchase of BHP Billiton’s US onshore assets last October.

Bonus payments related to Outer Continental Shelf lease sales will rise slightly this year. The US Bureau of Ocean Energy Management has scheduled two lease sales, Nos. 252 and 253, to take place during 2019. OGJ forecasts that such payments will total $310 million, up from $303 million last year.

During 2018, BOEM held two lease sales. The first one, No. 250, resulted in $124.76 million in bonus payments. The other, No. 251, produced $178 million in bonus payments.

**US firms’ spending plans**

ExxonMobil expects 2019 capex of $30 billion, up from $25.9 billion in 2018 and $23 billion in 2017. ExxonMobil spent $7.67 billion on US upstream in 2018, up from only $3.7 billion for such outlays in 2017. Key drivers of upstream growth in the US this year are in the Permian, where the company has trebled the size of its resource since 2017.

Chevron has budgeted $20 billion for capital and exploratory expenditures for 2019, with $17.3 billion earmarked for upstream spending. Upstream expenditures were $17.6 billion for 2018 and $16.4 billion for 2017, respectively.

Despite a lower total upstream spending, Chevron’s upstream capital outlays on projects in the US will rise to $7.6 billion this year from $7.1 billion last year and $5.1 billion in 2017. Specifically, upstream spending for the Permian is budgeted at $3.6 billion. About $1.6 billion is allocated to other shale and tight investments.
ConocoPhillips anticipates capital spending of $6.1 billion in 2019, which is flat with the expected full-year 2018 capital expenditures excluding acquisition costs. The company’s full-year 2019 production guidance is 1.3 million boe/d to 1.35 million boe/d, up from 1.26 million boe/d last year. This represents the first production gain since 2015.

About $3.1 billion, or 51%, is allocated to the Lower 48, roughly flat to 2018 spending. About $1.2 billion, or 20%, is allocated to Alaska compared with $900 million in 2018. Capital expenditures in Canada also will increase to $500 million from $300 million last year, reflecting ongoing activity in the Montney unconventional program and Surmont upgrades.

Antero Resources Corp. is trimming its drilling and completion budget to $1.2 billion in 2019 from $1.5 billion last year. The company plans to operate an average of 5 drilling rigs and 4 completion crews, down 1 to 2 crews from 2018. Antero is expecting to increase production by 18%.

Apache Corp. is slashing spending by 22% to $2.4 billion, with 75% allocated to its Permian basin assets. It still expects 6-10% production growth after adjusting for divestitures.

Anadarko Petroleum Corp. expects full-year capital investments ranging $4.3-4.7 billion (excluding WES), which represents a 9% decrease relative to its 2018 program and still delivers 10% oil growth year over year. Specifically, 70% of investments are directed towards US onshore assets, mainly in the Delaware and DJ basins. While spending in the Gulf of Mexico is lower than in 2018, the number of wells and production will be similar.

Continental Resources Inc.’s capital expenditures budget for 2019 is $2.6 billion compared with $2.8 billion spent in 2018, with the majority of 2019 drilling and completion budget focusing on oil-weighted areas in the Bakken and SCOOP. Under the current commodity price environment, planned capital expenditures for 2019 are expected to be funded entirely from operating cash flows.

Chesapeake Energy Corp. plans to reduce its 2019 capital expenditures by lowering its rig count by 20%, expecting to average 14 rigs vs. a current rig count of 18.

Concho Resources Inc. is expecting an increase its capital spending during 2019 to $2.9 billion after closing its $9.5-billion acquisition of RSP Permian last July.

Devon Energy Corp. reported a plan to sell its Barnett shale and Canadian oil assets, which represents more than 40% of its fourth-quarter 2018 production. Devon stated that its upstream capital spending this year will range $1.8-2 billion, with the midpoint about 10% less than in 2018. Devon expects to achieve oil production growth of 13-18% in 2019.

Diamondback Energy Inc. plans capital expenditures in 2019 to reach $2.7-3 billion, including $2.3-2.55 billion for drilling and completion. During 2018, capital expenditures for drilling, completing, and equipping wells were $1.4 billion.

Gas-weighted EQT Corp., embroiled in a spat with Rice Energy Inc. founders, is slashing outlays from $2.7 billion last year to $1.9 billion this year to reduce leverage and return additional free cashflow to shareholders. About 80% of its capital spending will be deployed in the Marcellus shale, with the balance being invested in the Utica shale.
EOG Resources Inc.’s exploration and development expenditures for 2019 are expected to range $6.1-6.5 billion compared with $6.2 billion in 2018. EOG expects to increase US crude oil production by 12-16%, fund capital investment, and pay the dividend with net cash from operating activities in 2019 at $50/bbl oil.

EOG expects to complete about 740 net wells in 2019 compared with 763 net wells in 2018. Activity will remain focused in EOG’s highest rate-of-return oil assets in the Delaware basin, Eagle Ford, Rockies, Woodford, and Bakken.

Hess Corp. is expected to spend $2.9 billion, about 40% more than in 2018, due to higher spending in the Bakken and Guyana. About $1.4 billion will be used to fund an increase to 6 rigs from an average of 4.8 rigs in 2018, and the shift to higher intensity plug and perforated wells in the Bakken.

The company expects to drill about 170 new wells and to bring online 160 new wells in 2019.

Marathon Oil Corp.’s 2019 capital budget totals $2.6 billion, down slightly from 2018. More than 95% of its $2.4-billion development capital budget will be allocated to the four US resource plays: Eagle Ford and Bakken (60%) and Oklahoma and the Northern Delaware (40%). Marathon Oil expects oil growth of 10% in 2019.

Occidental Petroleum Corp. announced a 2019 capital program of $4.5 billion compared with 2018 spending of $5 billion. Upstream spending in the Permian will account for $3.1 billion, down from $3.3 billion spent last year.

**US refining, petrochemical outlays**

Given their access to low-cost natural gas and price-advantaged crudes, US refiners still face a favorable business environment. Distillate demand growth outpaces gasoline, driven by transportation and industrial sectors and the impact from the International Maritime Organization’s enforcement of a 0.5% global sulfur cap on fuel content from Jan. 1, 2020, lowering it from the current 3.5% limit.

OGJ projects that capital spending at US refining and marketing this year will increase 3% to $15.5 billion from 2018 spending of $15 billion. The growth in investments focuses on upgrading capabilities, yield flexibility, and conversion capacity.

PBF Energy will spend $625-675 million in net capital expenditures during 2019 for facility improvements and maintenance.

Marathon Petroleum Corp. spent $1 billion and $832 million on its refining and marketing business in 2018 and 2017, respectively. The 2018 spending included part of Andeavor’s results since October. In 2019, Marathon Petroleum’s key projects include increasing Garyville coking capacity by 50%, Galveston Bay STAR Program, and others.

Phillips 66’s capital budget, excluding Phillips 66 Partners, is $2.3 billion this year. Phillips 66 plans $923 million of capital spending in refining, with $512 million for reliability, safety, and environmental projects. Refining growth capital of $411 million is for high-return projects to enhance the yield of higher-value products, including an upgrade of the fluid catalytic cracking unit at the Sweeny refinery, as well as other low-capital, quick-payout projects.

Valero Energy Corp. expects to invest about $2.5 billion of capital in both 2019 and 2020, of which 60% is for sustaining the business and 40% is for growth projects. In 2018, Valero’s capital investments totaled $2.7 billion.

US petrochemical manufacturers remain advantaged with access to cheaper and more abundant feedstocks and energy.

Phillips 66’s capital contributions to Chevron Phillips Chemical Co. will rise to $572 million from $339 million a year ago.

Since 2010, 333 chemical industry projects cumulatively valued at more than $200 billion have been announced, with 53% of the investments completed or under construction and 41% in the planning phase, according to The American Chemistry Council.

**US pipelines**

Many pipeline construction projects are under way in the US to aid in debottlenecking oil and gas from the Permian basin and other plays.

According to OGJ’s most recent Worldwide Pipeline Construction report, plans call for a total of 2,571 miles of gas pipelines to be constructed in the US in 2019, mostly larger than
32 in. (OGJ, Feb. 4, 2019, p. 48). In addition, plans call for the construction of 3,763 miles of crude and product pipelines in the US this year. Many of these lines will be 22-30 in.


Given the strong boom in pipeline constructions, OGJ forecasts that US capital spending on pipelines will increase 5% for crude and product pipelines and 28% for gas pipelines this year from a year ago.

**Canadian E&P, oil sands**

All Canadian spending figures in this section are expressed in Canadian dollars.

Capital expenditures for oil and gas exploration, drilling, and production in Canada will decline 1.5% to $31.4 billion (Can.) in 2019, following a 11% increase in 2018.

Faced by record discounts for its crude and brimming inventories, Alberta announced mandated temporary production cuts of as much as 325,000 b/d for an initial period of 3 months of 2019.

The Canadian rig count decreased to 212 in February from 342 in the same time last year, with oil rigs down 90 units and gas rigs down 40 units, according to Baker Hughes.

According to OGJ forecasts, oil sands capital spending, which includes funds for in-situ extraction, mining, and up-graders, will climb 8% from a year ago to about $13 billion. This follows a decrease of 13% last year.

The Canadian Association of Petroleum Producers reported that oil sands capital expenditures totaled $13.8 billion in 2017, the latest year for which the association has reported such data.

Suncor Inc. has set a 2019 capital spending program of $4.9-5.6 billion, and average upstream production of 780,000-820,000 boe/d. The midpoints of these ranges represent a flat capital spend compared with 2018 and a year-over-year production increase of 10%, including estimated mandatory production curtailments, from 730,000 boe/d in 2018.

Suncor’s upstream oil sands spending this year ranges $3-3.4 billion. This compares with $3.5 billion and $5 billion for 2018 and 2017, respectively. Upstream E&P spending ranges $1-1.2 billion, up from $0.95 million and $8 million for 2018 and 2017, respectively.

Canadian Natural Resources Ltd.’s 2019 base capital bud-
get is targeted to be $3.7 billion, about $1 billion less than the 2018 forecast due to increased capital flexibility.

The company’s 2019 capital budget for total oil sands mining and upgrading will increase to a base budget of $1.5 billion, up from $1.3 billion estimated for 2018. Budgets for North America E&P will decrease to $1.1 billion from $1.55 billion a year ago, while its international E&P spending will increase to $460 million from $410 million last year.

Husky Energy Inc.’s capital spending budget ranges $3.3-3.5 billion, including $1.8 billion in sustaining and corporate capital. Midrange average annual 2019 production of 295,000 boe/d includes reductions related to government-mandated curtailments in Alberta, and the temporary suspension of operations at the SeaRose floating production, storage, and offloading vessel in the Atlantic region.

Husky’s capital budgets for thermal and oil sands this year ranges $730-760 million, down from $915 million last year. Spending for conventional heavy oil and Western Canada resource play drilling ranges $280-300 million, down from $350 million a year ago.

Cenovus Energy Inc. plans to invest $1.2-1.4 billion in 2019, with much of the budget going to sustain base production at its Foster Creek and Christina Lake oil sands operations. The company also plans to complete construction of the Christina Lake Phase G expansion.

Capital investment continues to increase in Latin America

Siddhartha Sen
IHS Markit, Houston

IHS Markit expects global gross domestic product to remain resilient over the next few years, backed by low interest rates across regions and a relatively low inflation rate. Latin America upstream spend is still expected to see an increase of 37%, from $80 billion in 2018 to $110 billion in 2022. However, the main countries—Argentina, Brazil, and Mexico—are experiencing fiscal and external deficits and weak economic recovery.

Activity remains strongest in Brazil, Argentina, and Mexico. Brazil deployed four floating production, storage, and offloading vessels in 2018: one in Tartaruga Verde field, one in Buzios field, and two in Atlanta field. Of the seven FPSOs that Brazil's state oil firm Petroleo Brasileiro SA (Petrobras) had plans to award in 2018, four are currently in the bidding process and are expected to be awarded soon. The total capacity addition from these seven FPSOs would be 910,000 b/d.

Argentina was planning its first offshore bid round in nearly 2 decades in February. The blocks to be put up in these bid rounds are the Argentina Norte, Austral, and Malvinas Oeste. For Mexico, uncertainty exists with the new administration and three bid rounds had been postponed from late 2018 to February 2019.

Utilization rates for the global offshore rig markets have come down from an average of 90% in 2014 to about 60% currently. Supply has exceeded demand, and while 160 rigs were retired globally since 2014, only 12 were from Latin America. The average drilling rig day rate in Latin America is close to $265,000. Most of the Latin American countries have long-term contracts (3-7 years) with extension periods, hence the day rates of a lot of their current drilling rig fleets are based on old contracts.

Brazil is one of the most important countries for subsea activity, followed by Mexico. Latin America will remain the largest regional deepwater rig market. Demand is expected to continue to grow as activity picks up in deepwater exploration in Mexico. Recently operators have pushed towards having shorter-term contracts to enable them to shift gears and maneuver volatility in commodity prices.

Crude pipeline infrastructure in Argentina is located around the main crude-producing basins, thus connecting the production to the main refineries in the region. In Brazil, pipeline infrastructure is limited in its reach and for the population not living close to a refinery, the common mode to transport is rail, barge, or truck. Mexico’s pipeline infrastructure is quite extensive and reforms have opened opportunities for private players to invest in.

A breakeven price for a major field like Cerro Dragon in Argentina is estimated to be $30/bbl. For projects such as Lapa, the producing phases have very competitive breakevens at $25/bbl, while new phases have breakeven close to $46/bbl. With increased activity in the region, the pressure on contractor’s market, supply chain, and infrastructure is expected to rise. Countries like Argentina are expected to manage these constraints by balancing development activity between onshore unconventional and offshore conventional activity. Production for Argentina’s unconventional assets is expected to contribute 33% of total production by 2020, increasing to 64% by 2025.

Most of the upstream activity in Latin American countries is driven and managed by state oil companies. However, with the opening of the region, there are opportunities for international companies to collaborate with state oil companies and develop the oil and gas resources in the region. A fair exchange of technological knowhow, along with fair and equitable fiscal regime, could lead to increased exploration and development activity in the region. This is expected to bring with it cost pressures and hence it will be important for international operators to enter the region while the opportunities exist.
The 4% reduction in total planned capital spending compared with Cenovus’s 2018 forecast is largely the result of efficiency improvements at the company’s oil sands operations and reduced development plans for the Deep basin.

Imperial Oil Ltd.’s capital expenditures totaled $1,427 million in 2018. In 2019, capital expenditures are expected to range $2.3-2.4 billion, including about $800 million associated with the Aspen in-situ project.

Imperial Oil’s $2.6 billion Aspen project in northern Alberta is the first new oil sand development to be green-lighted since 2013.

Elsewhere in Canada

Imperial Oil’s capital spending on Canadian refining is expected to rise from $383 million last year. Cenovus Energy and Husky Energy may also increase their spending on Canadian refining this year.

Suncor’s spending on Canadian downstream ranges $700-770 million this year compared with $856 million for 2018 and $634 million for 2017.

Enbridge Inc., the country’s largest pipeline operator, secured total 2019 and 2020 capital program of $16 billion. The company’s $5.3 billion Canadian Line 3 replacement program is expected to enter service in this year’s second half. The $500-million Spruce Ridge expansion program and $1-billion T-South expansion program are both in pre-construction status.

In 2019, TransCanada expects to spend $8 billion in 2019 on growth projects, maintenance capital expenditures, and contributions to equity investments.

TransCanada’s capital spending on Canadian natural gas pipelines totaled $2.18 billion in 2017 and $2.47 billion in 2018. As a comparison, its spending on US natural gas pipelines totaled $3.8 billion in 2017 and $5.7 billion in 2018. The estimated cost for secured gas pipeline projects in Canada could reach $5 billion in 2019, according to OGJ.

Canada’s petrochemical industry is headed for its biggest surge of expansion spending in 5 years in 2019, thanks in large part to incentive programs by federal and provincial governments.

Several capital-intensive petrochemical projects have been announced in Canada, including Inter Pipeline’s $3.5-billion propane dehydrogenation and polypropylene complex in Strathcona County, Alta., Kuwait Petrochemical’s $4-billion propylene complex, and NOVA Chemical’s $1.2-billion polyethylene plant expansion.

International spending

The latest Barclay’s E&P Spending Survey, released on Jan. 8, expects spending growth of at least 8% from almost every international region, with the exception being Russia and the FSU. International spending is forecast to reach $286 billion in 2019.

Despite the Dec. 6 decision to reduce production by 1.2 million b/d, the Middle East is expected to lead international spending, up 8% to about $43 billion. Spending grew only 2% in 2018, according to the report.

Most of the estimated spend will come from Saudi Aramco, which awarded several notable oil field services contracts in 2018 for onshore and offshore rigs and unconventional gas stimulation services. The amount is more than twice that of the second-highest spender, Abu Dhabi National Oil Co.

Latin America’s spending is expected to grow 11% to an estimated $34 billion (see sidebar, p. 24). This is up from a decline of 6% in 2018. Brazil’s Petroleo Brasileiro SA (Petrobras) and Mexico’s Petroleos Mexicanos (Pemex) are the top Latin American spenders at $13.2 billion (+19%) and $10.5 billion (+15%), respectively. For Petrobras, about 56% of E&P capital is expected to go toward presalt, while the balance will go to post-salt.

In Africa, Barclay’s report shows 12% spending growth for 2019 to about $18 billion compared with 1% spending growth in 2018. The growth is driven by Algeria’s Sonatrach, Nigerian National Petroleum Corp., and Angola’s Sonangol along with Tullow Oil Ltd. and Kosmos Energy Ltd.

Offshore spending is poised to fall another 7% in 2019. Barclays expects 2019 to mark the fifth consecutive year of
offshore spending declines, although early signs point to a potential 2020 inflection as the floater rig count is expected to end 2019 at 130 units, up from 116 currently.

Barclays also reported that international upstream spending by NOCs and European IOCs are both expected to rise by 8%. Spending growth from the international IOCs come after international upstream spending fell by 4% in 2018.

BP’s capital expenditures are expected to range $15-17 billion this year compared with $15 billion last year and $16.5 billion in 2017.

Equinor and Total SA’s capital budgets are estimated at $11 billion and $16 billion this year compared with $9.9 billion and $15.5 billion last year.

US-based companies have also released details of their capital budget plans outside North America.

IEA: Crude oil quality matters amid lower supply

Global supply fell 1.4 million b/d to 99.7 million b/d in January, according to data from the International Energy Agency’s latest Oil Market Report.

The decline reflected factors including sanctions against Iran, a supply fall in the Organization of Petroleum Exporting Countries of 930,000 b/d in January, US sanctions against Venezuela’s state oil company Petroleos de Venezuela (PDVSA), and Alberta supply cuts.

These production cuts, however, all directly impact the supply of heavy, sour oil. Therefore, crude oil quality becomes another important issue in the wider context of supply in the early part of 2019, IEA said.

Less exports from PDVSA

In 2018, about 450,000 b/d of Venezuelan crude oil was shipped to the US. This is only a fraction of the 1.7 million b/d exported in 1998 when President Hugo Chavez was on the verge of power. Much of the oil is used in PDVSA’s US refining system, run by its subsidiary Citgo Petroleum Corp.

IEA said, “The collapse in exports mirrors the collapse of production over the same period from 3.4 million b/d to about 1.3 million b/d today. In addition, Venezuela took a political decision to ship oil to China; initially to diversify export markets as Canada’s shipments to the US soared, but more recently as repayment for tens of billions of dollars of loans. Shipments to India too, have grown, reaching 360,000 b/d in 2017, but last year they fell by 11%.”

Meanwhile, PDVSA’s oil is typically of the heaviest quality and requires the addition of sufficient quantities of imported diluents or domestic blending. “With the import of diluents now sanctioned by the US, and problems in producing its own lighter crudes, PDVSA will have a tough job to make enough on spec barrels available for export. This is before it gets to the issue of who will buy them,” IEA said.

However, with less exports from PDVSA, headline benchmark crude oil prices have hardly changed on news of the sanctions. This is because, in terms of crude oil quantity, markets may be able to adjust after initial logistical dislocations. Stocks in most markets are currently ample and, with the implementation of the new Vienna Agreement at the start of the year, there is more spare production capacity available, IEA explained.

Crude oil quality spreads

The price of Mars—a medium, sour crude oil produced in the US Gulf of Mexico—has increased compared with light, sweet crude oil.

The premium of Light Louisiana Sweet crude over Mars crude has fallen to below $1/bbl from more than $4/bbl in November. Since the US sanctions against Venezuela were announced, the premium of Mars over WTI has soared from $4.5/bbl to over $7.50/bbl.

Fundamentals

IEA’s global demand estimate for 2018 is unchanged at 1.3 million b/d. Growth in demand in 2019 is expected to be 1.4 million b/d, unchanged from last OMR. The growth is supported by lower prices and the start-up of petrochemical projects in China and the US. Slowing economic growth will, however, limit any upside potential.

Global supply fell 1.4 million b/d to 99.7 million b/d in January as the Vienna Agreement and Alberta’s cuts took effect. Non-OPEC growth estimates have increased to 2.7 million b/d in 2018 and to 1.8 million b/d in 2019. This is mainly due to higher US output.

OPEC crude output was 930,000 b/d lower in January at 30.83 million b/d, a near 4-year low. Compliance with the Vienna Agreement was 86%, with Saudi Arabia, UAE and
Kuwait cutting by more than promised. Compliance by non-OPEC participants was only 25%.

In December, global refining throughput fell 700,000 b/d year-over-year instead of an expected increase due to lower activity in Asia’s four largest refiners: China, India, Japan, and South Korea. IEA’s 2019 forecast is unchanged, with runs expected to grow by 1.2 million b/d.

At yearend 2018, OECD oil company stocks were 5.6 million bbl below the November level at 2,858 million bbl, up 4.6 million bbl compared with yearend 2017. The major stock build in the second half of 2018 was in non-OECD countries. Government stocks increased in 2018 by 22.1 million bbl, mainly in the US and Europe.

Brent futures reached a 2-month high of $62.75/bbl in early February, with WTI prices about $10/bbl below average. The Brent-Dubai EFS narrowed to an 8-year low as sour crude markets tightened. Ample supplies of gasoline saw cracks decline into negative territory.

Queensland’s CSG-LNG plants unlikely to reach full capacity

Rick Wilkinson
OGJ Correspondent

The three LNG plants on Curtis Island near Gladstone in Queensland are unlikely to ever fulfill their combined name-plate capacity of 25.3 million tonnes/year, according to a new study by Adelaide-based energy analyst EnergyQuest.

The problem is a shortage of coal seam gas (CSG) reserves on which they rely. The consultancy’s report indicates that the supply concerns come from an emerging reliance on feedstock based on gas reserve estimates that could fall well below delivery expectations.

The three plants, each with two LNG trains, are the world’s first LNG producers to use CSG rather than gas from conventional sources. The CSG is sourced from the Surat and Bowen basins in southeast Queensland, however the wells supplying the gas have been less productive than expected.

Consequently the three plants have been running below capacity, operating at an average of 82% during 2018. Queensland Curtis LNG (QCLNG) operated by Royal Dutch Shell PLC, averaged 87% capacity last year, while Gladstone LNG (GLNG) operated by Santos Ltd., only averaged 65% according to EnergyQuest Chief Executive Officer Graeme Bethune.

“The emerging and critical shortages are resulting from the fact that the CSG-LNG projects were sanctioned on ambitious estimates of 2P reserves, not proven (1P) reserves that underpin conventional LNG projects,” Bethune said.

“Building six LNG trains in Queensland using CSG was bold and visionary, but ultimately a bridge too far,” he said.

The consultancy has made a detailed study of government and company drilling and production data and reserves booked for CSG prospects and permits. It found that only 56% of booked proved and probable reserves have shown commercial productivity.

Bethune forecasts that by 2025 at least two trains will have to be shut down to keep four trains running at full capacity. This will reduce medium-term exports to about 17 million tpy, down from 21 million tpy in 2018. About 70% of the LNG exports go to China, 16% to South Korea, and 9% to Japan.

Bethune said the supply problem has been exacerbated by the pressure on the producers to increase gas sales into the
Eastern Australian domestic market to shore up falling supply from aging conventional gas fields, particularly offshore. Not helping the shortage is the attitude of some states, notably New South Wales and Victoria, which restrict onshore exploration drilling. The three CSG projects in Queensland supplied about 25% of Australia’s eastern demand last calendar year.

**BP lets rig contract for Ironbark wildcat off Western Australia**

Rick Wilkinson  
OGJ Correspondent

BP Developments Australia Pty. Ltd., acting operator of a joint venture in Western Australian offshore exploration permit WA-359-P, has signed a contract for a rig to drill the Ironbark-1 wildcat well.

Diamond Offshore Drilling Inc.’s Ocean Apex semisubmersible drilling rig will begin the program during next year’s second half. Ironbark-1 is expected to drill to a depth of 5,500 m.

After many delays, mostly to do with permit leasehold er Cue Energy Ltd. offsetting the forthcoming exploration program costs through farm-in deals, the rig contract sets a path to fulfillment of the drilling program. BP has now initiated environmental planning activities for a site survey of the well location and the drilling activities.

Ironbark, in the offshore Carnarvon basin, has the potential to hold up to 15 tcf of recoverable gas resource and is seen as a world-scale prospect in a proved gas-prone basin.

Ironbark is a Mungaroo formation prospect with a mapped area of up to 400 sq km. It lies less than 50 km from the North West Shelf joint venture’s North Rankin platform. It is also close to Chevron Corp.’s Wheatstone infrastructure and Woodside Petroleum Ltd.’s Pluto infrastructure, thus providing multiple development options if gas is found.

The permit partners BP PLC, Cue, Beach Energy Ltd., and New Zealand Oil & Gas Ltd. (NZOG) reported a coordination agreement in October 2018 that provides for BP to act as operator on behalf of Cue in planning the Ironbark wildcat prior to title transfers and creation of a formal joint venture.

As required under this agreement, Cue has contributed $8.087 million from its existing cash reserves into an escrow account to secure the proportion of its costs that are not carried by other parties. With funding from the other parties on completion of the agreement, full funding for the well is agreed.

Execution of the rig contract and Cue’s funding of the escrow account satisfy two outstanding conditions of completion of the coordination agreement, the BP Option agreement and farm-in agreements with Beach and NZOG.

Regulatory approval of an extension to the WA-359-P permit to allow time to drill is also required and Cue is currently preparing an extension application for submission to the Australian National Offshore Petroleum Titles Administrator.

When all conditions are satisfied, and regulatory approvals are received, the coordination agreement provides for BP to become official operator. The participating interests in the well will then be BP 42.5%, Cue 21.5%, Beach 21%, and NZOG 15%.

**APLNG to buy Ironbark coal seam gas prospect from Origin Energy**

Rick Wilkinson  
OGJ Correspondent

The Australia Pacific LNG (APLNG) combine has agreed to acquire the Ironbark coal seam gas (CSG) project from Origin Energy Ltd., Sydney, for $231 million (Aus.). Ironbark—not to be confused with the BP PLC-led group’s conventional gas prospect of the same name offshore Western Australia—lies near Tara in the Surat basin of southeast Queensland.

APLNG uses CSG from southeast Queensland coal seams to produce LNG at its liquefaction plant on Curtis Island, near Gladstone.

Ironbark has been a disappointment for Origin, which halved the project’s production potential last year from 249 petajoules down to 129 petajoules of gas resource.

Origin is a 37.5% interest holder and operator of the APLNG group, so it will retain responsibility for development of Ironbark. Company Chief Executive Officer Frank Calabria explained, however, that the sale represents the best way for Origin to maximize value from the project.

“APLNG is able to realize additional value from the Iron bark asset by utilizing its existing nearby gas and water processing infrastructure to efficiently bring the gas to market,” Calabria said. “Origin will derive value from the development of the prospect through its investment in APLNG.”

If Origin still owned Ironbark, the company would have had to enter negotiations with its APLNG partners (ConocoPhillips with 37.5% and Chinese state-owned Sinopec with 25%) to process and transport the gas and this could have caused concern.

Origin acquired Ironbark for $660 million (Aus.) in 2009 and initially estimated the resource at 840 petajoules. It submitted proposals in 2015 for the drilling of up to 600 wells...
so that the project could supply about 21 petajoules/year of CSG over 40 years.

Development plans dwindled at regular intervals as more exploration and engineering work was carried out. The company finally began a Stage 1 front-end engineering and design program in August 2018, but it was obvious by then that permeability problems in the coal seams had halved the potential reserves such that the project would contribute less volumes of gas over fewer years.

Origin entered the FEED program, but at the same time began assessing alternative strategic options for development. The result has been the sale of Ironbark to APLNG, albeit at a third of the price it paid for the asset 10 years ago.

**Aramco forms combine for $10-billion Chinese refining complex**

**Robert Brelsford**
Downstream Technology Editor

Saudia Aramco has signed a $10-billion agreement to form a joint venture with China North Industries Group Corp. (Norinco) and Panjin Sincen to develop a fully integrated, grassroots refining and petrochemical complex in Panjin, in China’s Liaoning province.

Under the agreement—the largest Sino-foreign JV to date—the partners will create a new company—Huajin Aramco Petrochemical Co. Ltd.—as part of a project that will include a 300,000-b/d refinery as well as a 1.5 million-tonne/year ethylene cracker and 1.3 million-tpy paraxylene unit, Aramco said.

Alongside supplying up to 70% of required crude feedstock for the proposed complex, Aramco will hold 35% interest in the newly formed company while Norinco and Panjin will hold the remaining 36% and 29% interest, respectively.

The new complex is scheduled for commercial startup sometime in 2024.

“Our participation in the integrated refining and petrochemical project in Panjin will strengthen our collaborative efforts to enhance energy security, revitalize key growth sectors and industries in Liaoning, and also meet rising demand for products and goods in China’s northeast region,” said Amin Nasser, Aramco’s chief executive officer.

The JV agreement also includes additional plans to establish a fuels retail business, which will further integrate into the value chain, Aramco said.

By yearend, Aramco said it expects to form a three-party marketing JV company with North Huajin Chemical Industries Co. Ltd. and Liaoning Transportation Construction Investment Group Co. Ltd. to develop a retail fuel stations network in target markets.

**Additional Chinese agreements**

Separately, Aramco also signed three memoranda of understanding aimed at expanding its downstream presence in China’s Zhejiang province.

Aramco signed the first MOU with the government of Zhoushan to acquire its 9% ownership interest in Zhejiang Petrochemical Co. Ltd.’s (ZPC) grassroots 800,000-b/d refining and chemical integrated complex currently under construction in Zhoushan, with a second MOU signed with ZPC’s other shareholders Rongsheng Holding Group Co. Ltd., Juhua Group Corp., and Tongkun Group Co. Ltd. (OGJ Online, Feb. 14, 2017).

Aramco inked a third MOU with Zhejiang Energy Group to invest in construction of a large-scale retail fuel network to be built during the next 5 years in Zhejiang province that will be integrated with ZPC’s complex as an outlet for refined products produced at the site.

The new MOUs follow Aramco’s previous agreements with ZPC under which Aramco agreed to acquire ownership interest in and supply crude on a long-term basis to the new complex, as well as use ZPC’s crude storage at the site to serve Aramco customers in the Asia-Pacific region (OGJ Online, Oct. 26, 2018).

The project will come with a long-term crude supply agreement and the ability to utilize Zhejiang Petrochemical’s large crude oil storage facility to serve its customers in the Asian region.

Previously scheduled for commercial startup by yearend 2018, Phase 1 of ZPC’s project includes a newly built 400,000-b/d refinery, a 1.4 million-tpy ethylene cracker unit, and a 5.2 million-tpy aromatics unit.

Phase 2 of the project—which will double processing and production capabilities at the site, as well as include deeper chemical integration than Phase 1—most recently was scheduled for commissioning during first-quarter 2021 (OGJ Online, Jan. 17, 2019).

**Meridian Energy plots grassroots refinery for Permian basin**

**Robert Brelsford**
Downstream Technology Editor

Meridian Energy Group Inc. has let a contract to Winkler Cos. LLC to provide site control for a full-conversion refinery in Winkler County, Tex., in the heart of the Permian basin.

The Permian basin refinery, which will process local crude from the Delaware basin into a full slate of refined...
NAPE: Croatia opens licensing round in Dinarides onshore area

Paula Dittrick
Upstream Technology Editor

Croatia has opened a licensing round for oil and gas exploration in its central and southern regions with the bid deadline being Sept. 10. Licenses are tentatively scheduled to be announced in December, a spokesman with the Croatia Hydrocarbon Agency (CHA) said.

CHA Pres. Marijan Krpan told the North American Prospect Expo in Houston on Feb. 14 that Croatia recently enacted a hydrocarbon law to attract investors and ensure what he calls a smoother transition from exploration into production.

Since the 1940s, Croatia has produced more than 400 million boe, most of which has been natural gas. Krpan said Croatia has produced more than 700 million bbl of oil.

Available exploration blocks in Croatia’s Dinarides thrust belt cover 12,134 sq km. Krpan said some seismic surveys were shot in this area during the 1950s.

Meanwhile, Croatia has an ongoing bid round for the Pannonian basin that started in November 2018 with a bid deadline of June 28. Awards are expected to be awarded in October.

The second round involves seven exploration blocks in the Pannonian basin, Krpan said. “Total acreage available is 14,272 sq km. The available blocks range in size from 1,361 to 2,634 sq km.”

He said at least 37 unevaluated wells exist in this area. The Pannonian basin is characterized by Palaeozoic to Mesozoic sedimentary deposits.

Previously, Croatia offered six onshore exploration blocks in its first onshore bid round, which it launched in July 2014. That round covered the Pannonian subbasins of Drava, Sava, and Eastern Slavonia.

Croatia awarded a block to Croatia’s state-owned INA Group and four blocks to Canada’s Vermilion Energy Inc. In Croatia, Vermilion holds 100% working interest in acreage covering nearly 2.35 million acres.

The American Association of Petroleum Landmen is the chief sponsor of NAPE, where industry buys and trades prospects and producing properties.
Ukraine outlines latest concessions, production-sharing agreements

Roman Opimakh
Association of Gas Producers of Ukraine
Kyiv, Ukraine

Ukraine has outlined a series of licensing rounds through online auctions and production-sharing agreement (PSA) tenders in ongoing efforts to reduce its dependence on natural gas imports. The 2019 licensing rounds offer 42 onshore blocks covering nearly 12,000 sq miles.

Government officials have improved the fiscal regime, simplified the permitting system, and adjusted the rules for access to gas and oil reserves to increase Ukraine’s upstream attractiveness to international oil companies.

The licensing rounds are being offered in stages. The State Geological Service of Ukraine released 30 onshore petroleum blocks for sale in online auctions on public trading platform ProZorro.Sale.

Fig. 1 shows the licensing offerings for 2019 plus valid exploration and production licenses.

The 2019 first round, announced Dec. 6, 2018, offers 10 blocks in six regions, covering more than 1,120 sq miles. A second round, announced in London Jan. 29, offers another 7 blocks in five regions, covering over 621 sq miles. Bidders were asked to submit applications within 90 days with the online auctions scheduled for Mar. 6 and May 2, respectively.

In addition, the Ukrainian government approved PSA tender terms for 12 onshore blocks covering more than 8,200 sq miles. PSA tenders are expected to be announced in February or beginning of March, at which time bidders will have three months to submit their applications. The onshore blocks hold both conventional and unconventional resources.

Royal Dutch Shell and other IOCs showed interest in Ukraine during 2010-12, particularly in the possibility of developing unconventional gas resources (OGJ, June 6, 2013, 31/33).
p. 54). But changing market conditions caused Shell to pull out of a May 2012 PSA. Shell was the winning bidder for the Yuzivske PSA in the Kharkiv and Donetsk regions of Eastern Ukraine. Resources were estimated at 4 trillion cu m of gas, trapped primarily in tight sand formations. Estimated exploration costs were at least $20 million.

Shell and state-owned Nadra Yuzivske were each to hold a 50% interest with Shell to be the operator. However, Shell withdrew from the project in 2015, citing high costs and dropping commodity prices. The 2019 Ukrainian PSAs are the first to be offered since then. As of Feb. 1, EP Holding (EPH) was working to gain Shell’s stake in the 2012 Yuzivska PSA. Ukrainian government officials expect to finalize that as soon as EPH submits a bank guarantee that EPH can invest $200 million.

In a different deal, EPH agreed to drill at least 15 exploration wells within 5 years. Finalization of the pending agreement remains subject to approval by regional councils and an anti-monopoly committee.

EPH currently holds 90% interest. Its partner is Nadra Yuzivska, which represents Ukraine in this legacy deal. EPH’s subsidiary, Nafta, will operate the project. The Slovak Republic owns 25% interest of Nafta. EPH holds 75% interest.

Government officials also see opportunities to redevelop legacy fields. Mature fields require technologies and expertise from international service companies. State-owned UkrGasVydobuvannya (UGV) has signed multiservice agreements with Schlumberger Ltd., Halliburton Corp., Baker Hughes GE, and Weatherford.

UGV also seeks additional cooperative partnerships under Production Enhancement Contracts (PEC) to develop depleted fields and unconventional formations. The PEC tender was launched in October 2018. Results are scheduled to be announced in May.

Ukraine produced more than 21 billion cu m (bcm) of gas in 2018, one of Europe’s largest outputs, yet still depends heavily on imported gas. The Ukrainian government is prioritizing domestic production to reduce imports and enhance energy supply security.

**Gas supply, demand**

Gas accounts for 35% of Ukraine’s energy mix. In 2018, Ukraine consumed 31.5 bcm, making it the seventh largest consumer in Europe. Imports accounted for 34% of 2018 domestic consumption.

The Energy Strategy of Ukraine estimates future gas demand at 30-35 bcm/year until 2035.

Prices for Ukrainian gas are in parity with imported gas prices, ensuring profits for gas producers. In 2018, the average wholesale price for Ukrainian gas was $9.20/MMbtu.

Ukraine has 905 bcm of gas reserves across two proved petroleum basins with another 408 bcm estimated resources. The reserves-production (R-P) ratio is nearly 45 years compared with an average European R-P of 12 years.

Fig. 2 shows gas production by region and by company in Ukraine. Producers operating in Ukraine believe they can produce most proved, undeveloped reserves through improved recovery methods and by expanding existing fields with satellite fields.

Ukraine has a well-developed gas pipeline system with surplus capacity, which is used both for domestic gas distribution and for transporting Russian gas to Europe.

The state-run transmission system operator ensures third-party access to gas pipelines under equal, non-discriminatory, and transparent terms in line with European energy laws.

The National Regulatory Commission sets gas transportation, distribution, and storage tariffs using Regulatory Asset-Based (RAB) methodology and based on the European entry-exit booking capacity approach.

Ukraine has no restrictions or special duties on gas imports or exports, and gas exports to central Europe were scheduled for January. No trade permits are required.

Rigs are readily available in Ukraine, where 150 onshore gas wells were spudded in 2018. A qualified local workforce, wide range of services, and existing supply chain for pipes and cement also ensure companies can increase gas production volumes quickly. Yet, Ukraine needs additional IOC investment and technology to reach its production potential. The Ukraine Parliament enacted upstream reforms in 2018 to attract more international investment.
Ukraine revised its taxation system for onshore gas wells drilled in 2018 and later to help attract investors from outside Ukraine. Currently, gas produced from such wells is subject to 6% or 12% royalties depending on depth of reserves.

The government guarantees the stability of these rates through a 5-year stabilization clause. Five percent of the royalty payment is allocated to local communities’ development to motivate their cooperation with industry.

Ukrainian regulators simplified a prescriptive, outdated permitting system by signing a deregulation law which cut government red tape and updated exploration and production rules. This streamlining means production could start 18 months after licensing.

Parliament also approved an Extractive Industries Transparency Initiative (EITI) covering international standards of public reporting. Government officials adjusted reserves-access and transparency rules by authorizing online auctions, improving public access to geological data, and liberalizing companies’ turnover of geoscience information to the government.

**Geology**

Ukraine offers three main hydrocarbon basins: Dnieper-Donets basin, Pre-Carpathian basin, and the North Black Sea basin. Almost all production comes from onshore fields. The Dnieper-Donestsk region in eastern Ukraine is developed with several thousand gas, oil, and condensate wells.

Companies have found gas in depths ranging 5,000-5,800 m and oil as deep as 4,500 m. The Association of Gas Producers of Ukraine (AGPU) reports 244 conventional oil and gas fields producing in this province.

The Pre-Carpathian (Foreland) basin in Western Ukraine covers 7,500 sq km and reaches the borders of Hungary, Poland, Slovakia, and Romania. AGPU reports 116 conventional oil and gas fields producing in this area.

The North Black Sea basin is less explored, with 42 oil and gas fields, including 15 offshore fields, AGPU reports.

About 95% of gas production and most onshore oil and gas reserves are concentrated in eastern Ukraine, primarily in the Kharkiv and Poltava regions. Of Eastern Ukrainian reserves, 73% are found at depths of 3,000 m or deeper. In Western Ukraine, 65% of reserves are found above 3,000 m.

The 17 blocks offered in Round 1 and Round 2 and 12 PSAs blocks are in proved petroleum provinces with well-developed midstream infrastructure and completed seismic surveys. License terms for 16 of the concession blocks call for 20 years of exploration and production, the final block calling for a 5-year exploration period. All PSAs block have 50-year duration, unless otherwise agreed by the parties.

The web site GoUkraineNOW outlines the geology and overview for the auction and PSA blocks.

Ukraine officials offered large parcels in known petroleum provinces to give oil and gas companies a better chance to find discoveries.

The table shows the three biggest PSA blocks in eastern Ukraine are Varvinska, Sofiyvska, and Ichnyanska. Most gas in this petroleum basin is trapped in the Carboniferous section below a lower Permian salt seal.

**References**


**The author**

Roman Opimakh is executive director of the Association of Gas Producers of Ukraine (AGPU). Opimakh previously advised the Minister of Energy of Ukraine. During 2011-15, he worked as a coordinator for oil and gas at the Economic Reforms Center where he supervised various energy projects. Opimakh obtained an MS (2006) from the Institute of International Relations of Taras Shevchenko National University of Kyiv. He later participated in a 1-year Hubert H. Humphrey Fellowship Program at Michigan State University and completed his professional affiliation with the Center for Energy Studies at Louisiana State University.

---

**UKRAINE’S INITIAL 2019 PSA TENDERS**

<table>
<thead>
<tr>
<th>Block name</th>
<th>Region</th>
<th>Area, sq km</th>
<th>Minimum investment, million $</th>
</tr>
</thead>
<tbody>
<tr>
<td>Varvinska</td>
<td>Poltava-Chernihiv</td>
<td>3,471</td>
<td>35.7</td>
</tr>
<tr>
<td>Rusanivska</td>
<td>Sumy-Poltava</td>
<td>766</td>
<td>28.5</td>
</tr>
<tr>
<td>Grunivska</td>
<td>Sumy-Poltava</td>
<td>1,108</td>
<td>30.3</td>
</tr>
<tr>
<td>Ohtiriska</td>
<td>Sumy-Poltava-Kharkiv</td>
<td>717</td>
<td>21.4</td>
</tr>
<tr>
<td>Buzivska</td>
<td>Kharkiv-Dnipropetrovsk</td>
<td>669</td>
<td>21.4</td>
</tr>
<tr>
<td>Zinkivska</td>
<td>Sumy-Poltava</td>
<td>571</td>
<td>17.8</td>
</tr>
<tr>
<td>Ivanivska</td>
<td>Kharkiv</td>
<td>841</td>
<td>28.5</td>
</tr>
<tr>
<td>Ichnyanska</td>
<td>Chernihiv</td>
<td>2,477</td>
<td>35.7</td>
</tr>
<tr>
<td>Balaklijska</td>
<td>Kharkiv</td>
<td>1,119</td>
<td>28.5</td>
</tr>
<tr>
<td>Sofiyivska</td>
<td>Chernihiv-Sumy-Poltava</td>
<td>2,716</td>
<td>35.7</td>
</tr>
<tr>
<td>Berestyska</td>
<td>Lviv-Kharkiv</td>
<td>286</td>
<td>16.0</td>
</tr>
<tr>
<td>Ugnivska</td>
<td>Lviv-Ivano-Frankivsk</td>
<td>967</td>
<td>21.4</td>
</tr>
</tbody>
</table>

Source: GoUkraineNow
The International Energy Agency (IEA) estimated about 375 enhanced oil recovery (EOR) projects worldwide produced slightly more than 2 million b/d in 2018. They forecast this could grow to 4.5 million b/d, or around 4% of world production, by 2040.

EOR projects accounted for about 2% of world oil production since 2014. IEA analysts expect modest EOR production growth until about 2025, noting industry currently focuses on shale production growth in US, Brazil, and Canada.

They also suggest carbon dioxide (CO₂) EOR could address climate change concerns. IEA expects CO₂ EOR to play an increased role in carbon capture, utilization, and storage (CCUS) projects.

IEA released an updated list of EOR projects¹ and evaluated the outlook for future EOR in different scenarios presented in its World Energy Outlook.²

Fig. 1 shows IEA’s tally of EOR production to be 700,000 b/d higher than an Oil & Gas Journal EOR survey reported in 2014 (OGJ, May 5, 2014, p. 92). While updating EOR production statistics from the OGJ database, IEA added new projects and reviewed EOR in regions sparsely covered previously, such as China and the Middle East.

Industry traditionally used EOR primarily for US and Canadian projects but the technology increasingly is being used worldwide, both onshore and offshore. IEA reported 15 offshore EOR projects worldwide as of 2018.

ExxonMobil Exploration and Production Malaysia Inc. started EOR production at Tapis field offshore Malaysia during 2017.

The Tapis EOR project marked Malaysia’s first large-scale EOR project and remains one of the largest offshore EOR projects in Southeast Asia. ExxonMobil’s joint venture partner is Petronas Carigali Sdn Bhd (PCSB). Each holds 50% interest.

IEA’s EOR update lists projects in the United Arab Emirates, Kuwait, Saudi Arabia, India, Colombia, and Oman.

Oman has increased its oil production since 2007 through steam injection, polymer injection, miscible gas injection, and other EOR methods. Oman is evaluating large-scale solar EOR projects to save natural gas. Petroleum Development Oman (PDO) is working with GlassPoint Solar. After a pilot, PDO and GlassPoint are building Miraah solar plant (OGJ, Jan. 1, 2018, p. 46). A separate solar EOR technology center is being developed in Muscat, Oman. PDO reported 16% of its oil production came from various types of EOR in 2016 compared with 3% in 2012.

Abu Dhabi National Oil Co. Onshore (ADNOC Onshore) injects CO₂ into Bab-Rumaitha field. ADNOC uses low-molecular-weight hydrocarbon-immiscible (HC) gas injection to increase production from Abu Al Bukhoosh (ABK) field offshore Abu Dhabi. UAE’s goal is to expand EOR production 30% by 2020 from 2014.

Currently, North American EOR accounts for 40% of all EOR projects compared with 75% of 2013 EOR projects, which provided 800,000 b/d.

**EOR incentives**

While EOR projects can be cost competitive with other production, they frequently involve high upfront capital requirements and long payback periods. Consequently, EOR production historically relied on financial incentives such as tax breaks.

More than 80% of world EOR production benefits from government incentive programs. National oil companies prioritize EOR in efforts to maximize production and profits.

IEA said US policy demonstrates how government can promote EOR projects. Faced with declining US oil production, the Crude Oil Windfall Profit Tax Act of 1980 promoted EOR by reducing producers’ EOR-related taxes.

Last year, a federal tax credit was amended under section 45Q of the US tax code to promote underground carbon storage. The amendment increased the amount of money available to companies willing to capture and store carbon emissions in geologic formations or to use CO₂ EOR on existing wells.

The tax credit was amended to provide a tax reduction of $35/tonne of CO₂ for 12 years for CO₂ stored in EOR operations. Previously, the tax credit was $10/tonne but it will increase to $35/tonne by 2024.

Yet, EOR project growth has been slower than expected. IEA analysts found no one reason for this, but possible explanations included:

- Resource scarcity concerns. These traditionally drive EOR projects, but ample world oil supplies have discouraged...
new EOR projects since 2014.

- Industry desire for fast returns. An EOR project requires time to plan, test, and implement, meaning that EOR adds incremental production only late in a field’s life.
- Limited availability of EOR skills, technologies, and expertise. The technology has become a niche business among oil and service companies.
- Relative expense. EOR costs have declined since 2014, but costs of other projects—including shale plays and offshore developments—have declined more quickly. EOR technologies struggle to compete with other investment opportunities.

**EOR outlook**

IEA analysts evaluated EOR prospects in the World Energy Outlook. They estimated that systemic application of all EOR technologies across conventional crude oil resources could, in theory, unlock up to 300 billion bbl of crude oil.

In the WEO’s New Policies Scenario projections, only a fraction of that 300 billion bbl is produced. By 2025, IEA analysts foresee larger production related to EOR projects. US tight oil will near its production plateau and numerous regions and countries also will have become mature production provinces by 2025, making them more inclined to pursue EOR to maintain production or slow declines.

Numerous measures and initiatives will need to gain momentum before EOR production growth forecasts can materialize. Examples of such efforts include:

- Concerted effort by governments and industry to screen fields and determine EOR potential in resource-rich areas.
- Timely EOR pilots in countries where EOR has not yet been used.
- Continued fiscal incentives, including emissions credits for CO₂ EOR.
- Technological advances such as decreasing the volume of chemicals injected and using digitalization to grasp a better subsurface understanding.

In the WEO Sustainable Development Scenario, total EOR production grows to around 4 million b/d in 2040. This is smaller than WEO’s New Policies Scenario because oil demand and prices are lower.

However, CCUS advancements could support much larger CO₂-EOR production. In this scenario, climate imperatives emerge as a key driver behind EOR technologies. Given suitable geology, companies can use CO₂ EOR to reduce their CO₂ emissions intensity. If CO₂ is captured and injected in enough quantities, negative-emissions carbon credits could be available for oil. Oil produced from a CO₂-EOR sequestration project can be carbon neutral or carbon negative, depending upon the source of the CO₂ emissions.

IEA analysts evaluated the possibility of negative-emissions oil in the World Energy Outlook and expect to publish a future commentary on it.

**References**

Like the characters of L. Frank Baum’s Oz series of novels written during the early 1900s, US ethylene producers have had to find their way to the mythical Emerald City by surviving a series of disasters.

After the storms of second-half 2017, US Gulf Coast skies cleared in first-half 2018, with most USGC ethylene producers finding soft landings in second-half 2018. Ethylene producers took the first steps on the journey to the Emerald City in fourth-quarter 2018.

USGC ethylene producers had booked their tour to Emerald City via the Yellow Brick Road several years ago. But now, in 2019-20, they will have to focus on surviving the journey. Trends in polyethylene exports indicate production from new polyethylene plants began to ramp up to full capacity in second-half 2018. The transition of focus from North America to the global market for ethylene, polyethylene, and other ethylene derivatives is well under way.

**New plant startups**

In second-half 2018, ExxonMobil Chemical Co., Shintech Louisiana LLC, and Indorama Ventures Olefins LLC were scheduled to start up new ethylene plants. ExxonMobil Chemical was the only producer to meet its target, commissioning its new 1.5-million tonne/year ethane steam cracker at Baytown, Tex., in late July (OGJ Online, July 26, 2018). In first-half 2019, Formosa Petrochemical Corp., Indorama, Sasol Ltd., and LACC LLC—a 50-50 joint venture of Lotte Chemical Corp. subsidiary Lotte Chemical USA Corp. and Westlake Chemical Corp.—are scheduled to commission new plants with combined nameplate capacity of 9.1 billion lb/year. Petral Consulting Co. also forecasts Shintech’s new plant will start operations second-half 2019.

While some new plants reach full-capacity in 30-60 days, others require 3-4 months. Since ethylene supply is already at modest surplus levels, production from new plants in Louisiana will increase surpluses in USGC markets in first-half 2019.

**Ethylene production**

Petral Consulting tracks US ethylene production via a monthly survey of operating rates and feed slates. Results of the monthly survey showed a strong rebound in ethylene production in first-quarter 2018 following the hurricane-depressed production rates of late 2017. Production in first-quarter 2018 increased 14.2 million lb/day (8.4%) from fourth-quarter 2017 before quarterly growth slowed to 4.3 million lb/day (2.4%) in second-quarter 2018. Production during third-quarter 2018 was 179.3 million lb/day, unchanged from the previous quarter. Production, however, increased to 183 million lb/day in fourth-quarter 2018, up 3.7 million lb/day (2.0%) from the third quarter.

Variations in quarterly growth rates for ethylene production paralleled growth in polyethylene exports to destinations other than Canada and Mexico (rest of world, ROW). Exports to ROW destinations in first-quarter 2018 were 4.6 million lb/day (49.8%) more than in fourth-quarter 2017. Growth in polyethylene exports slowed to 0.99 million lb/day (7.2%) in second-quarter 2018 before rebounding to 1.79 million lb/day (12.2%) in the third quarter. The trend in polyethylene exports to ROW destinations in second-half...
2018 was a positive leading indicator of the trend in USGC ethylene production rates for 2019 and 2020.

Petral Consulting estimates industry nameplate capacity in operation was 189.1 million lb/day in first-quarter 2018. Production capacity increased to 198 million lb/day in second-quarter 2018 and was 206.5 million lb/day in the fourth quarter.

On a regional basis, plants in Texas accounted for all production growth in second-half 2018. Texas plants produced 131.8 million lb/day in the third quarter and 135.8 million lb/day in the fourth quarter. Production from Texas plants in third-quarter 2018 increased 1.4 million lb/day from the second quarter, and fourth-quarter production increased 4 million lb/day (3.1%) more than in the previous quarter. Plants in Louisiana produced 41.3 million lb/day in third-quarter 2018 and 40.7 million lb/day in the fourth quarter (Table 1).

Operating rates dipped to 85.6% in second-quarter 2018 and were 86-90% in second-half 2018. Texas plants operated at 86.3% in third-quarter 2018 and 89.0% in the fourth quarter, while plants in Louisiana operated at 87.5% in the third quarter and 86.2% during the following quarter.

Results of the monthly survey showed some USGC ethylene producers curtailed operating rates in several existing plants during second-half 2018 to limit ethylene oversupply in the Texas Gulf Coast spot market. Petral Consulting estimates ethylene production from Texas and Louisiana plants was reduced by 9-10 million lb/day due to these curtailments, offsetting production from ExxonMobil Chemical’s new 3.3-billion lb/year Baytown plant.

Average operating rates for all ethylene plants mask important variations. In second-half 2018, 17 units (combined nameplate capacity of 34.7 billion lb/year) operated at less than 90% of nameplate capacity, while 20 units (combined nameplate capacity of 40.5 billion lb/year) operated at 90-100%. Of these 20 units, 6 units (combined nameplate capacity of 10.1 billion lb/year) operated at 100% or more of nameplate capacity.

Fig. 1 shows trends in ethylene production.

**Ethylene production costs**

Ethylene production costs are determined by raw material costs and coproduct credits. Based on variations in yield patterns for the various feeds, coproduct volumes vary widely between the three categories of plants (ethane-only, LPG-only, and multifeed plants). Raw material costs are determined by each feedstock’s price and its conversion to ethylene. Similarly, coproduct credits are determined by spot prices and production volumes for each coproduct but only for those plants that upgrade all coproduct streams to meet purity specifications.

A few ethylene plants can upgrade all coproducts to purity streams and sell all coproducts at market prices. Some ethylene plants produce purity coproduct propylene but produce all other coproducts as mixtures (mixed butylene-butadiene and mixed aromatics) and sell mixtures at discounted prices. Variations in realized revenue for coproducts result in large differences in coproduct credits from one plant to another. Cash production costs are determined by simple addition of raw material costs and coproduct credits (see accompanying box).

Crude oil price trends are always a strong influence on prices for propane, naphtha, gas oil, and most coproducts. Domestic crude oil prices reached their peak in May 2018 and began to decline in June primarily because of constraints in crude pipelines from West Texas to the Texas Gulf Coast. Prices for international benchmark crude continued to increase in second-quarter 2018 but settled into a plateau during the third quarter. International benchmark prices began to decline in second-half October and continued to fall in November and December. Initially, the decline in second-half October appeared to be a short-lived correction following 15 months of steadily rising prices, but correction became a collapse in November.

The collapse in crude, motor gasoline, and naphtha pric-
ES around the world resulted in a sizeable compression in spot prices for heavy feeds vs. light feeds. The crash in crude prices also squeezed ethylene production cost differentials between ethane and all other primary feeds as well as between propane and heavy feeds.

USGC ethylene producers continued to increase ethane’s share of fresh feed in third-quarter 2018, but some ethylene producers responded to the compression in production costs by reducing ethane consumption in fourth-quarter 2018 while continuing to increase ethylene production.

In third-quarter 2018, ethylene produced from ethane was 78% of total production, but ethylene production from ethane fell to 75% in fourth-quarter 2018. At the same time, ethylene produced from propane averaged 11.3% of total production in the third quarter but jumped to 15-16% in the fourth quarter.

Cash production costs in third-quarter 2018 were 18.7¢/lb for purity ethane, 24.0¢/lb for propane, and 28.6¢/lb for natural gasoline.

Following a series of short-covering episodes in the ethane spot market in Mont Belvieu, Texas, in the third quarter, monthly spot prices for purity ethane declined 10¢/gal both in October and November and by an additional 2.75¢/gal in December. Prices for propane and natural gasoline also declined sharply in fourth-quarter 2018, with cash production costs at 16.2¢/lb for purity ethane, 19.4¢/lb for propane, and 22.4¢/lb for natural gasoline. Propane’s cost advantage to natural gasoline was 3.0¢/lb in the fourth quarter vs. 4.6¢/lb in the third quarter.

Table 2 shows production costs for major ethylene feedstock.

**Ethylene pricing, profit margins**

Spot prices for ethylene generally fluctuate within a range defined by cash costs for the higher-cost feedstock. The low end of the range is determined by the cash cost for high-cost feedstock with margins in a range of -5¢/lb to +5¢/lb. The high end of the range is determined by cash costs plus margins of 10-15¢/lb. Occasionally, a buying void in one or more USGC trading hubs triggers a collapse in spot prices. Sec-
gins of 10-15¢/lb. Occasionally, a buying void in one or more

Spot ethylene prices fell sharply in second-quarter 2018. Af-
ter spot ethylene prices dipped to a low of 13¢/lb in May, a modest rally began in July and extended through September. Spot ethylene’s rising cash cost of production from purity ethane was the key factor that sparked the modest rally. Spot ethylene prices averaged 16.7¢/lb in third-quarter 2018 but varied between 13-20¢/lb, according to PetroChem Wire. Prices were 19.7¢/lb in September, up from 13-14¢/lb in May and June.

A series of short-covering episodes in the Mont Belvieu ethane market pushed purity ethane prices to 60-61¢/gal in mid-September. The bullish impact was enough to support spot prices for purity ethane above 40¢/gal through early October before prices fell to 33-36¢/gal in late October and even weaker in November and December.

Gross margins (spot ethylene prices minus cash production costs) in third-quarter 2018 were -2¢/lb for purity ethane, -7.3¢/lb for propane, and -11¢/lb for natural gasoline. Margins improved in the fourth quarter to 3.5¢/lb for ethane, breakeven for propane, and -2.76¢/lb for natural gasoline. As new plants start up, ethylene supply in the spot market will remain plentiful. Spot prices and gross margins will remain weak for another 4-6 quarters.

Consistent with three full quarters of weak spot prices, PetroChem Wire monthly reports showed the volume of fixed-price trades in Texas and Louisiana fell sharply in sec-
ond-quarter 2018 and remained weak through yearend. The combined volumes of all fixed-price trades (current month only) for all trading locations were 4.4-4.7 million lb/day in second-half 2018, 35-40% less than the 2015-17 average.

Fixed-price trades at Choctaw Dome, La., accounted for 34% of all fixed-price trades in second-half 2018, according to PetroChem Wire. Trade volumes at Choctaw Dome historically account for 3-6% of fixed-price trades. Leveraging their ownership of ethylene pipelines and weak pricing in the Mont Belvieu spot ethylene market, a few ethylene sellers in Texas took advantage of premium prices for spot trades at Choctaw Dome.

The modest rally in spot ethylene prices in second-half 2018 contributed to an increase in net transaction price (NTP) contract settlements of 7.3¢/gal during third-quarter 2018. NTP settlements averaged 30.1¢/lb in the third quarter, reaching a peak of 33.75¢/lb in September. As purity ethane prices fell from a third-quarter peak of 53¢/gal in September to 29-32¢/gal in November-December, NTP con-

<table>
<thead>
<tr>
<th>ETHYLENE PRODUCTION COSTS</th>
<th>Table 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017-18 Ethane Propane n-Butane Pentane +</td>
<td></td>
</tr>
<tr>
<td>Q3 13.0 23.3 16.2 20.8</td>
<td></td>
</tr>
<tr>
<td>Q4 12.3 20.2 18.9 26.3</td>
<td></td>
</tr>
<tr>
<td>Q1 12.4 20.5 7.2 28.5</td>
<td></td>
</tr>
<tr>
<td>Q2 13.3 20.5 8.6 32.0</td>
<td></td>
</tr>
<tr>
<td>Q3 18.7 24.0 13.0 28.6</td>
<td></td>
</tr>
<tr>
<td>Q4 16.2 19.4 10.8 22.4</td>
<td></td>
</tr>
</tbody>
</table>

Source: Petral Consulting estimates

<table>
<thead>
<tr>
<th>ETHYLENE FEED SLATE DEMAND</th>
<th>Table 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017-18 Ethane LPG Natural gasoline Naphtha, gas oil</td>
<td></td>
</tr>
<tr>
<td>Q3 1,115.1 379.7 41.3 102.5</td>
<td></td>
</tr>
<tr>
<td>Q4 1,232.4 303.6 54.7 127.7</td>
<td></td>
</tr>
<tr>
<td>Q1 1,342.2 367.6 48.7 114.9</td>
<td></td>
</tr>
<tr>
<td>Q2 1,394.6 343.7 37.7 104.7</td>
<td></td>
</tr>
<tr>
<td>Q3 1,424.7 345.6 27.1 101.0</td>
<td></td>
</tr>
<tr>
<td>Q4 1,454.6 358.1 32.6 99.0</td>
<td></td>
</tr>
</tbody>
</table>

Source: Petral Consulting monthly survey
tract settlements fell to 29.25¢/lb for November-December.

Cash production costs based on purity ethane were 15-23¢/lb in second-half 2018, averaging 18.7¢/lb in the third quarter and 16.2¢/lb in the fourth quarter. Cash production costs for propane were 24¢/lb in the third quarter and 19.4¢/lb in the following quarter. Production costs for natural gasoline were 28.6¢/lb in the third quarter before falling to 22.4¢/lb in the fourth quarter.

Gross margins in third-quarter 2018 were 11.4¢/lb for ethane, 6.1¢/lb for propane, and 1.5¢/lb for natural gasoline. Gross margins in the fourth quarter were 13.7¢/lb for ethane, 10.5¢/lb for propane, and 7.5¢/lb for natural gasoline.

Fig. 2 shows historical trends in ethylene spot prices and NTPs.

**Olefin-plant feed slate trends**

Petral Consulting’s monthly survey of plant operating rates and feed slates showed industry demand for NGL feedstocks jumped to 1.73 million b/d in first-quarter 2018 and 1.74 million b/d in the second quarter. Demand for NGL feeds in first-half 2018 was 209,000 b/d (13.7%) more than in second-half 2017. Full recovery from hurricane-related down-time was the primary factor for the increase in demand in first-quarter 2018. In second-quarter 2018, voluntary plant shutdowns in response to the collapse in spot ethylene prices and production curtailments offset increased production from new capacity (Table 3).

Ethane demand was 1.37 million b/d in first-half 2018, up 195,000 b/d from second-half 2017. Ethane demand increased by 71,000 b/d in second-half 2018 to 1.44 million b/d. Ethane’s share of total fresh feed was 72.9% in first-half 2018 before increasing to 75% second-half 2018. In Texas, ethane’s share of fresh feed was 71.6% in first-half 2018 vs. 67.0% in second-half 2017. In Louisiana, ethane’s share of fresh feed was 70.0% in first-half 2018 vs. 70.5% in second-half 2017.

Propane demand was 267,000 b/d in first-half 2018 and 264,000 b/d in the second half. Propane’s share of fresh feed averaged 14.2% in first-half 2018 and 13.7% in the year’s second half. After first-quarter 2018, demand for heavy feeds varied within a range of 120,000-150,000 b/d, averaging 130,000 b/d in second-half 2018.

**Monomer exports**

Ethylene and propylene are used as raw material feeds for production of derivative products, with polyethylene and polypropylene as the most important derivatives. US chemical companies focus primarily on selling surplus supplies of polyethylene, ethylene glycol, PVC, polypropylene, and acrylonitrile into international markets. With one ethylene export terminal in operation, however, US suppliers export only small volumes of ethylene monomer.

US International Trade Commission (ITC) data showed ethylene monomer exports averaged 1 million lb/day in third-quarter 2018, down 0.45 million lb/day (30.8%) from second-quarter exports. During 2015-18, monomer exports on a quarterly average basis were within a range of zero to 1.6 million lb/day.
Until a new USGC ethylene export terminal becomes operational, ethylene export volumes will remain just 1-2% of US production and of no practical importance.

**Polyethylene exports**

According to US ITC statistics, US exports of polyethylene—including high-density polyethylene (HDPE), low-density polyethylene (LDPE), and linear low-density polyethylene (LLDPE)—rebounded in January-May 2018, continuing to increase during June-October 2018. Exports to all destinations in January-May were 22.9 million lb/day, increasing by 4.9 million lb/day (21.5%) to 27.8 million lb/day in June-October.

Exports to Canada and Mexico in June-October were 10.3 million lb/day, up 0.73 million lb/day (7.7%) from January-May. More importantly, however, exports to all other destinations (ROW) in June-October were 17.8 million lb/day, or 4.4 million lb/day (33.1%) more than in January-May (Fig. 3). If polyethylene exports to ROW destinations increase at a sustained rate of 20% per quarter, Petral Consulting estimates they will reach 40-42 million lb/day by first-half 2020. The ability of US chemical companies to ramp up polyethylene exports at 20%/year every quarter for 6 quarters depends on how many companies decide to play hardball while taking the various turns along the Yellow Brick Road. Increasing exports at 20%/year for 18 months seems like a big hurdle but the ramp up in US exports is about 5%/year based on global polyethylene demand; also, growth rates in global demand are allegedly 4-5%/year. Prices for polyethylene exports will remain under downward pressure for 18-24 months.

According to PetroChem Wire, spot prices for HDPE (free on board, FOB Houston) were steady at 55¢/lb in first-half 2018. Prices, however, began to decline in the third quarter, falling to 45¢/lb in fourth-quarter 2018. Pricing differentials between HDPE and spot ethylene were 34.5¢/lb in third-quarter 2018 before dipping to 24.9¢/lb in the fourth quarter. Differentials between HDPE and NTP ethylene prices were 21.1¢/lb in the third quarter before slipping to 14.7¢/lb in the fourth quarter. Trends in HDPE-polyethylene differentials show prices for monomer and polymer also were weaker in fourth-quarter 2018.

The strong increase in exports is a harbinger of continued and sustained growth in the polyethylene export market. The increase in exports to ROW destinations, and the increase in polyethylene spot prices are indicators that second-half 2018 and 2019 may be “the best of times” after all (Fig. 4).

**Propylene supply**

Olefin-plant coproduct supply. Coproduct propylene supply depends primarily on the use of propane, normal butane, naphtha, and other heavy feeds. In first-half 2018, the monthly survey showed demand for LPG feeds (propane and normal butane) was 356,000 b/d, while demand for heavy feeds was 153,000 b/d. In the third quarter, demand for LPG feeds fell to 346,000 b/d, with demand for heavy feeds slipping to 128,000 b/d. Demand for ethane increased in the third quarter but not enough to offset the drop in heavy feed demand. Demand for LPG and heavy feeds, however, increased in the fourth quarter, with LPG feed demand rising to 460,000 b/d (about 105,000 up from the third quarter) and heavy feed demand averaging 132,000 b/d. Demand for ethane was down by about 30,000 b/d.

Coproduct supply was 19.3 million lb/day in third-quarter 2018, down 0.4 million lb/day (2.1%) from second-quarter 2018 and 1.3 million lb/day (6.1%) from third-quarter 2017. Coproduct supply jumped to 22.6 million lb/day in fourth-quarter 2018, up 16.8% from the previous quarter. Coproduct supply from light feeds (ethane, propane, and normal butane) was 14.6 million lb/day in third-quarter 2018 and 17.7 million lb/day in the fourth quarter. Supply from light feeds in the third quarter was 0.6 million lb/day less than third-quarter 2017 but 4.9 million lb/day more than the previous year’s fourth quarter. Coproduct supply from heavy feeds in second-half 2018 was 4.9 million lb/day, down 1.4 million

---

**COPRODUCT PROPYLENE FROM ETHYLENE PLANTS**

<table>
<thead>
<tr>
<th>Year</th>
<th>From light feeds</th>
<th>From heavy feeds</th>
<th>Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017-18</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Q1</td>
<td>15.2</td>
<td>5.4</td>
<td>20.6</td>
</tr>
<tr>
<td>Q2</td>
<td>12.8</td>
<td>7.1</td>
<td>19.9</td>
</tr>
<tr>
<td>Q3</td>
<td>14.9</td>
<td>6.1</td>
<td>21.0</td>
</tr>
<tr>
<td>Q4</td>
<td>14.4</td>
<td>5.3</td>
<td>19.7</td>
</tr>
<tr>
<td>Q1</td>
<td>14.6</td>
<td>4.8</td>
<td>19.4</td>
</tr>
<tr>
<td>Q2</td>
<td>17.0</td>
<td>4.9</td>
<td>21.9</td>
</tr>
</tbody>
</table>

Source: Petral Consulting estimates.
half 2018 feed rates 69,000 b/d higher vs. first-half 2018. 3.74 million b/d in the fourth quarter, with overall second-quarter 2018. Petral Consulting estimates feed rates were the USGC and Midcontinent were 3.78 million b/d in third-quarter 2018, up 42,000 b/d (0.8%) from the second quarter. Based on EIA monthly statistics for October and weekly statistics for November-December, Petral Consulting estimates FCCU feed rates in fourth-quarter 2018 declined by 61,000 b/d to average 5 million b/d.

Refinery supply. Refinery propylene sales into the merchant market are a function of:
• Fluid catalytic cracking unit (FCCU) feed rates (most important variable).
• FCCU operating severity (important but not directly measurable).
• Economic incentive to sell propylene rather than use it as alkylate feed.

Variations in FCCU feed rates generally are the most important parameter determining refinery-grade propylene supply. Economic factors that may result in changes in operating severity are generally of secondary importance.

Statistics from the US Energy Information Administration (EIA) show US refineries operated FCCUs at 5.1 million b/d in third-quarter 2018, up 42,000 b/d (0.8%) from the second quarter. Based on EIA monthly statistics for October and weekly statistics for November-December, Petral Consulting estimates FCCU feed rates in fourth-quarter 2018 declined by 61,000 b/d to average 5 million b/d.

Regionally, EIA statistics showed feed rates for FCCUs in the USGC and Midcontinent were 3.78 million b/d in third-quarter 2018. Petral Consulting estimates feed rates were 3.74 million b/d in the fourth quarter, with overall second-half 2018 feed rates 69,000 b/d higher vs. first-half 2018.

Refinery-grade propylene supply from USGC and Midcontinent refineries was 49.7 mm lb/day in third-quarter 2018 and 49.2 mm lb/day in the fourth quarter. USGC merchant sales—which include all supply from USGC and Midcontinent refineries—in second-half 2018 was up 1 million lb/day (2%) from first-half 2018 (Table 5).

US supply. EIA statistics for refinery-grade propylene and Petral Consulting estimates for coproduct supply and PDH plant production show total USGC propylene supply was 79 million lb/day in third-quarter 2018 and 84 million lb/day in the fourth quarter. Supply from all sources in second-half 2018 was 81 million lb/day, up 4.4 million lb/day (5.7%) from first-half 2018.

Fig. 5 shows trends in coproduct supply, PDH plant production, and refinery merchant sales of propylene.

**Propylene economics, pricing**

Before any USGC PDH capacity came on stream, Petral Consulting periodically received questions regarding the impact of propylene supply from PDH plants on propylene prices. Based on the operational issues that were generally known in 2010, Petral Consulting’s answer to these questions was consistent: more supply from PDH plants translates into greater pricing volatility for polymer-grade propylene. The same holds true for refinery-grade propylene pricing.

In distinct contrast with persistently weak spot ethylene prices, spot prices for refinery-grade propylene were stronger for most of second-half 2018 based on premiums to unleaded regular gasoline.

At 85% of nameplate capacity, USGC propylene supply from PDH plants will average 11 million lb/day. In the absence of any offsetting reduction in refinery-grade propylene supply, USGC polymer-grade propylene markets should trend toward chronic surplus. The previously anticipated chronic propylene surplus did not occur because US suppliers were able to offset supply growth with increasing monomer exports.

Before 2016, propylene exports were just enough to offset imports from Canada. Exports averaged 0.85 million lb/day in 2010 through first-quarter 2015. During the past 13 quarters (second-half 2015 through third-quarter 2018), however, propylene exports averaged 2.8 million lb/day (about three times more than in 2010 through first-quarter 2015) and were never less than 1.9 million lb/day in the last 9 quarters. In the past 6 quarters, propylene exports were 3.5 million lb/day. Exports are now equal to typical propylene production from one world-scale PDH plant.

Discounts for refinery-grade propylene vs. polymer-grade propylene exceeded 10¢/lb for the first time in second-quarter 2010, but discounts were consistently less than 10¢/lb in fourth-quarter 2010 through third-quarter 2011. During the next 4 years (2012-15), discounts varied within a range of 7-12¢/lb, averaging 10.1¢/lb. Since 2015, discounts for refinery-grade propylene were never less than 10¢/lb in any quarter and averaged 15.7¢/lb in first-half 2018. Discounts were 13.4¢/lb in second-half 2018 and varied within a range of

| **Table 5** REFINERY PROPYLENE PRODUCTION |  |
|---|---|---|---|---|
| 2017-18 | Texas Gulf Coast | South Louisiana | Other areas | Total |
| Q3 | 17.5 | 18.5 | 13.8 | 49.8 |
| Q4 | 21.2 | 18.8 | 14.8 | 54.8 |
| Q1 | 21.5 | 17.5 | 12.9 | 51.9 |
| Q2 | 20.4 | 17.4 | 13.6 | 51.4 |
| Q3 | 21.5 | 17.3 | 13.8 | 52.6 |
| Q4* | 20.0 | 19.0 | 15.4 | 54.4 |

*Petral Consulting estimates.
Source: EIA Petroleum Supply Monthly, Petral Consulting estimates
Discounts for refinery-grade propylene are now routinely 10-12¢/lb and are three to four times more than in 2005-09.

While trends in refinery-grade propylene pricing discounts vs. polymer-grade propylene support a bearish view, trends in refinery-grade propylene prices vs. unleaded regular gasoline prices are bullish. Price premiums for refinery-grade propylene vs. USGC unleaded regular gasoline prices were 5.4¢/lb in second-quarter 2018 before surging to 9-13¢/lb in July-September to average 10.9¢/lb during third-quarter 2018. As the global collapse in motor gasoline prices extended into November-December, however, premiums fell to 6.84¢/lb in November and only 1.7¢/lb in December.

In the current market, unpredictable variations in supply-demand balances result in large swings in polymer-grade propylene pricing and differentials. The unpredictable variability in operating rates of the USGC’s three PDH plants will continue to influence spot prices for polymer-grade and refinery-grade propylene.

Pricing volatility (measured as the standard deviation of day-to-day variation in spot prices for each month) increased as propylene supply from PDH plants and the number of PDH plants in operations increased. In 2017, the standard deviation for day-to-day variation in spot prices averaged 0.62¢/lb and was 1.0¢/lb or more in only 1 month. In first-half 2018, the standard deviation averaged 1.09¢/lb and was 1.0¢/lb or more in 3 months.

All PDH plants settled into a period of sustained and steady operations in fourth-quarter 2018. As anticipated, when PDH plants ran consistently at high operating rates, pricing volatility declined. In third-quarter 2018, standard deviations for daily variations in polymer-grade propylene prices were 0.23-0.73¢/lb, averaging 0.5¢/lb. In the fourth quarter, standard deviations measured 0.5-1.1¢/lb and averaged 0.71¢/lb.

Propylene, polypropylene exports

For the first 3 quarters in 2018, monomer exports varied within a range of 3.0-5.5 million lb/day. Monomer exports in second and third-quarters 2018 were 4.23 million lb/day, up 0.56 mm lb/day (15.1%) from second and third-quarters 2017.

The primary destinations for monomer exports remain Colombia and Mexico. Exports to Mexico were 1.99 million lb/day in first-half 2018, up 0.61 million lb/day (43.9%) from second-half 2017. Exports to Columbia also increased in first-half 2018 vs. second-half 2017, with first-half 2018 exports averaging 1.44 million lb/day, or 0.26 million lb/day (22.1%) more than in second-half 2017. Exports to Mexico slipped to 1.84 million lb/day in July-October 2018. Exports to Colombia were also weaker in July-October, averaging 1.33 million lb/day.

US ITC statistics also show US polypropylene exports were weak in first-half 2018 relative to 2015 through first-half 2017. Polypropylene exports remained weak in second-
half 2018 based on July-October statistics. Exports in first-half 2018 were 5.97 million lb/day before falling below 5 million lb/day in September-October. July-October exports averaged 5.11 million lb/day, down 0.87 million lb/day (14.5%) from first-half 2018.

**2019 outlook**

Domestic chemical companies have taken the first major steps from a period when all important variables within North America were known and developments in markets outside North America were of interest but not generally reason for concern. The future is all about integrating North America into the global marketplace. In 2019, however, producers’ primary focus will be on the new plants in Louisiana and Texas that will start up in 2019.

Petral Consulting forecasts US ethylene production will average 190-210 million lb/day in first-half 2019 and 200-220 million lb/day in second-half 2019. During first-half 2019, production will average 20-25 million lb/day more than in 2018. Year-over-year growth in second-half 2019 will increase 25-30 million lb/day.

The outlook for first-half 2019 has characteristics similar to first-half 2018. Three new plants in Louisiana are scheduled to come on stream in 2019. Indorama’s restart of the 950-million lb/year plant acquired from LyondellBasell is in the early phase of commissioning, while Sasol is likely to begin an extended startup for new ethylene and derivative units at its Lake Charles, La., complex.

After 2019, ethylene producers will have access to additional ethylene export capacity. As one or two export terminals dedicated to ethylene service begin operations in 2020 or 2021, ethylene producers will be able to adjust exports to maintain balanced markets, and a collapse in spot prices similar to first-half 2018 will become less likely.

**The author**

Daniel L. Lippe (danlippe@petral.com) is president of Petral Consulting Co., which he founded in 1988. He has expertise in economic analysis of a broad spectrum of petroleum products including crude oil and refined products, natural gas, natural gas liquids, other ethylene feedstocks, and primary petrochemicals.

Lippe began his professional career in 1974 with Diamond Shamrock Chemical Co., moved into professional consulting in 1979, and has served petroleum, midstream, and petrochemical industry clients since. He holds a BS (1974) in chemical engineering from Texas A&M University and an MBA (1981) from Houston Baptist University. He is an active member of the Gas Processors Suppliers Association.
In-depth phase characterization improves naphtha cracker emulsion breaking

Fabrice Cuoq
Jérôme Vachon
Saudi Arabian Basic Industries Corp.
Geleen, the Netherlands

Research by Saudi Arabian Basic Industries Corp. (SABIC) shows that colloid chemistry analytical tools combined with advanced analytics enable clearer understanding of the emulsion properties. Dynamic surface tension as well as zeta and streaming potential titrations yield valuable information on the molecular size, electrostatic charge, and isoelectric point (IEP) of the emulsifier. These combined, measured parameters can be used to determine the emulsion-stabilization mechanism, which in turn allows a proper and tailored optimization of plant conditions.

Background

Naphtha-cracking processes often suffer from oil-in-water (OW) emulsions in quench water towers (QWT). Organics within the water phase can deposit in the dilution steam generators (DSG) and cause severe fouling that can lead to critical energy losses and threaten production. In practice, emulsion-breaker dosage or pH reduction are commonly used to break these emulsions. The mechanism of emulsion stabilization via emulsifiers, however, is often unknown due to the complex composition of both aqueous and gasoline phases.

An ethylene plant’s cracked gas needs to be cooled before proceeding to the cracked-gas compressor section. This is generally achieved by quenching the cracked gas with a water stream in a QWT. The QWT is generally followed by a quench-water settler tank that allows water and pyrolysis gasoline (pygas) separation. The pygas usually contains a mixture of light hydrocarbons such as benzene, toluene, styrene, ethylbenzene, cyclic hydrocarbons, and C₅-C₁₀ unsaturated components. This stream is commonly recovered after the QWT for further treatment, and the water phase is sent to a process-water stripper (PWS) column to remove dissolved hydrocarbons. Depending on plant design, condensates from the top of the PWS can be rerouted to the QWT as quenching water or sent to the water treatment plant. The bottom of the PWS is finally routed to the DSG, where process steam is produced for use as diluent in the furnaces. The system from the QWS to DSG is called the dilution steam system (DSS) (Fig. 1).

Either OW or water-in-oil (WO) emulsions can form in the first compartment of the QWT and may lead to carry-over of process water or pygas to sections not adapted to treat such effluents, which can lead to severe issues impacting plant economics, including corrosion, formation of polymeric deposits, or in extreme cases, an unplanned shutdown of the petrochemical plant. OW emulsions are generally the largest cause for concern. Solid fouling deposits—which result from the high reactivity of pygas—can be formed in the DSS, which subsequently leads to severe energy capacity losses in PWS, preheaters, and the DSG.

In practice, emulsion-breaker dosage or pH reduction are used to break these emulsions. Physical separation methods such as coalescers can also be applied. If missing, however, this solution requires a high-cost hardware change to the cracker.
Despite the different existing solutions, the mechanism of emulsion stabilization and the structure of the emulsifier(s) are often unknown due to the complex composition of both phases and the high variability of feedstocks cracked in an ethylene plant. Empirical solutions are often developed for these systems by using simple shake-bottle tests without investigating an emulsion’s true nature and properties.

To our knowledge, this is the first time that colloid chemistry analytical tools have been applied to resolving OW emulsion issues in a naphtha cracker. The results presented in this article have all been obtained using real plant samples from one of SABIC’s European naphtha crackers.

**Materials**

Four OW emulsion samples (pH = 8.8, σ = 135 microsiemens (μS/cm)) were taken at different times from a QWS at one of SABIC’s naphtha crackers. The milky-colored water samples—which indicate dispersed organics in the water—were obtained from the bottom of the gasoline-water separator vessel (Fig. 2).

**Methods**

A SITA science line t-60 maximum bubble-pressure tensiometer measured dynamic surface tension. Streaming potential titration determined the charge density of the emulsion. Measurements were performed on a Mueck PCDO3PH streaming potential detector. A total of 19.81 g of process water was titrated with a polydiallyldimethylammonium chloride (PolyDADMAC) (1 milliequivalent (meq)/l) organic coagulant. While 0.282 ml of the PolyDADMAC solution was needed to neutralize all charges in the process water, the titration of the cell itself required 0.220 ml of the blank solution.

The pendant-drop method determined interfacial tensions. In this method, the shape of a droplet suspended from a needle in a nonmiscible bulk-liquid phase is determined. The interfacial tension can be derived from the drop shape and the density difference between the two phases. Analysis was performed with an Attension CAM-200.

Average gasoline-droplet size was measured using a Malvern Mastersizer 2000, with the mean diameter (volume-weighed mean) of the droplets found to be about 11.08 μm.

Salting out the process water (NaCl 100g/l) measured the amount of gasoline dispersed in the water. Once the emulsion was broken, the amount of phase-separated gasoline was measured volumetrically, revealing that the process water contained about 0.1% of dispersed gasoline.

Zeta potential values were obtained with a Malvern Zetasizer NanoZS at 70º C., and the emulsion’s pH was lowered using a 0.1 volume-to-volume (v/v) % HCl solution.

DSM R&D Solutions BV, Geleen, the Netherlands, measured liquid chromatography-mass spectrometry (LC-MS) on a Bruker Daltonics maXis Quadrupole Time-of-Flight (Q-TOF) mass spectrometer with electrospray ionization (ESI), atmospheric-pressure chemical ionization (APCI), and sometimes atmospheric-pressure photoionization (APPI) in the positive and negative-ion mode. The elemental compositions of the visual peaks were manually determined based on the accurate mass.

Direct insertion probe-mass spectrometry (DIP-MS) was performed by DSM Resolve on a Waters Autospec sector-field mass spectrometer.

**Discussion**

Zeta potentials (ζ) of -80 ± 6 mV (pH = 8.8, σ = 135 μS/cm) were obtained for the emulsion at both 25º C. and 70º C. (average values of the four samples), indicating that the electrostatic component is relatively strong since ζ < -30 mV are generally representative of stable emulsions. Using titration, the charge density of the emulsion was found to be about 2.7 μeq/l. at pH 8.8. By considering an 0.1 v/v % OW emulsion (volumetric value determined by salting out the emulsion) and an average spherical-droplet size of 11.08 μm, the charge density of the emulsion was calculated at 0.62 μeq/sq m.

This calculated value seems low compared to the charge density generally considered for a stable emulsion. While
the low charge density and the highly negative zeta potential seem contradictory; they can be partially explained by the low conductivity of the continuous phase (i.e., 135 μS/cm), which could be indicative of the presence of low amounts of adsorbed counter ions. It can finally be concluded that the electrostatic component of the emulsion is not negligible in the specific conditions of the naphtha cracker’s QWT studied. Furthermore, zeta potential measurements can be used to optimize the emulsion-breaker dosing rate in process water. For this, dynamic zeta potential measurements upon emulsion breaker addition can be recorded offline or monitored online.

- Determination of IEP and its relation to emulsion destabilization. Recording the titration curve (streaming potential vs. pH) while titrating the emulsion with HCl (Fig. 3) determined its IEP.

From the process water’s original pH of 8.88 to pH 3.45, the streaming potential shows a continuous increase from about -400 mV to +200 mV. The charge inversion (at streaming potential = 0 mV) is obtained at pH 5.45, which corresponds to the IEP. At pH values above the IEP, the droplets are negatively charged, while below the IEP, the droplets are positively charged. In this case, cationic charges are generally caused by amines, whereas anionic charges are generally due to carboxylic acids. Around the IEP, the emulsion is not charged and becomes very unstable. Determination of the IEP will therefore indicate the system’s optimum pH.

Fig. 4 shows the process water at different pH values after 24 hours.

At pH < 3.86, the streaming potential decreases again slightly because of either the compression of the double layer or a systematic decrease in streaming potential, both induced by the high concentration of ions.

Recording dynamic surface tension measurements allowed estimates of the time needed for the emulsifiers to diffuse to a newly created hydrophobic surface (Fig. 5).

Surface tensions of both emulsion bottles (measured in duplicate) lie well above the ones for pure water, indicating that no free-surface active species are present in the process water. Also, the stable high surface tension indicates that the emulsion is not stabilized by small molecules but rather by amphiphilic polymers because these do not have time to migrate from the emulsion droplet onto the bubble surface for a bubble life of even 10 sec. The fact that the values are slightly above the pure-water value is because the samples were colder (18° C.) than the water reference (25° C.), giving them a slightly higher ionic strength. Surface tension generally increases with lower temperatures and increased ionic strength.

Fig. 6 shows the evolution of the zeta potential as a function of time.

Process water at higher pH values after 24 hours increased in murkiness (Fig. 4).
upon an increase of the conductivity to 2.3 ms/cm (achieved by NaCl addition).

Upon addition of a high concentration of NaCl, the zeta potential starts to slowly increase (become less negative), finally reaching a plateau value of -20 mv. This observation is unusual as zeta potential—like other electrostatic effects involving small ions—is generally rapidly affected within seconds or minutes once the conductivity of the continuous phase is changed. Once the salt solution is added to the system, however, molecular rearrangements at the droplet surfaces occur, causing this slow increase in zeta potential and showing that the thermodynamic equilibrium has not yet been reached. This last observation suggests that the charged groups are attached to polymeric species for which structural rearrangements take place at time scales of minutes to hours.

For a polymeric species to be surface active, it should possess an amphiphile character, meaning that part of its chain must be in the aqueous phase (hydrophilic side) and part of it in the oil phase (lipophilic side). The presence of molecular-chain segments in the aqueous phase implies that steric phenomena play a role in stabilizing a surface. The combined action of electrostatics and sters is generally called electrosteric stabilization. Based on the presented data and observations, we can conclude the emulsion is electrosterically stabilized.

Analytical chemistry for emulsifiers identification. Results of earlier testing showing the emulsifier as charged with a polymeric nature prompted selection of the freeze-drying method to isolate and analyze chemical structures of the emulsifiers. Freeze drying consists of freezing the main water phase and sublimating the ice under vacuum. This treatment method evaporates water and light compounds (i.e., volatile monomers) from the dispersed gasoline, leaving only heavier species (i.e., potential emulsifiers).

Fig. 7 shows the residue obtained after freeze drying 1 l. of process water. Interfacial tension between water and pygas was determined with addition of the extract residue (tested concentration: 1,000 ppm vs 100 ppm in process water) to confirm the surface-active properties of the material. Results indicated
Path ahead

Based upon findings of our study, zeta and streaming potential allows quantification of the electrostatic component of the OW emulsion stabilization. Operators can use these data to help find the appropriate root cause of emulsion and fine tune a proper treatment plan for naphtha-cracking operations, such as decreasing or increasing emulsion-breaker concentration or finding the optimum pH range.

This type of analysis, we believe, brings a major benefit compared to the classical conductivity-turbidity-pH analyses usually performed by the industry on such a system.

The authors

Fabrice Cuoq (fabrice.cuoq@sabic.com) has worked at Saudi Arabian Basic Industries Corp. since 2013, currently serving as a senior scientist in the technology department. During this time, he has provided chemistry support on the process and water sides to SABIC’s operating plants in Europe and Saudi Arabia. Cuoq holds a MS (2009) in material sciences from Institut National des Sciences Appliquées de Lyon, France, and a PhD (2012) in colloidal chemistry from the University of Aix-Marseille, France.

Jérôme Vachon (jerome.vachon@sabic.com) has worked at Saudi Arabian Basic Industries Corp. since 2010, currently serving as a lead scientist in the technology department. After previously providing chemistry support on the process and water sides to SABIC’s operating plants in Europe, he now focuses on development of polyolefin material. Vachon holds a MS (2002) in chemical engineering from CPE Lyon, France, and a PhD (2006) in organic chemistry from the University of Geneva, Switzerland.

that interfacial tension is lower once the material is added to the water-gasoline, demonstrating its strong surface-active properties, most notably at lower pH (Figs. 8-9).

The dual-technique analyses (LC-MS, DIP-MS) of residue material identified specific compounds that could be responsible for emulsion stabilization: polyethylene glycol (PEG, with different end groups); fatty acids and sulfonate-type compounds; and large styrenic-fulvenic types of molecules. While the origin of such species remains under investigation, it is possible that the PEG, fatty acids, and sulfonate-type compounds are a result of recycling-process additives to the QWT or related to feedstock oxygenates, whereas the large styrenic-fulvenic compounds could be formed and inherent to the cracked-gas stream. Overall, the combination of these three types of functional groups fit with an electrosteric stabilization mechanism.
US DOE details Marcellus-Utica ethane, petrochemical options

Expanding the US petrochemical asset base beyond the Gulf Coast, where almost all US ethylene production is sited, would enhance its geographic diversity and support reliability of the petrochemical industry. More than 95% of US ethylene production capacity is in Texas or Louisiana. Further, the development of new petrochemical capacity elsewhere would not necessarily conflict with continued Gulf Coast expansion. New capacity beyond the Gulf Coast could serve regional demand for NGL derivatives, freeing up Gulf Coast production for other markets, including exports.

The US Department of Energy (DOE) prepared a report to Congress in November 2018 titled “Ethane Storage and Distribution Hub in the United States.” It addressed the feasibility of a new ethane storage and distribution hub in the US. Large hubs for NGL storage, including ethane, are already in place in the US, but the boom in crude oil and natural gas production from shale formations may present opportunities for industry to establish additional hubs.

DOE gathered and analyzed information regarding ethane supply and related infrastructure. This analysis considered projected trends in ethane production over the coming decades, where changes in ethane production are projected to occur, the location and capacity of established ethane storage hubs in North America, and NGL pipelines, among other things. The analysis focused on identifying regions in which significant growth in ethane production is projected and established ethane hubs do not exist.

In its “Annual Energy Outlook 2018 (AEO 2018),” the US Energy Information Administration (EIA) projected natural gas plant liquids (NGPL) production to nearly double between 2017 and 2050 (Fig. 1), supported by an increase in global petrochemical demand. Most NGPL production growth in the report’s reference case occurs before 2025 when increased demand spurs higher ethane recovery and producers focus on NGL-rich plays.

The large increase in NGL will come from the Marcellus and Utica plays in the east and from the Permian basin in the southwest over the next 10 years. By 2050 the east and southwest regions account for more than 60% of total US NGL production in the AEO 2018 reference case.

Between early 2011 and mid-2013, industry announced capacity expansions, feedstock changes, and new plant construction because of the significant increase in availability of ethane in the US. These investments focused near the Mont Belvieu, Tex., NGL hub on the Gulf Coast and near the hub in Sarnia, Ont. Construction of three new ethylene crackers on the Texas Gulf Coast was completed end-2017. Additional pipeline and export infrastructure was built to export ethane by tanker from terminals at Morgan’s Point, Tex., and Marcus Hook, Pa.; both sites opened in 2016.

Lacking storage in the east, several pipelines have been built to deliver NGL from the east region to Mont Belvieu and Sarnia; the first pipeline to enter service that moves ethane out of the Appalachia region to Canada was Sunoco Logistics’ Mariner West pipeline, which was commissioned in De-

December 2013. Early in 2014, the Appalachia-Texas-Express (ATEX) pipeline began shipments of ethane from the Appalachian region into the Midwest and Gulf Coast.

Projected growth in NGPL production in the east region presents an opportunity for industry to establish an ethane storage and distribution hub near Marcellus and Utica shale production. Ethane production in the region is projected to continue its rapid growth. Projected 2025 production of 640,000 b/d, is more than 20 times the regional ethane production in 2013 (Fig. 2). By 2050, ethane production in the region is projected to reach 950,000 b/d.

North America has the second largest ethylene production capacity in the world behind the Asia-Pacific region. Production, however, is highly concentrated on the US Gulf Coast; more than 95% of US ethylene capacity is in either Texas or Louisiana (Fig. 3).

Significant production capacity growth is projected across the ethane value chain, which includes intermediate products such as polyethylene, ethylene oxide, ethylene dichloride, and others. Fig. 4 shows projected capacity growth by region in the US; between 2018 and 2040, production capacity of ethylene and intermediate petrochemical products is expected to increase by more than 85%. The unspecified capacity depicted in Fig. 4 represents projected new capacity that has not been attached to a specific location to date.

The required investments to build a petrochemical hub are significant. For example, a new 125,000 b/d NGL fractionator and related infrastructure (including additional storage capacity) in Mont Belvieu announced by Oneok Inc. is reported to cost $575 million. Shell Chemicals’ ethane cracker project under construction in Pennsylvania is reported to cost $6 billion.

Natural gas produced in the Appalachian basin tends to contain higher amounts of ethane, and regional processing plants extract most ethane separately to manage pipeline natural gas heat content.

In support of the dramatic increase in production between 2010 and 2016, natural gas processing capacity in the Marcellus and Utica plays grew nearly tenfold and fractionation capacity increased twentyfold.

The establishment of an ethane storage and distribution hub near production from the Marcellus and Utica plays could provide supply-diversity benefits to the broader petrochemical and plastics industries. The geographic concentration of petrochemical infrastructure and supply along the Gulf Coast may pose a strategic risk, where severe weather events limit the availability of key feedstocks. Petrochemical expansion beyond the Gulf Coast would increase geographic diversity. This geographic diversity could provide manufacturers with flexibility and redundancy regarding where they purchase their feedstock and how it is transported to them. Moreover, this flexibility and redundancy, as well as the overall increase in U.S. feedstock production, could mitigate the potential for any price spikes in petrochemical feedstocks caused by severe weather or other disruptive events in any one region.
Natural gas, NGL production

AEO 2018 projects natural gas production from shale resources will more than double by 2050 (Fig. 3). Continued development of the Marcellus and Utica plays is the main driver of growth in total US natural gas production across most cases and the main source of total US dry natural gas production. EIA forecasts production from the Eagle Ford and Haynesville shales to be a secondary source of domestic dry natural gas, with production largely leveling off after 2028. Associated natural gas from tight oil production in the Permian grows strongly through 2050.

The Appalachian basin’s shale resources are such that, were the region an independent country, it would be the world’s third largest producer of natural gas. Appalachian natural gas production is projected to continue very steady growth in the short and long-term. Natural gas output, estimated at 8.19 tcf in 2017, is projected to increase by 65% to 13.55 tcf in 2025. Output in 2050 is projected at 19.5 tcf.

AEO 2018’s reference case projects NGPL production to nearly double between 2017 and 2050. Most NGPL production growth occurs before 2025 (Fig. 1), when producers focus on NGL-rich plays and increased demand spurs higher ethane recovery. After 2025, production migrates to areas where NGL yields are lower.

NGPL output in the east region, and by proxy the Appalachian basin, will continue to grow throughout the forecast period. As natural gas production gradually migrates away from liquids-rich gas areas, which are expected to slowly deplete, to dryer areas, the rate of growth in NGPL production will slow relative to the rate of natural gas production growth. NGPL output from 2017 to 2025 will more than double from 610,000 b/d in 2017 to 1.35 million b/d in 2025. NGPL output is projected to reach 1.93 million b/d in 2050.

Ethane production in the region will continue its rapid growth. Projected production in 2025, at 640,000 b/d, is more than 20 times greater than regional ethane production in 2013. By 2050, ethane production in the region is projected to reach 950,000 b/d (Fig. 2), on the back of both higher NGL production in general, and higher recovery of ethane as gas plants improve their capacity to extract a higher proportion of ethane. A world-scale ethane cracker typically consumes around 90,000 b/d of ethane for ethylene production.

Beyond moving ethane from the Appalachian basin to established North American hubs and export markets, the projected growth in NGPL production in the east presents an opportunity for industry to establish an ethane storage and distribution hub near the Marcellus and Utica shales. The extent to which Appalachian NGL will be converted and consumed locally depends on regional infrastructure additions and, more specifically, the interplay between storage and transportation. NGL storage solutions in the Appalachian region are beginning to expand. As storage capacity in the region increases, so too does the potential to use locally produced NGL as petrochemical feedstocks in manufacturing operations expanding and coming online within Appalachia.
**Storage**

US underground NGL storage sites extend from Kansas to southern Texas and New Mexico. Sites in Mont Belvieu, Conway, Kan., and Sarnia, Ont., all benefit from access to underground salt formations. Mont Belvieu, the largest NGL hub in North America, has more than 240 million bbl of NGL storage capacity. Conway has salt cavern NGL storage capable of holding 21 million bbl. And Sarnia has more than 20 million bbl NGL storage capacity.

The Appalachian region has generally depended on storage elsewhere to satisfy peak-season NGL demand. There are only a few significant regional sites, nearly all of which store propane and are connected to Enterprise Products Partners (EPP) LP’s Texas Eastern Products Pipeline Co. (TEPPCO) pipeline.

Crestwood Midstream Partners’ proposed Finger Lakes NGL storage site at Watkins Glen, NY, was held in regulatory stasis for more than 7 years, first filing a request to convert the depleted salt caverns to hydrocarbon storage in 2009, and satisfying all of the New York State Department of Environmental Conservation’s (DEC) requirements by mid-2013.10 The project involved use of two existing caverns on the shore of Lake Seneca at Watkins Glen, near EPP’s Watkins Glen terminal and with a connection to TEPPCO.

As originally proposed, the site would have been capable of holding a combined 2.1 million bbl of propane and butane. Crestwood, seeking support from the adjacent communities, revised the project numerous times, most recently by reducing its scope to storing just propane, and in only the larger, 1.5-million bbl cavern.11 It has also shifted from building the terminal to include rail and truck access, with pipeline access now the only option. In September 2017, one of the last challenges to Crestwood’s DEC application was struck down, allowing the project to possibly proceed.12 But in December 2018 the company said it was no longer pursuing the project.13

Sunoco’s site at Marcus Hook, Pa., sits 300 ft above five granite caverns capable of storing a combined 2 million bbl of NGL and olefins.14 These caverns were mined in the 1950s, 60s, and 70s, and were an integral part of operations at its shuttered Marcus Hook refinery. The smallest cavern, at about 200,000 bbl, now belongs to Braskem and is integrated into its polypropylene operations. The remaining capacity belongs to Sunoco with the largest cavern capable of holding roughly 1 million bbl. Some of the capacity is set aside to serve PBP Energy’s Paulsboro, NJ, refinery across the Delaware River, while the rest are part of Sunoco’s operations at the Marcus Hook terminal, including exports.

Sunoco expanded storage at the site as part of developing its Mariner East pipeline. The initial phase of the expansion project, which accompanied the Mariner East pipeline reversal and repurposing for NGL service, included a 300,000-bbl ethane tank and a 500,000-bbl propane tank. Expansion plans include adding a 900,000-bbl propane tank, a 589,000-bbl propane tank, a 575,000-bbl butane tank, and a 300,000-bbl ethane tank.

Energy Storage Ventures LLC, a joint venture between Mountaineer NGL Storage and Powhatan Salt Co., is developing an NGL storage site in Monroe County, Ohio. Phase 1 of the subterranean storage will operate multiple caverns totaling 2-million bbl, solution-mined in the Salina bedded salt formation roughly 6,500 ft below the Ohio River Valley. The site will serve as centrally-located storage for NGL in the Appalachian region with rail and truck loading capacity as well as two 10-in. OD bi-directional pipelines to Blue Racer Midstream LLC’s nearby Natrium fractionator. Initial storage is scheduled to begin in 2019 and ramp up to full operable capacity by mid-2020. With sufficient interest, the company may develop Phase II and expand to the site’s permitted 3.25-million bbl capacity.

Appalachia Development Group LLC (ADG) is developing the Appalachia Storage and Trading Hub (ASTH), a proposed underground NGL storage site. The project is intended to be a catalyst for further mid- and downstream development associated with the Marcellus, Utica, and Rogersville shales. To determine its basic eligibility for a federal loan guarantee, ADG submitted a Part I application in September 2017 to the US DOE Loan Program Office (LPO). In January 2018, the LPO invited ADG to submit a Part II application for a loan guarantee under the DOE Title XVII Loan Program, which entails submitting a comprehensive application for the proposed project. ADG is seeking a $1.9-billion loan guarantee that will first require securing an additional $1.4-billion in equity. The site of the proposed hub has yet to be determined. ADG in August 2018 selected Parsons Corp. as its engineering, procurement, and construction partner for ASTH.

The accompanying box details further in-region options for Appalachian NGL storage.

**Development**

There are three potential paths future infrastructure development could follow, influenced by: global capacity expansion, global demand growth, international aggressiveness in pricing for market share, domestic production trends, capital market preferences, domestic regional incentives, and technological change, among other factors. Underlying each scenario is the general assumption that shale production and the related supply of natural gas and NGL for petrochemical feedstock will continue to grow and that the Marcellus and Utica shales will make major contributions to total domestic supply. The following three scenarios focus on where processing will occur.

In Scenario A, development of a petrochemical cluster in Appalachia is assumed to increase to the point that much incremental Appalachian supply is processed locally. Scenario B assumes focus on continued development in the existing Gulf Coast complex. In Scenario C, incremental processing...
occurs elsewhere, supplied by US feedstock exports.

• **Processing in Appalachia.** This scenario assumes market participants individually pursue a partial or complete build out of a new petrochemical supply chain in the Appalachian region. The supply chain and the overall size would be smaller and less comprehensive than what is currently in place on the Gulf Coast. Local and regional capital investment would be the largest of the three scenarios.

Required investment to build a petrochemical hub in Appalachia would be significant. Shell Chemicals’ ethane cracker under construction in Pennsylvania is reported to cost $6 billion. New infrastructure would include gathering lines, processing plants, fractionation, NGL storage, ethane crackers, and some combination of plants for polyethylene, ethylene dichloride, ethylene oxide, and other infrastructure. It is likely that without building petrochemical plants that would serve as demand for all components of the NGL stream, some would still be transported out of the region. This would be more likely in the initial years as the petrochemical complex first develops.

Growth in the petrochemical industry would also impact other industries, and additional required supporting infrastructure would be needed. For instance, increased electricity demand could require additional power plant capacity; increased truck traffic could impact existing road infrastructure. These impacts could be mitigated to some degree through coordinated planning and infrastructure development.

New and expanded transportation infrastructure would be especially important to move intermediate or end-use products from Appalachia to markets in the Midwest, Gulf Coast, Canada, or Northeast for consumption or export. These transportation systems would need to be created or expanded. New suppliers and contracts would have to be established.

The required large capital investments highlight the need for coordination across the petrochemical industry since their products are all highly interdependent on feedstock provided by others. Major petrochemical facilities take years to construct, and for the investments to make economic sense, the necessary market demand needs to exist when new plants come online.

Under this scenario, the economic benefit from significant growth in the petrochemical sector would be concentrated in Appalachia through jobs creation and economic multipliers, and this would benefit neighboring markets as well. For example, the Midwest could benefit from lower prices for delivered plastics. Producing and processing ethane in Appalachia using new, more efficient plants and shorter transportation distances to the Midwest than from the Gulf Coast could lower costs and environmental impact. A new Appalachian petrochemical supply area would also be closer to demand in Ontario and Europe.

Adding a new petrochemical supply source would improve the security of supply for markets in the Midwest and potentially across the US. Adding another petrochemical cluster would increase the geographic diversity of petro-

---

**Prospective Marcellus-Utica subsurface NGL storage sites**

In August 2017, the Appalachian Oil and Natural Gas Consortium (AONGRC) released a geologic study that looked at and mapped potential underground storage options for NGLs produced in the Marcellus and Utica shale plays.

This study evaluated prospective geologic formations in West Virginia, Ohio, and Pennsylvania that offered subsurface conditions eligible for hosting underground NGL storage, prerequisite for an ethane storage and distribution hub and potential growth of the petrochemical industry in the region. Specifically, the following three subsurface storage prospects were investigated and found suitable for prospective underground storage:

- **The Northern Prospect** encompasses the northern panhandle of West Virginia and adjacent portions of eastern Ohio and western Pennsylvania, presenting storage opportunities in the Clinton-Medina sandstones of Ohio’s Ravenna-Best Consolidated field and two Salina F4 salt cavern opportunities straddling the Ohio River. In addition, the Oriskany sandstone occurs throughout this portion of the Appalachian basin, overlying both intervals, and offers a potential stacked opportunity based on available subsurface data.

- **The Central Prospect** includes portions of southeastern Ohio, southwestern Pennsylvania, and north-central West Virginia and contains five storage opportunities: Greenbrier limestone mined-rock cavern options; depleted gas reservoirs in the Keener-to-Berea interval in and between the Maple-Wadestown and Condit-Rogtown fields; a depleted gas reservoir in the Upper Devonian Venango group in the Racket-Newberne (Sinking Creek) gas storage field; depleted gas reservoirs in Upper Devonian sandstones in the Weston-Jane Lew field; and a Salina F4 Salt opportunity near Ben’s Run in West Virginia.

- **The Southern Prospect** is situated in the Kanawha River Valley of West Virginia and comprises the most storage opportunities of any prospect evaluated in the AONGRC study, including mined-rock caverns in the Greenbrier interval; an Oriskany sandstone natural gas storage field; and various depleted gas fields in the Keener-to-Berea, Oriskany sandstone, and Newburg sandstone intervals. What’s more, many stacked and adjacent opportunities are available within a relatively small geographic area. The number, variety and stacking of storage opportunities in the Southern Prospect shows its potential to support a thriving petrochemical industry, according to the study.

AONGRC operates from the West Virginia University (WVU) Energy Institute and is a partnership among two WVU departments and the state geological surveys of West Virginia, Ohio, Pennsylvania, and Kentucky.
chemical supply, helping other markets in the event of supply interruptions. Development of an Appalachian cluster is also not necessarily in conflict with Gulf Coast expansion, since Appalachian capacity could serve regional demand for NGL derivatives, freeing up Gulf Coast production for other markets, including export.

- **Gulf Coast processing.** This scenario assumes a focus on building gathering and gas processing plants to separate and ship purity NGLs rather than building a local petrochemical industry. Increased NGL production would require new pipelines and possible new marine export terminals to be built to take NGL to the Gulf Coast and export markets, and these market opportunities would help expand capacity to handle greater feedstock volumes. Finished petrochemical products (e.g., plastic pellets, etc.) would then either be shipped back to the Appalachian region or exported via the Gulf of Mexico, increasing reliance on using chemical manufacturing at existing industrial centers in the Gulf Coast region.

Scenario B would result in considerably less regional investment in Appalachia. Most initial investment in Appalachia would concentrate on Y-grade (NGL mixed product) pipelines and storage. The new transportation infrastructure would connect to existing infrastructure in the Gulf Coast. Growth of Gulf Coast petrochemical production capacity would ramp up with the new purity product supply, affecting local markets and the labor pool. Economic growth would be split between Appalachian NGL production and processing and Gulf Coast petrochemicals production.

Construction of storage and pipeline infrastructure would provide increased economic activity initially, followed by the gains from increased production. In the Gulf Coast region the increase in NGL supply and associated increase in petrochemical manufacturing capacity would raise economic output and labor employment.

In this scenario, there would be less US security of supply for plastics markets since petrochemical production would remain concentrated on the Gulf Coast. Supply disruptions caused by hurricanes or other factors could impact petrochemical supply chains across the country.

- **International processing.** Purity NGL products would be shipped from Appalachia for processing elsewhere. This scenario assumes these shipments would be focused internationally to take advantage of existing, but underutilized, petrochemical processing capacity idled due to high feedstock prices and competition from low-cost Middle Eastern petrochemical supplies. New pipelines and marine export terminals would be required to transport Appalachian NGL to foreign processing and consumption centers. Export would also allow Appalachian producers and shippers to take advantage of European naphtha crackers now being converted to use ethane as feedstock.

Initial investments would focus on pipelines to move NGL to Canada for plastics production and to East Coast ports for export to Europe. Existing port capacity may be constrained, requiring expansion, which may not be possible at some locations. Ports would likely need upgrades to efficiently handle the expanding flow of NGL. Initial availability of suitable ships meeting port specifications also may be limited.

In this scenario, economic growth would be more distributed, with investment more widely dispersed and smaller than with the buildout of new US petrochemical plants. The export of large volumes of ethane and other NGL would provide economic benefits and positively impact the trade balance.

This scenario increases Appalachian producers’ sales options as it would provide several outlets for their NGL. If one route was constrained or out of service for some reason, the other markets could provide alternatives.

**Appalachian potential**

Other studies have examined the opportunity for increased petrochemical activity in Appalachia tied to the region’s abundant ethane supply. In March 2018, IHS Markit released a study on the shale region of Ohio, Pennsylvania, and West Virginia.13 The study compared a hypothetical investment of almost $3 billion in an ethylene-polyethylene plant in the region versus the US Gulf Coast over a 20-year timeframe. The study points to the access of low-cost ethane and proximity to polyethylene consumption as drivers for financial advantage in the Marcellus-Utica region. Findings of note included:

- The region will supply 37% of US natural gas production by 2040.
- Base case, and using a 15% discount rate, the analysis predicted a net present value (NPV) in 2020 on earnings before interest, taxes, depreciation, and amortization of $930 million over the life of the project compared to $217 million for a similar Gulf Coast project.
- Under a stress test that included higher capital costs and lower operating rates, a Marcellus-Utica project resulted in negative NPV returns in only 1% of 10,000 simulations.
- Expected returns for a project in the region versus the Gulf Coast are higher under all analyzed scenarios.

The synopsis of the study closes with the statement: “The comparative financial advantage for a [Marcellus-Utica] project would be further enhanced if more-than-anticipated transportation facilities, natural gas and NGL storage, and pipeline infrastructure occurs in the region.”10

Industry has made significant investments in natural gas and NGL infrastructure to support the boom in production in Appalachia over the past decade. Between 2010 and 2016, natural gas processing capacity increased tenfold, and fractionation capacity in the Appalachian region increased from 41,000 b/d in 2010 to nearly 850,000 b/d in 2016 and may grow as high as 1.1 million b/d in 2019. Underground storage projects are being considered, and a world-scale ethane cracker is already under construction in Pennsylvania.

NGL storage is necessary for a future hub since produced...
volumes typically exceed pipeline takeaway capacity and processing capacity. Storage helps mitigate production volatility and in turn reduces risk for end users.

Appalachia’s abundant resources coupled with extensive downstream industrial activity may offer a competitive advantage that could enable the region to displace marginal producers and help the US gain global petrochemical market share. Nearly one-third of US petrochemical activity occurs within 300 miles of Pittsburgh, with over $300 billion of net revenue. US petrochemical manufacturing capacity and growth is poised to continue expanding given the expectation of shale production growth. Projected, but unspecified to a particular region, incremental petrochemical capacity will generate nearly $227 billion in revenue between 2018 and 2040.

References

ABRIOX

*Wireless Pressure Monitoring System Monitors Gas Pressure at Multiple Locations*

Osprey supplements surveillance of gas distribution systems at multiple locations by monitoring, gathering and processing real-time data to help ensure sufficient flow rates and pressure.

“Osprey allows us to see daily compilations of pressure at different points and get real-time alerts if pressures move outside of pre-set ranges,” says Matt Stennett, P.E., vice president of engineering for Abriox.

Certified to Class 1, Division 1, Osprey is available in single and multi-channel models, offers flexible pressure ranges and has a sensor accuracy of ± 0.15 percent FS. A key feature of Osprey is its built-in GPS module. In addition to displaying its geographical location, the data collected from satellites allows Osprey to establish the exact time and date of every pressure measurement it records.

Abriox: Newport, UK

OSPREY MONITORING SYSTEM

*Hunting*

Introduces Perforating System with Higher Charge Performance in a Shorter Footprint

The H-2 Perforating System features EQUAfrac shaped charges in a single plane configuration, creating the shortest gun length on the market. The plug-and-play perforating gun system is capable of firing up to four shots per 7.5-in. cluster. H-2 simplifies loading and arming by utilizing proprietary charge puck and Shorty ControlFire cartridge technology to eliminate detonating cord.

The H-2 system is ideal for high gun per stage operations and scenarios where rig up length is limited. H-2 will be available in a 3 ½-in. gun diameter, which is an optimal size for well completions with 4 ½-in. and 5 ½-in. casing. Hunting: Houston

H-2 PERFORATING SYSTEM

*Pure Safety Group*

Announces Two S-Series Harnesses

Pure Safety Group completes its Series line-up of three safety Guardian Fall Protection safety harnesses with the Series 3 and Series 5 full-body fall protection harnesses.

Used for personal fall arrest, work positioning, restraint and rescue/confined space applications, both harnesses feature a captivated chest strap that prevents improper adjustment and accidental slippage, rubber web ends that fold over and protect the harnesses against damage, and dual lanyard keepers for safe storage of unused lanyard legs.

The Series 3 and Series 5 have a loop for connecting to a dual SRL connector, freeing up the D-ring for other attachments, and an optional heavy-duty waist pad and belt to accommodate tools. Capacity for the harnesses is 130-420 pounds. All harnesses meet OSHA standards, exceed ANSI standards and are pending CSA certification. Pure Safety Group: Pasadena, TX

Guardian Series 3

SUBSEA INTEGRATION ALLIANCE

*Awarded Integrated EPCIIC Contracts Offshore Australia by Esso Australia*

Subsea Integration Alliance, a worldwide non-incorporated partnership between OneSubsea, Schlumberger, and Subsea 7, was awarded integrated subsea engineering, procurement, construction, installation and commissioning contracts by Esso Australia Pty Ltd. The contracts represent the first integrated subsea project for Subsea Integration Alliance in Australia combining OneSubsea and Subsea 7 expertise in subsea production systems and subsea umbilical, riser and flowline systems.

Subsea Integration Alliance work scope includes engineering, procurement, construction and installation of two production wells. The wells are in approximately 45-m water depth, and will tie back to the Longford onshore gas plants. OneSubsea and Subsea 7 offices in Perth and Melbourne, Australia will provide project management and engineering. Offshore installation activities are scheduled for 2020. OneSubsea, Schlumberger: Houston; Subsea 7 S.A.: London

TRENDSETTER ENGINEERING

*Delivers Subsea Production Equipment*

Trendsetter Engineering completed the design and build of subsea production equipment for Noble Energy’s Leviathan Project, a large natural gas field development in the Eastern Mediterranean Sea off the coast of Israel.

Trendsetter’s scope of work included
multiple clamp connection systems, subsea distribution equipment, MEG filter modules, 2-in. connection systems and subsea manifolds. Trendsetter Engineering, Inc.: Houston

Trendsetter Engineering Subsea Production Equipment

**UNIVERSAL SUBSEA**

*Introduces Subsea Equipment Preservation Fluid*

Defender Stasis LT preservation fluid is a lightweight, nontoxic, biodegradable preservation fluid that provides long-term protection for subsea equipment components and interface profiles. The fluid is compatible with all commonly used metals and nonmetallic materials in oilfield service.

"This patented preservation fluid far exceeds U.S. EPA and OSPAR requirements for offshore drilling fluids discharged to sea. The fluid also meets or exceeds the much stricter regulations for Environmentally Acceptable Lubricants and Total Loss Lubricants per U.S. EPA, OSPAR, E.U. Ecolabel and other national Ecolabel programs. Defender Stasis LT is the first subsea wellhead preservation fluid that meets regulatory requirements for 24-hour per day use in offshore oil-producing countries worldwide," states Sean Thomas, P.E., general manager, Universal Subsea, Inc. Universal Subsea, Inc: Houston

Defender Stasis LT Preservation Fluid

"This patented preservation fluid far exceeds U.S. EPA and OSPAR requirements for offshore drilling fluids discharged to sea. The fluid also meets or exceeds the much stricter regulations for Environmentally Acceptable Lubricants and Total Loss Lubricants per U.S. EPA, OSPAR, E.U. Ecolabel and other national Ecolabel programs. Defender Stasis LT is the first subsea wellhead preservation fluid that meets regulatory requirements for 24-hour per day use in offshore oil-producing countries worldwide," states Sean Thomas, P.E., general manager, Universal Subsea, Inc. Universal Subsea, Inc: Houston

Defender Stasis LT Preservation Fluid

Order Today!

Visit our website for complete listings!

www.PennWellBooks.com

1-800-752-9764 (toll free)

Our nontechnical series is tailored for energy industry professionals, especially those who lack technical training in an area, providing a basic understanding of the industry in a simple, easy-to-understand language.

Whether you need quick information for a new assignment or just want to expand your knowledge in other areas of the industry, we have your nontechnical needs covered. Best of all, our books and videos fit easily into your budget!

Many topics to choose from, including:

- Basic petroleum
- Drilling
- Financial management
- Geology & exploration
- Natural gas
- Petrochemicals
- Petroleum production
- Petroleum refining
- Pipelines
- Well logging
Additional analysis of market trends is available through OGJ Online, Oil & Gas Journal’s electronic information source, at http://www.ogj.com.

### Imports of Crude and Products

<table>
<thead>
<tr>
<th>Districts 1-4</th>
<th>District 5</th>
<th>Total US</th>
</tr>
</thead>
<tbody>
<tr>
<td>2-15 2019</td>
<td>2-8 2019</td>
<td>2-15 2018</td>
</tr>
<tr>
<td>Total motor gasoline</td>
<td>412</td>
<td>420</td>
</tr>
<tr>
<td>Mo. gas. blending comp.</td>
<td>316</td>
<td>368</td>
</tr>
<tr>
<td>Distillate</td>
<td>424</td>
<td>431</td>
</tr>
<tr>
<td>Residual</td>
<td>49</td>
<td>202</td>
</tr>
<tr>
<td>Jet fuel-kerosine</td>
<td>84</td>
<td>62</td>
</tr>
<tr>
<td>Propane-propylene</td>
<td>127</td>
<td>133</td>
</tr>
<tr>
<td>Other</td>
<td>585</td>
<td>365</td>
</tr>
<tr>
<td><strong>Total products</strong></td>
<td>1,681</td>
<td>1,613</td>
</tr>
<tr>
<td><strong>Total crude</strong></td>
<td>6,270</td>
<td>5,105</td>
</tr>
<tr>
<td><strong>Total imports</strong></td>
<td>7,951</td>
<td>6,718</td>
</tr>
</tbody>
</table>

*Revised.

Source: US Energy Information Administration.
Data available at PennEnergy Research Center.

### Exports of Crude and Products

<table>
<thead>
<tr>
<th>Total US</th>
</tr>
</thead>
<tbody>
<tr>
<td>2-15-19</td>
</tr>
<tr>
<td>Finished motor gasoline</td>
</tr>
<tr>
<td>Jet fuel-kerosine</td>
</tr>
<tr>
<td>Distillate</td>
</tr>
<tr>
<td>Residual</td>
</tr>
<tr>
<td>Propane-propylene</td>
</tr>
<tr>
<td>Other oils</td>
</tr>
<tr>
<td><strong>Total products</strong></td>
</tr>
<tr>
<td><strong>Total crude</strong></td>
</tr>
<tr>
<td><strong>Total exports</strong></td>
</tr>
</tbody>
</table>

*Revised.

Source: US Energy Information Administration.
Data available at PennEnergy Research Center.

### Crude and Product Stocks

<table>
<thead>
<tr>
<th>Crude oil</th>
<th>Total</th>
<th>Blending comp.</th>
<th>Jet fuel, kerosine</th>
<th>Distillate</th>
<th>Fuel oils</th>
<th>Propane-propylene</th>
</tr>
</thead>
<tbody>
<tr>
<td>PADD 1</td>
<td>13,400</td>
<td>67,588</td>
<td>61,909</td>
<td>9,506</td>
<td>44,429</td>
<td>6,192</td>
</tr>
<tr>
<td>PADD 2</td>
<td>137,221</td>
<td>59,446</td>
<td>52,567</td>
<td>7,289</td>
<td>33,614</td>
<td>1,309</td>
</tr>
<tr>
<td>PADD 3</td>
<td>232,642</td>
<td>89,558</td>
<td>79,111</td>
<td>15,750</td>
<td>42,425</td>
<td>16,364</td>
</tr>
<tr>
<td>PADD 4</td>
<td>20,645</td>
<td>7,457</td>
<td>5,741</td>
<td>808</td>
<td>4,262</td>
<td>230</td>
</tr>
<tr>
<td>PADD 5</td>
<td>50,604</td>
<td>32,797</td>
<td>30,652</td>
<td>10,011</td>
<td>13,953</td>
<td>5,317</td>
</tr>
</tbody>
</table>

*Includes PADD 5.

Source: US Energy Information Administration.
Data available at PennEnergy Research Center.

### Refinery Report—Feb. 15, 2019

<table>
<thead>
<tr>
<th>Gross inputs</th>
<th>Crude oil inputs</th>
</tr>
</thead>
<tbody>
<tr>
<td>1,000 b/d</td>
<td></td>
</tr>
<tr>
<td>PADD 1</td>
<td>784</td>
</tr>
<tr>
<td>PADD 2</td>
<td>3,478</td>
</tr>
<tr>
<td>PADD 3</td>
<td>8,568</td>
</tr>
<tr>
<td>PADD 4</td>
<td>597</td>
</tr>
<tr>
<td>PADD 5</td>
<td>2,560</td>
</tr>
<tr>
<td><strong>Feb. 15, 2019</strong></td>
<td><strong>15,987</strong></td>
</tr>
<tr>
<td><strong>Feb. 8, 2019</strong></td>
<td><strong>15,989</strong></td>
</tr>
<tr>
<td><strong>Feb. 16, 2018</strong></td>
<td><strong>16,313</strong></td>
</tr>
</tbody>
</table>

1Includes PADD 5.

Source: US Energy Information Administration.
Data available at PennEnergy Research Center.

### Refinery Operations

<table>
<thead>
<tr>
<th>Total motor gasoline</th>
<th>Jet fuel, kerosine</th>
<th>Distillate</th>
<th>Fuel oils</th>
<th>Propane-propylene</th>
</tr>
</thead>
<tbody>
<tr>
<td>3,132</td>
<td>81</td>
<td>242</td>
<td>26</td>
<td>156</td>
</tr>
<tr>
<td>2,500</td>
<td>252</td>
<td>1,106</td>
<td>38</td>
<td>247</td>
</tr>
<tr>
<td>2,556</td>
<td>881</td>
<td>2,634</td>
<td>100</td>
<td>1,918</td>
</tr>
<tr>
<td>305</td>
<td>29</td>
<td>210</td>
<td>13</td>
<td>120</td>
</tr>
<tr>
<td>1,520</td>
<td>447</td>
<td>567</td>
<td>102</td>
<td>—</td>
</tr>
</tbody>
</table>

1Includes PADD 5.

Source: US Energy Information Administration.
Data available at PennEnergy Research Center.
OGJ GASOLINE PRICES

<table>
<thead>
<tr>
<th>Price</th>
<th>Pump ex tax</th>
<th>Pump price*</th>
<th>Pump price*</th>
</tr>
</thead>
<tbody>
<tr>
<td>2-20-19</td>
<td>2-29-19</td>
<td>2-20-19</td>
<td>2-21-18</td>
</tr>
<tr>
<td>(Approx. prices for self-service unleaded gasoline)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Atlanta</td>
<td>154.2</td>
<td>207.9</td>
<td>241.7</td>
</tr>
<tr>
<td>Baltimore</td>
<td>156.1</td>
<td>209.8</td>
<td>246.7</td>
</tr>
<tr>
<td>Boston</td>
<td>148.0</td>
<td>207.5</td>
<td>242.7</td>
</tr>
<tr>
<td>Buffalo</td>
<td>157.3</td>
<td>219.8</td>
<td>256.7</td>
</tr>
<tr>
<td>Miami</td>
<td>151.2</td>
<td>203.8</td>
<td>256.1</td>
</tr>
<tr>
<td>New York</td>
<td>152.7</td>
<td>232.5</td>
<td>250.7</td>
</tr>
<tr>
<td>Norfolk</td>
<td>183.1</td>
<td>246.6</td>
<td>266.7</td>
</tr>
<tr>
<td>Philadelphia</td>
<td>155.0</td>
<td>218.6</td>
<td>261.7</td>
</tr>
<tr>
<td>Pittsburgh</td>
<td>155.1</td>
<td>230.7</td>
<td>267.7</td>
</tr>
<tr>
<td>Wash., DC</td>
<td>166.9</td>
<td>224.0</td>
<td>252.7</td>
</tr>
<tr>
<td>New York Harbor</td>
<td>162.9</td>
<td>230.2</td>
<td>261.7</td>
</tr>
<tr>
<td>Gulf Coast</td>
<td>153.1</td>
<td>208.2</td>
<td>257.0</td>
</tr>
<tr>
<td>PAD avg</td>
<td>169.5</td>
<td>224.0</td>
<td>252.7</td>
</tr>
<tr>
<td>Chicago</td>
<td>241.6</td>
<td>292.0</td>
<td>331.7</td>
</tr>
<tr>
<td>Cleveland</td>
<td>177.5</td>
<td>224.0</td>
<td>259.4</td>
</tr>
<tr>
<td>Des Moines</td>
<td>177.5</td>
<td>225.6</td>
<td>265.0</td>
</tr>
<tr>
<td>Detroit</td>
<td>163.9</td>
<td>220.7</td>
<td>252.9</td>
</tr>
<tr>
<td>Indianapolis</td>
<td>155.7</td>
<td>217.0</td>
<td>252.2</td>
</tr>
<tr>
<td>Kansas City</td>
<td>169.6</td>
<td>295.3</td>
<td>351.3</td>
</tr>
<tr>
<td>Memphis</td>
<td>182.6</td>
<td>227.0</td>
<td>277.3</td>
</tr>
<tr>
<td>Milwaukee</td>
<td>160.9</td>
<td>205.8</td>
<td>246.2</td>
</tr>
<tr>
<td>Minn.-St. Paul</td>
<td>170.4</td>
<td>221.7</td>
<td>250.0</td>
</tr>
<tr>
<td>Oklahoma City</td>
<td>162.2</td>
<td>208.6</td>
<td>234.0</td>
</tr>
<tr>
<td>Omaha</td>
<td>170.2</td>
<td>223.0</td>
<td>250.0</td>
</tr>
<tr>
<td>St. Louis</td>
<td>171.2</td>
<td>227.0</td>
<td>270.0</td>
</tr>
<tr>
<td>Tulsa</td>
<td>164.1</td>
<td>202.0</td>
<td>236.3</td>
</tr>
<tr>
<td>Wichita</td>
<td>163.5</td>
<td>205.6</td>
<td>236.9</td>
</tr>
<tr>
<td>PAD II avg</td>
<td>173.1</td>
<td>219.2</td>
<td>242.7</td>
</tr>
<tr>
<td>Albuquerque</td>
<td>161.9</td>
<td>199.2</td>
<td>228.7</td>
</tr>
<tr>
<td>Birmingham</td>
<td>156.7</td>
<td>196.1</td>
<td>232.0</td>
</tr>
<tr>
<td>Dallas-Fort Worth</td>
<td>155.4</td>
<td>198.1</td>
<td>230.0</td>
</tr>
<tr>
<td>Houston</td>
<td>158.5</td>
<td>194.2</td>
<td>227.0</td>
</tr>
<tr>
<td>Little Rock</td>
<td>170.9</td>
<td>223.2</td>
<td>272.3</td>
</tr>
<tr>
<td>New Orleans</td>
<td>170.6</td>
<td>209.1</td>
<td>229.8</td>
</tr>
<tr>
<td>San Antonio</td>
<td>167.8</td>
<td>206.2</td>
<td>228.7</td>
</tr>
<tr>
<td>PAD IV avg</td>
<td>162.2</td>
<td>200.9</td>
<td>230.0</td>
</tr>
<tr>
<td>Cheyenne</td>
<td>171.3</td>
<td>213.7</td>
<td>243.4</td>
</tr>
<tr>
<td>Denver</td>
<td>187.9</td>
<td>219.1</td>
<td>253.3</td>
</tr>
<tr>
<td>Salt Lake City</td>
<td>173.8</td>
<td>222.2</td>
<td>248.4</td>
</tr>
<tr>
<td>PAD IV avg</td>
<td>174.8</td>
<td>218.5</td>
<td>248.4</td>
</tr>
<tr>
<td>Los Angeles</td>
<td>239.2</td>
<td>311.9</td>
<td>331.7</td>
</tr>
<tr>
<td>Phoenix</td>
<td>272.5</td>
<td>269.0</td>
<td>284.7</td>
</tr>
<tr>
<td>Portland</td>
<td>216.8</td>
<td>251.9</td>
<td>275.7</td>
</tr>
<tr>
<td>San Diego</td>
<td>246.2</td>
<td>318.9</td>
<td>330.7</td>
</tr>
<tr>
<td>San Francisco</td>
<td>258.2</td>
<td>330.9</td>
<td>365.1</td>
</tr>
<tr>
<td>Seattle</td>
<td>218.1</td>
<td>285.9</td>
<td>300.7</td>
</tr>
<tr>
<td>PAD V avg</td>
<td>230.3</td>
<td>293.4</td>
<td>312.9</td>
</tr>
<tr>
<td>Week's avg</td>
<td>177.9</td>
<td>228.0</td>
<td>255.1</td>
</tr>
<tr>
<td>Jan. avg</td>
<td>175.1</td>
<td>222.5</td>
<td>251.4</td>
</tr>
<tr>
<td>Dec. avg</td>
<td>189.6</td>
<td>239.5</td>
<td>246.2</td>
</tr>
<tr>
<td>2019 to date</td>
<td>173.8</td>
<td>223.6</td>
<td>265.0</td>
</tr>
<tr>
<td>2018 to date</td>
<td>205.3</td>
<td>265.7</td>
<td>331.7</td>
</tr>
</tbody>
</table>

Includes state and federal motor fuel taxes and state sales tax. Local governments may impose additional taxes. Source: Oil & Gas Journal.

IHS PETRODATA RIG COUNT

FEB. 22, 2019

<table>
<thead>
<tr>
<th>IHS PETRODATA RIG COUNT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total US: 1,007,000</td>
</tr>
<tr>
<td>Canada: 212,308</td>
</tr>
<tr>
<td>Grand total: 1,259,308</td>
</tr>
<tr>
<td>US oil rigs: 833,799</td>
</tr>
<tr>
<td>US gas rigs: 164,179</td>
</tr>
<tr>
<td>Total US offshore: 17,119</td>
</tr>
<tr>
<td>Total US cum. avg. YTD: 1,056,935</td>
</tr>
</tbody>
</table>

Includes state and federal motor fuel taxes and state sales tax. Local governments may impose additional taxes. Source: Oil & Gas Journal.

US CRUDE PRICES

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$/bbl</td>
<td>$/bbl</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OPEC reference basket</td>
<td>56.94</td>
<td>58.74</td>
<td>60.02</td>
</tr>
<tr>
<td>Basra light-Iraq</td>
<td>60.47</td>
<td>58.20</td>
<td>58.99</td>
</tr>
<tr>
<td>Bonny light-Nigeria</td>
<td>57.82</td>
<td>58.01</td>
<td>58.57</td>
</tr>
<tr>
<td>Es Sider-Lebanon</td>
<td>58.66</td>
<td>58.27</td>
<td>58.02</td>
</tr>
<tr>
<td>Grass-Oil-Angola</td>
<td>57.52</td>
<td>59.98</td>
<td>59.08</td>
</tr>
<tr>
<td>Iran heavy-Iran</td>
<td>58.44</td>
<td>56.29</td>
<td>56.29</td>
</tr>
<tr>
<td>Kuwait export-Kuwait</td>
<td>57.10</td>
<td>58.65</td>
<td>58.35</td>
</tr>
<tr>
<td>Merv - Venezuela</td>
<td>57.07</td>
<td>59.50</td>
<td>59.50</td>
</tr>
<tr>
<td>Murban - UAE</td>
<td>59.33</td>
<td>60.81</td>
<td>60.81</td>
</tr>
<tr>
<td>Oman - Ecuador</td>
<td>51.26</td>
<td>55.10</td>
<td>54.11</td>
</tr>
<tr>
<td>Saudi Arabian blend - Algeria</td>
<td>52.79</td>
<td>59.27</td>
<td>59.27</td>
</tr>
<tr>
<td>Zafiro - Equatorial Guinea</td>
<td>57.66</td>
<td>60.09</td>
<td>59.66</td>
</tr>
</tbody>
</table>

US NATURAL GAS STORAGE

<table>
<thead>
<tr>
<th>Natural gas storage</th>
<th>Change, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>East</td>
<td>395</td>
</tr>
<tr>
<td>Midwest</td>
<td>436</td>
</tr>
<tr>
<td>Mountain</td>
<td>87</td>
</tr>
<tr>
<td>Pacific</td>
<td>135</td>
</tr>
<tr>
<td>South Central</td>
<td>649</td>
</tr>
<tr>
<td>West</td>
<td>75</td>
</tr>
<tr>
<td>Middle East</td>
<td>425</td>
</tr>
</tbody>
</table>

Total US: 1,705,182

US NATURAL GAS STORAGE

<table>
<thead>
<tr>
<th>Natural gas storage</th>
<th>Change, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>East</td>
<td>395</td>
</tr>
<tr>
<td>Midwest</td>
<td>436</td>
</tr>
<tr>
<td>Mountain</td>
<td>87</td>
</tr>
<tr>
<td>Pacific</td>
<td>135</td>
</tr>
<tr>
<td>South Central</td>
<td>649</td>
</tr>
<tr>
<td>West</td>
<td>75</td>
</tr>
<tr>
<td>Middle East</td>
<td>425</td>
</tr>
</tbody>
</table>

Total US: 1,705,182


IHS Natural Gas Storage

Source: EIA weekly report.

Oil & Gas Journal | Mar. 4, 2019
**Statistics**

**PACE REFINING MARGINS**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>US Gulf Coast</td>
<td>5.95</td>
<td>4.91</td>
<td>4.92</td>
<td>11.55</td>
<td>(6.63)</td>
</tr>
<tr>
<td>Composite US Gulf Refinery</td>
<td>5.95</td>
<td>4.91</td>
<td>4.92</td>
<td>11.55</td>
<td>(6.63)</td>
</tr>
<tr>
<td>Mars (Coking)</td>
<td>6.68</td>
<td>5.65</td>
<td>4.63</td>
<td>11.78</td>
<td>(5.67)</td>
</tr>
<tr>
<td>Mars (Cracking)</td>
<td>5.26</td>
<td>4.16</td>
<td>3.27</td>
<td>8.75</td>
<td>(5.49)</td>
</tr>
<tr>
<td>Bonny Light</td>
<td>0.45</td>
<td>(1.76)</td>
<td>(0.18)</td>
<td>6.47</td>
<td>(6.65)</td>
</tr>
<tr>
<td>US PDO II</td>
<td>13.20</td>
<td>6.88</td>
<td>4.65</td>
<td>14.02</td>
<td>(9.37)</td>
</tr>
<tr>
<td>Chicago (WTI)</td>
<td>4.86</td>
<td>3.35</td>
<td>2.59</td>
<td>6.80</td>
<td>(3.86)</td>
</tr>
<tr>
<td>US East Coast</td>
<td>6.03</td>
<td>4.82</td>
<td>3.86</td>
<td>8.55</td>
<td>(4.69)</td>
</tr>
<tr>
<td>Brass River</td>
<td>8.83</td>
<td>10.60</td>
<td>8.38</td>
<td>9.73</td>
<td>(1.35)</td>
</tr>
<tr>
<td>Mediterranean</td>
<td>2.83</td>
<td>0.59</td>
<td>0.42</td>
<td>0.28</td>
<td>(0.70)</td>
</tr>
<tr>
<td>Italy (Urals)</td>
<td>3.51</td>
<td>1.04</td>
<td>0.29</td>
<td>1.54</td>
<td>(1.82)</td>
</tr>
<tr>
<td>Far East</td>
<td>3.21</td>
<td>(0.29)</td>
<td>(0.10)</td>
<td>4.15</td>
<td>(4.25)</td>
</tr>
</tbody>
</table>

**DEMAND/SUPPLY SCOREBOARD**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total gas</td>
<td>3,228</td>
<td>3,005</td>
<td>2,838</td>
<td>390</td>
<td>33,708</td>
</tr>
<tr>
<td>Production</td>
<td>1,662</td>
<td>1,827</td>
<td>1,767</td>
<td>(165)</td>
<td>17,941</td>
</tr>
<tr>
<td>Stocks</td>
<td>23,679</td>
<td>23,675</td>
<td>4</td>
<td>23,679</td>
<td>22,863</td>
</tr>
<tr>
<td>Natural gas in underground storage</td>
<td>3,283</td>
<td>3,057</td>
<td>3,048</td>
<td>3,283</td>
<td></td>
</tr>
</tbody>
</table>

**US NATURAL GAS BALANCE**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total gas</td>
<td>3,283</td>
<td>3,057</td>
<td>3,048</td>
<td>3,283</td>
<td>3,048</td>
</tr>
<tr>
<td>Working gas</td>
<td>3,031</td>
<td>3,237</td>
<td>2,951</td>
<td>3,789</td>
<td>(678)</td>
</tr>
<tr>
<td>Total gas</td>
<td>7,387</td>
<td>7,594</td>
<td>7,307</td>
<td>8,062</td>
<td>1,799</td>
</tr>
</tbody>
</table>

**WORLDWIDE NGL PRODUCTION**

<table>
<thead>
<tr>
<th></th>
<th>Nov. 2018</th>
<th>Oct. 2018</th>
<th>Nov. 2017</th>
<th>11 month production</th>
<th>Change vs. previous</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brazil</td>
<td>115</td>
<td>115</td>
<td>127</td>
<td>130</td>
<td>(3)</td>
</tr>
<tr>
<td>Canada</td>
<td>940</td>
<td>929</td>
<td>906</td>
<td>849</td>
<td>58</td>
</tr>
<tr>
<td>Mexico</td>
<td>213</td>
<td>210</td>
<td>219</td>
<td>252</td>
<td>(32)</td>
</tr>
<tr>
<td>United States</td>
<td>4,571</td>
<td>4,580</td>
<td>4,336</td>
<td>3,718</td>
<td>(18)</td>
</tr>
<tr>
<td>Venezuela</td>
<td>139</td>
<td>144</td>
<td>155</td>
<td>189</td>
<td>(34)</td>
</tr>
<tr>
<td>Other Western</td>
<td>206</td>
<td>214</td>
<td>206</td>
<td>213</td>
<td>(7)</td>
</tr>
<tr>
<td>Western</td>
<td>6,184</td>
<td>6,192</td>
<td>5,849</td>
<td>5,349</td>
<td>600</td>
</tr>
<tr>
<td>Norway</td>
<td>340</td>
<td>336</td>
<td>326</td>
<td>341</td>
<td>(15)</td>
</tr>
<tr>
<td>Other Western</td>
<td>119</td>
<td>106</td>
<td>89</td>
<td>84</td>
<td>6</td>
</tr>
<tr>
<td>Europe</td>
<td>9</td>
<td>9</td>
<td>9</td>
<td>9</td>
<td>0</td>
</tr>
<tr>
<td>Western Europe</td>
<td>468</td>
<td>451</td>
<td>425</td>
<td>434</td>
<td>(9)</td>
</tr>
<tr>
<td>Russia</td>
<td>832</td>
<td>823</td>
<td>792</td>
<td>817</td>
<td>(25)</td>
</tr>
<tr>
<td>Other Western</td>
<td>449</td>
<td>431</td>
<td>434</td>
<td>445</td>
<td>(11)</td>
</tr>
<tr>
<td>Eastern Europe</td>
<td>1,289</td>
<td>1,244</td>
<td>1,235</td>
<td>1,270</td>
<td>(44)</td>
</tr>
<tr>
<td>Africa</td>
<td>728</td>
<td>745</td>
<td>721</td>
<td>744</td>
<td>(23)</td>
</tr>
</tbody>
</table>

**OXYGENATES**

<table>
<thead>
<tr>
<th></th>
<th>Nov. 2018</th>
<th>Oct. 2018</th>
<th>Nov. 2017</th>
<th>Change %</th>
<th>Total OXYGENATES 1,000 bbl</th>
<th>Change %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel ethanol</td>
<td>31,514</td>
<td>32,380</td>
<td>(866)</td>
<td>350,664</td>
<td>343,810</td>
<td>6,854</td>
</tr>
<tr>
<td>Stocks</td>
<td>23,679</td>
<td>23,675</td>
<td>4</td>
<td>23,679</td>
<td>22,863</td>
<td>816</td>
</tr>
<tr>
<td>MTBE Production</td>
<td>1,662</td>
<td>1,827</td>
<td>(165)</td>
<td>17,941</td>
<td>15,061</td>
<td>2,880</td>
</tr>
<tr>
<td>Stocks</td>
<td>920</td>
<td>897</td>
<td>23</td>
<td>920</td>
<td>1,201</td>
<td>(281)</td>
</tr>
</tbody>
</table>

**US HEATING DEGREE—DAYS**

<table>
<thead>
<tr>
<th></th>
<th>Nov. 2018</th>
<th>Oct. 2018</th>
<th>Nov. 2017</th>
<th>% change</th>
<th>Total degree days YTD 2018</th>
<th>% change</th>
</tr>
</thead>
<tbody>
<tr>
<td>New England</td>
<td>803</td>
<td>457</td>
<td>743</td>
<td>8.1</td>
<td>5,287</td>
<td>9.0</td>
</tr>
<tr>
<td>Middle Atlantic</td>
<td>758</td>
<td>351</td>
<td>699</td>
<td>8.4</td>
<td>4,835</td>
<td>13.9</td>
</tr>
<tr>
<td>East North Central</td>
<td>905</td>
<td>419</td>
<td>774</td>
<td>16.9</td>
<td>5,418</td>
<td>20.7</td>
</tr>
<tr>
<td>West North Central</td>
<td>1,005</td>
<td>495</td>
<td>895</td>
<td>24.8</td>
<td>5,869</td>
<td>22.8</td>
</tr>
<tr>
<td>South Atlantic</td>
<td>372</td>
<td>99</td>
<td>322</td>
<td>15.5</td>
<td>2,136</td>
<td>25.9</td>
</tr>
<tr>
<td>East South Central</td>
<td>568</td>
<td>139</td>
<td>408</td>
<td>39.2</td>
<td>2,853</td>
<td>35.4</td>
</tr>
<tr>
<td>West South Central</td>
<td>385</td>
<td>69</td>
<td>180</td>
<td>113.9</td>
<td>1,790</td>
<td>65.6</td>
</tr>
<tr>
<td>Mountain</td>
<td>475</td>
<td>183</td>
<td>383</td>
<td>38.0</td>
<td>3,899</td>
<td>31.9</td>
</tr>
<tr>
<td>Pacific</td>
<td>338</td>
<td>185</td>
<td>351</td>
<td>(3.7)</td>
<td>2,586</td>
<td>(3.5)</td>
</tr>
<tr>
<td>US average*</td>
<td>588</td>
<td>253</td>
<td>490</td>
<td>20.0</td>
<td>3,540</td>
<td>16.8</td>
</tr>
</tbody>
</table>

*Excludes Alaska and Hawaii.

Source: DOE Monthly Energy Review.

**OIL & GAS JOURNAL** | Mar. 4, 2019
**MARKET CONNECTION**
WHERE THE INDUSTRY GOES TO CLASSIFY

The Oil & Gas Journal has a circulation of over 100,000 readers and has been the world’s most widely read petroleum publication for over 100 years.

**PRODUCTS & EQUIPMENT | EMPLOYMENT**

---

**Offshore Catering Jobs Available**

Offshore Experience Required
Executive Steward/Campboss
Cooks
UTs (Housekeeper/Janitorial)
Lead Stewards
Bakers (Pastry Chefs)

**How to Apply:**
Online: www.essgulf.com
Email: Patricia.Feibert@compass-usa.com

**VALID TWIC CARD IS REQUIRED TO APPLY**

---

**SODEXO IS HIRING**

Cooks, Bakers, Housekeeping & Janitorial Workers

Full benefits package
Must be able to work any shift, day, night and weekends, holidays during the hitch rotations (i.e. 28/14, 21/7, 14/7)
TWIC Card required!
Background checks, substance screening, physical exam also required

Please apply online
http://sodexo.balancetrak.com

EOE/AA/M/F/D/V

---

**Visit the**

**MARKET CONNECTION**
WHERE THE INDUSTRY GOES TO CLASSIFY


Contact Grace at
gracej@pennwell.com
713-963-6291

---

**NEW/UNUSED HEAT EXCHANGERS FOR SALE**

<table>
<thead>
<tr>
<th>Area sf</th>
<th>psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>8,499(2)</td>
<td>425/425</td>
</tr>
<tr>
<td>7,704(2)</td>
<td>385/385</td>
</tr>
<tr>
<td>6,179</td>
<td>425/500</td>
</tr>
<tr>
<td>5,464</td>
<td>365/360</td>
</tr>
<tr>
<td>4,602</td>
<td>304/365</td>
</tr>
<tr>
<td>3,239(2)</td>
<td>2,226/1,994</td>
</tr>
<tr>
<td>3,074(2)</td>
<td>2,163/2,006</td>
</tr>
</tbody>
</table>

All above with stainless tubes
Also: 1,092(2), 150/150, Hastelloy Tubes
11,238(12), 1,440/400, steel tubes

[www.ippe.com/ExchangerSales](http://www.ippe.com/ExchangerSales)

---

**SURPLUS GAS PROCESSING/REFINING EQUIPMENT**

25 MMCFD x 1100 PSIG PROPAK REFRIGERATION PLANT
28 TPD SELECTOX SULFUR RECOVERY UNIT
1100 BPD LPG CONTACTOR x 7.5 GPM
CAUSTIC REGEN
NGL/LPG PLANTS: 10 - 600 MMCFD
AMINE PLANTS: 60 - 3300 GPM
SULFUR PLANTS: 10 - 180 TPD
FRACTIONATION: 1000 ñ 25,000 BPD
HELIUM RECOVERY: 75 & 80 MMCFD
NITROGEN REJECTION: 25 ñ 100 MMCFD

**MANY OTHER REFINING/GAS PROCESSING UNITS**

We offer engineered surplus equipment solutions.
Bexar Energy Holdings, Inc.
Phone 210 342-7106/ Fax 210 223-0018
www.bexarenergy.com
Email: info@bexarenergy.com

---

**IMMEDIATE SALE:**

30k GAL 250 PSI TANK
4 (12k gal 250 PSI TANKS)

**WILL BUY:**

90K GAL 100 PSI TANKS

---

**NEW/UNUSED HEAT EXCHANGERS FOR SALE**

**NEW/UNUSED HEAT EXCHANGERS FOR SALE**

[www.ippe.com/ExchangerSales](http://www.ippe.com/ExchangerSales)

---

**LET’S MAKE A DEAL...**

Are you selling equipment, land, or other assets?
List your business opportunity in **Oil & Gas Journal’s Market Connection,** and reach +100,000 potential buyers.
To learn more, contact:
GraceJ@PennWell.com • 713-963-6291

---

**SEE RESULTS—Ask me how!**

GRACE JORDAN
713-963-6291
GraceJ@PennWell.com
Twitter: @ogjmarket

---

**Offshore Catering Jobs Available**

*Executive Steward/Campboss*
*Cooks*
*UTs (Housekeeper/Janitorial)*
*Lead Stewards*
*Bakers (Pastry Chefs)*

**How to Apply:**
Online: www.essgulf.com
Email: Patricia.Feibert@compass-usa.com

**VALID TWIC CARD IS REQUIRED TO APPLY**

---

**SODEXO IS HIRING**

*Cooks, Bakers, Housekeeping & Janitorial Workers*

*Full benefits package*
*Must be able to work any shift, day, night and weekends, holidays during the hitch rotations (i.e. 28/14, 21/7, 14/7)*
*TWIC Card required!*
*Background checks, substance screening, physical exam also required*

*Please apply online*
http://sodexo.balancetrak.com

EOE/AA/M/F/D/V

---

**Visit the**

**MARKET CONNECTION**
WHERE THE INDUSTRY GOES TO CLASSIFY


Contact Grace at
gracej@pennwell.com
713-963-6291

---

**NEW/UNUSED HEAT EXCHANGERS FOR SALE**

<table>
<thead>
<tr>
<th>Area sf</th>
<th>psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>8,499(2)</td>
<td>425/425</td>
</tr>
<tr>
<td>7,704(2)</td>
<td>385/385</td>
</tr>
<tr>
<td>6,179</td>
<td>425/500</td>
</tr>
<tr>
<td>5,464</td>
<td>365/360</td>
</tr>
<tr>
<td>4,602</td>
<td>304/365</td>
</tr>
<tr>
<td>3,239(2)</td>
<td>2,226/1,994</td>
</tr>
<tr>
<td>3,074(2)</td>
<td>2,163/2,006</td>
</tr>
</tbody>
</table>

All above with stainless tubes
Also: 1,092(2), 150/150, Hastelloy Tubes
11,238(12), 1,440/400, steel tubes

[www.ippe.com/ExchangerSales](http://www.ippe.com/ExchangerSales)

---

**LETS MAKE A DEAL...**

*Are you selling equipment, land, or other assets?*

*List your business opportunity in **Oil & Gas Journal’s Market Connection,** and reach +100,000 potential buyers.*

*To learn more, contact:*
GraceJ@PennWell.com • 713-963-6291
Total HVAC system solutions in the field of marine & offshore application.

www.heinlinea.co.kr
hairkorea@hairkorea.co.kr
www.novenco-marine.com
novenco@novencogroup.com

Looking for Job Opportunities?

Visit the Market Connection online for up-to-date job postings.

http://www.ogj.com/market-connection.html
ADVERTISERS INDEX

<table>
<thead>
<tr>
<th>COMPANY NAME</th>
<th>PAGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ariel Corporation</td>
<td>7</td>
</tr>
<tr>
<td><a href="http://www.arielcorp.com/dedicated">www.arielcorp.com/dedicated</a></td>
<td></td>
</tr>
<tr>
<td>Chaparral Energy</td>
<td>14</td>
</tr>
<tr>
<td><a href="http://www.chaparralenergy.com">www.chaparralenergy.com</a></td>
<td></td>
</tr>
<tr>
<td>China Petrochemical Technology Co., LTD</td>
<td>C4</td>
</tr>
<tr>
<td><a href="http://www.sinopectech.com">www.sinopectech.com</a></td>
<td></td>
</tr>
<tr>
<td>DistributionNOW</td>
<td>C2</td>
</tr>
<tr>
<td><a href="http://www.distributionnow.com">www.distributionnow.com</a></td>
<td></td>
</tr>
<tr>
<td>Enventure Global Technology</td>
<td>23</td>
</tr>
<tr>
<td><a href="http://www.EnventureGT.com/ESET">www.EnventureGT.com/ESET</a></td>
<td></td>
</tr>
<tr>
<td>Fluor Corporation</td>
<td>25</td>
</tr>
<tr>
<td><a href="http://www.fluor.com">www.fluor.com</a></td>
<td></td>
</tr>
<tr>
<td>Frac Fuel Solutions</td>
<td>13</td>
</tr>
<tr>
<td><a href="http://www.fracfuelsolutions.com">www.fracfuelsolutions.com</a></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>COMPANY NAME</th>
<th>PAGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>MapSearch</td>
<td>43</td>
</tr>
<tr>
<td><a href="http://www.mapsearch.com">www.mapsearch.com</a></td>
<td></td>
</tr>
<tr>
<td>PennWell Books</td>
<td>4, 19, 42</td>
</tr>
<tr>
<td><a href="http://www.pennwellbooks.com">www.pennwellbooks.com</a></td>
<td></td>
</tr>
<tr>
<td>PNEC Conferences 2019</td>
<td>C3</td>
</tr>
<tr>
<td><a href="http://www.pneccvenues.com">www.pneccvenues.com</a></td>
<td></td>
</tr>
<tr>
<td>REXA Inc</td>
<td>27</td>
</tr>
<tr>
<td><a href="http://www.rexa.com">www.rexa.com</a></td>
<td></td>
</tr>
<tr>
<td>Seepex GmbH</td>
<td>15</td>
</tr>
<tr>
<td><a href="http://www.seepex.com">www.seepex.com</a></td>
<td></td>
</tr>
<tr>
<td>SINOPEC Catalyst Company</td>
<td>5</td>
</tr>
<tr>
<td><a href="http://www.sinocegroup.com">www.sinocegroup.com</a></td>
<td></td>
</tr>
<tr>
<td>Subsea Tieback Forum &amp; Exhibition 2019</td>
<td>2</td>
</tr>
<tr>
<td><a href="http://www.subseatiebackforum.com">www.subseatiebackforum.com</a></td>
<td></td>
</tr>
</tbody>
</table>

This index is provided as a service. The publisher does not assume any liability for errors or omissions.

---

Take industry news into your own hands. Anytime, anywhere.

Now get the power of Oil & Gas Journal — for your mobile devices.

- Current news briefs and articles
- Weekly statistics
- Weekly insight and commentary
- Save your news for offline viewing.

Get the weekly digital Oil and Gas Journal with your Annual Subscription. For subscription inquiries email: OGJ@hrpsgroup.com

PennWell Books
1455 West Loop South, Suite 400, Houston, TX 77027
www.pennwellbooks.com

Oil & Gas Journal | Mar. 4, 2019 | 63
THE EDITOR’S PERSPECTIVE

Study: Bill C-69 no cure for Canadian investment disease
by Bob Tippee, Editor

With Bill C-69, “Ottawa’s proposed cure looks likely to worsen Canada’s present disease,” according to a new study.

The disease: Investment in Canadian natural resources is plummeting.

Citing a Natural Resources Canada data series begun in 2014, the C.D. Howe Institute study says planned investment for major forest, energy, and mining projects fell from a peak of $711.7 billion (Can.) in 2015 to $584.9 billion in 2018.

For energy projects only, the 2018 total was $510 billion, down from a peak of $598 billion in 2016 and about even with the level of 2014. The declines reflect cancellations and slumping additions to planned investments.

For energy, investment additions fell to $35 billion last year from $146 billion in 2015.

Of course, oil and gas investments dropped worldwide in that period. But the Canadian outlay fell more, say study authors Grant Bishop and Grant Sprague, citing data from Statistics Canada and the International Energy Agency.

As a share of global upstream investment, the capital outlay in Canadian oil and gas extraction fell from nearly 9% in 2014 to less than 6% in 2018.

As discussed here 2 weeks ago, Bill C-69 purports to cure a presumed ill federal approvals apparatus. Vague and open-ended, it mainly would give project opponents new ways to stymie work.

Of major concern to project investors, the Howe study says, would be expansion of the range of projects subject to political decision-making. Current law limits decisions by ministers and cabinet officials to projects found, after independent analysis, likely to produce “significant adverse environmental effects.”

Bill C-69 would require public-interest determinations by those officials for projects with any—not just “significant”—adverse effects. Its loose definitions would broaden “subjective discretion.” And it would require consideration of “various new and uncertain factors” in any impact assessment.

“By increasing the role for political decision-making and crowding fuzzy policy questions into project-specific assessments,” the study says, “…Bill C-69 risks amplifying current uncertainty and further undermining investor confidence in Canada.”

(From the subscription area of www.ogi.com, posted Feb. 22, 2019. To comment, join the Commentary channel at www.ogi.com/oilandgascommunity.)

Governors cool to oil, gas

Maine Gov. Janet T. Mills (D) formally withdrew the state from the Outer Continental Shelf Governors Coalition on Feb. 25. The organization’s work promoting the expansion of US offshore oil and gas activity is not compatible with the state’s interests, she told Alabama Gov. Kay Ivey (R), who chairs the coalition.

“My concern instead is protecting coastal Maine from the potentially devastating effects of this industrial activity,” Mills said.

Opposition to offshore oil and gas activity off the Pine Tree State’s coast is bipartisan and overwhelming, she said. Its congressional delegation is unanimously against it, and the state’s Senate and House of Representatives unanimously passed a joint resolution last year declaring that offshore drilling and exploration would endanger commercial fishing jobs and be an economic and ecological disaster, the governor said. “I couldn’t agree more,” she added.

“My opposition to new or expanded offshore oil and gas drilling is in alignment with the positions of the governors of other East and West Coast states. I intend to work with those governors to fight any federal proposal that would open the waters off the Maine coast to this activity,” Mills said.

Such opposition among state governors who are Democrats is not surprising. But there are several across the country who have proposed ambitious renewable and alternative energy initiatives instead. These include chief executives in producing states, including Jared Polis in Colorado and Michelle Lujan Grisham in New Mexico.

Republican governors in producing states can’t be characterized as oil and gas cheerleaders either these days. They simply didn’t mention the industry much (if at all) in their 2019 State of the State addresses and listed other priorities instead.

“We all know that Texas leads the nation in areas like oil and gas. Importantly though, Texas is in the middle of an innovation renaissance that weans our economy off of energy,” Gov. Greg Abbot said on Jan. 31.

Neglecting opportunities

“Since Prudhoe Bay came online, we have become more narrowly focused on oil and government programs as the basis for our economy, while neglecting other opportunities that could create more jobs and wealth for our state,” Alaska Gov. Michael J. Dunleavy said.

The nation’s northernmost state must attract other industries and investments to fully realize its potential, including its global location, vast resources, and “unbridled quality of life”, Dunleavy said.

Their comfort apparently stems from ample, low-cost domestic supplies that allow them to address other priorities. It’s safe to bet that they also appreciate the jobs oil and gas activity provides and the taxes which are generated. This ultimately could matter more than the Maine governor’s opposition to offshore drilling.
23rd International Conference and Exhibition on Emerging Trends in Petroleum Data

Data + Infrastructure + Technology

May 21-22, 2019 >> Westchase Marriott, Houston, TX

www.pnceconferences.com >> #pnce
SINOPEC TECH
FOCUSING ON
UPGRADING AND OPTIMIZATION

- **IMPROVING PRODUCT YIELD AND PRODUCTIVITY**
  To improve yield and conversions of feedstock, increase production capacity by modification of existing units.

- **EXPANDING PRODUCT PORTFOLIO AND IMPROVING QUALITY**
  To improve product quality and produce products with high added value through upgrading and optimizing.

- **REDUCING ENERGY CONSUMPTION**
  To reduce energy consumption and to be more environmentally friendly by upgrading and optimizing.

- **IMPROVING FEED FLEXIBILITY**
  To improve feedstock adaptability and flexibility.

- **IMPROVING UNIT RELIABILITY**
  To improve unit reliability and to achieve long-term and stable operation.

**SINOPEC TECH**
CHINA PETROCHEMICAL TECHNOLOGY CO., LTD.
Tel: +86 10 69166661 / 6678
Fax: +86 10 69166658
E-mail: g-technology@sinopec.com

Learn more at:
[www.sinopectech.com](http://www.sinopectech.com)