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This month we give you 15 facts on emissions controls!

One of four compression trains that Elliott’s Engineered Solutions and Field Service teams overhauled during a turnaround at a petrochemical facility in China. The project included the overhaul of the charge gas, ethylene and propylene trains, and the heat pump compressor, as well as the installation of upgraded cartridge seals in the charge gas compressors and actuators in the steam turbine drivers.
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COMMENT

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VER the last few years, we have witnessed our fair share of political gambles here in the UK. Former Prime Minister David Cameron, started the trend with his decision to support a referendum on Scottish independence. On that occasion, the PM’s gamble paid off. Just. The following year, during a tightly-fought general election, Cameron promised the British public a vote on its membership of the European Union; should his Conservative party be elected into government.

The rest, as they say, is history. After months of campaigning for the UK to remain within the EU, Cameron duly fell on his sword just hours after the results of the referendum were announced, making way for Theresa May to take the reins of the country and, in turn, the impending Brexit negotiations.

In March, the government triggered Article 50, signalling the start of formal procedures for the UK to leave the EU. A few weeks later, the Conservative party decided to roll the dice once again; calling a snap general election. The reason?

To convert the party’s overwhelming lead in the opinion polls into a stronger parliamentary majority that would ultimately strengthen Theresa May’s ability to secure the Brexit deal envisioned by her party.

The gamble did not pay off. The opinion polls narrowed throughout the short election campaign as a rejuvenated Labour party gained momentum under the leadership of Jeremy Corbyn. In the end, the Conservative party lost its overall majority, leaving the UK with a hung parliament and Theresa May’s premiership in peril. As I write this, the UK has just started its official Brexit negotiations with the EU, despite the cloud of uncertainty looming back home.

Following the results of the UK general election, the UK Petroleum Industry Association’s Director General, Chris Hunt, called for “stability and clarity” over the industry’s operating environment “in order to maintain investor confidence and drive all businesses to grow and thrive.” Michael Burns, Oil and Gas Partner at law firm Ashurst, added: “A hung parliament can only lead to the potential for further uncertainty for an industry that has suffered from that theme over the last few years with the fluctuations in oil and gas prices.”

While a succession of political gambles has left the UK in a sticky situation, across the pond, the Trump administration’s recent bet on leaving the Paris climate accord threatens to have even wider implications. While experts suggest that the withdrawal will not necessarily impact US regulation of carbon emissions, it is undoubtedly a controversial move from the US President. Frank Melum from the Point Carbon team at Thomson Reuters warns: “The US could very well be the one that will lose the most from this withdrawal. Before and after the announcement [...] stakeholders have come out reiterating their support for the Paris Agreement. This includes other large emitters like China, Russia and the EU. But also large companies, including the fossil fuel industry. The strong support of the agreement highlights the investment opportunity the Paris Agreement provides.”

Emissions control is a key topic throughout this issue of Hydrocarbon Engineering, with feature articles looking at emissions of SOx (BASF Corp., p. 30), NOx (ClearSign Combustion, p. 36), and methane (Opgal, p. 43), as well as emissions from flaring (NEL, p. 45).

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**USA | CB&I awarded EPC contract**

CB&I has been awarded a contract valued at approximately US$40 million by E. I. du Pont de Nemours and Co. to provide engineering, procurement and construction (EPC) for an ethane cracking furnace expansion project at DuPont’s Sabine River Works ethylene plant in Orange, Texas.

The new cracking furnace will have an ethylene capacity of 200 million lbs/y. The facility will utilise CB&I’s SRT® (Short Residence Time) pyrolysis heater technology. CB&I was previously awarded a contract for the ethylene technology license, engineering and supply of the new furnace, which was fabricated at CB&I’s facility in Thailand.

Luke V. Scorsone, Executive Vice President of CB&I’s Fabrication Services operating group, said: “CB&I’s ability to deliver single source supply of every phase of this project – from concept to mechanical completion – provides DuPont with a cost effective, low risk solution as they expand their ethylene copolymers capacity to meet market demand.”

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**USA | Braskem approves new construction**

Braskem’s Board of Directors has approved the final investment decision (FID) to proceed with the largest polypropylene production line in the Americas. Braskem will commit up to US$675 million in investment capital towards the design and construction of the new facility, which will be named Delta and will be located next to Braskem’s existing production facilities in La Porte, Texas.

With the engineering design phase well underway, the new production line will have a manufacturing capacity of 450 kilotons (kt). The new line will represent additional production capacity of homopolymers, random copolymers, impact copolymers, and reactor thermoplastic olefins (TPOs), building upon Braskem’s current polypropylene production plant in La Porte, which has a production capacity of 354 kt/y and will continue operations.

Construction is expected to begin mid-summer, with the final phase of main construction targeted for 1Q20.

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**China | Sinopec and Linde sign JV**

Sinopec and The Linde Group have announced that they have established a €145 million joint venture (JV) to supply vital industrial gases to local customers from key industries such as petrochemical, steel and electronics, within the Ningbo Chemical Industrial Zone in China’s Zhejiang province.

Sinopec Zhenhai Refining & Chemical Co. (ZRCC) and Linde will each hold a 50% stake in the newly formed Ningbo Linde-ZRCC Gases Co. Ltd (Linde-ZRCC), the sixth consecutive JV between the companies. The agreement will see Linde-ZRCC acquire two existing air separation units (ASUs) from ZRCC and construct a third for a combined 150 000 m³/hr of oxygen capacity. The new ASU, expected to be on stream in 2018, will incorporate Linde’s intelligent solutions for remote operation, diagnostics and analytics, as well as a modular design to increase efficiency, reduce energy requirements and enhance flexibility of production.

These three additional ASUs will double Linde production capacity of air gases in the Ningbo cluster and will be connected to Linde’s pipeline supply network across Ningbo.

Linde’s Engineering Division will design and construct the new ASU.

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**Nigeria | Air Liquide to supply hydrogen production technology**

Air Liquide Engineering & Construction has been selected to supply two hydrogen production steam methane reformer (SMR) units to Dangote Group, the largest manufacturing conglomerate in West Africa.

The SMR units will be fundamental to a new hydrogen generation complex producing 200 000 Nm³/hr of hydrogen and high quality steam for a new refinery located in the Lekki free trade zone in Nigeria.

The new refinery is part of the large industrial complex currently under development in Africa and will produce Euro V compliant low sulfur fuels among other products.

Hydrogen is used today in many industrial sectors, especially in the oil refining process to produce sulfur-free fuels. This project will considerably improve refining infrastructure in Nigeria and consequently enable the country to manufacture refined products locally, reducing the reliance on the imported goods.

This equipment supply agreement follows an agreement that Air Liquide signed with Dangote in 2015.

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This equipment supply agreement follows an agreement that Air Liquide signed with Dangote in 2015.
South Africa | Petredec and Bidvest to develop LPG storage facility

Petredec Ltd and Bidvest Tank Terminals have entered into an agreement for the development of a new facility for the import and storage of LPG. The facility will be a 22 600 t storage facility at Bidvest’s existing site in Richards Bay. The completed facility will be the region’s largest pressurised LPG import terminal, featuring four mounded tanks, each capable of storing more than 5500 t of gas, guaranteeing year-round availability.

Despite growing demand in domestic and regional markets, LPG imports have historically been hampered by high costs resulting from South Africa’s small coastal terminals and distance from major supply hubs. With the breaking-of-ground planned for September 2017 and an estimated 27 month construction schedule, South African consumers can expect to be using LPG imported via the new Richards Bay terminal from 4Q19.

Petredec believes further investment in large, dedicated infrastructure is the only way to increase the fuel’s popularity and bring lower prices to consumers. The company’s CEO, Giles Fearn, said: “Delivering LPG to South Africa on a previously unprecedented scale brings with it financial savings to our customers that will ultimately benefit consumers with lower gas prices.”

USA | Cheniere and KOGAS celebrate commencement of 20 year LNG contract

Cheniere Energy Inc. and Korea Gas Corp. (KOGAS) have hailed the commencement of their 20 year sales and purchase agreement (SPA) to supply US-sourced LNG to KOGAS from the Sabine Pass liquefaction facility in Louisiana. The SPA, which was originally signed in January of 2012, officially commenced on 1 June 2017, with the first cargo loading the following day. Under the terms of the SPA, Cheniere will sell and make available for delivery to KOGAS approximately 3.5 million tpy of LNG, which represents more than 10% of South Korea’s total annual demand.

USA | LNG Ltd has extended the validity period of its current binding engineering, procurement and construction (EPC) contract with KSJV (a KBR, SKE&C joint venture) for its wholly owned subsidiary, Magnolia LNG. The binding lump sum turnkey EPC contract is now valid through December 2017.

USA | Pinnacle Midstream has announced it has begun engineering and construction on the Sierra Grande Gas Processing Plant, a 60 million ft³/d cryogenic gas plant located in Texas. The plant is expected to commence operations in 4Q17, offering full cryogenic recoveries with ethane rejection capability. Upon completion, Pinnacle foresees a site expansion to increase its capacity to meet demand.

EUROPE

INEOS has announced that it is looking at sites across Europe including Antwerp in Belgium for its new world scale 750 000 t propane dehydrogenation (PDH) plant, while also planning to increase the capacity of its crackers at Grangemouth in Scotland and Rafnes in Norway to over 1 million t each. With these cracker expansions, INEOS will have added up to 900 000 t of ethylene to its overall production capacity.

USA

AMETEK Inc. has completed its acquisition of MOCON Inc. for US$30/share. The completion of the transaction follows approval from MOCON shareholders and the receipt of all regulatory approvals. MOCON joins AMETEK as part of its Process & Analytical Instruments Division within AMETEK’s Electronic Instruments Group.

China | Chevron Lummus Global wins four new technology licenses

Chevron Lummus Global (CLG) has been awarded the license, engineering design and catalyst supply for a grassroots integrated refining and petrochemical project in China. The new complex will use CLG’s ISOCRACKING®, ISOTREATING® and delayed coking technologies feeding kerosene, diesel, vacuum gasoil, and residuum feedstocks to produce finished products. The high quality, heavy naphtha produced by the complex will be used in a downstream plant employing BP paraxylene OPEX advantaged crystallisation technology, which is exclusively licensed by CB&I. CLG is a joint venture between Chevron U.S.A. Inc. and CB&I.
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LICENSED TECHNOLOGIES AND CATALYSTS
FULL-SCOPE EPFC SERVICES
PROJECT MANAGEMENT AND CONSULTING
AFTERMARKET SERVICES
USA | Baker Hughes and GE reach agreement with DOJ

Baker Hughes Inc. (BHI) and General Electric Co. (GE) have reached an agreement with the US Department of Justice (DOJ) that would allow the parties to complete their proposed transaction under US law.

Pursuant to a proposed consent decree filed in the District Court in Washington, D.C., GE agreed that it will divest its GE Water & Process Technologies business after closing the BHI transaction. GE announced in March that it had agreed to sell GE Water to Suez for US$3.4 billion. No other remedies are required by the proposed consent decree.

The companies also recently received clearance from the European Commission to complete the transaction without conditions, and BHI scheduled its shareholders vote for 30 June.

USA | Jacobs Engineering Group Inc.

Jacobs Engineering Group Inc. has signed an engineering services agreement with Keyera Partnership. The agreement enables Jacobs to provide engineering services for the Wapiti Liquids Handling and Gas Processing Facility, a key part of Keyera’s Wapiti Development project for constructing a natural gas gathering and processing complex in the Wapiti area south of Grand Prairie, Alberta.

USA | Honeywell

Honeywell has announced that Flint Hills Resources will use the Honeywell Connected Plant Process Reliability Advisor to provide ongoing monitoring of the refinery’s CCR Platforming™ unit along with early detection and mitigation of performance issues before they become costly. The CCR Platforming unit will produce a range of transportation fuels.

KAZAKHSTAN | CB&I

CB&I has been awarded a contract by TOO Hill Resources for the license and engineering design of a grassroots lubricant base oil plant in Shymkent. The plant will use Chevron Lummus Global’s (CLG) proprietary technologies for the production of high quality base oils and clean fuels.

USA | MMEX Resources Corp.

Chevron Phillips Chemical Co. LP has announced that the two polyethylene (PE) units of its US$6 billion petrochemical investment on the US Gulf Coast reached the milestone of mechanical completion. The PE units are now undergoing a series of rigorous commissioning activities, system checks and final certifications to ensure a safe and reliable start-up, and consistent, high-quality production. Once operational, each PE unit will produce at least 500 000 tpy of product.

USA | Grace licenses technology

W. R. Grace & Co. has contracted to license its UNIPOL® polypropylene (PP) process technology to Hengli Petrochemical (Dalian) Refinery Co. Ltd., a subsidiary of Hengli Group. The installation will be made at the company’s facility in Dalian, Liaoning province, and is expected to begin operations in 2019 using Grace’s SHAC® Ziegler Natta PP catalysts.

Hengli Petrochemical’s PP unit is part of its new refinery complex designed to process 20 million tpy of crude oil. The facility will produce homopolymer, random co-polymer, and impact co-polymer thermoplastic resins in dual reactor lines. The project is one of 22 UNIPOL PP process technology reactor line licenses in China.
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  - Provides more flexibility at stable operating conditions without loss of tray efficiency
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- Non-moving valve legs do not cause erosion or enhanced corrosion
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**EPRA | New president appointed**

Dr Béla Kelemen has been appointed as President of the European Petroleum Refiners Association for the next two year term. Dr Kelemen currently holds the position of Vice President of the Center of Business Excellence at MOL Group and is in charge of process and performance improvement across the entire asset portfolio of the company.

The EPRA represents the interests of nearly all EU refiners and actively contributes to the development of EU policies. FuelsEurope (formerly EUROPIA), a division of the EPRA, represents the interest of 40 companies operating refineries in the EU, including Shell, ExxonMobil, Total and BP. Members account for almost 100% of EU petroleum refining capacity and 75% of EU fuel sales. FuelsEurope aims to promote economically and environmentally sustainable refining, supply and use of petroleum products in the EU, by providing expert advice to EU institutions, governments and the wider community.

**EIA | US refineries running at record level**

Gr oss inputs to US petroleum refineries, also referred to as refinery runs, averaged a record high of 177 million bpd for the week ending 26 May, before dropping slightly to 175 million bpd for the week ending 2 June and 17.6 million bpd for the week ending 9 June. Product supplied to the US market, as well as inventories and exports, are also at relatively high levels.

Weekly US refinery runs have exceeded 17 million bpd only 24 times since the US Energy Information Administration (EIA) began publishing the data series in 1990, and all of those instances have occurred since July 2015. Despite record-high inputs, refinery utilisation did not reach a new record, because refinery capacity has increased in recent years. Refinery utilisation reached 95% for the week ending 26 May, slightly lower than the levels reached in mid-July through mid-August 2015.

US refinery capacity has increased by 659 000 bpd since mid-August 2015. Refinery capacity represents the amount of input that a crude oil distillation unit can process in a 24 hour period under usual operating conditions (averaged over the entire year), accounting for both planned and unplanned maintenance.

**DOE | Investment in Advanced Energy Systems**

The US Department of Energy (DOE) has announced the availability of approximately US$28 million for cost-shared research and development. Three new funding opportunities will aid technologies related to advanced combustion systems, advanced turbines, and gasification as part of the Office of Fossil Energy’s (FE) Advanced Energy Systems programme.

US$12.8 million will be invested in small scale modularisation of gasification technology components for radically engineering modular systems, US$10 million will go towards existing plant improvements and transformational technologies for advanced combustion systems, while US$5.15 million will be spent on the university turbine systems research (UTSR) programme.
Product Bulletin
NeXRing™: covering all your random packing requirements

Why it’s better
NeXRing provides an extremely large and uniform open area regardless of ring orientation, allowing high surface area contact with the liquid and vapor streams. This high performance design allows successful replacement of the more traditional ring types for process upgrades and increases design and operating flexibility.

Concrete benefits
NeXRing™ makes it possible to reduce the capital cost for newly constructed plants while column sizes can be further optimized. There are significant improvements when compared with 2nd or 3rd generation rings:
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• Up to 10% increased capacity compared to I-Ring

More capacity
For capacity limited designs, Sulzer can offer a NeXRing alternative which will provide higher capacity, and lower pressure drop with no penalty in the efficiency.

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The operation characteristic of NeXRing is the same as traditional rings. Applications for NeXRing include:
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• Natural Gas Liquids treatment (LNG)
• Demethanizer/Deethanizer
• Butadiene purification
• Degassing
• Liquid/Liquid Extraction

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• Butadiene purification
• Degassing
• Liquid/Liquid Extraction

Summary
NeXRing is a patented high performance ring which provides extremely large and uniform open area regardless of ring orientation to vapor flow with the following benefits:
• Higher capacity
• Lesser pressure drop
• Lower investment cost
NeXRing is successfully replacing many types of older generation packing.

Successful design of columns with high performance random packing requires the right internals, but the payout can be significant. Sulzer’s Application Team can help evaluate all possible options and provide an optimal solution for your column.

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The Sulzer Applications Group
Sulzer has over 150 years of in-house operating and design experience in process applications. We understand your process and your economic drivers. Sulzer has the know-how and the technology to design internals with reliable, high performance.

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Gordon Cope, Contributing Editor, examines the current state of the oil and gas industry across Latin America, and what the future has to hold.

SOUTH OF THE RIO GRANDE
Latin America is rich in crude. Countries in the region, including Mexico, Venezuela, Brazil, Argentina and Colombia, produce over 9 million bpd, almost 10% of global production. It also has a bounty of natural gas, most of it produced in conjunction with crude. Yet the region imports much of its fuels and petrochemical products. While some countries are moving ahead with adding value to their hydrocarbon production, others are languishing. What makes some Latin American countries big winners – and others losers – depends on a wide range of factors.

**Petrochemicals**

Latin America has several significant petrochemical facilities. Pemex produces 815 000 tpy of polyethylene in high density (HD), low density (LD) and linear low density (LLD) in Mexico. Braskem has 3.2 million tpy of HD, LD, LLD capacity in Brazil. Dow produces 581 000 tpy of HD, LD and LLD in Argentina and Pequiven makes 430 000 tpy of HD, LD and LLD in Venezuela. In addition, Braskem-Idesa has recently launched a new petrochemical complex in the Gulf of Mexico port of Coatzacoalcos. The 1 million tpy facility produces HD and LD.

Growth in gross domestic product (GDP) in most of Latin America has been steady over the last decade, with standards of living rising at a significant pace. According to Platts, a consultancy, South and Central America already consume 1.5 million tpy more petrochemicals than the region produces, making a case for new facilities in the region. Latin America also has an abundance of natural gas feedstock; the Energy Information Administration (EIA) estimates that Argentina alone has 802 trillion ft³ of unconventional gas, and Mexico is building a pipeline infrastructure in order to import billions of cubic feet of cheap shale gas daily from Texas.
Several companies have tentative plans to build new capacity in Brazil, Argentina and Venezuela. However, except for the Braskem-Idesa plant in Mexico, no new plants are expected to come onstream in the near future.

The reasons for lack of investment in the region are complex, but several main factors stand out. International manufacturers began repatriating facilities to the US several years ago when the shale gas revolution in North America caused regional feedstock prices to plunge. Although the pace of greenfield investment has now begun to slow, capacity in the US is now sufficiently high enough to deliver low cost petrochemicals to not only North American consumers, but to markets in Latin America as well.

North America is also more politically stable when compared to regions in Latin America. At a recent Latin American Petrochemical and Chemical Association (APLA) conference, representatives of global petrochemical companies noted that Latin America has the resources to replicate the petrochemical growth seen in the US, but key decision makers in the region must work to make sure they are creating environments where the industry can thrive.

**Refineries**

There are eight major refineries in Argentina, with a total of over 600 000 bpd nameplate capacity. They include Yacimientos Petrolíferos Fiscales’ (YPF’s) La Plata refinery (189 000 bpd), Royal Dutch Shell’s Buenos Aires refinery (110 000 bpd) and the Esso Campana refinery (84 000 bpd).

Two decades ago, Argentina produced over 900 000 bpd and 4.5 billion ft³/d of gas. Under the Kirchner regimes, however, the oil and gas sector was partly re-nationalised and generally mismanaged, to the point where production fell to current levels of 523 000 bpd, and gas to 3.5 billion ft³/d. According to the CIA World Factbook, the country imports more than 600 000 bpd of fuel products, around 600 000 bpd must be imported.

Petrobras has been plagued by scandal and mismanagement over the last several years, however. In 2007, the police arrested 13 people for corruption relating to an organised scheme to take bribes in exchange for public partnership tenders from Petrobras. Since then, scores of people, including two former Petrobras directors, have been formally accused of offering and accepting approximately US$800 million in bribes and other inducements by inflating Petrobras contracts and funneling part of the money back, including to the ruling Workers’ Party.

The scandal also generated significant political fallout. Public sentiment turned against President Dilma Rousseff when allegations surfaced that she had been part of the board of directors when the graft was occurring. Although no direct evidence of her involvement emerged, calls for her impeachment led to the Senate charging her with breaking budget laws and voting to remove her from office. She was replaced by Vice President Michel Temer. In turn, Temer brought Pedro Parente, the former chief of staff to President Henrique Cardoso, out of retirement in order to lead Petrobras.

Since then, Petrobras has been overhauling its governance and management. It is also moving aggressively to lower debt and costs. In late 2016, it sold its stake in ethanol producer Guarani SA and two petrochemical facilities in northeastern Brazil for a total of US$87 million, capping off over US$13 billion in divestitures. The company has plans to sell assets and develop partnerships worth US$21 billion over the next two years.

**Colombia**

With over 1 million bpd production, Colombia has five refineries capable of handling a total of 340 000 bpd, the majority of which are owned and operated by Ecopetrol. They include the Barrancabermeja-Santander refinery (252 000 bpd) and Reficar’s Cartagena refinery (80 000 bpd). Plans are underway to expand Barrancabermeja’s capacity to 300 000 bpd, and Cartagena’s to 165 000 bpd. Because Colombia consumes less than 300 000 bpd of fuel products, it is a net exporter of gasoline and diesel, as well as crude.
**EXXONMOBIL COMPLETES INSTALLATION OF PRE-ASSEMBLED RACKS AT ROTTERDAM REFINERY**

Following ExxonMobil's latest update on the successful heavy lift of the reactors and vacuum fractionation tower, the pre-assembled racks (PARs), for the new hydrocracker, have been installed at the Rotterdam refinery. Manufactured in Spain, the PARs were shipped by water to the Rotterdam refinery during mid-May 2017.

**TOPSOE TECHNOLOGY SELECTED FOR INDIAN REFINERY**

HPCL-Mittal Energy Ltd (HMEL), an Indian refinery company, has selected Topsoe’s diesel hydrotreater unit and hydrogen generation facilities to meet its upgrading requirements. When completed in 4Q19, the revamped refinery in Bathinda, Punjab will meet the BS VI (equivalent to Euro VI) fuel specifications.

**SALINA CRUZ REFINERY TO RESUME OPERATIONS**

Pemex Transformacion Industrial has announced that it is currently carrying out several actions to restart operations at the Antonio Dovalí Jaime de Salina Cruz refinery, affected by floods and fire caused by tropical storm Calvin. The programme contemplates actions in three ways: resumption of operations; cleaning and rehabilitation of the affected site; and general maintenance, taking advantage of the stoppage process.

**A CLEAR VIEW**

Ankur Pariyani, Nancy Zarrow, Ulku Oktem and Deborah Grubbe, Near-Miss Management LLC, USA, discuss methods to reduce cognitive bias in industrial operations.

For further information go to: www.hydrocarbonengineering.com
The country’s oil and gas sector has made a remarkable recovery after years of civil war with FARC guerrillas had cut the country’s 990 000 bpd output in half. In 2003, however, under the Uribe government, a series of fiscal and regulatory changes opened up the sector to privatization. Since then, international investments exceeding US$5 billion annually have resulted in a renaissance. Although former state monopoly Ecopetrol has been a significant contributor to the resurgence, international companies such as Geopark, Pacific Rubiales and Gran Tierra have also whole-heartedly entered the jurisdiction.

Peace has also largely returned to Colombia’s hinterland. In a historic step in 2016, the government of President Juan Manuel Santos reached a disarmament agreement with FARC, the main rebel group in Colombia. The half-century guerilla war, which left 250 000 dead and millions displaced, officially ended after successful negotiations in Cuba.

Other resistance groups remain a problem for the nation’s oil and gas sector, however. The Canon-Limon pipeline, running from the interior to the Caribbean port of Covenas, has a nameplate capacity of 210 000 bpd. Ecopetrol estimates that rebel attacks on the line by the ELN Army have resulted in almost 900 000 bbls of lost production in the first three months of 2017 alone. Until all rebel groups negotiate ceasefires, bombings, kidnappings and disruptions will remain a risk for the foreseeable future.

**Venezuela**

Petróleos de Venezuela S.A (PDVSA) operates seven refineries in Venezuela with a total of 2.5 million bpd nameplate capacity, including the Paraguana refinery complex (956 000 bpd) and the Amuay-Cardon-Bajo Grande complex (950 000 bpd). Underinvestment (and a major fire at Paraguana) means that the country produces slightly less than 1 million bpd of refined products.

Since the ascension of Hugo Chavez and his Socialist Party, crude production has plunged from 3.5 million bpd to approximately 2.1 million bpd in 2016. According to Thomson Reuters, PDVSA’s crude exports fell from 1.82 million bpd in 1Q16 to 1.59 million bpd in 4Q16.\(^\text{5}\)

The drop in exports is only part of PDVSA’s problems. In October 2016, a congressional report found that PDVSA’s former president Rafael Ramirez was responsible for mischief that cost the state oil monopoly US$11 billion. The charges involved pricing of drilling rigs and money laundering in Andorra. The Supreme Court, however, approved an injunction by Ramirez against the probe.

Because much of the alleged ill-gotten gains passed through the US financial system, several federal agencies, including Homeland Security and the FBI, are investigating activities that date back to 2005. Roberto Rincon-Fernandez, a Venezuelan national living in Houston, Texas, US, was successfully prosecuted for taking part in a US$1 billion bribery scheme. Further prosecutions are expected.

Unlike Brazil, Venezuela’s federal government (and its regulatory and judicial systems) show little inclination to clean up the mess. As a result, Venezuela is considered a high risk climate for international investment in either refining or petrochemicals.

**Mexico**

Mexico has six major refineries with a total nameplate capacity of 1.25 million bpd, all operated by Pemex. They include the Tula refinery (300 000 bpd), the Salina Cruz refinery (227 000 bpd) and the Salamanca refinery (152 000 bpd). Years of underinvestment have resulted in capacity levels falling well behind consumption; Mexico now imports over 700 000 bpd of gasoline and diesel, primarily from the US.

The majority of fuel arrives in Mexico via ship; currently, 20 – 30 tankers dock in Gulf ports each month, putting a strain on existing infrastructure. In order to alleviate import bottlenecks, TransCanada is partnering with Mexico’s Sierra Oil & Gas to expand fuel infrastructure. It recently announced a plan to spend US$800 million to construct a marine terminal near Tuxpan, Veracruz, and a 265 km, 100 000 bpd refined products pipeline that would connect to a central distribution hub north of Mexico City.

Mexico’s refining sector may be in for better times, as well. When President Enrique Peña Nieto cancelled the state monopoly in oil and gas, few could have predicted the rapid pace at which the industry has evolved. Once the sole domain for state oil company Pemex, the landscape has been transformed as open bidding on leases, JVs and divestments have attracted international investment in the upstream, midstream and downstream sectors.

Pemex is looking to build and operate a new coking plant at its Tula refinery. The US$2.1 billion project is being put out to tender, and Mitsui, Eni, Royal Dutch Shell and Chevron have all expressed interest. The Tula refinery is currently operating at 60% capacity, producing less than 200 000 bpd of refined products. The coking facility will help boost the production of gasoline from the heavy crude feedstock.

Even if Mexico does not expand its refinery base, US companies have its future needs well in hand. Raven Petroleum, based in Texas, is planning to build a 50 000 bpd refinery north of the Mexican border in Duval County. The gasoline and low-sulfur diesel facility is expected to come online in 2019. MMEX Resources also has plans for a similar-sized facility east of Laredo, Texas. Both plants will be designed to process light crude from the prolific Eagle Ford shale. “Demand for fuels in Mexico is growing at over 3% per year,” said Christopher Moore, MMEX Managing Director. “A constrained market won’t be resolved internally, so it will have to import as they are doing now.”\(^\text{6}\)

**Conclusion**

While the expansion of petrochemical and refining capacity is warranted in many jurisdictions in
Latin America, including Mexico, Colombia and Brazil, the current low commodity price environment has constrained many country champions (such as Pemex) from investing in downstream assets. Others (such as Petrobras) are busy re-balancing their budgets and reducing debt through the sale of non-core properties. The private sector (Braskem-Ideasa) has shown some initiative, but major petrochemical producers have concentrated their expansion efforts in the US, where low feedstock prices and favourable regulatory and fiscal regimes attract investment.

Latin America possesses under-served fuel and petrochemical markets; in order to attract major investment, it must take several steps. Country champions are key to inviting international investment as they offer potential JV partners existing infrastructure and access to markets. But scandals associated with executive misdeeds need to be addressed in the courts and internal governance re-organisation in order to restore confidence.

Regulatory and fiscal environments also need to be upgraded to promote transparency and independent oversight. Government monopolies should be eliminated. Internal strife must be addressed at the federal level (such as in Colombia), but also in the courts: in Mexico, Native American rights enshrined in the constitution are often given short-shrift, resulting in violent protests that have impeded the construction and operation of assets such as pipelines.

While some countries have taken admirable steps to reform, too many others remain stuck in the mire. For the foreseeable future, Latin America’s growth in fuel and plastics demand is likely to be largely met by increased imports.

References
Rixt Dijkstra, Fluor Corp., the Netherlands, highlights the importance of conducting feasibility studies during the planning stages of petrochemical projects.
A feasibility study therefore usually starts with a product screening phase, in which a ‘long list’ of potential products or groups of products are evaluated and ranked based on market attractiveness, market accessibility and potential profitability. The objective is to create a shortlist of the most attractive products, which are then subject to more detailed analysis.

Based on the results of the screening phase, the long list products are ranked on an agreed set of selection criteria, such as pricing, market volume, growth prospects or strategic considerations. Product ranking can also be influenced by qualitative factors. Examples of these ‘soft’ factors include: experience with the product type, confidence in the market and/or technology, or preferences of potential partners. After ranking all products in the long list, an agreed number of products are shortlisted for further development based on, for example, the products with the best strategic fit, demand forecast, pricing forecasts, and consideration of feedstock, products and intermediates. By reducing the product long list to a shortlist, the amount of petrochemical complex configurations to be investigated in detail is decreased, thereby saving time and costs during the feasibility study.

A more detailed market analysis can be performed for the shortlisted products. The market survey is usually performed in conjunction with a specialised marketing consultant, which may include a cost of production analysis and an assessment of costs for logistics and transportation to the target markets or regions. Geographical aspects are important when determining the financial feasibility of a new petrochemical complex. If the new complex is to be located in a remote region, a feedstock cost advantage can be offset by high transportation costs. Some locations may lack sufficient infrastructure for the import of feedstock or export of certain products. These (and other) parameters determine the optimum product output for the new complex. The market survey determines which markets are best targeted by the new facility and, ultimately, results in a ‘sales plan’. This sales plan then sets the constraints for the optimum products and their volumes for the new complex.

Although only a small fraction of total project expenditure is spent at the feasibility phase, most of the key decisions that determine the profitability and successful execution of a project are undertaken during this phase. Therefore, a properly executed feasibility study, in which a solid basis is set for subsequent project phases, is paramount to the success of a project. Sometimes this type of study is also used to benchmark the involved CAPEX, the financial model and the technical concept against previously performed studies. This article explains the feasibility study methodology and some of the lessons learned while executing them.

A feasibility study is generally built-up of the following activities (see Figure 1):
- Kick-off meeting.
- Product screening.
- Market survey.
- Configurations development.
- Licensor input and in-house data gathering.
- Support activities.
- CAPEX estimate.
- Financial model development.
- Configuration selection.

Kick-off meeting
A feasibility study starts with a kick-off meeting, where all parties involved gather to discuss the project scope. During this meeting, items such as project execution, project schedule, study scope and roles and responsibilities are defined. Also, more practical project execution items, such as project language and communication procedures are agreed upon. The kick-off meeting must be well prepared, perhaps more than any other meeting, to set the basis for a successful feasibility study.

Product screening and market survey
The first step in developing a new petrochemical complex is determining its product slate and product output volumes. A
Configurations development and licensor involvement

Configurations development starts by defining the feedstock type and availability. Based on the defined feedstock, the product slate and the product volume scenarios resulting from the market survey, the overall complex configurations are developed. Similar to the linear programming (LP) modelling used for refineries, different petrochemical complexes are modelled considering the following:

- Developing the sequence of processing steps, including material and energy balances.
- Licensor experience and market share.
- Proven unit capacity ranges.
- Technology analysis, including the determination of the differences with competing technologies.
- Non-licensor scope such as storage, utilities, buildings, infrastructure, and their integration with available facilities and infrastructure.
- Plot plans.

During the configurations development, both in-house data and data from reference projects are used and supplemented with technology licensors’ input if needed. The involvement of a technology licensor usually requires a non-disclosure agreement (NDA) between the client and/or contractor and the licensor. The NDA signing process can be quite time consuming and is therefore usually started directly after, or even before, the kick-off meeting. Fluor, being a technology neutral company, has often started directly after, or even before, the kick-off meeting. Fluor, being a technology neutral company, has contact with a number of technology licensors, and often a secrecy agreement is already in place, hastening the contact with a number of technology licensors, and often a secrecy agreement is already in place, hastening the process.

When all applicable NDAs are signed, licensors are approached with a request to provide technology-specific data, such as:

- Overall block flow diagrams.
- Mass and energy balances.
- Utility and chemicals consumption.
- Plot plan requirements.
- Technology references.
- Staffing requirements.

The information provided by technology licensors is benchmarked against Fluor’s in-house ‘as-executed’ project data and corrections are applied where needed to make the data project-specific. Examples include corrections for ambient conditions and differences in design standards and specifications. In this phase of the project (front-end loading [FEL 1] phase), obtained licensor information is used as an input to the CAPEX estimate and financial model. Licensor evaluation is performed during a later stage of the project and is considered outside the scope of this article.

An indicative overall plot plan is developed as input to the CAPEX estimate and as a basis for the subsequent pre-front-end engineering and design (pre-FEED) phase. This is usually based on the combined information from licensors and in-house data. Utility systems (e.g. steam/condensate, cooling water, power, etc.) and off site requirements, such as feedstock, intermediate and product storage and packaging, are defined to the level of detail needed for the cost estimate and the model, and will serve as a basis for the pre-FEED phase.

Feasibility study support activities

Several support activities can be performed during the feasibility study as input to the final complex configuration selection, such as site selection, logistics, infrastructure and off-site development.

Fluor has an in-house global location strategy group that specialises in determining the optimum site location for a plant, considering factors such as the location’s technical fit for the project, environmental permitting, land purchase and labour characteristics. This specialised group is involved during the feasibility study when the site location is yet to be determined, or if a client needs to decide between several options.

Logistics studies can be performed for feedstock and product logistics, but also for large size equipment or modules during construction. A logistic study for equipment transport during construction can highlight transportation challenges in an early stage of the project. Examples of transportation limits are rivers that run dry or are frozen during parts of the year, or bridges and roads that impose limits on the weight or size of the equipment transport. Sometimes the design is changed to accommodate transport restrictions. One example is designing parts of the facility with two parallel trains of equipment, which would be too large to transport to a specific location using a single train design. These factors can greatly impact the planning of the project or the design and, therefore, should be identified during an early stage of the project.

One important note is that off-plot scope can have a significant impact on the final business case, e.g. when new jetties, railroads, motorways, pipelines or buildings are required.

CAPEX estimate

A rough order of magnitude (ROM) capital cost estimate is prepared for all complex configurations. This kind of estimate is defined by the Advancement of Cost Engineering International (AACE) as a Class V estimate (ref. IR-97). The results from the technical configuration development and

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Figure 1. Feasibility study workflow.
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feasibility study support activities from the input to the CAPEX estimate. This includes production capacity, technologies, utility balances, required storage facilities, additional or corrective equipment data, indicative overall plot plan, and approximate project location and timing.

For a Class V estimate, Fluor applies a plant capacity-factored estimate methodology, using its in-house database of ‘as-built’ cost data from executed projects, normalised for time, location, and plant capacity.

If no reference data for a similar scope is available, an alternative cost estimating approach is used to reach a similar accuracy level. Cost values will be applied against a high level scope of facilities, taking the appropriate level of detail into account to reach the required cost estimate accuracy level. Input is based on preliminary engineering data, e.g. preliminary sized equipment lists and process flow diagrams (PFDs) received from the licensor. A similar approach is used for the high level scope of services. In principle, this Class V estimate is based on in-house available market pricing.

Financial model development
The financial model requires the following main input (see Figure 2):
- CAPEX estimate.
- Feedstock prices – by the client or market consultant.
- Product prices – result of a market survey performed by a market consultant.
- Process configurations, utility balances.
- Other assumptions, such as financial, labour and utilities cost – by the client.

The financial modelling can be performed by just Fluor using its proprietary model, with the company and the client using a jointly developed model, or just the client. The financial model calculates the financial indicators for the different complex configurations considered, such as net present value (NPV), internal rate of return (IRR) and the payback period.

Financial indicators are subject to analysis. Fluor performs sensitivity analysis and Monte Carlo simulations. The former reveals variables that have a significant impact on financial performance of configurations studied, e.g. CAPEX, feedstock and product prices. With Monte Carlo, the probability of experiencing a negative financial performance from economically viable configurations, or vice versa, is calculated.

Configuration selection
At the end of the feasibility study, one or more optimum configurations can be recommended based on financial performance indicators such as NPV, IRR and other agreed ranking criteria. All items are considered for the configuration selection, ranking both technical and financial parameters for the different complex configurations. This results in the optimal configuration for a particular client and location. This final complex configuration can then be used as a basis for further development during pre-FEED and FEED phases.

Figure 3 illustrates the project expenditure vs the project lifecycle. It depicts the early stages of the project, where overall influence is high and project expenditure is low. The further a project is developed, the harder it becomes to significantly impact the final project costs. It is therefore essential that all key decisions impacting the project cost are taken during the early stages.

Conclusion
Considering the relatively small investment for the feasibility study and the potentially large expenditure savings during the rest of the project, performing a solid feasibility study during the planning stage of a project can therefore be considered as a viable investment.

Notes
This article is based on the following presentations:

Special thanks to Aleksandra Mikhailova, Eugene Schipper, Kurt Wiederkehr, Martijn Koster and Marcel Verschuur.
Over the past several years, there has been increased interest in combining refinery and petrochemical projects in order to maximise production of the highest value products while meeting transportation fuel needs. To accomplish these (often competing) objectives, the hydroprocessing approaches utilised in the refinery are critical. Both the processes and catalysts selected have a significant impact on petrochemical feedstock production. Recently, Chevron Lummus Global (CLG) has been assisting several clients with identifying ways to increase project values based on the portfolio of residue hydrotreating, residue hydrocracking, and vacuum gas oil (VGO)/distillate hydrocracking technologies. This article shares some of the new approaches available and compares their benefits with the traditional paths for producing petrochemical feedstocks.

A refinery’s role in petrochemical production

The conventional roles of hydroprocessing in petrochemical production have been to pretreat fluid catalytic cracking (FCC) – or residual FCC (RFCC) – feed to increase propylene and naphtha yields, especially heavy naphtha as it is an important reformer feedstock and a source for C8 – C10 aromatics. Other refinery streams suitable for petrochemical production include light naphtha and LPG steam cracker feeds.
The manufacturing of petrochemical feedstocks frequently competes with the manufacturing of transportation fuels. This is because of the following:

- Maximum propylene production requires the (R)FCC to operate at higher severity as compared to maximum gasoline production. Figure 1 illustrates this for a residue hydrotreating (RDS) RFCC refinery configuration at different RFCC severities.
- Maximum aromatics production requires maximum reformate production, which in turn requires maximum heavy naphtha production. A VGO hydrocracking unit can be tailored toward maximum heavy naphtha production with as high a C8 – C10 aromatics content as possible, but maximising the naphtha-range aromatics yield will be at the cost of the middle distillate yield, in particular the diesel yield. Interestingly, there appears to be a shift in transportation fuel demand from diesel toward gasoline in some of the very same regions that are interested in enhanced production of petrochemical feedstocks.

**Residue conversion approach implications**

Irrespective of a refinery’s focus on the manufacture of transportation fuels or of petrochemical feedstocks, the fate of the residual oil is frequently a critical component of the refinery margin. There are three major residue conversion options of interest to most projects:

- Delayed coking has historically been the most popular full conversion technology. However, it has a disadvantage in that this process yields a comparatively large fraction of less desirable products such as fuel gas and coke. Coke yields can be as high as 30 – 35 wt%.
- RDS is attractive for maximising gasoline and thereby propylene yields. A disadvantage is that this process exhibits limited feedstock flexibility, and that it struggles in particular to handle the heaviest feedstocks.
- Residue hydrocracking (RHC) is attractive for maximising the yields of liquid product manufacturing with the broadest possible feed slate. Typical residue conversion yields with an ebullated bed process, such as LC-FINING™, are 65 – 80+ wt%. Combining this process with coking can boost conversion levels toward 85 – 90 wt% and reduce the coke make to 12 – 14 wt%. This combination results in 15 – 20 wt% higher liquid yields compared to coking by itself (Figure 2). Also shown are the latest RHC high conversion offerings of LC-MAX™ and LC-SLURRY™, which have higher total liquid yields. The higher total liquid yields accessible with the LC-FINING technology platform tend to be in the middle distillates boiling range, so they require further processing to be turned into petrochemical feedstocks.

Refiners invariably want the reliability of proven technologies in new projects yet want to maximise profitability by their ability to respond to supply and price volatility for both feedstocks and products. Due to recent technical advances, CLG can now offer...
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solutions based on LC-FINING and RDS technology platforms that expand feedstock optionality and provide the desired flexibility to diversify product dispositions, e.g., switching emphasis from diesel to naphtha or from transportation fuel to petrochemical feedstock production. These advances include both processes and catalysts.

**Advances in process technology**

**RDS**

So as to mitigate the feedstock limitations intrinsic to RDS/RFCC and thereby expand the range of RDS applications, the company offers Upflow Reactor (UFRTM) technology for both new and existing units. This reactor is added in the front of the fixed bed reactors. Since it has a very low pressure drop it is an excellent solution for revamp applications. It can be isolated from the main fixed bed reactors and the UFR catalyst can be changed out while the main RDS reactors continue in service. The reactor has been successfully employed by several of CLG’s licensed RDS units.

**Aromatics production**

The LC-MAX process can help to increase aromatics production. This is a LC-FINING-based process that first hydrocracks residue at low conversion, subsequently utilises a solvent deasphalting step to reject compounds likely to form sediment, and finally achieves nearly complete conversion of the desasphalted oil (DAO) and heavy VGO (HVGO) products in an additional LC-FINING step.

Figure 3 illustrates the LC-MAX process, which makes approximately 10 wt% more VGO and 13 wt% more distillates as compared to coking. Figure 2 highlights the process’ yield advantage, so it has been selected for two large residue conversion projects, both in the engineering phases.

This process’ VGO is a good hydrocracker feedstock, as the combination of solvent deasphalting and high conversion residue hydrocracking effectively eliminates the feed components that make high refractory VGOs.

**Increased FCC feedstocks**

For applications where increased FCC feedstocks are desired, a modified LC-MAX-G process is available. Here, the hydrocracked residue is fractionated and only the unconverted oil is deasphalted. The VGO and DAO are subsequently combined and hydrotreated (Figure 4). The desired VGO/DAO hydrotreating severity depends on the desired FCC performance. High quality distillates and naphtha can be manufactured more or less independent of the VGO/DAO quality objectives.

**Hydrocracking RHC distillate product**

CLG has pioneered the integration of RHC and both RHC product hydrotreating and RHC product hydrocracking into a shared RHC high pressure loop. The addition of an integrated product hydrotreating option is fairly straightforward, requiring only a few additional catalyst beds or a small additional cracking reactor.

With integrated distillate hydrocracking, there is a significant shift from distillates to naphtha, implying an increased production of reformate and FCC feedstocks that can be used for petrochemical production. Figure 5 shows how LC-MAX can shift yields depending on the product objectives.

The process’ VGO can be processed in a high conversion, naphtha selective hydrocracker. In this scenario, the yield of reformer feed can be as high as 45 wt% of the vacuum residue. For the LC-MAX-G cases, where the objective is maximum propylene yield, the potential reformer feed can approach 22 wt%, after the FCC heart cut naphtha is sent to the reformer. In this case, the vacuum residue yields some 8 wt% overall propylene after conversion of the hydrotreated VGO/DAO in the FCC unit.

**Advances in catalyst technology**

A suitable choice of catalysts leads to a higher tolerance of feedstock contaminants, and to an RDS atmospheric residue product with a higher hydrogen content. The overall impact is improved selectivity toward propylene and naphtha in the (R)FCC unit. As shown in Figure 6, RDS catalysts continue to advance in both activity and selectivity. This allows for the
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processing of feedstocks with high contaminant levels and producing high quality products, thereby improving the RFCC product selectivity.

An integral and often underestimated part of this monetisation of residue is the upgrading of the RHC products. These products contain an unusually high concentration of refractory components (particularly polynuclear aromatic hydrocarbons) that threaten run length if left untreated. Specially designed co-gel catalysts combine the required high aromatics saturation capability with a high selectivity to specifically hydroconvert most refractory components. Early elimination of these residue-derived poisons is essential to the conversion of VGO into transportation fuel or petrochemical feedstocks, particularly.

After sufficiently deep hydrogenation, the boiling point of RHC products can be further reduced in a hydrocracking step. There has been a continuous evolution of hydrocracking catalysts, each generation exhibiting an improved tradeoff between yield structure (selectivity) and sustainable run length (activity). Provided the ancillary equipment has the capacity to handle the changes in product streams, a straightforward change in catalyst from one geared towards jet or diesel, to a catalyst geared toward naphtha and jet can impart a dramatic change in hydrocracking yield structure from diesel to naphtha-range aromatics, suitable for reforming and petrochemicals production (Figure 7).

For maximum VGO hydroconversion into transportation fuel or chemicals, CLG has traditionally offered a two-stage hydrocracking process. The first stage’s objective is primarily to remove contaminants and hydrogenate, although there is some conversion taking place. The second stage completes the conversion in a clean reaction environment, thus allowing high selectivity to desired products.

The increasing demands for propylene and gasoline have made RDS and RFCC more attractive. There have been further advances in RDS and FCC designs and catalysts that can enhance propylene production.

Case studies
To illustrate the opportunities associated with the addition of various residue hydrocracking technologies and VGO conversion approaches, CLG evaluated several options utilising its comprehensive process planning and optimisation models.

Case study 1: heavy naphtha production
Production of heavy naphtha can vary significantly, based on the following:
- Residue conversion yields.
- VGO hydrocracking selectivity.
- Synergies between the residue conversion and VGO conversion processes.

When comparing processes such as delayed coking to LC-MAX, the combined light and heavy naphtha yields are within approximately 1 wt% of each other. This by itself would suggest that these processes would result in similar C8 – C10 aromatics yields after reforming. But because the VGO yield difference is 13 wt%, the impact of the downstream VGO conversion unit also needs to be taken into account.

Figure 8 shows the combined yields of the naphtha and distillate products from the residue conversion unit.
and a high conversion VGO hydrocracker operating in various modes. Because the LC-MAX case converts significantly more residue into liquids as compared to coking, the resulting naphtha and distillate yields are highest in this option.

For this case, the second and third columns show the shifts in yields dependent on the VGO hydrocracker selectivity. Both heavy and light naphtha can be increased with a naphtha selective operation, resulting in more steam cracker and C8 – C10 aromatics feedstocks.

Alone, LC-FINING does not show a high naphtha and distillate yield, its unconverted oil could be processed in a delayed coker, significantly augmenting these yields.

Case study 2: maximising gasoline and propylene

Figure 9 shows the overall refinery yields for RDS, RFCC, LC-MAX-G, and FCC flow schemes. The respective yields from each option also depend on the operating mode of the (RF)FCC unit.

For the RDS and RFCC flow scheme, the gasoline yield could be significantly reduced when the RFCC is geared toward maximising the propylene yield. In this operation, propylene yield can be further enhanced if the C4 production – usually used for alkylate production – can be minimised.

LC-MAX-G, with the integrated distillate product hydrocracking option, can result in higher gasoline yields compared to an RDS and RFCC flow scheme. Although it has less (RF)FCC feedstock, the FCC feed quality is higher. In addition, it produces a significant amount of naphtha alone. The effective result is high overall gasoline and C8 – C10 aromatics yields. RDS and RFCC will be used if high propylene yield is preferred.

Conclusion

Residue and VGO conversion are important for maximising the production of petrochemical feedstocks. CLG can help with tailoring combinations of LC-FINING or LC-MAX with VGO hydrocracking toward the maximum production of feedstocks for ethylene cracker and aromatics plants, while minimising residue byproducts. The proper integration of RDS and RFCC can maximise propylene production. Advances in RDS catalysts and a combination of UFR and traditional RDS reactors expands the feedstock range for this application. LC-MAX-G and FCC facilitates both high propylene and gasoline yields.

References

Melissa Clough and Kitty Cha, BASF Corp., USA, demonstrate the benefits of applying SO\textsubscript{x} reduction additives for regulatory compliance, with reference to three refinery case studies.
Oil refinery concern over sulfur oxides (SOx) emissions is steadily present. SOx emissions cause damage to both the environment through acid rain and to human health by inhalation. In the US, SOx emissions are regulated per the National Ambient Air Quality Standards (NAAQS); globally, similar regulations are implemented on a regional basis. In oil refining, sulfur originates from the crude oil processed. Sour crudes (i.e. high sulfur crude oil) are especially troublesome and require sulfur mitigation strategies. In fluid catalytic cracking (FCC), strategies include desulfurisation of the feed via a hydrotreating unit, operations, catalyst additive technology, or a combination thereof. The former two require significant capital expense, whereas catalyst additive technology can be implemented with lower monetary investment. Catalyst additives aimed at reducing SOx emissions interact with SOx in the regenerator and facilitate a transformation to hydrogen sulfide (H2S), which is released in the riser. The additive is added directly to the catalyst inventory and works immediately to combat SOx emissions. BASF offers an additive, EnviroSOx, to meet environmental regulation requirements.

The level of SOx emissions is dictated by the amount of sulfur in coke. All sulfur in coke is burned off in an FCC regenerator as SOx, thus all sulfur that ends up in coke ends up as SOx. For non-hydrotreated feeds, 5 – 10% of feed sulfur ends up in the coke. For hydrotreated feeds, this value is higher; approximately 15 – 30% of feed sulfur ends up as coke sulfur (and ultimately SOx) since the easy-to-remove sulfur species have been taken care of in the feed hydrotreating step. Resid feeds and feeds with high aromatic content will typically generate higher SOx.

The mechanism of SOx reduction involves three main active ingredients within a catalyst additive particle: cerium, magnesium and vanadium. In the regenerator, sulfur is oxidised to form SO2 and/or SO3 depending on the partial pressure of oxygen. Cerium from the additive promotes the formation of SO3 by facilitating the oxidation of SO2. Magnesium interacts with SO3 to form magnesium sulfate (MgS), which is carried over to the reactor side of the FCC. In the reactor, under reducing conditions, MgS is formed, which then interacts with vanadium oxide species of the additive to form H2S. H2S leaves with the reactor effluent and is later separated or treated, e.g. used in the sulfur plant to produce elemental sulfur. The optimal combination of active ingredients and how they are incorporated into the final additive particle dictates the additive’s efficacy in SOx reduction ability.
Measuring the efficacy of SO$_x$ reduction additives

When predicting uncontrolled (no additive use) SO$_x$ emission, many variables influence SO$_x$ including the type of sulfur coming in and feed metals (for instance, metals such as iron can act as a reverse SO$_x$ additive increasing SO$_x$). Slurry sulfur is the preferred method for estimating the amount of uncontrolled SO$_x$ vs using feed sulfur. The Gulf correlation (Equation 1) is one method used to estimate coke sulfur, which can be converted to expected SO$_x$ emissions. Multivariate statistical analysis more accurately estimates coke sulfur and SO$_x$ emissions levels. The analysis derives a model from refinery operating data to predict uncontrolled SO$_x$ emissions and is therefore a more accurate representation of emissions. Once built, this model can then be used to track the efficacy of a SO$_x$ additive.

A performance indicator used to evaluate the effectiveness of the additive is the pick-up factor (PUF), which is kg of SO$_x$ captured divided by kg of additive used. A typical PUF is between 15 and 40. While SO$_x$ reducing additives are employed in both full and partial-burn operations, the PUF for partial burn units is approximately half that of full burn units, and can be as low as 3 – 4 in very deep partial burn. The PUF is also highly dependent on various operating parameters including excess O$_2$ in the regenerator, regenerator temperature, stripper efficacy, catalyst circulation, air distribution and mixing in the regenerator, and partial pressure of SO$_2$ in the regenerator.

This article explores three cases, all using SO$_x$ reduction additives, with different methods used to track efficiency.

**Case 1: multivariate statistical analysis in a multi-vendor trial**

A side-by-side full burn vacuum gasoil (VGO) unit in North America that trialled BASF’s additive benefitted from a multivariate statistical model to analyse the effectiveness of the additive vs the incumbent non-BASF SO$_x$ additive. EnviroSOx was added during the startup after a long-term unit shutdown. Unstable operation of the pre-feed hydrotreater meant that SO$_x$ reducing additive requirements were variable, and were therefore modified per the FCC need. For this case, the Gulf correlation could not be used to compare pick up factors due to the unavailability of slurry samples. To track the SO$_x$ additive effectiveness, BASF developed and utilised a multivariate statistical analysis model using operating data while on the incumbent additive. This multivariate approach utilised the refinery’s data to correlate multiple variables to the SO$_x$ reducing additive rate, including feed sulfur, feed API, flue O$_2$, riser outlet temperature, feed rate, and dilute phase temperature. The final equation was determined using stepwise regression with second order interactions of the incumbent data. The model was then projected to the EnviroSOx period, while taking into account operating changes. A comparison of the actual addition rate and modelled addition rate showed that this period required 14% less additive to achieve the same SO$_x$ reduction target as demonstrated in Figure 2. This demonstrates a higher PUF for the additive. Finally, the availability of reliable unit data, cooperation with refinery personnel, and BASF’s advanced multivariate statistical analysis tools enabled a successful post audit.

**Equation 1.** Gulf correlation is used to estimate uncontrolled SO$_x$; UF is a unit factor, which must be uniquely determined for each unit.
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Case 2: optimising SO\textsubscript{x} additive use without using a loader

Common practice for environmental additives is to use a separate loader to control the addition rates. However, not all units have an extra loader since they can be cost prohibitive. Furthermore, additives that are introduced via a separate loader dilute the activity of the catalyst and can have negative effects on yield slates off the FCC.

A North American refinery trialled the BASF SO\textsubscript{x} reduction additive that was pre-blended with the catalyst to avoid the added burden on the refinery of managing additions and utilising a separate loader. An added benefit of pre-blending additive into the fresh catalyst inventory is the ability to offset active catalyst dilution that occurs when adding via a separate loader. For this trial, a base case statistical model was built using operating data, including riser outlet temperature, oxygen injection, feed sulfur, slurry sulfur, and catalyst circulation. The base case predicted SO\textsubscript{x} emissions accurately — it was then projected to the EnviroSO\textsubscript{x} period. The difference in predicted SO\textsubscript{x} and actual SO\textsubscript{x} is the result of BASF’s additive.

Figure 3 shows the model predicting higher SO\textsubscript{x} emissions than actual during the additive period — the difference is applicable to the use of the SO\textsubscript{x} additive. Its application in this refinery resulted in a 34% reduction in SO\textsubscript{x} emissions, allowing the refinery to operate in compliance with local regulations and alleviating other units’ SO\textsubscript{x} emission requirements within the battery limits of the refinery. These results demonstrate the competitive advantage that the SO\textsubscript{x} additive can offer refineries, including those who pre-blend to offset the need for an additive loader.

Case 3: monitoring SO\textsubscript{x} additive trial in the absence of dedicated refinery equipment

One problem encountered while refineries implement SO\textsubscript{x} additives into their emissions strategy portfolio is the availability of reliable equipment or hardware to use in conjunction with a trial. In some cases, a refinery may not be outfitted to properly take SO\textsubscript{x} readings from effluent gas streams. However, the need for reduced SO\textsubscript{x} emissions is still present. In a recent case such as this, BASF’s technical service team, hardware solutions, and efficient SO\textsubscript{x} additive was the three-pronged approach to solving the refinery’s problem.

The use of a mobile effluent gas monitoring equipment and on-site training enabled the refinery to obtain a baseline of SO\textsubscript{x} emissions (without the additive) and allowed for the continual monitoring after adding the SO\textsubscript{x} additive to the circulating inventory.

As shown in Figure 4, a reduction of 72% on average in SO\textsubscript{x} emissions vs the steady base case was seen at the refinery after a transition period.

Past the trial period, the refinery continued to use the SO\textsubscript{x} additive given these results. This trial was enabled by engaged refinery personnel, BASF’s hardware solution, and the accompanying on-site training.

Conclusion

The use of SO\textsubscript{x} reduction additives, which is becoming more common due to global regulatory compliance requirements, can be complementary to a refinery’s existing hardware and operations to reduce SO\textsubscript{x} emissions. SO\textsubscript{x} reduction additives can also be employed during hydrotreater outages (e.g. unit trip, lack of H\textsubscript{2}, turnaround during a catalyst change) or can be employed to take advantage of sour opportunity crudes. While FCC catalyst activity can be significantly diluted when over 10% additive is required, this dilution can be offset by pre-blending. Furthermore, the additive shows higher initial activity and overall better cycle stability and regeneration rates while maintaining good attrition characteristics in multiple refinery trials.

BASF’s SO\textsubscript{x} reduction additive helps to alleviate the need for high capital monies, requires less loading, shows competitive attrition in third-party testing, and allows refineries to operate within local regulatory requirements. As a lower attrition additive, it allows for reliable operation, offsetting cases seen in other refineries that resulted in FCC unit shutdowns due to ancillary equipment.

Advanced multivariate statistical analysis is an effective tool to accurately predict uncontrolled SO\textsubscript{x} emissions and to analyse the performance of SO\textsubscript{x} reduction additives. BASF’s advanced technical service tools, including training of mobile gas effluent devices, are a key enabler for success for those without reliable gas effluent monitoring equipment.

In conclusion, the latest SO\textsubscript{x} reduction additive innovation has demonstrated improved performance in multiple competitive trials and has helped refiners meet SO\textsubscript{x} emissions requirements.
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Refinery fuels present manifold challenges to achieving ultra-low emissions. Most refinery heaters are natural draft rather than forced draft (as was the case with a refiner in California, US, which is discussed later in this article). Natural draft offers minimal airside momentum for flame shaping. Additionally, many ultra-low nitrogen oxide (NOX) solutions rely on flue gas recirculation (FGR) – an inconvenience for natural draft units. If FGR is used, a costly conversion to forced draft is often required.

Moreover, refinery fuel is notoriously variable. Most hydrocarbons require approximately 100 ft³ of air per Btu of heating value (ft³/Btu), but hydrogen requires about 20% less air on that basis. It is not atypical for hydrogen content in a refinery fuel to swing threefold in concentration, with occasional excursions to much higher concentrations. Hydrogen has a higher flame temperature than hydrocarbons. Since NOX formation is thermally driven, rising hydrogen content typically leads to higher NOX.

NOX formation
Except from upset conditions or maloperation, refinery fuels typically contain no fuel-bound nitrogen. Without fuel-bound nitrogen, the major pathway to NOX formation is actual fusion of the nitrogen (N₂) and oxygen (O₂) from the combustion air. This occurs primarily in the thermal (Zeldovich) NOX-formation mechanism. Thermal NOX formation may be understood as a function of the integral of time (linear), temperature (exponential), and oxygen concentration (square root). This is given in the following equation where \( C_{NOX}, C_{N2}, \) and \( C_{O2} \) are the concentration of

Joe Colannino and Roberto Ruiz, ClearSign Combustion, USA, introduce an innovative piece of technology that was able to help a Californian refinery reduce its NOX emissions.
nitric oxide, $N_2$, and $O_2$, respectively; $A$ and $b$ are constants; $t$ is time; and $T$ is temperature:

$$C_{NO} = AC_{N_2} \int_0^t e^{-\frac{b}{T}} \sqrt{C_{O_2}} d\theta$$

**How ULNBs work**

Ultra-low NOx burners (ULNBs), which produce less than 10 ppm NOX, typically reduce NOX by attempting to reduce flame temperature, and to a lesser extent, local $O_2$ concentration. One way to reduce the flame temperature is through the use of FGR. The flue gas adds inert mass to cool the flame, as well as homogenising it. Since NOX is exponentially weighted with temperature, small regions of peak flame temperature can dominate NOX production. Adding additional mass and momentum in the form of recirculating flue gas can help to homogenise the flame and reduce peak flame temperatures, thereby lowering NOX.

Another common ULNB technique is to stage combustion in discrete zones to decrease local available $O_2$ concentration. If local $O_2$ can be minimised, then less $O_2$ is available to fuse with $N_2$ and form NOX.

Staging fuel and air also stretch the flame. A longer flame has more radiating surface and can exchange heat with the surrounding process to lower its temperature and thermal NOX.

**Common problems with ULNBs**

Common problems with ULNBs in refinery service are the requirement for FGR, potential for plugging of fuel nozzles, decreased stability, and flame impingement. First, FGR is difficult to come by in a refinery because most heaters are natural draft and do not have enough excess draft pressure to induce sufficient FGR to reduce NOX. This can be overcome by converting the heater to forced draft operation, but this is often not economically practical. Moreover, FGR contains significant moisture, which can condense or corrode moving parts such as air dampers and registers. Second, UNLBs generating less than 9 ppm require copious quantities of FGR — approximately 30% of the total flue gas must be returned to the burner inlet. Even greater amounts of FGR are required to achieve sub-5 ppm NOX. For all these reasons, FGR is generally impractical as a sub-5 ppm NOX solution in a refinery. This limits UNLBs in refinery service to approximately 10 ppm NOX, except under exceptional circumstances.

Staging fuel requires a multiplicity of orifices. Since the heat release for a given unit is fixed, dividing the fuel circuit into a greater number of fuel orifices reduces individual orifice size. Refinery fuels are typically not as clean as natural gas and small holes in the fuel circuit may plug, leading to safety, stability, and operational problems. Moreover, ULNBs tend to have much longer flames due to air and fuel staging, and such flames can impinge on process tubes and downstream structures, again creating safety and operational problems. For example, continual flame impingement can lead to fouling inside the process tube. The fouling acts as an insulator and interferes with the ability of the process fluid to cool the tube, resulting in local overheating and the possibility of rupture or explosion. Intermittent flame impingement can lead to cyclical reduction and oxidation of superalloy tubes in refinery heaters. The superalloys in refinery heaters rely on a protective oxide coating to maintain their high temperature resistance to oxidation. Flame impingement can reduce this oxide coating, so when the metal is re-exposed to oxygen it re-oxidises. As this cycle re-occurs, the metal is slowly consumed, resulting in reduced wall thickness and ultimately rupture.

In short, ULNBs are generally impractical for sub-5 ppm NOX in refinery service.

**SCRs**

In some cases, selective catalytic reduction (SCR) provides a solution for NOX reduction that can achieve sub-5 ppm NOX. With SCR, ammonia ($NH_3$) is reacted with NOX over a catalyst in a downstream reactor to produce elemental nitrogen and water, according to the global reaction:

$$NH_3 + NO + \frac{1}{2} O_2 = N_2 + 3/2 H_2O$$

Often, it makes more economic sense to control process units with a central SCR, rather than individual SCR reactors for each process unit. However, SCR requires a
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catalyst, a constant supply of ammonia or similar reagent, and the potential transport of hazardous material. SCR is also an order of magnitude more expensive than ULNBs. However, SCR can achieve sub-5 ppm NOX levels, which typically requires the use of ammonia in excess. It is common for NH3 to slip from the reactor through the stack and into the atmosphere. This is now regulated to less than approximately 5 ppm.

**Distal surface architecture**

Combustion emissions can be minimised at the source to sub-5 ppm NOX levels, through a combustion reaction occurring distal (rather than proximal) to the burner. A flame in a typical process heater may be 10 or 20 ft long, depending on the time it takes to mix the fuel and the air in a combustion reaction. If combustion were to take place downstream of the burner, after where the fuel and air are mixed, the resulting combustion reaction could occur in inches rather than feet. However, this requires a downstream surface to hold the resulting flame.

**Case study**

A California refiner required a sub-6 ppm solution for a multiple-burner heater. ClearSign Combustion's DUPLEX technology was selected for the project. The technology uses a porous ceramic matrix to provide a downstream combustion surface (Figure 1), which can retrofit to any existing conventional, low NOX, or ultra-low NOX burner. The technology reduces NOX from every element of the Zeldovich mechanism. First, because the surface behaves nearly as a blackbody with an emissivity much higher than the flame, more heat is radiated to the process, cooling the flame and reducing NOX. Moreover, since the combustion occurs in inches rather than feet, there is little time for NOX to form. Finally, prior to combustion, the fuel and air have already entrained flue gas produced at the surface, thus lowering the initial oxygen concentration. The result is sub-5 ppm NOX without any need for external flue gas recirculation, fans, SCR apparatus, long flame lengths or other associated but problematic issues associated with ULNBs.

A typical operating scenario for the technology requires two steps: first, heating the surface above the fuel's automatic ignition temperature; and second, transferring the combustion from the burner to the surface (Figure 2). The first step is typically accomplished with an existing burner. Once the wall is sufficiently warm, the flame transfer is brought about by a second set of nozzles designed to stabilise at the surface rather than the burner. A flame scanner with a view of the surface identifies flame transfer and combustion per design, resulting in sub-5 ppm NOX. Moreover, because existing burners can be retrofitted to work with the technology, it de-risks a retrofit – existing burners can always be re-utilised to generate process heat (albeit with higher NOX).

**Installation and results**

Such was the case for the Californian refiner, whose permitted NOX level was 6 ppm corrected to conditions of 3% dry excess oxygen. The technology was installed during a two-day shutdown (one day to cool the heater down and half a day to install the surface comprising a modular ceramic support structure and porous ceramic tiles).

Data were collected to verify NOX performance under operating conditions using a Testo 350 analyser equipped with a low-NOX cell. Flue gas samples were drawn from the furnace stack and conditioned using a sample dryer to give NOX on a dry basis. Wet oxygen data were obtained using an in-situ zirconium oxide oxygen probe located.
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downstream of the convection section. Over 100 data
dPoints were obtained during a six week period (Figures 3, 4
and 5) representing averaged daily data. Figure 3 shows the
NOx performance as a function of the process heater
bridgwall temperature, while Figure 4 plots NOx as a
function of wet O2.

The reboiler process heater serves a downstream
reformer. As such, refinery operations requested a plot of
NOx from the technology's operation as a function of the
reformer charge rate. Note that daily unit and reboiler
charge rates were kept constant and experienced minor
daily deviations (Figure 5).

NOx results met or exceeded the project's objectives.
In addition, average CO emissions were 25 ppm
(corrected to conditions of 3% excess O2 on a dry basis)
and were consistently lower than the permitted level of
50 ppm in spite of the relatively low bridgwall
temperature. Furthermore, performance of the surface
was stable over all of the process conditions
encountered during the evaluation period. Figure 6 shows
the operating surface.

Conclusion
The technology was able to generate sub-5 ppm NOX in
the refinery heater without the need for additional
excess air, FGR, or catalysts and reagents. As a retrofit
strategy, it worked with the existing burner. With the
flame stabilised on the surface, sub-5 ppm NOx was
demonstrated independent of the original burner NOx
and without additional production of CO.

Note
Fuel-bound nitrogen refers to nitrogen-bound within the fuel
molecule, in contrast to small concentrations of nitrogen in the fuel
gas, which act merely to reduce the heating value slightly.
In 2016, the US Environmental Protection Agency (EPA) published the QuadOa regulations, which were designed to reduce the amount of greenhouse gases (GHG) emitted by the oil and gas industry. How these regulations will be implemented is far less clear.

However, some clarity remains. Natural gas has a reputation as the ‘clean’ fossil fuel, a title that has been earned because it emits significantly less soot and approximately half of the carbon dioxide (CO₂) produced when burning coal. However, this ignores the problems caused by methane – a powerful greenhouse pollutant that has been analysed to be more than 80 times more potent than CO₂.

With the shale gas boom essentially altering the shape of the US energy market, and natural gas being promoted as the link to a low-carbon future, it is an important energy source that cannot afford to be wasted. But, until methane emissions are measured, monitored, controlled and reduced, the position of natural gas as a ‘greener’ substitute for coal and oil is open to debate.

The sector’s response
Developing a systematic approach to reducing methane emissions is in the best interests of oil and gas operators from both a safety and cost perspective. It is also beneficial for their
customers, shareholders, and the communities in which these companies operate — regardless of regulatory drivers.

This is something that national and super-national regulators have long recognised, as have the organisations they oversee. A few months after the EPA published its QuadOa regulations, the five Nordic states in Europe announced that they were committed to developing a global target to reduce oil and gas methane emissions.

Concurrency, Mexico and Canada both committed to reducing methane emissions by 45%, while companies such as BP, Engie, Eni, Repsol, Saudi Aramco, Statoil and Total have all expressed concerns regarding methane and have followed up these concerns with the implementation of monitoring for emissions and disclosing information. Within the US itself, regulations regarding methane emissions can be stronger in individual states such as California, Colorado and Wyoming rather than at a federal level.

The current overall consensus within the oil and gas industry is that methane emissions must be better controlled for reasons of public safety, employee safety, environmental protection and operational efficiency. This includes both planned releases of gas and unplanned emissions in the form of leaks, and requires a three-pronged approach, as outlined below.

First step
The first step is to ensure that all the new systems are designed in such a way that continuous monitoring and catastrophe prevention is still in place. This will help to mitigate serious events, such as the 100,000 t of methane that was emitted from a natural gas system in Aliso Canyon, Los Angeles, US, in 2015. This one is a long-term effort.

Second step
The second step is to build or modify systems in such a way that means they emit less and also prevent losses. Where burning off excess gas from vents was once standard practice, more new and modified plants incorporating vapour recovery systems that use the excess gas for pneumatic pumps and valves are being designed and constructed. Often, these existing emission sources are not well documented and a site survey is the only way to identify fugitive emissions.

Third step
The third step is to manage repairs more effectively. In any process facility where there are hundreds (if not thousands) of connections, seals and vents, a gas leak of some kind is inevitable. Leak detection and repair (LDAR) systems that enable early identification and swift mitigating action in hazardous environments are essential. Aliso Canyon was a compelling incident that received a lot of coverage, however, the far more common culprit of a gas leak is a faulty valve on a well-side storage tank, which, once spotted, may be fixed simply with a spanner.

A functional LDAR solution
Whereas the first step requires a long-term investment and system design, the second and third steps are much quicker and easier to address. Much of the existing regulation around gas emissions and gas leak detection are based on a series of protocols known as Method 21. These require operators to use ‘sniffers’ — devices that use a physical or chemical reaction — to identify the presence of gas leaks.

Sniffers are excellent for routine inspections of known trouble spots — as is often mandated in the regulations. What sniffers do not do is identify the source of a leak, particularly when it comes from an unexpected source or a facility with complex piping.

However, since 2008, operators have been including optical gas imaging (OGI) in their maintenance and operational regimes, particularly in hazardous locations, to great effect. Using an infrared thermal-imaging camera, these portable and remote OGI devices enable operators to safely identify specific hydrocarbons from the facility’s unique electro-magnetic radiation absorption rates — and, hence, observe any plumes of leaking methane and the exact source of the leak, even when the parts per million (ppm) rate is relatively low.

There is a growing body of evidence that demonstrates that OGI methods can, and will, safely identify the vast majority of emissions in a fraction of the time taken by previously employed labour-intensive methods. OGI can also be used to verify that any given leak has been fixed. During recommissioning and following plant repairs, OGI can be used to rapidly verify the integrity of repairs in order to decrease the time that the plant has to be offline.

OGI is considered such an effective method that it has now been defined by the European Parliament Commission as the best available technique (BAT) for the reduction of volatile organic compound emissions. In Taiwan, the regulations in place mirror those adhered to in the US, in that they require Method 21 but also include OGI. Similar OGI-focused regulations are also making their way to China and Canada. For truly global firms, implementing a standard OGI solution across all worldwide operations is the smartest thing to do to ensure safe, efficient and cost effective operations.

A regulatory curveball?
Even if the QuadOa regulations are watered down or lack fully funded enforcement mechanisms, the safety and operational efficiency of OGI means it is still a shrewd choice. In an interesting twist, the actions of the new Trump administration may in fact encourage the adoption of OGI to occur across facilities much quicker. To date, much of the EPA’s regulation has been committed to labour-intensive sniffers and Method 21, which has often been to the disadvantage of operators who are working with remote or unmanned sites, for which sniffers are not always appropriate.

With its promises to reduce regulatory burdens and boost industrial growth in the US, the new government could also look for ways to ease the burden of LDAR programmes that are currently in place, while still maintaining the public protection that citizens demand and deserve. As they are cost effective and flexible in their deployment, OGI devices would also allow operators to capture the majority of leaks quickly and more efficiently than current practice allows, thus making operations much safer.

Conclusion
Predicting the future can be a thankless task, and not always one with an accurate outcome. But even as details continue to change, LDAR is likely to remain and be implemented worldwide. With oil prices still resting at the lower end of the curve, margins are tough to maintain and profits are hard won. Under these circumstances, OGI is a cost-effective technology that will help to enhance operations, maintain safety records, and avoid the continuation of major pollution.!
Greenhouse gas (GHG) emissions such as carbon dioxide (CO₂) have risen significantly over the past 100 years, and are thought to be the primary cause of global warming. In order to combat their effect, many governments have agreed to reduce the amount of GHGs they release into the atmosphere through different conventions and policies, some of which are legally binding.

One of the first was the United Nations Framework Convention on Climate Change (UNFCCC) – an international treaty set up at the ‘Earth Summit’ held in Rio de Janeiro, Brazil, in 1992. The objective of this treaty was to keep GHG emissions at a stable level that would not cause any permanent effects to the atmosphere or climate. As of May 2011, 194 countries had signed up to this treaty, however, it has no real deliverables (the only convention for each member country is to reduce its GHG emissions).

The Kyoto Protocol extended this premise by holding member countries responsible for their GHG reductions. The protocol came into effect in 2005 and aims to reduce the levels of GHG emissions by 5.2% compared to the 1990 level. In total, 37 countries signed up to this legally binding agreement to reduce emissions. The majority of these countries were from the developed world. However, the number of countries signing up to the Kyoto Protocol has increased significantly since then and currently sits at 192 (March 2017).

Marc Laing, NEL, UK, examines the challenges involved in measuring flare gas and their resulting emissions.
Gas flaring is an important safety critical operation that is required when producing hydrocarbons. The flare gas line forms part of the pressure relief valve, which is required by law on all platforms. The flare system is used to burn the excess hydrocarbons that cannot be recovered or recycled. While these hydrocarbons are mostly gaseous, on occasion there can also be small amounts of liquid.

Not a simple process
Gas flaring is by no means a simple measurement process, and this is primarily due to the large variations in conditions often found in a flare stack. In order to fully appreciate the challenges involved in measuring flare gas, it is important to first acknowledge the varying conditions and their effect on measurement.

Firstly, it is worth noting that flares are usually of bespoke design and are entirely based on individual production sites. Some installations have one flare to deal with all operating conditions, while others have two or more, which often differentiate between low pressure (LP ~ atmospheric pressure) and high pressure (HP ~ 10 barg) applications. Typically, HP flares are more complex when compared with LP flares, and require additional equipment to achieve ideal flaring conditions. There are also temperature considerations to address. Around the world, gas flares are often found to be in the range of -70˚C and 150˚C.

In recent years, environmental regulations have imposed limits on flaring, which must be abided by. Failure to comply with these limits, accidental or intentional, will result in highly punitive fines being incurred. It is therefore of critical importance to ensure that flare gas is metered accurately.

Traditionally, flare gas systems use single path ultrasonic flow meters (USM). This is for a number of reasons, primarily due to cost, pressure loss and turndown ratio. Single path USMs are significantly cheaper than multipath USMs, which provide higher accuracy.

As flare gas is essentially a waste product, operators prefer to use cheaper metering technologies. In flare gas lines, it is essential that nothing obstructs the flow during the evacuation of the hydrocarbons, therefore ruling out all intrusive meters.

Finally, the flowrate in a flare gas line is highly variable. Generally, the flowrate will be low, but this can instantaneously increase by one, or even two, orders of magnitude during an emergency blowdown situation. This requires a very high turndown ratio in the meter and USMs are best placed to achieve this requirement. An example of the varying flowrates in flare gas systems is shown in Table 1.

Although blowdown conditions only represent a small amount of time, they have a dominating effect on the annual quantity of gas emitted, thus accurate metering of these conditions is important.

Single path USMs are, by design, very sensitive to disturbances in flow profile. General requirements of such a flow meter are that it is installed with 20 pipe diameters of straight undisturbed flow upstream of the meter, and 10 pipe diameters of straight undisturbed flow downstream (data for a GF868 single path USM). Ideally, within this 20 dia. upstream and 10 dia. downstream, there should be no valves, flanges, expansions or elbows, swirl, or low spots where condensed liquid can collect.

In flare lines, due to space constraints on offshore platforms, it is often the case that such a location does not exist. Therefore, with disturbances in the flow path upstream of the USM, accurate measurement is harder to achieve. Consequently, it is possible that the meter can either over-read or under-read. If the installation criteria for the meter cannot be met for a given system, it is likely that an auditor will require a computational fluid dynamics (CFD) analysis to be carried out to predict the magnitude of any metering error and the nature, i.e. over-read or under-read.

Meter inaccuracies
In the event that the USM over-reads, incorrect management decisions can be made. In the European Union (EU), this includes shutting down production to stay within the amount of emissions allocated by the EU’s Emissions Trading Systems (ETS) for each field. Therefore, production rates can be limited by flaring.

Flare gas meters that over-read by 40% is not unheard of in the sector. This shows that although flare gas is a waste product, metering it accurately is crucial in order to make the field financially viable by maximising hydrocarbon recoveries. Although the operator can purchase additional CO2 allowances to continue producing, this would also have serious financial implications.

If meters are found to be under-reading in the annual reports submitted by the operator to the EU ETS, then this can lead to substantial financial penalties, along with damaged reputations.

### Table 1. Example of the varying flowrates in flare gas systems

<table>
<thead>
<tr>
<th>Types</th>
<th>Potential source</th>
<th>Velocity range (m/s)</th>
<th>Time (%)</th>
<th>Estimated annual quantity (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Background</td>
<td>Pilot, leakage,</td>
<td>0 – 5</td>
<td>96.2</td>
<td>35.4</td>
</tr>
<tr>
<td></td>
<td>purge gas</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Normal</td>
<td>Process upsets</td>
<td>5 – 50</td>
<td>3.5</td>
<td>43.3</td>
</tr>
<tr>
<td>Blowdown</td>
<td>Emergency</td>
<td>50+</td>
<td>0.3</td>
<td>21.3</td>
</tr>
</tbody>
</table>

**Figure 1.** Example of a flare gas installation.
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**CFD solution**

CFD can be used to model bespoke installations to determine flare gas metering errors. This technique is widely used throughout the oil and gas industry in order to derive correction factors to reduce measurement uncertainty and allow compliance with the EU ETS regulations.

To undertake such a calculation, it is necessary to construct a 3D computer aided design (CAD) model to represent the installation. An example of a flare gas meter installation is shown in Figure 1, which illustrates a non-ideal piping layout.

The CAD model is then meshed in order to solve the fluid mechanics. Meshing is the process of dividing up the full model geometry into small sub-domains, known as elements, usually taking the form of squares (hexahedral) or triangles (tetrahedral). Typically, the geometry will be divided into millions of elements. This is necessary to ensure that the fluid mechanics are represented accurately. The governing equations of fluid mechanics are then discretised and solved in each of these sub-domains.

In order to predict how the meter will perform, it is necessary to model the transducer paths explicitly. There are various different installation configurations that can be used. Examples of these are as follows:

- Diagonal 45˚.
- 90 – 45˚ diagonal.
- Mid-radius bias 90˚.
- 90 – 180˚ diagonal.

CFD is a powerful tool when modelling flare gas meters, as it is possible to predict the fluid velocity in the direction of the transducer path (or paths). This must be carried out twice – once for the ‘as-installed’ case and once for what would be an ‘ideal installation’ (or fully developed flow profile).

Once the transducer path velocity data is extracted from CFD, the error can be calculated, based on calculating the volumetric flowrate of the ‘ideal installation’ and comparing that to the volumetric flowrate predicted for the ‘as-installed’ case (Figure 2).

The effect of a non-ideal installation on the flow profile is clear. Figure 3 represents the difference between an example of an ‘as-installed’ case vs an ‘ideal installation’ case. These types of deviations are not uncommon and can have a significant effect on the performance of the flare gas meter.

Once the calculations have been carried out using CFD, correction factors can be applied directly to the flow computer, which means that the error correction is carried out in real time. As such, no burden is placed on an operator to perform corrections, while potential sources of permanent error are removed.

The error correction is carried out by providing velocity distribution factors (VDFs) to the flow computer. These can be generated easily once the CFD data is available. It is also important that the CFD itself is accurate when modelling flare line installations.

**Conclusion**

While gas flaring is an important safety critical operation, its measurement is not a simple process. Fortunately, CFD analysis can be carried out to predict the magnitude, and nature, of any metering error. Single phase CFD simulations are now very well established with a vast amount of available test data to validate models where required.
Energy is the single largest controllable cost for most refineries, comprising more than 60% of non-crude operating costs of which utilities consume a major part but are often neglected. A 10% reduction in net energy use, at constant other costs, will typically lead to an increase in refinery net margin of US$0.40 – US$0.70/bbl. This makes energy savings an important topic in refinery cost control.

Reducing energy use typically cuts CO₂ and other emissions from the refinery/petrochemical complex, making them greener, which helps in realising the mission to combat climate change. Operating conditions vary widely among different refineries based on the complexity, vintage, different crudes/blends of crudes and intermediates processed, overall production rates, and the relative amounts of the different products. The effects on
the energy requirements for the refinery are twofold. The demand for the individual energy sources — fuel, steam, and power — varies significantly, and the composition of the internally generated fuel varies as the production from different sources within the refinery changes.

As refineries are energy intensive, the better approach to reduce these unnecessary energy costs is to improve their energy efficiency. It is difficult to improve energy consumption if it cannot be measured and monitored closely. Real-time modelling and monitoring of the energy use in plants permits a refinery to make allocation decisions more frequently and accurately, which explains the calls for optimisation tools for combined heat and power (CHP) system optimisation.

**A typical refinery/petrochemical utility system**

Refineries have relatively complicated utility systems with many different fuels and utilities, as well as many sources and users. Steam and electricity are also produced internally or purchased from outside. Each utility system is a piping network that supplies or receives various utilities such as steam, air, water, lubrication oil, fuel gas, fuel oil, and electricity to and from the process units. Often only the network’s main headers and branches are instrumented, which leaves many areas unmeasured. This limited coverage may help calculate the overall consumption and identify the main supplier’s and consumer’s performance, but it does not help close the material balance or identify possible leaks or wasted use. There are multiple header steam system suppliers and consumers across the site, but many of them do not have sufficient flow measurements to know where the steam is being used. To reduce energy use significantly, it is critical that the operation of captive power plant for power generation (CPP) and boiler house for steam generation is improved.

The software tools currently available can analyse various generation/consumer units and provide information about whether steam is being used or wasted, either through broken steam traps or inefficient operation. The optimisation of steam generation among boilers and heat recovery steam generators (HRSG) can also be handled. Thus, steam balance helps to reduce header pressures, close let down valves and stop venting, resulting in an improved steam system by minimising losses.

Similarly, a power balance across the entire unit helps to identify areas of improvement. This is possible through the optimisation of power generation among individual gas turbines (GTs), between GTs and steam turbine generators (STG) with regard to steam system balance, swapping between motors and turbines, etc.

Coming to the fuel system, fuel gas headers do not have a high surge capacity, so they need to consume what is provided or the excess will be blown down to the flare stack. Incomplete measurements make it difficult to identify possible leaks, wasted use, or to optimise. So, the software tools will help to estimate the actual fuel consumption for typical steam and power generation, thus helping to identify and minimise fuel losses.

The same is valid for other utilities, such as fuel oil, boiler feedwater (BFW), demineralised (DM) water, etc. Actual requirements for running the refinery/petrochemical plant at that load are identified and the difference measured is the anticipated loss. Monitoring this loss can help to minimise the consumption of these utilities as the pumping cost is proportional to the cubic power of flow.

Through optimisation, equipment is evaluated against throughput. There is a large initial component at low feed rates. At higher rates, energy use is typically proportional to throughput, often linearly, but occasionally following more of a quadratic form. This means that energy use per unit feed is non-linear. Specific energy use (energy per bbl of feed) is higher at a low capacity than at high capacities. Thus, incorporating software can help to understand the ‘present energy’ scenario of a process unit.

**Software overview**

The EngCHP software can help during the optimisation of the CHP system, and can be used to develop a tailor-made model for any typical refinery/petrochemical facility. There are various stages involved in developing a refinery/petrochemical specific model, which are illustrated below:

- **Data collection and review:**
  - Through site visit, continuous interaction.
  - Finalisation of base case for optimisation.
  - Involves data reconciliation.

- **Preliminary model building and optimisation of the utility network:**
  - Model based on refinery/petrochemical specifications.
  - The model also meets all demands within constraints.

- **Preliminary review with clients:**
  - Review of the tailor-made refinery/petrochemical utility model.
  - Improvement based on the clients’ suggestions.

- **Final model development and deployment:**
  - The model incorporates all suggestions.
  - The software is deployed/installed at site.

- **Users training:**
  - Training for better hands-on experience of various users.

The model consists of individual headers for various steam levels (very high pressure [VHP], high pressure [HP], medium pressure [MP], etc.), fuels (natural gas, fuel oil, low sulfur heavystocks [LSHS], fuel gas, etc.), electricity, BFW and condensate systems, including all interactions among these systems, constraints and degrees of freedom of their operation. Other utility systems such as air, nitrogen, flare, cooling water, seawater and hydrogen networks can also be included. The model also includes sub-models of a boiler, GT-HRSG, STG, turbines, deaerators, a thermocompressor, a flash drum, pressure reducing desuperheating valve (PRDS), etc. The complete models help during the
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optimisation of a refinery/petrochemical-wide energy consumption.

Such a model is scheduled to perform automatic executions for the optimisation of the entire system, and is continually populated with validated, live plant data.

The typical areas of optimisation are as follows:

- Power generation from individual GTs, between GT and STG.
- Steam production at boilers/HRSG.
- Pump swaps (steam turbines/electrical motors switches).
- Turbines (condensing turbines, extraction-condensing turbines).
- Choice of fuel gas/fuel oil.
- Electricity generation in CPP/import.
- Natural gas make-up to the fuel gas system.
- Steam letdown, excess condensing and vents.
- Deaerator water make-up preheating with low pressure (LP) steam, etc.

The model can be optimised by meeting the demand under various constraints, such as the following:

- Steam and power balance to meet process demand.
- Availability of fuel.
- Capacity limitations (full/turn down).
- Emission limits (by state or central pollution control boards).
- Contractual constraints (e.g., electricity supply, natural gas and steam supply).

The same software used for the online, real time optimisation can also be used in offline mode using the current/historical data, to analyse various cases to optimise the system (Figures 1, 2 and 3).

Understanding optimisation

The main objectives of the software is to minimise the company’s energy cost, taking into account all available resources by meeting process demand under operational constraints. Since the energy system is highly non-linear and includes continuous and discrete optimisation variables, it requires a mixed integer, non-linear optimisation technique. Optimisation is carried out by minimising the objective function with regard to various constraints. The objective function to be minimised is the total cost, which depends on various utilities, as follows: fuel costs (e.g. cost of natural gas, fuel oil); power cost (e.g. cost of purchased/export electricity), and other cost (e.g. cost of cooling water, seawater, fresh water).

'What-if' analysis

The software can be used to perform ‘what-if’ analysis in offline mode. Various energy saving schemes identified can be analysed, regardless of whether they provide benefits. For example, if the boiler is already running near turn-down and if through various schemes there is steam saving/generation, which leads to investment in equipment. However, by doing so, if the steam generated by the boiler cannot be further minimised as it reached the turn-down condition, the steam has to be vented, which is a loss. For performing a 'what-if' analysis, an actual base case or optimised case is compared with the new scenario by maintaining all imbalances to find the impact of this change.
A win-win situation
By installing the software, refiners can save energy costs and minimise emissions indirectly. Through simple optimisation of the system, in a case study, approximately 32 000 tpy of savings can be achieved for a typical 16 000 tpy refinery/petrochemical plant. It also saved 104 321 tpy of greenhouse gas (GHG) emissions.

As a monitoring tool
The EngCHP tool helps to monitor the entire system. The important areas of monitoring are as follows:
- Total steam/power demand/generation.
- Efficiency of boilers, GT-HRSG, STG, turbines, etc.
- Imbalances at every steam pressure level header.
- Energy consumption per unit rate (heat rate) for individual pieces of equipment.
- Total savings after optimisation.
- Cost of generation of utilities such as steam/power.
- Number of imports/exports of various utilities.

The predicted savings based on the system/equipment efficiency, as well as operational practices, are the key performance indicators. It can be expected that, if the operators implement all the proposed recommendations, the potential gap between the base case scenario and the optimum scenario will start to decrease over time. By regular monitoring and auditing of the entire system through EngCHP, imbalances can be identified and proper actions can be taken to reduce the same. It also helps in identifying inaccurate meters because imbalances could also be due to improper reading.

Reporting
An important feature of the software is its capability to report the results of simulation in a detailed way. The reporting can be carried out based on the level of information required to be dissipated to operators/decision-makers/technical service division/plant head. The steam report helps to minimise steam system losses effectively.

Conclusion
Software can be a utility management, auditing, and energy cost control tool for the refining/petrochemical sector. It can be operated in online mode for continuous monitoring or in offline mode for ‘what-if’ analysis. The company’s software has been time tested and can be implemented in any refinery with a cost saving potential for improving profit margins.

As a robust optimiser, the software can be used on a routine basis by operators. It can be used for auditing and accounting of fuel, steam and BFW. Continuous monitoring prevents plant upsets, quickly identify wastes, and can help management to make quick decisions during upsets.
Colin Cooper, Eka Software, UK, examines the recent developments in data handling and analytics software, and what this means for the future of the downstream sector.
With crude oil at a modest price, the global oil and gas industry is continuing to experience one of the toughest operational periods in recent memory. While upstream and vertically integrated operators have deployed a variety of techniques to optimise the cost effectiveness of exploration and production – broadly definable as doing more with less – the role of margin preservation and loss avoidance in the downstream industry’s transporters, marketers, traders, and even refiners, continues to be sharply highlighted.

After all, downstream is where sourcing strategies for both raw materials and refined product must be optimised to secure value. It is where seamless transport, storage, and logistics make a real difference to profits. It is where customer behaviour must be clearly understood to ensure the supply of refined products matches the demand. It is where traders try to understand the impact of wholesale market movements, volatility, and the consequences of international politics and economics to minimise price risk and maximise hedging strategies.

Rethinking IT investment
Downstream operations have also been the recipients of extensive investments in technology. Almost every operator rightly has a full complement of enterprise resource planning (ERP), treasury, accounting, business intelligence, customer relationship management, and, of course, energy or commodity trading and risk management systems in place.

Each of these systems certainly delivers significant value in their own field of specialisation. But they are not designed for the current reality of most downstream operators who must coordinate a multitude of interdependent actors, mitigate significant connected risk factors, and make real time decisions with consequences that ripple out to almost every area of the business.
Discussions with industry participants and anecdotal evidence also show that individuals within many downstream organisations still use spreadsheets to get answers about business functionality and the level of risk to which the company is exposed. Spreadsheets are not analytical, and do not give users the opportunity to deploy today’s advanced analytics. Even energy companies that invest in generic business intelligence (BI) tools end up supplementing analyses with spreadsheets because their BI tools lack the complex logic required to manage unique commodity and energy market challenges, and they cannot provide a complete picture of the company’s global positions, exposures, dependencies, and counterparties.

Nor are they designed to provide the predictive capabilities or proactive support for today’s decision makers, who are wrestling with a myriad of data sources with little insight to help inform their choices. The consequence is that crucial decisions are made with limited or insufficient evidence.

**A changing environment**

The need for greater analytical capability has become pressing for two reasons. The first is that the downstream environment is changing rapidly; consider refining as an example. In recent years, the US has become a net exporter of crude oil due to the technological advances that have made shale oil and gas viable. It has lifted the ban on crude exports, and since 2006 has seen a reduction in foreign crude imports for domestic refineries.

Furthermore, now that the Dakota Access pipeline is back in play, the US will be able to transport up to 570 000 bbls of domestically produced light sweet crude oil from the Bakken producing area to major refining markets in the Midwest and East Coast, as well as the Gulf via crude oil terminals in Texas – substantially changing the shape of US production once more.

Meanwhile, the EU no longer has a ready market in the US for its surplus. What is more, a number of European countries are putting in place environmental legislation to either ban or limit the use of diesel vehicles. This alone is having a severe impact on European refineries, many of which are now being closed or mothballed. Meanwhile, India and China are both expanding their refining capacity.

The resulting turmoil in the refining industry has diminished the value of historical data. Instead it has placed a premium on predictive and proactive visualisations and advanced analytics, simulations, and modelling to provide the necessary understanding of business impact in this new world order.

**Understanding the data deluge**

The second factor is that technology itself has rapidly increased the volume, velocity, and variety of data that can be produced and made available to decision-makers. In other words, even if the refining industry were to remain static, operators would still be faced with a tidal wave of information that requires interpretation.

This can be seen among commodity and energy trading environments, where prices respond not just to volatility in the markets, but to new insights from users, customers, and counterparties that were previously unavailable.

Traditional trading systems may be able to handle volatile pricing coming from trading venues and price indices, however, smart traders are increasingly supplementing this formal data with informal information from sources such as social media, which were simply non-existent or non-exploitable just a few years ago. Where legacy trading platforms have been implemented, they are starting to creak under the strain.

The same broad trend is also observable when it comes to information on geopolitical positions or meteorological conditions, such as the impact of El Niño or the possibility of another Polar Vortex. In the current climate, where relations between Middle East oil producers, Russia, and the US have become harder to predict, the ability to rapidly react to informal and unstructured data is as much a part of the simulation and modelling process as accepting feeds from traditional data sets.

The ability to use this kind of data is critical for more speculative activity or securing alpha – a better price than the market benchmark – on the spot market. But it is also important for firms taking hedging positions who wish to lock in the best price on a forward curve. Appropriately handled, this kind of data can offer traders unique insight that competitors relying on standard data indices do not have.

**Managing multi-dimensional risks**

Neither refining nor trading take place in isolation. Storage, inventory, and transportation logistics are all exposed to price and volume risk, as well as changing demand for availability of refined products.

For example, a medium-sized refinery transporting product will typically involve more than 100 000 separate truck movements per month, as well as vessel operations to purchase crude inputs, including port management, route planning, piracy avoidance, compliance with emissions standards, and matching vessels to selected routes – not to mention the forward freight contracts and sales-in-transit to coordinate.

An error, an unexpected movement of any these factors, or a sudden change in demand patterns, could have a knock-on effect on delivery, storage, customer contracts, and, eventually, margins. In this multi-dimensional game of chess, one wrong move can have wide-reaching consequences – particularly as the whole operation is conducted under the watchful eye of diverse and often overlapping national, international, and supranational regulators.

These are just some of the uniquely complex challenges facing downstream operators, whether independent businesses or part of a vertically integrated organisation. The risk of insufficient support and insight in the refining, logistics, trading, and customer-serving segments of the business, can easily offset upstream investments in risk mitigation, or the carefully calculated internal balancing that is designed to reduce exposure to price-makers and others.
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A technology blueprint

So, what does technology for downstream operations look like in 2017, and in the future? As with all other industrial and commercial sectors, the use of mobile, Cloud and analytics are key characteristics. The adoption of the Cloud, in particular, is only set to accelerate, not least to provide the computing power required to provide real-time analysis and visualisations of key data.

There has been a shift from retroactive assessment to predictive, proactive models of analysis that is set to become the standard for creating ‘what-if’ scenarios, models and simulations in the future.

Perhaps one of the most notable features is that analytics will no longer be the sole preserve of data scientists, IT experts, or system administrators. Nor will queries be limited to what can be coded or programmed into the system. Business users will be able to find out what they want, when they want, and without being constrained by the availability of IT support or the functionality of the underlying database.

In terms of system capabilities, operators should look for systems that offer the most appropriate combination of the following:

- Coverage of the entire lifecycle of crude and refined products, including purchase, refining, blending, storage, transportation, sales, distribution, trading, and risk management.
- Artificial intelligence (AI) and machine learning algorithms to analyse bigger, more complex data and deliver faster, more accurate results – even on a very large scale.
- The ability to aggregate and analyse data from disparate systems throughout the value chain, including energy trading, transaction and risk management (ETRM) software, accounting systems, and inventory management systems.
- In-memory data grids provide unprecedented processing speeds, enabling commodities managers to get the results of advanced calculations in minutes rather than hours.
- Predictive analytics to run complex forecasting models and scenarios to answer essential ‘what-if’ questions.
- Dynamic visualisation to present data in easy to use and understand formats.

Conclusion

The downstream environment has never been so complex, and the pressure on managers to deliver has never been so high. But the possibilities presented by IT have never been so great either. Big data and simulation techniques have come together with delivery mechanisms such as the Cloud and mobile to give downstream operators more choice, more accuracy, and more evidence for decision-making than ever before. However, to make the most of this capability, advanced analytics are key – and the critical target for the next wave of IT investment.

Reference

Linking 3D models that have been created in plant design systems with the as-built record of the plant has made tremendous advances over the past few years, with most software vendors investing in laser scanning and point-cloud technologies to capture the ‘as-built’. This enables the linking of the 3D modelling environment with other information sources to support rapid decision making around asset life extension and revamps where more space and/or equipment replacement is required. With 90% of capital spent on existing plants, quickly accessing situations, and making confident decisions is a huge benefit. However, how often do engineers revisit the complex engineering analyses they carry out when the plant is first conceived? And when should they re-analyse a piping system that has been corroding for many years, to predict under what circumstances it might fail? This article looks at the technologies available to maintain accurate engineering information about assets over their lifecycle to provide decision makers with more predictable and consistent results.

Current state
Sophisticated plant design technology that model plants in 2D (process flow diagram [PFD], process and instrument drawing [P&ID]) and 3D, prior to construction and operation, have been available for over 40 years. These
applications are used on practically every capital project, large and small. The models contain all the information required to procure equipment, construct the plant, and simulate the stress under the range of operating conditions, so that management can be certain pipes will not leak and the structures can bear the loads. Engineers carry out exhaustive analyses to ensure the plant meets exacting codes and gains the necessary permits to operate.

Additionally, there are many engineering data management systems available that share these 3D models with all project stakeholders, including those who operate and maintain the plants. The highly technical engineering information contained in these systems is extremely valuable and useful when considering the safety and viability of today’s plant infrastructure, a great deal of which is being extended beyond its originally anticipated life. It is important that the information is broken out of silos and shared across the entire project team, not just during the time the asset is being built, but throughout the operations and maintenance of that asset, which could be 50 years or more.

Bentley has developed technologies, such as i-models, that move data and information from system to system, providing the ability to access the information from anywhere, using mobile devices onsite and in the plant. In addition, new technologies, such as using digital cameras on mobile devices, can turn simple photographs into 3D models and, when combined with laser scans, provide an accurate 3D model of the ‘as operated’ plant.

Through project examples, the author will explain how the company’s users in the hydrocarbon engineering space are maintaining and operating their assets using technology that enables information mobility across the entire project team.

Eastman searches for better information security
A recent example is Eastman Chemical Company, which kept its records for engineered systems reliably up-to-date with an in-house record drawing change process management system. Eastman successfully managed nearly 4 million files for 2500 active users worldwide, in sectors that included engineering and construction, maintenance and reliability, operations and support, procurement, and real estate. However, it became clear that Eastman needed a system that would deliver better information security and reliability, and lower software maintenance costs. Moreover, it needed to improve information security by using standard access control functionality along with customised features to align with internal security policies.

Using ProjectWise, Bentley’s collaboration and information management system, Eastman facilitated collaboration across its enterprise and delivered a significant return on investment (ROI) above implementation costs. The system was customised to enable Eastman’s unique record and drawing management process, ensuring integration with internal SharePoint environments, and aligning the system with internal security policies.

The partnership between the two companies developed database migration programming that allowed for attribute mapping and file loading with maximum database integrity throughout the migration from Eastman’s legacy system into ProjectWise. The data integrity and smooth transition was of significant value to Eastman due to ongoing capital projects, planned shutdowns, and overall reliance on the system to support operations, maintenance and engineering activity.

Implementing a stable construction environment
When an oil refinery in Houston, Texas, US, wanted to apply an advanced work packaging methodology in an environment where construction planning is typically carried out while in progress, it turned to Insight-WFP to deliver a stable construction environment with predictable project outcomes, while maintaining safety in the operational facility. Insight-WFP recommended Bentley’s ConstructSim Planner and ConstructSim Work Package Server, which work together to combine 3D models from engineering with construction constraints and automate the production of installation work packages. The firm also needed support from the information management team that would be using the software in order to build workforce plans in a controlled, systems-driven environment.

The ConstructSim application provided a single source of online documentation where construction contractors can search, pull, and make revisions to electronic documents with near-zero lag time. Using information mobility through the Bentley Navigator software that was installed on tablets, superintendents and foremen could access live packages and 3D images of the latest designs in the field. This reduced the risk of contractors working with incorrect drawings. Moreover, defining the task at hand through work packages reduced the inefficiencies associated with a typical construction project, and improved onsite safety.

Connected data environment improves information sharing
Collaboration and information sharing was also a key aspect for Russian engineering firm Soyuzhimpromproekt, when it designed the country’s first production facility for methylchlorosilane, a raw material used in industries such as space, aviation, and electronics. Facing a three year deadline to design and construct the massive project, comprising of 18 new buildings, and renovate the existing former rubber plant, the engineering firm deployed a multi-discipline process supported by 3D modelling and analysis applications to implement an integrated design approach.

The project team faced three challenges that required all engineering disciplines to work simultaneously to make informed decisions – the amount of materials, the complexity of implementing the piping and electrical connections, and the short construction time. To facilitate this process, the team used ProjectWise to coordinate hundreds of schedules across various disciplines. The content management application streamlined workflows and optimised information mobility, which simplified the
correlation of the different solutions for various parts of the project. By enabling the secure exchange of information, any project team member could see the most current information at any time. Automated version control eliminated the risk of using outdated documents and data, while working in a connected data environment improved accurate information sharing. Moreover, the information is maintained and updated throughout the life of the asset. Using Bentley technology to facilitate electronic information exchange enhanced collaboration, reduced the costs of producing documentation by 50%, and cut the travel budget by 30%.

**Shell ProjectVantage**

Manually managing and analysing information on large, complex projects is an extremely inefficient process. On projects where there are hundreds of thousands of documents, the cost of using a manual system can no longer be justified. Shell realised it had to change the way it approached large projects and created an integrated engineering environment called ProjectVantage that covers all aspects of the project lifecycle. The new environment is a multi-vendor integrated data-centric approach to capital project delivery. As part of ProjectVantage, last year, Shell implemented a global framework to improve its capital project construction execution through automated 4D/5D construction management solutions and chose to base this on Bentley’s ConstructSim. The ProjectVantage program delivers safer and better projects faster by improving cross-discipline and supplier collaboration, controlling data throughout the capital project lifecycle, and applying standards and enabling replication so that projects can re-use designs and start faster. The construction management application visually supports workforce planning, so that work fronts can be optimised safely and efficiently.

Through a Cloud-based collaborative environment, owners and contractors can identify risks earlier and agree on a strategy to return to plan. Mobile solutions enable field supervisors to use their time more efficiently, updating central project data from the field. As-built 2D drawings and 3D models are validated and updated through laser scans and can be maintained centrally at low-cost centres. With complete and timely handovers of data maintenance, the Shell ProjectVantage environment allows the organisation to know its facilities are safe.

**Conclusion**

The projects outlined in this article have one thing in common – they are unlocking information to be used across the entire project team to enable collaboration, improve efficiency, and reduce risk. This information can be quickly updated when changes occur, so teams have the latest information at their fingertips. This information can be kept for decades and is easily accessible when it is time to rehabilitate or decommission an asset. The end goal with any project is to build, maintain, and reuse effectively and efficiently. Bentley builds its business on ensuring its users have the right information at the right time, and is easily accessible to deliver projects faster and more cost effectively, leading to greater ROI.

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Oil is a well-travelled commodity. Refined into a broad range of petroleum products, it moves from production fields to refineries to distribution centres all before final delivery to users. At some point on its journey from the wellhead to the fuel tank, a barrel of crude oil will almost certainly spend some time in a storage tank. The world consumes a lot of oil, which means a lot of storage tanks.

In the US alone, storage tank capacity totals more than 1.1 billion bbls of crude and refined oil products, and this number is increasing. According to a 2016 report by the US Energy Information Administration (EIA), the global supply for crude oil has outpaced demand. As a result of, generally, rising crude oil inventories since the end of 2014, the global oil industry is building — and filling — more storage facilities.

While a storage tank may appear to be a simple structure, there is more than meets the eye. Large petroleum storage tanks can be more than 400 ft (120 m) in diameter and contain 1.5 million bbls. However, tanks can change over time. The volume of fluid puts enormous stress onto tank walls and floors, which can result in deformation. Other issues may be induced by corrosion, subsidence and weather. In extreme cases, a tank could fail and release hazardous or toxic material into the environment.

In order to keep storage tanks working safely and efficiently, tank owners undertake a programme of regular inspection and maintenance.
In 1991, the American Petroleum Institute (API) published standards for inspection, repair, alteration and reconstruction of steel aboveground storage tanks used in the petroleum and chemical industries. Known as API 653, the standards are widely accepted around the world. The US requires tank inspections every five years, while older tanks may require more frequent attention.

A key component of API 653 tank inspections is accurate physical measurement of tank shells, floors and roofs, yet precise measurement is not always a simple task. The work to gather and analyse data on such large structures provides a good example of the flexibility and power of geospatial technologies. By integrating field and office work processes, modern solutions are reducing costs while improving accuracy and productivity in storage tank inspections.

A new path to inspection reports

The API 653 standards call for measured data on the verticality of tank walls, the roundness of tank shells, flatness of floors and any subsidence. Today, measurements are typically gathered using surveying instruments known as total stations. Depending on the size of the tank, as per API 653 standards, crews of two or three people use a total station to capture data on 12 locations (or stations) around a 120 ft tank. Many total stations can measure directly to the tank shell, which provides additional data for vertical checks.

For out-of-service tanks, inspectors can gather data on a tank’s interior and exterior, including the floor and roof. The entire floor can be measured to check for subsidence. Interior measurements may also capture any structural or other components inside the tank (known as deadwood) that affect tank capacity. This work adds time to the inspection, but produces more comprehensive information.

While the current methods are well defined and accepted, one company, Mistras Group Ltd, is turning to a newer technology – laser scanning – in an effort to provide faster, more thorough and more accurate inspections.

Laser scanning uses light detection and ranging technology (lidar) to capture millions of individual points on a tank’s shell, floor and roof. Laser scanning also collects information on tank appurtenances (nozzles, access points, stairs and ladders) and nearby structures and terrain. Built-in cameras capture digital images that provide additional documentation of tank conditions. The 3D laser scan data can also be used for fitness-for-service assessments (FFS).

Laser scanners are roughly the same size as total stations and use a similar tripod and workflow in the field. To conduct a scan, a Mistras operator places the scanner at a few locations around a tank. In just a few minutes, the scanner captures a ‘point cloud’ consisting of closely-spaced 3D points on the tank and structures. Depending on the size of the tank, the operator performs multiple scans to capture the entire site. In most situations, crews using high-speed scanners can complete the work in less than one hour.

When visiting a jobsite, inspectors need to follow defined processes to plan and execute the field work. Prior to starting large projects, inspectors may use Google Earth views to develop approaches to capturing data. For example, tanks with pumps, those with piping close to the tank, and tanks with external floating roofs may require additional scans to capture complete information. When the field work is completed, the inspectors send the data files. At this point, laser scanning software is essential to process the data and analyse the tank’s condition.

Expanding the inspector’s view

Early lidar data-processing software was focused on managing point clouds and offered only limited functionality for analysis or modelling. Due to advances in software technology, the additional data that laser scanning provides offers a more detailed look at a tank, and the analysis process itself is far less cumbersome.
When exploring solutions for emission reduction, the moves you make now can have a large impact on your environmental compliance and plant operations.

Our team of experts at CRI Catalyst Company, which is part of CRI/Criterion, Inc., the global catalyst technology company of the Shell Group, offers energy-efficient solutions for catalytic reduction of emissions. CRI’s proprietary Shell DeNOx System, Shell Dioxin Destruction System and the CRI N₂O Abatement Technology System can be designed to achieve emission reductions in excess of 99%. All systems feature our unique Lateral Flow Reactor design and low-temperature operation enabling your facility to exceed clean air regulations and reduce greenhouse gas emissions. Reduction of greenhouse gases could potentially earn valuable carbon credits.

It is all part of our commitment to delivering innovation.

CRI Catalyst refers to certain of the companies of the Royal Dutch/Shell Group which are engaged in the catalyst business. Each of the companies which make up the Royal Dutch/Shell Group of companies is an independent entity and has its own identity.
Today, when data is received from an inspection, it is input into Trimble® RealWorks® software, which can automatically merge multiple point clouds into a single cohesive dataset. It then performs basic clean-up and organisation and the resulting point cloud provides a comprehensive and precise picture of the entire tank.

Mistras then uses the software’s built-in functions for tank analysis to produce the standard API reports, and transfers results from the software into its in-house software for additional evaluation.

Manually analysing data and producing reports from total station data typically required approximately four hours, but with today’s laser scanning data and software, Mistras can produce API reports and gather even more information in under two hours.

Once the scanning data has been imported and processed, the software can be used to examine the entire tank. Working closely with clients, Mistras uses these reports to develop recommendations and approaches for any required maintenance or repairs. On out-of-service tanks, where the interior is scanned, the company develops detailed maps of the tank floor, using colour-coding to indicate bends or depressions. Similarly, the software can compare the tank shell to a vertical cylinder model and automatically identify bulges or deformations that exceed a specified amount.

The software also helps in managing the area around a tank. With only a marginal increase in time on site, field operators can extend the scans to capture the surrounding ground and features. Customised analysis routines in the software enable technicians to efficiently isolate the structure or earthen berms that make up a secondary confinement. From there, the software can identify low areas or spill points in the containment berms and then compute the capacity of the containment. This value is compared to the measured capacity of the tank to determine efficacy of the secondary containment. The analysis can even account for any expected rainfall and adjust the containment capacity as needed.

Throughout the processing, analysis and reporting phases, the software provides a 3D visualisation of a tank. Users can easily create virtual views from anywhere in the project, including viewpoints from inside or above the tank. Viewing software, provided at no charge, enables clients to view the project and make basic measurements while preserving the integrity of the original data.

Clients can also use the visualisation tools to explain any issues to stakeholders. For municipal agencies, as an example, aspects such as budget authorisation must be reviewed before making repairs or improvements. The graphics and extra reporting provided by the software help them to justify the needed expenditures.

Scanning also enables a virtual revisit to be conducted at any time. When a client requests additional information or questions a report, technicians can quickly access actual measurements and field data to address the issue.

**Taking scanning to the mainstream**

Laser scanning brings a large potential upside to tank inspection, including improved time, cost, and safety. Rather than requiring two or three personnel on a site for several hours, one individual can complete a job in an hour or less for an in-service tank. Scanning also cuts the time spent in tank interiors, which reduces safety concerns and enables the analysis of interior features even after the tank has been refilled.

The specialised software functionality is an essential part of tank analysis. Traditional surveying approaches can miss problem areas, but the point clouds and tank-specific processing provide comprehensive inspection and evaluation. As a result, inspectors can identify exactly what is going on with a tank, and can build a better picture, which enables their clients to make more informed decisions about the maintenance planning and repair process.

**References**


During planned shutdowns, the equipment in refineries and petrochemical plants has to be checked. The downtime can require several weeks when tanks, vessels, distillation columns, and pipes have to be drained and cleaned for maintenance or repair. Shutdowns are labour-intensive and require accurate scheduling and organisation between all projects, as often hundreds of workers are on-site. A variety of materials such as greases, tars, fatty oils, polymers, or coke and iron sulfide deposits have to be removed. There is a particular duty of care to protect the health of personnel when carcinogenic benzene, toxic hydrogen sulfide, volatile hydrocarbons, or other hazardous gases can be released. Senior level personnel try to minimise exposure to any situation where health risks or accidents could be initiated. This article describes chemical cleaning and decontamination technologies to achieve a significant reduction in downtime and health hazards.

Treatment programmes

Coke fouling on furnace tubes can be taken off by controlled combustion with steam and air, but higher amounts of coke deposits, or polymers, have to be removed manually. Iron sulfide (FeS) is one of the most common fouling materials in oil refineries. It easily accumulates in heat exchangers, vessels, pipes or columns equipped with valve trays or packings. If FeS deposits are not removed, they must be kept wet all the time. Otherwise there is a high potential for spontaneous ignition in the presence of oxygen due to its pyrophoric iron nature. FeS oxidises exothermally when in contact with air, so most pyrophoric iron fires occur during shutdowns as this is when distillation equipment is open for maintenance and inspection.

There are different possibilities to form FeS during operation and the term ‘iron sulfide’ covers a range of crystallographic forms, which are both non-magnetic and magnetic.

The reaction (1) describes the conversion of iron oxide to FeS in an oxygen-free atmosphere and presence of hydrogen sulfide (H₂S). Reactions (2) and (3) occur as a corrosion product between iron (Fe⁰ or Fe²⁺) and hydrogen sulfide species:

\[
\begin{align*}
\text{Fe}_2\text{O}_3 & \rightarrow 2\text{FeS} + 3\text{H}_2\text{O} + \text{S} \quad \text{(1)} \\
\text{Fe}^0 + \text{H}_2\text{S} & \rightarrow \text{FeS} + \text{H}_2 \quad \text{(2)} \\
\text{Fe}^{2+} (aq.) + \text{H}_2\text{S} & \rightarrow \text{FeS} + 2 \text{H}^+ (aq.) \quad \text{(3)}
\end{align*}
\]

Reactions (4) and (5) can occur when vessels, columns, heat exchangers or pipes are opened for maintenance and inspection. Due to its pyrophoric nature, it is a rapid exothermic oxidation process and will ignite in the presence of combustible hydrocarbons. Therefore, it is of great importance to avoid self-ignition of the accumulated fouling material that could cause a fire.

\[
\begin{align*}
4 \text{FeS} + 3\text{O}_2 & \rightarrow 2\text{Fe}_2\text{O}_3 + 4\text{S} \quad \text{(4)} \\
4 \text{FeS} + 7\text{O}_2 & \rightarrow 2\text{Fe}_2\text{O}_3 + 4\text{SO}_2 \quad \text{(5)}
\end{align*}
\]

Chemical programmes are required when the equipment has to be cleaned as quickly as possible to minimise downtime costs. In most cases, wash water is...
used as the diluent and additional solvents such as diesel or light cycle oil (LCO) are only required if that is part of the normal cooling process prior to the cleaning and decontamination process. Many refinery customers renounce the use of acid cleaning, chelating agents or strong oxidising chemicals as they can cause numerous threats, such as unwanted chemical reactions or corrosion on the steel equipment, while benzene, hydrogen sulfide or volatile gases cannot be eliminated simultaneously.

Contemporary cleaning concepts use environmentally friendly chemical programmes, where the disposal and/or treatment of waste after cleaning and decontamination is always a consideration. The difficulty is the simultaneous treatment of liquids, gases and solids, where sticky deposits have to be removed at the same time as dangerous gases and associated odours. The chemical constituents must be compatible with all metals when in contact with the washing solution. In most cases, chemical cleaning includes the safe removal of encapsulated hazardous gases (i.e. benzene, H₂S) and should be finished after 8 – 16 hours (at the latest) circulation of the cleaning solution. A cleaning and decontamination of a storage tank may require some days of operation.

The preferred method is ‘recirculation’ (see Figure 1), where approximately 20 – 30% of the system’s volume is taken into account when calculating the required wash water volume. Before the cleaning solution is added into the circulation loop, the system has to be drained and flushed with water. Best practice ensures the cleaning solution can flow from top to bottom. This provides good contact with the equipment and sticky deposits that have to be dissolved and removed. Typically, a 0.5 – 2.0 wt% aqueous cleaning solution is applied within a short period of time at 60 – 80°C. After 6 to 16 hours of circulation, the dirty cleaning solution can be drained off. After flushing with some water and 1 – 3 hours steaming, the manholes can be opened, when the decontamination goal for benzene, H₂S and lower explosive limit (LEL) is achieved with analytical results at zero or near-zero.

Benzene should be removed from the metal surface and sludge without additional mechanical action. It can be extracted much faster into the water or is diverted to the flare or other collection systems. Hydrogen sulfide and pyrophoric iron species have to be eliminated and mild oxidisers react with FeS in a rather slow and impeded manner without creating dangerous exothermic problems. Small coke or polymer particles can be transported with the cleaning solution, but it is not possible to dissolve crystallised coke or polymer fouling deposits. In general, clogged heat exchanger tubes can minimise the performance when product flow through the tubes is virtually impossible.

The oxidiser has to work in both liquid and vapour phase applications. This is important when ‘steaming’ is selected, where the cleaning agent is continuously added into the steam in the parts per million (ppm) range for 6 to 16 hours. As a rule of thumb, steaming with a chemical programme will reduce the downtime up to 75% compared to conventional steaming. One disadvantage of this method is that fouled packings bear the risk of channeling effects. The steam could be released through some channels too quickly to be in contact with the remaining fouling deposits.

‘Cascading’ seems similar to ‘recirculation’, but, in total, more chemicals may be needed and smaller

![Figure 1. Flow directions of the cleaning solution.](image)

![Figure 2. The cleaning procedure in four steps.](image)
Process Insight:

What Happens in the Flash Zone Stays in the Flash Zone

Refinery process engineers covering complex units such as this Atmospheric Column (Fig. 1) can appreciate the challenges when basing process models on real plant measurements. In a typical column, there are about 30 temperature, pressure, and flow measurements in addition to a crude feed characterization. All have unknown errors associated with them, and reconciling these errors is a daunting task which many choose to avoid.

One very simple and effective starting place is to isolate the flash zone region from the upper sections of the tower. Defining a system from just above the Flash Zone to the Atmospheric Residue Crude (ARC), shown as the boxed area of Fig. 1, allows for simple validation of the model and process data. In the flash zone, the majority of the crude is separated as vapor which rises to the upper sections. The liquid residual from the flash falls down through the steam stripping section and exits the unit. Stripped vapors (Stripout) return to the Flash Zone. A small internal reflux (Overflash) from the stage above the Flash Zone also falls into the Flash Zone. A good rule of thumb is to assume the Overflash flow rate is 2% of crude charge.

In a previous study, there was a discrepancy between the ARC flow measurement of 19.3 MBPD vs the model result of 29.2 MBPD. The customer had high confidence in the measured flow rate as it was confirmed by tank levels, so the cause of the mismatch was not the flow meter. By reducing the scope of the model, finding the error was easy. It was quickly found that the initial flash zone pressure in the model was in error and was corrected from 28.3 psig to 23 psig. Next the 190 psig stripping steam had been assumed to be saturated but was actually 200°F superheated. These corrections improved the model match, but not entirely. It was decided to match the ARC rate by increasing the Flash Zone temperature by 19°F. Fig. 3 shows these changes which brought a close match to both the ARC product flow rate and temperature.

Matching Flash Zone operation is very important in understanding the rest of the column as this section strongly affects the upper sections of the tower. Conversely, the upper sections have negligible impact on the Flash Zone, making this sub-process isolation feasible. The Flash Zone sub-process is very simple to set up without having any column specifications. It is a great starting point for new process engineers hoping to develop their process simulation skills.

Hopefully this simulation strategy interests you. We at BR&E look forward to discussing how to implement it at your refinery.

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amounts of the cleaning agent would be continuously dosed for some hours.

**Case study 1**
In an oil refinery in western Europe, a vacuum column needed to be completely dismantled and replaced after many years of operation. Large amounts of materials had accumulated over time in the bottom section of the column, meaning there was a high risk of self-ignition during the destruction of the distillation equipment. It was also suspected that some health threatening gases might be released during destruction. Therefore, a ‘circulation’ of the chemical treatment programme was selected, combining the removal of sticky materials, the elimination of pyrophoric iron species, and the safe removal of hazardous gases.

Typically, a circulation loop is used for cleaning and decontamination procedures, where the cleaning solution is pumped at 60 – 80°C from the bottom section to the top of the column, where it can flow downwards. In this case, it was not considered a good option because the high amounts of dissolved materials would be pumped into the upper part, which was not so polluted. Therefore, the circulation was divided into four parts (Figure 2), where the cleaning solution was drained in stages after several hours to the next lower level to avoid contaminating the clean sections. Flexible, chemical-resistant hoses and mobile dosing pump equipment were used to ensure the circulation and transfer of the cleaning solution at all circuits. Every 30 to 60 minutes, samples were taken to control the relevant analytical parameters such as pH, conductivity, concentrations of iron, sulfide, sulfate, H$_2$S, LEL, strength of the cleaning solution, and appearance of the samples.

Kurita’s new cleaning solution (Figure 3) was added to the top pumparound for circulation and the upper part was later used for storing the cleaning solution. After some hours of circulation, the cleaning solution was drained from the top pumparound section to the medium pumparound level to clean that part as well. Figure 4 (from left to right) shows the chronological sequence during the medium pumparound cleaning. High amounts of sticky deposits were
HIGH STANDARD VALVES FOR NON-STANDARD CONDITIONS.
mobilised and the formation of an oil phase clearly demonstrates the cleaning effect. After five hours, the very dirty and oily cleaning solution was drained off to the wastewater plant for further treatment. A new cleaning solution was added and circulated for several hours. A release of hazardous gas was not observed at any time.

Part of the dirty cleaning solution was drained off some hours later to the wastewater plant and the remaining liquid phase was mixed with fresh cleaning solution from the top pumparound section. This solution was then transferred to the bottom pumparound circuit. While this part was cleaned, fresh cleaning solution was pumped to the top section to keep the top pumparound and medium pumparound in operation.

Finally, the bottom part of the column and the furnace were cleaned with the same approach. The appearance of the bottom samples showed high amounts of dissolved deposits, sludge and oil bound in a temporary emulsion phase, while the dirty cleaning solution was drained off and the bottom section and furnace tubes were filled again with cleaning solution from the upper sections. After several hours circulation, the column was completely drained off and flushed with clean water, which was added to the top section to flow downwards. The cleaning and decontamination results were excellent and no pyrophoric iron, benzene, LEL or other hazardous gases were observed. One advantage was achieving specific deadlines without delays.

Case study 2
In a crude distillation unit, the heat exchangers of the hot preheat train were frequently fouling and needed to be cleaned regularly. Equipped with flanges and valves, single exchangers can be separated during operation from the heat exchanger train, which is when two of them were cleaned.

An intermediate storage tank with mobile circulation pump and flexible hose lines was connected to the flanges and valves of the two heat exchangers. Shell and tube sides of the two exchangers were cleaned one after the other. First of all, crude oil was rinsed through the connected shell sides for two hours. The dirty hydrocarbon phase was discharged to the slop oil system. Afterwards, a 2 wt% aqueous solution of a cleaning agent was circulated through the shell sides of the two heat exchangers with the mobile equipment for approximately eight hours at 80°C. The same procedure was then carried out with the tube sides of the two heat exchangers.

Samples were frequently taken from the intermediate container during the cleaning procedure to monitor the treatment’s progress.

The green markers in Figure 5 show the improvement after cleaning. The customer expected an improvement in the heat exchanger performance by +1.5 Gcal/hr after cleaning. This is the common result when a conventional chemical cleaning programme is used. Later, both heat exchangers were put back into service to evaluate the performance of the cleaning. It was confirmed there was an improvement of +2.0 Gcal/hr, a benefit of more than 30%.

Conclusion
Today, shutdown work must be carried out as soon as possible in order to minimise production losses. This is why modern cleaning concepts are becoming more important, as they can safely remove materials that are difficult to manage or harmful gases.

In collaboration with personnel, the temporal sequences can be planned and performed to a higher standard. Compared to traditional steaming methods, this can result in time savings of up to 70%, justifying the use of modern cleaning and decontamination programmes during shutdown procedures.
According to Douglas Westwood’s World Downstream Maintenance Market Forecast 2017 – 2021, maintenance in the downstream sector is on the up, rising 7% between 2011 and 2016 and set to increase dramatically in the next five years.1 With a stronger commitment than ever to staying online for longer, why is investment in new cleaning technologies still so low? Refineries often bypass innovation in downstream cleaning technologies in favour of traditional solutions.

A 2016 article by Hala Abinader Long, Head of Energy EMEA, XL Catlin, outlined the opportunities and challenges for downstream oil companies in a changing economy.2 The challenge, says Long, is in balancing CAPEX on maintenance budgets against expectations for prices and demand. Refineries that are reluctant to take plants offline for maintenance when margins and demands are strong, are failing to create the resilience the market needs with a long-term commitment to maintenance and safety.

The industry has not evolved quickly enough to tackle the downturn in oil prices. Now that the bubble has burst, those that did not prepare for market volatility by not embracing new maintenance technologies struggle to shutdown long enough to remove fouling and inspect...
strategic assets, leaving replacement as the only unwelcome option, much to the disappointment of shareholders.

**Does planning or reaction dictate asset integrity?**
The global oil crisis has had an impact on revenues, so there is a fair argument for cost-cutting. However, maintenance should be planned and budgeted for, and not reactive. When markets are good, rather than re-investing in maintenance, 600+ refineries extend run times for the benefit of both consumers and shareholders alike, and try deferring maintenance for as long as feasible. Meanwhile, the domino effect starts to take hold, for example the exponential increase and fouling volume and tenacity within fired and unfired process equipment. As a result, one's assets will corrode and erode more quickly, likely leading to a forced shutdown or a critical path situation (and hopefully not catastrophic). When left for so long, standard cleaning methods struggle to remove enough of this abnormally tenacious fouling, leaving non-destructive testing (NDT) companies unable to inspect the assets integrity. This results in costly critical path extensions thereby negating the many perceived benefits of a longer run.

Refinery operators who seek short-term gains may eventually have to be more transparent to their investors when communicating the benefits of such valuable technology. An inconsistent innovative culture may hold refineries back in the short and mid-term during exposure to low oil prices; this includes the disregard for challenging its traditional cleaning suppliers.

**Time for an industry API 'cleaning standard'?**
No industry benchmark exists in refinery cleaning quality levels. Refineries have approved suppliers that have used the same cleaning equipment and processes for decades. Cleaning contractors may provide clients with little, if any, form of proactive monitoring, measuring, recording or archiving of their activities in order to protect the little profit one makes from traditional cleaning, often having to make up for this by adding waste handling as a service. This provides no appraisal for future learning as shutdowns often continue to be dictated by its exchanger cleaning activities.

Too few refineries challenge or benchmark 'how clean is clean?' Whilst no American Petroleum Institute (API) standard exists as to how clean something should be, Tube Tech International’s Enhanced internal rotary inspection system (IRIS) standard tube polishing offers a solution for heat exchanger tubes. The company guarantees cleanliness to IRIS standard inspection for asset integrity.

**Barriers to innovation**
Currently, there is remote and robotic technology that can access near 100% of an assets heat transfer area and remove the fouling in-situ, without dismantling and avoids unsafe man entry. There are even methods that clean process assets whilst the plant continues to run. By contrast, traditional manual lance blast technologies barely achieve physical contact with more than 1% surface area. Tube Tech can provide simple asset design changes both at the design stage and retrospectively, in order to accommodate its bespoke cleaning tools that achieve this in-situ and live online cleaning capability. They do not impact American Society of Mechanical Engineers (ASME) or Tubular Exchanger Manufacturers Association (TEMA) guidelines.

It is important that the industry embraces innovation. Robotic and automated cleaning technology is here now and offers impressive benefits, with less environmental and human risk and a step change reduction in downtime. Any resultant increase in maintenance costs will be small compared to the increased life cycle benefits, production, run times and reduced energy costs and CO₂.

There is often a perceived risk in implementing new processes. It is important to change this term to ‘acceptable and manageable risk’. How can it be accepted that the increased burn and average financial loss in energy from a fouled, inaccessible fired heater convection bank within a refinery or ethylene plant can be a minimum of US$1 million to US$8 million/y, but a fraction of that loss invested in a proven but new technology is deemed a risk?

**Unlocking more revenue from a plant**
To embrace innovation, every stakeholder needs to be informed and understand what the quantifiable benefits are. While there may be misconceptions at board, investor and procurement level, employees and contractors at the coalface are accepting risk at a much more personal level because they are given processes to work with and may not know or are unable to see
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When every minute of downtime matters, you need responsive support you can rely on. Mitsubishi Heavy Industries has established a world-scale manufacturing and service facility in Pearland, Texas to provide rapid response for your product’s entire lifecycle. This state-of-the-art facility, Pearland Works, offers 24/7 emergency response for MCO-I machinery and all other manufacturers equipment, as well as advanced machine tools, field service, spare parts support and over 50,000 sq. ft. of storage space.

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where opportunities exist. To pave the way for the future, the industry needs to challenge, collaborate with and invest in their contractors to develop better technologies. It is important to look closely at old traditional processes and quantify the benefits of embracing innovation that can unearth surprising commercial, environmental and safety benefits, while increasing return on investments (ROI) for all parties.

Refineries, petrochemical plants, etc., are generally built to ASME and TEMA guidelines, which are over 130 years old. Designs are usually managed by engineering, procurement and construction (EPC) companies, who review outputs at the request of investors. They do not consider designing in the accessibility to aid cleaning and inspection of assets, often due to a lack of knowledge of what cleaning and inspection technology is available. Savings are available to refineries that collaborate with a leader in cleaning and inspection to factor in accessibility and clean-ability of an entire plant ready to apply bespoke cleaning tools. This would remove fouling at source, while lifetime asset monitoring and measurement would ensure that all assets are cleaned at the right time and with the right tool, faster, safer, in-situ and even online, which ends up providing an improved run length, energy savings, asset life and plant profit.

Accepting risk
All too often, refineries struggle to assess heat exchanger integrity of the asset for insurance purposes or risk analyses when using NDT because the nominated cleaning service contractor cannot achieve the desired standard needed for inspection. Often a unit will go back into service based on a superficial inspection that could still leak with catastrophic consequences. On average, only 10% of exchanger tubes are ever inspected to an IRIS standard during a shutdown or on an ‘as and when’ basis. This is like playing Russian roulette. So, what is happening to the other 90%? When traditional water jetting struggles to achieve IRIS standard cleanliness, clients may turn to eddy current data (which can be difficult to read) or rely on visual confirmation (which is a disaster waiting to happen). A possible solution to this is that exchangers subject to a highly corrosive or erosive environment could be subject to a pre-determined periodic maintenance ‘spring clean’ service, e.g. every four years, a minimum of 60 – 100% of tubes both cleaned and inspected back to IRIS. This at least ensures that the laws of safety averages are in one’s favour. This is even more important now as every refinery tries to extend run times due to lower market margins.

The stark fact is that oil and gas worker fatalities have risen year-on-year. It is a largely unmeasured statistic on a global scale, but a report from the Bureau of Labor Statistics claimed that oil and gas fatalities in the US alone rose from 85 in 2003 to 142 in 2014. The whole industry should be asking how it can mitigate risk. One solution is increased end user investment in innovative culture companies that strive to invent unique services and products. This would help introduce working prototypes and newly developed but safely proven technologies now, when they are most needed. The ideas and technology are here now.

Case study one
Critical CCR platformers polished to enable IRIS inspection standard
A Canadian site was concerned over the tube integrity of both its two vertical combined feed effluent exchangers (VCFE), commonly referred to as Texas Towers, within its continuous catalyst regeneration (CCR) platformer unit. To anticipate asset life, the site needed to accurately determine tube wall thickness. Traditional contractors were unable to achieve IRIS (ultrasonic) inspection standards using water jetting/chemicals, so a CAPEX replacement of the heat exchanger seemed inevitable.

The challenge required all 3000 VCFEs exchanger tubes to be unblocked and cleaned to production standard, with 20% polished to IRIS standard, within a seven day timeframe. On inspection, tubes contained gummy deposits, coke and iron oxide, as well as being coated in a tenacious hydrocarbon scale.

Tube Tech delivered its bespoke Rotafl ex Enhanced IRIS standard cleaning system to access the small 18 in. dia. manway/nozzle, located on the side of a fully welded header, right angles to the tube sheet and applied using remote technology. All tubes were drilled, descaled, polished and inspected full length of 20 m (65 ft). Both VCFEs were cleaned simultaneously within the client’s seven day timeframe.

In the past, the client had to clean and re-clean, which proved to be costly. When IRIS testing is carried out first
Get accurate flare gas heat values fast, with the FlarePro™ Mass Spectrometer.

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time and there is no rework, there is no added cost. Although the outset costs may be higher, the overall cost is cheaper because of less re-work and less compounding costs from other resources.

Case study two

Ethylene heater convection bank robotic cleaning in the Netherlands

One of the world’s largest ethylene producers avoided the costly convection bank replacement of a cracking furnace by using Tube Tech’s robotic cleaning technology to fully clean its steam cracking furnace convection bank coils.

Convection coils consist of multiple finned and bare tube banks often 6 to 10 rows deep, where fouling is estimated to be 2 – 4 mm thick, insulative, light, friable scale adhered between and on the fins as well as bridging external tube and finned surfaces. Access to the convection section was via small 250 mm x 200 mm inspection hatches.

Tube Tech’s robots removed almost 100% of all packed fouling from every convection tube bank. The robot used an endoscope to verify levels of cleanliness had been exceeded.

Cleaning was completed within 36 hours (during shutdown) using two robots. This dramatically reduced stack temperatures to normal and improved heat transfer, allowing increased throughput, exceeding the clients’ expectations. The client anticipated a first year energy return of US$2 – US$8 million, excluding cost of replacement.

The root-cause of the decreasing performance of the furnace was reduced heat transfer in the convection section due to external fouling. After the robotic cleaning, the heat duty of each convection bank increased by 11% and the stack loss was reduced by 16%. The quality of high pressure steam generated was improved. Thorough cleaning avoided damage to the low temperature sections and flue gas fan. The client noted that the external cleaning was a success and will bring benefits in the coming years.

Conclusion

The time to have a benchmark for refinery cleaning quality levels is long overdue, and industry-wide practices and standards need to be put in place to enable refineries to measure delivery. New standards should also require operators to include quality, safety and the environment in equal measures to cost. Innovation is essential to evolve and create better, safer, cleaner environments. The technology is here now, the only barrier to the benefits it can bring is the endemic culture to think that cost cutting is the only way forward.

References

Today, the oil and gas downstream industry extends worldwide and is characterised by a large degree of technological sophistication. After its first developments in the US, at the beginning of the last century, the refining and gas processing industry has continued to expand. Within downstream plants, rotating machinery technology has been pushed, over decades, to continuous improvement. One of the main reasons why rotating machinery technology has been developed is due to the high impact this machinery has on overall process capabilities, performance and limitations.

Today, as in the past, the search for higher plant output efficiencies drives the move towards more powerful machines that work at higher speeds and under more severe operating conditions. Machinery plays a primary role in the downstream industry because it is integral to the overall increase of plant and process performance. Within process machinery, centrifugal pumps play an important role, and are often critical or in downstream processes. Even when they are not considered vital, the pump’s role always remains important and a determining factor in the full functionality of many auxiliary and ancillary services. Confirmation of how important this kind of machine is in the downstream sector is evident by the fact that the centrifugal pump market continues to extend over a large number of process applications, with a wide range of sizes and capabilities. Over the decades, many centrifugal pumps have been developed for different applications, from single to multi-stage, axial or radial split, horizontal or vertical rotor position, covering power ranges from hundreds of kilowatts to dozens of megawatts.

The continuous search for market competitiveness has been the driver toward higher plant performance, with consequent development to centrifugal pump technology and auxiliaries able to provide performance increases, as well as reductions to the overall costs associated with running a facility.

Main developments
The following notes will provide an overview of some of the main developments in the pump technology arena over the last few decades.
Firstly, the key role that metallic materials played in the technology evolution should be mentioned. These materials were used for pressure containing parts, rotor assemblies, and for fluid exposed components in general. The implementation of these steels and special alloys allowed for rapid expansion to the centrifugal pump’s application range.

One ongoing challenge during this expansion was achieving higher performances and operative speeds, which sent a strong signal to those working in the field of pump rotor dynamic research in particular. Here, an important factor was the rapidly increasing availability of computational techniques and powers, along with the intense research activity on both theory and testing areas. One considerable contribution has been the determination of the experimental coefficient necessary for the appropriate modelling of rotors, bearings, and for shaft wet supports in general.

In Figure 1, (an API 610 rotodynamic analysis of a canned motor pump) the free-free (zero bearing stiffness) response is shown for the first bending mode no. 1 at 1290 rpm. The multi-stage pump is modelled with its three bearings, the canned motor section (green) and the added inertias and masses of the attached impellers, wear ring forces, gyroscopic effects, etc. The curved line through the model displays the deflection mode’s shape during the first bending and at the first critical speed.

The inclusion of rotodynamic analyses for high speed pump rotors within standard design procedures allowed the operational range of these machines to increase, while maintaining the requested level of availability and lifetime. This improvement was made possible through the development and commercial availability of rotodynamic software, such as advanced rotating machine dynamics (ARMD) by RBTS Inc., and other such commercial packages.

Modern rotating machinery design has the opportunity to take advantage of the dedicated design software available. These tools allow for delicate evaluations of some topical mechanical design points, such as the bearing selection, balancing pistons, and sleeve clearance sizing. Modern software also provides a valuable support when fulfilling the detailed design requirements of applicable normative emanated for original equipment manufacturers (OEMs) and pump user committees (i.e. API 610, API 684).

Figure 2 is a visual representation of the pressure profile of a cylindrical journal bearing from a canned-motor pump. This is operating at 3300 rpm, at a 294 W power loss, a maximum film pressure of 6.8E+05 Pa, a minimum film thickness of 0.007 mm, and at a 5.76 l/min lubricant flow (water).

Another element that has consistently contributed to pump technology improvements has been the development of testing methods. In particular, the commercial availability of the advanced measurement of system vibrations that allowed for the acquisition of a considerable amount of data and detailed analyses and verification of pump behaviour, in respect to vibratory design provisions. Additionally, the hydraulic design received a positive contribution from the availability of reliable computational codes at industry level.

The hydraulic design of a pump flow pattern’s 3D shapes is a delicate task. The introduction of computational fluid dynamics (CFD) software tools has highly influenced the development of process pump design practices beyond the traditional ones. The increased computational power and the availability of reliable codes has allowed for consistent improvements to the centrifugal pump design process and the integration of OEM experience with reliable simulation predictions.
Finding the right caustic treating solution to remove impurities from hydrocarbon streams is a challenging task for any operator. Thanks to Merichem Company’s extensive experience and commitment to innovation, treating gaseous and liquid hydrocarbons can be efficient, economical and clean. Merichem Company brings 70 years of experience in the treatment and handling of spent caustic streams to the petroleum refining and petrochemical industries. Technical expertise allows us to recommend the right caustic treating process for your specific needs and handle most resulting caustic solutions in a non-waste, environmentally friendly manner utilizing a portfolio of caustic treating technologies as well as beneficial reuse channels.

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Another discipline contributing to the increased availability of centrifugal pumps is the control system area. Today, control systems are based on physical models of machinery that may accurately predict the pump performance in every operating condition. This capability is useful for several purposes, though mainly targeted towards diagnostics. The ability to determine the performance parameters as expected and according to design, allows for the early detection of possible deviations, providing enough time to formulate a solution to the incoming upsets. A significant example is the efficiency. From field reading it is possible, in fact, to calculate the operative (actual) efficiency. In order to evaluate if this value is acceptable or not, it is necessary to compare it to the value that the machine would have when running as if it had just left the shop (i.e. in optimal working conditions). This comparative value may be obtained by adjusting design performance to actual conditions. For the centrifugal pumps, this comparison is quite easy since the efficiency does not have a great variation under different operating conditions.

Being able to trend deviations among measured and expected values over time, gives an up-to-date account of a machine's health status and how it is changing. These types of features, coupled with the implementation of variable frequency drive (VFD) techniques, also contribute towards achieving efficient machine management from an energy viewpoint, as well as reducing and containing its environmental impact.

Conclusion
Summing up all the effects of these features, these systems provide a substantial contribution to machine lifetime extension, availability increases, maintenance cost reductions, and adsorbed energy reductions, all allowing for better return on investment (ROI). As a result, many other areas of pump technology improvement are currently being pursued, from hydraulics to mechanical design and auxiliary technology. The authors of this article expect that the synthesis of these capabilities will lead the industry to market the next generation of machines, fully optimised – from a global energetic and environmental standpoint – with higher performances and better ROI.
Hydrocarbon Engineering presents an overview of some of the recent developments and technologies in pumps, valves and seals for the downstream oil and gas industry.
ARFLU INDUSTRIAL VALVES

Arflu has extensive experience in the design and manufacture of industrial valves for the petrochemical, gas, water, energy and marine markets. This experience enables the company to offer the respective industries with duly-tested valves of high quality and durability.

Arflu has a production plant in Sopela (Bizkaia, Spain) and offices in Madrid (Spain), the UAE, Houston (US), Mexico, Indonesia, and China. The company has partners in almost every country in the world, allowing it to supply products both quickly and effectively to its clients, as well as provide customers with optimum sales service from the manufacture of the product right through to its implementation and operation.

Arflu’s technical department is responsible for developing new products and revising existing ones based on market needs. For this purpose, the company has the latest tools for the design of its valves. All of its products are manufactured in order to ensure high quality and reliability. The use of 3D programmes and software from the initial steps of the design, enables Arflu to achieve increased efficiency in the sizing and adjustment of the different elements of the valve. This enables interferences between valve elements to be checked and modified in the design phase, significantly reducing design revision time. Once the design has been completed in 3D, the programmes allow the diagrams for machining to be prepared in a quick and effective manner. The finite element calculations enable the thicknesses of all elements to be adjusted, thereby ensuring optimised operation, along with savings in raw material costs without compromising on quality. All of this is achieved due to an ongoing innovation programme. In keeping with these technological advances, Arflu is committed to the supply of large diameter valves. The company has the capacity to produce larger valves to satisfy the increasing needs of the industry.

A ball drain valve from Arflu.

BAL SEAL ENGINEERING INC.

Although they have been around for a long time, O-Rings, compression packings, U-cups, and mechanical face seals can still deliver acceptable performance in many hydrocarbon processing equipment applications, as long as hardware, surface finish, material selection and other factors are all properly addressed. However, today’s escalating pressures and accelerated speeds can sometimes prove too much for them. The result can be unexpected failure, productivity loss and, in some cases, serious environmental impact.

In light of this fact, a growing number of the industry’s design engineers are evaluating the benefits of a multi-component approach to sealing. This approach leverages the unique properties of several materials and seal configurations to deliver better reliability and predictability.

An example of this approach is the LKS® High PV Seal. Described by Bal Seal Engineering Inc. as a ‘high pressure, high velocity seal’. The LKS consists of a spring-energised, graphite-reinforced polytetrafluoroethylene (PTFE) sealing ring coupled with a high temperature engineered thermoplastic anti-extrusion element and a metal locking ring.

In the LKS seal, each component has its own unique role to play. The metal locking ring reduces the OD shrinkage of the seal jacket at cold temperatures, and prevents the seal from becoming dynamic. The graphite-reinforced seal jacket performs well in high temperature, high pressure service conditions while providing a high level of extrusion resistance at moderate speeds. The thermoplastic anti-extrusion element minimises seal jacket extrusion, provides longer sealing life, forces wear to occur at the lip contact area, and extends seal performance range at low and high temperatures (-94°F to +550°F). The Hastelloy® Bal Spring® canted coil spring exerts uniform sealing force against the shaft, reducing heat build-up and extending seal life while providing excellent resistance to corrosion in a variety of media.

Multi-component seals, such as the LKS, represent a novel take on problem-solving, because they deal in capabilities instead of limitations. They allow engineers to consider a sealing challenge from a more holistic perspective, and they signal a measurable advance in seal technology for the industry.

CONVAL INC.

Conval Inc. is a US-based manufacturer of high performance severe service valves. The company recently had a major customer in the petrochemical industry with an application that required a flow of 52 800 lb/hr with pressure drop from 1400 to 10 psig. The media was a mixture of gases with a density of 0.02 lb/ft³ at STP and a k = 1.385.

The Conval engineering department custom-designed a four-stage Whisperjet® to accomplish this dramatic drop in...
pressure. The design was then tested using advanced engineering simulation software, custom-manufactured to exacting specifications, and subjected to rigorous quality control. Upon delivery and installation, the Whisperjets performed flawlessly.

Whisperjets are deliberately designed to reduce pressure through a combination of impingement, tortuous path and multi-stage pressure letdown. Each stage inside the Whisperjet has 4 – 6 orifices around its perimeter. The orifices discharge inwardly, which reduces the pressure without causing component wear. Pressure is reduced in stages, which prevents a critical pressure drop. Each stage is progressively larger, allowing for expansion. The orifices are carefully sized to keep the flow below critical velocity. This gives the advantage of reduced noise.

When used in conjunction with a valve or other system components, the seat life of the valve is substantially increased and damage to piping is minimised. When used before a condenser or flash tank, baffle and tank wear are also greatly reduced.

Due to their simple, practical design and operation, Whisperjets are economical solutions to pressure drop problems.

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**CRANE CHEMPhARMA & ENERGY**

With a vast portfolio of highly engineered valves, pipes and fittings, Crane ChemPharma & Energy, a business of Crane Co., has become a leading supplier of products designed for the most demanding, corrosive, erosive and high purity applications in the world. Since 1855, Crane has been an innovator and pioneer of practical flow control solutions, presenting the industry with new technologies and resources, including its latest offering, the Krombach® KFO 9136 Metal Seated Ball Valve (MSBV). This extreme temperature and wear-resistant MSBV features a uni-directional single seat that permits a tight shut-off, ensuring cavity-free performance. Its optimised energising seat with low friction bearing design enables a permanent seat/ball contact under recurrent thermal cycling and offers low cost of ownership through the reduction in operating torque by over 20%. With a temperature range of -29°F to 500°F (and special temperature ranges up to 700°F and 1300°F upon request), the MSBV also features excellent fugitive emissions controls, as a result of its robust stem seal design. The MSBV is appropriate for both upstream and downstream applications, but one process in particular

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where it can be used for both is coal gasification. While coal gasification results in the production of syngas, largely for the generation of electricity, there are downstream applications within the process that require reliable valve equipment that can withstand the severe conditions, specifically in its slag/fly ash system. Characterised by the presence of abrasive media, a high pressure class of 600 and a high temperature range of 270°F to 300°F, this system within a coal gasification plant involves the removal of residue through the gasifier either in the form of slag/fly ash, which must be removed downstream. Only a durable valve can withstand the abrasive nature of the media while still guaranteeing a tight shutoff with the added benefit of an exchangeable seat and closure that makes for easy and cost-effective maintenance.

Downstream leakage is also an area of concern within coal gasification where the MSBV can be used to minimise damage and costs. Featuring an energised seat with spring, the effect of thermal cycles and high pressure is minimised, and the sealing between the ball and seat is optimised, allowing for self-adjustment. Additionally, with a polygon stem design that distributes stress more evenly to reduce torsional shear of the stem, this valve will operate without required maintenance and will meet Class 5 or Class 6 leakage standards.

**CRYOGENIC INDUSTRIES INC.**

Cryogenic Industries Inc., together with its affiliates and subsidiaries, has been a leading global enterprise in the industrial gas and energy industries for over 50 years. Company expertise lies in the design, custom engineered solutions, sales and after-market service of its cryogenic machinery, process systems and heat transfer equipment including: pumps, turboexpanders, vapourisers, air separation plants, LNG liquefiers and systems, cryogenic and gas processing equipment, and engineered solutions/service. Cryogenic Industries’ network of companies offers the manufacturing, marketing and service support that the industrial gas, petrochemical and new energy industries expect.

ACD LLC is an engineering and manufacturing company specialising in machinery designed to operate at cryogenic temperatures as low as -420°F, the boiling point of liquid hydrogen. For 50 years, ACD has specialised in centrifugal and reciprocating pumps as well as turbines for air separation. With offices and service centres on four continents and in 12 countries, ACD provides a global presence while able to respond locally.

**EBARA INTERNATIONAL CORP.**

Ebara International Corp., Cryodynamics Division (EIC Cryo) is an established and recognised brand for cryogenic pumps and expanders for the diverse segments of the worldwide liquefied gas industries. For more than 40 years, EIC Cryo has been continuously designing, customising and advancing its equipment for hundreds of customers around the world, delivering thousands of machines for some of the largest, most prominent and complex facilities worldwide.

Starting in 2016 and continuing into 2018, EIC Cryo has teamed with the University of Nevada, Reno, US, to further the study and development of cryogenic turbines, specifically those utilised in the LNG liquefaction processes. Although single-phase expanders have been manufactured by EIC Cryo for more than 17 years, the results of this new study will apply to countless future applications, furthering the understanding and advancement of the newer two-phase technology. The industry’s acceptance and application of these machines will ultimately bring long-term economic and environmental benefits for customers and communities.

In addition to the full line of pumps and expanders, EIC Cryo also offers its customers complete global service packages including service engineering, parts support, training, and customised research. As the oil and gas industry has continued to mature and change, EIC Cryo has expanded its traditional product line into developing markets to support new requirements and applications such as fixed and mobile fuel stations, small scale various marine and floating projects, skids, and customised packaging solutions. EIC Cryo has a breadth of experience, industry knowledge, and the largest, most sophisticated test stand in the world. Staffed with qualified and devoted engineers and support personnel, EIC Cryo is an example of competitive high performance US manufacturing being put to work serving customers around the world.
EMERSON AUTOMATION SOLUTIONS

Plant owners and operators can realise significant, measurable improvements in their total cost of ownership (TCO) with a standardisation approach through Emerson’s engineering and technical experts. End users can potentially save millions of dollars by adopting this progressive programme for standardising models of valves and controls equipment.

The concept of standardisation of equipment and processes within global companies to lower the TCO of valves and controls and use the best possible technology is
an effective strategic approach that complements the Operational Certainty initiative that Emerson launched in October 2016. The standardisation process is designed to address opportunities for improvements in several critical areas such as procurement, inventory management, equipment installation and maintenance.

TCO benefits that customers can expect include, but are not limited to:
- Cost savings by commonly used processes across the enterprise to define, specify, and order technical equipment such as valves and controls.
- Availability of products on short notice to allow quick response and delivery to solve customers’ problems.
- Technology-driven product standardisation with reliable high quality products that significantly reduce plant downtimes, unexpected outages, and operational issues.

**EVERLASTING VALVE**

Everlasting Valve designed a unique valve nearly 100 years ago for blowing down steam locomotive boiler solids. The US Department of Energy (DOE), during its development of the clean coal technologies, selected this valve as a state-of-the-art valve for dry solids and slurries.

The basics of the original rotating disc design have been incorporated to the Everlasting Process Valve. The flat rotating disc renews the sealing surfaces each time the valve is cycled. Due to the internal design of the valve, there are no pockets for catalyst to accumulate, causing jamming. The catalyst is simply pushed out of the way, thereby reducing the possibility of the catalyst getting damaged and creating catalyst fines. The valve is capable of handling vacuum through 10,000 psig (689 bar) and temperatures up to 1500˚F (815˚C).

A major licensor of refining processes now specifies the Everlasting rotating disc metal seated valve for fluid catalytic crackers (FCCs) handling fresh catalyst and for hot catalyst withdrawal. A preeminent catalyst additive supplier has standardised on this valve concept for all of their chemical injection units. Spent catalyst recyclers use them on their vacuum truck load out systems.

After initially being installed many years ago in the slurry phase distillate (SPD) system at Sasol’s wax plant in Sasolburg, South Africa, Sasol selected the Everlasting valve for its two expansion projects. Additionally, the Everlasting rotating disc valve is installed on the raw wax catalyst slurry system at the ORYX gas-to-liquids (GTL) Plant in Qatar as well as the Chevron Escravos GTL Project in Nigeria.

**FLEXITALLIC**

Change™ is one of the most significant developments in the gasket and sealing industry in the past five years, with more than 50,000 sold into sectors such as steel, power, chemical, refining, and pulp and paper, around the world.

Developed by Flexitallic, Change was created in direct response to customers’ long-term heat exchanger sealing problems. It is a highly-resilient metal-wound gasket, designed to deliver the most dynamic static sealing technology ever.

To meet the growing demand for Change, Flexitallic has expanded its production capabilities and invested approximately £200,000 in state-of-the-art machinery at its facility in Cleckheaton, West Yorkshire, UK.

The new facilities will exist in addition to the Change production process in Texas, US, and will enable shorter lead times for Europe and the Eastern Hemisphere.
Manufactured using proprietary equipment, Change has a proven track-record showing it outperforms conventional gasket technology in challenging environments, especially in applications with mechanical and thermal cycling conditions.

Change has also achieved independent industry accreditation from TALuft for its ability to deliver the tightness of a Kammprofile with the recovery of a spiral wound gasket. This is achieved through the application of a unique metal spiral profile, which is more advanced than those found in standard gaskets. This profile, combined with a laser welding process, facilitates the construction of its robust and dynamic seal.

Change gaskets can be supplied with Flexitallic’s Thermiculite® gasket material, which was developed for use in critical services applications from cryogenics to temperatures in excess of 1000°C. The material is a critical component in eliminating graphite oxidation, which limits seal life and seal tightness.

**GE OIL & GAS**

An American Petroleum Institute (API) pumping solution, designed and built by GE Oil & Gas – Nuovo Pignone, has been supplied to Petrofac International Ltd (the UAE) for installation on the largest refinery in Kuwait. The project features 11 main skid-mounted pumping stations, based on hydraulic power recovery turbine (HPRT) technology in which GE is one of the global market leaders.

The Kuwaiti refinery had decided to produce environmentally friendly oil products to meet stringent European and US standards and the use of efficient pumping technology was important if the refinery’s capacity was to be increased. Petrofac, the engineering, procurement and construction (EPC) leader, contacted GE, who undertook the project, which offered significant challenges.

These challenges were met with a design based on hydraulic power recovery turbine (HPRT) technology, which typically relies on two pumps that are either connected with each other or on either side of an electric motor. One pump is driven by the electric motor and is connected with...
For more than 40 years, KAMAT GmbH (with its head office in Witten, Germany) has been a system-supplier for high pressure technology. The product range includes high pressure pumps and pump systems, hydraulic valves, rotating joints, as well as accessories for the pressured transport of different liquids in process technology, water hydraulics and high pressure water jet technology for working pressures up to 3500 bar and power inputs up to 800 kW per pump.

Besides the standard products of pumps and systems, KAMAT designs and supplies customised units and systems, especially based on the requirements of the respective application. The company’s main customers are service contractors in all industrial sectors, as well as direct customers in the chemical, petrochemical and steel industry, and shipbuilding, process engineering, energy, and surface and underground mining.

The company was founded in 1974 as the European branch of a big US pump manufacturer and sold in 1979 to the Managing Director at that time, Karl Sprakel. Today, more than 80% of company turnover is achieved abroad.

The new Inpro/Seal VB45-S™ bearing isolator is a non-contacting two-part compound labyrinth seal that increases pump reliability through premium bearing protection capabilities, a compact design and same-day shipments.

The VB45-S provides permanent bearing protection to rotating equipment through superior protection against contamination ingress and lubrication loss. It utilises the patented XX Interface and enlarged contamination chamber for an IP66 rating, providing premium ingress protection against both harmful dust particulates and powerful water jets from all directions, making it one of the best performing bearing isolators available. For superior protection against lubrication loss, the VB45-S utilises an enlarged D-Groove to capture oil and return it back to the bearing housing.

The new bearing isolator has been available since December 2016 and is the standard Inpro/Seal bearing isolator design for pumps. Already installed on thousands of pumps globally, it is helping to increase pump reliability through premium bearing protection in a compact design.

INPRO/SEAL

Inpro/Seal® is part of Waukesha Bearings Corp., a leader in hydrodynamic bearings and magnetic bearing systems, and an operating company of Dover Corp. Headquartered in Rock Island, Illinois, US, Inpro/Seal has manufacturing facilities in North America and Europe and sales offices in North America, Europe, Asia, Russia and the Middle East. Invented by Inpro/Seal in 1977, the bearing isolator revolutionised the pump industry by extending bearing life through protection against contamination ingress and lubrication loss – driving customer expectations for increased pump reliability. The original bearing isolator, a simple two-piece design, consisted of a rotor and stator interface to keep contamination from entering the bearing housing. Over the past 40 years, Inpro/Seal bearing isolators have continued to evolve to meet customer demand and expectations in permanent bearing protection. Now, developed through extensive R&D and customer feedback, the next generation of bearing isolator technology is here.

A total of 23 pumps (including spare items and auxiliaries) have now been delivered to site for commissioning before the end of 2017 when the HPRT pumping stations will help the refinery to increase capacity, while making use of its waste product and potentially saving up to 40 GWh annually.
Higher pressures, bigger cylinder diameters, and faster advance of roof supports are the current requirements which must be satisfied by high pressure pumps for underground roof supports. Concurrently, operators are calling for reduced noise levels and better energy efficiency. In response, KAMAT developed a new series of speed-controlled high pressure plunger pumps for pressures up to 3500 bar and motor ratings up to 800 kW. The technology of an upgraded mechanical drivetrain, combined with a speed control, allows for the replacement of multiple small pumps with one bigger, controllable, high pressure pump, or with a master-slave combination.

KELVION
Kelvion has launched a new transformer oil pump that combines maintenance-free sleeve bearings with a lightweight cast-aluminium case.

The Renzmann-PR 200 pump combines benefits such as low weight, a temperature application range down to 
-40°C, and maintenance-free sleeve bearings.

The propeller pump is designed to support the circulation of insulating oil for radiator cooling: for example, when natural convection does not suffice during startup, or if high ambient temperatures make more intensive cooling necessary.

Owing to the large cross-section of the propeller pump, the natural flow is not impeded, even when the pump is not in operation. As such, a bypass is not necessary.

LEWA GMBH
LEWA GmbH was founded by Herbert Ott and Rudolf Schestag in 1952. Today, it is a leading manufacturer of metering pumps and process diaphragm pumps, as well as complete metering packages for process engineering. The Leonberg, Germany-based company developed into an international group within a few decades and saw further improvement in the world market as part of integration into Nikkiso Co. Ltd in 2009. LEWA-Nikkiso America Inc. is part of the Lewa Group and is one of the leading providers of metering pumps and systems in North America. The company maintains subsidiaries in Holliston and Devens, Massachusetts, and Houston, Texas, US, in addition to numerous sales agencies.

The Nikkiso centrifugal canned motor pumps are used as the pump of choice for transfer and circulation tasks in the chemical industry and meet the specifications of the API 685 standard. They operate at pressures up to 40 bar, providing flow rates up to 1200 m³/hr as a result. The model has outstanding high pressure characteristics due to the encapsulated and leakproof design where both the pump and motor are integrated, providing environmental protection and operating reliability. At the same time, the centrifugal canned
motor pump requires little space, making it ideal for applications with a small installation footprint.

LEWA EcoFlow metering pumps are equipped with a sandwich diaphragm made of polytetrafluoroethylene (PTFE) and are driven by a motor with a frequency inverter. They are ideal for high discharge pressures and offer a reproducible metering accuracy of ±1%. Due to the patented deep suction pump diaphragm protection system, the pumps offer excellent process safety and reliability, allowing them to be started safely from any operating state. This makes the series ideal for applications that call for precise recipe settings as well as high product quality that remains consistent for years. In addition, the EcoFlow does not require any lubrication from the fluid.

**METSO FLOW CONTROL**

With a 90 year track record of delivering engineered performance and reliability to the oil and gas industry, Metso has supplied millions of control, on-off, and safety valves globally, and is one of the leading suppliers of intelligent valve controllers.

**Knowledge of refining and petrochemical projects**

For refining and petrochemical processes, Metso’s teams provide efficient engineering, execution and on-time startup that meet the toughest performance expectations. Metso’s valve technology and services help to significantly enhance a plant’s efficiency throughout its life cycle – from simplifying valve selection to improving process availability, maximising production performance and reducing safety risks. The company continuously develops intelligent solutions, enabling refining and petrochemical plants to improve sustainability and profitability.

**Comprehensive control valve range**

Metso’s control valves include globe, top entry rotary, triple eccentric disc, eccentric rotary plug and segment valves. They are suitable for most applications, ranging from general to severe service and from low to high temperatures and pressures.

All Metso valves are recognised for providing optimised performance and extreme reliability in demanding processes. They ensure reliable and safe operation that results in fewer production interruptions and less downtime, longer uptime between maintenance shutdowns, and compliance with environmental regulations and safety legislation.

**Project execution in action**

Samsung Engineering chose Metso’s valve technology for a demanding project from Abu Dhabi Oil Refinery that required fast execution. The convenient location of Metso’s valve factory in South Korea, in addition to good cooperation experience from past projects, led to this selection. To ensure smooth project delivery, Metso offered its wide product knowledge and application expertise, global manufacturing and service network along with comprehensive startup support.

Today, Abu Dhabi Oil Refinery Co. has Metso’s valves installed in a carbon black and delayed coker plant at its chemical refining complex in the UAE. Completed in December 2015, the plant processes 30,000 bpd of crude oil with a production capacity of 40,000 tpy of carbon black. The delivery scope included hundreds of Metso’s Neles globe control and on-off valves, most of which were equipped with Neles ND9000 intelligent valve controllers for efficient performance follow-up and predictive maintenance capabilities.

**NETZSCH PUMPS & SYSTEMS**

For over 60 years, NETZSCH Pumps & Systems has served markets worldwide for applications in every type of industry. The company has developed a series of multi-screw pumps with two, three and four spindles, which can generate high pressures of up to 80 bar in limited space. The NOTOS® pumps are highly efficient to operate and achieve long service lives without costly maintenance, due to specially adapted geometries, materials and hydraulic compensation. Depending on the type, they are suitable for lubricating or non-lubricating media at temperatures up to 300°C.

The geometry of the spindles and the housing are optimised to prevent turbulence, pulsation and vibration when conveying media. All NETZSCH pumps are custom-designed for the application, e.g. in terms of size and speed. This ensures a long service life without costly maintenance.
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chemistry matters
Hydraulic compensation and stable material
The pump’s ability to withstand high strains is in part due to the hard materials. Depending on the specific application, the engineers use cast iron, chrome-nickel steel, Duplex or Hastelloy. This ensures that the spindles themselves only deflect minimally at high loads. Hydraulic compensation also reduces the forces. The hydraulic compensation is achieved by means of the special NETZSCH design of the lobe rotors and results from a connection between the high pressure and intake sides. This connection reduces the pressure in the seal chamber and on the surfaces of the auxiliary spindles, to the level of the intake pressure so that the net axial force is zero. Separate bearing bushes also absorb the axial and radial forces at the running spindles.

Special geometry for high efficiency
The various design innovations in the NOTOS® deliver significantly higher efficiency than in traditional multi-screw pumps. The high performance metals, for example, allow for small manufacturing tolerances between the dynamic and static parts, as the components hardly deform at all in operation. This keeps backflow to a minimum and improves the ratio of performance to input energy. The 3NS also features a novel, patented media discharge, which prevents turbulence at the outlet and the associated higher energy consumption.

OMNIVALVE
OmniValve is a leading provider of valve solutions used in the exploration, production and distribution of crude oil, natural gas, and other commercial hydrocarbons and their derivatives. Valve sealing integrity is something that the industry is relentlessly striving for. Valves are constantly being improved upon in an effort to achieve a high level sealing integrity.

Recently, one of OmniValves’ valves was installed into a system where the company was told that only fuel oil and petrol would be flowing. Thus, the company supplied valves with a standard elastomer material used for its seats. However, unfortunately, the valve began to leak after just four weeks in operation. It transpired that this site also had octane boosters injected, such as methyltert-butylether (MTBE), methycyclopentadienylmanganesetricarbonyl (MMT), and methylethylketone (MEK). OmniValve was not told of this at the time of supply. The original specification was over 350 pages addressing the smallest of details but in terms of seat requirements it was vague.

In this particular case, the resume of the individual who interpreted the X-rays on the critical areas of the castings was impressive but the seal material was totally incorrect for this service. One of the most important items to achieve the required results of the valve was disregarded. Yet, there were over 350 pages of specification associated with this valve requirement. To finish this particular case,
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When fire incidents occur offshore and onshore, oil and gas installations must be immediately contained before they can cause a major disaster. In case of fire, the community, the operators, and the environment will be exposed to an extreme danger. Some of the many threats of a fire incident can extend from equipment damages, the shutdown of units or production loss, to human casualties. Fortunately, Onis is constantly seeking to improve the efficiency and the quality of its line blinds. Delivering safety to the entirety of its product range is the company’s priority.

Developed through more than 35 years of experience and research, the fire-safe design technology guarantees the integrity of the line blind. With only four seals (all of them being easily accessible on the slide gate) in a sturdy mechanical design that meets high manufacturing standards, Onis guarantees 100% positive isolation under extreme operating conditions (pressure and temperature) as well as through exceptional incidents such as fires.

The company’s fire-safe construction has a superior resistance to high temperature flames’ constraints; finite elements analysis (FEA) and simulation allow any appropriate material grade to be matched. Thus, any mechanical expansion is controlled, maintaining the tightness.

All fire-safe line blinds are fitted with expanded graphite body seals. The controlled compression of a graphite seal in a groove, with a specific design, and in the outer section of an elastomer O-ring, ensures a leak-free tightness even at very high temperatures.

The main result of this technology is that the Onis fire-safe line blinds reach the same set-up tightness before, during and after fire. Moreover, as well as tightness, the fire-safe line blind remains operable after the fire has been extinguished.

The fire-safe tests were carried out using a fire test bench, complying with the requirements of ISO 10497: 2010 and API 607 6th edition, September 2010, ensuring the highest level of security. Onis’ R&D team pursue designing the safest and most reliable positive isolation solution possible every day.

OmniValve replaced the elastomer with the correct elastomer for the service at hand. One year later, the system is fine and running smoothly.

This brief case study is intended to address the issue that sometimes the big picture can get lost during a project. If a satisfied client is the end-goal, then completely addressing the actual valve at hand is essential. Expanding double block and bleed plug valves must be treated as the unique entity that they are when writing specifications.

Traditional, the majority of valve actuators have been powered by either ring main pneumatic or hydraulic supply sources, or by high pressure natural gas taken from the pipeline in which the valve being actuated is located. Such technologies have existed for decades and, although well proven and used globally, are not ideal for operators in terms of CAPEX and OPEX costs, as well as from an environmental perspective.

Recent advances in low power control components have now allowed technically advanced valve automation system suppliers to develop systems that require no external power supply sources and no external supporting infrastructure. Solar Powered Self-Contained Electro-Hydraulic Valve Automations Systems (SSCEH) use integrally mounted solar panels and rechargeable battery packs to provide all the power the system needs to provide either on/off or positional valve control. Operators can realise numerous operational benefits using these systems.

Ring main pneumatic and hydraulic powered systems require extensive infrastructure, including large air compressors or hydraulic pumps, large pressure vessels and countless lengths of pneumatic or hydraulic tubing. Not only does sizing systems for the lowest pressure result in them being oversized for the majority of operating conditions, it means that additional actuator or control system components are required to avoid actuators exceeding the maximum allowable valve stem torques or thrusts when the ring main supply pressure is at its highest.

Since SSCEH generates its own hydraulic supply pressure, it remains constant, allowing for optimally sized valve actuators that are smaller for a given valve torque or thrust requirement.
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when compared to ring main powered valve automation systems. Direct gas and gas-over-oil valve automation systems are powered by the high pressure natural gas in the pipeline in which the valve being actuated is located. Although these systems require less infrastructure than ring main powered systems, they both suffer from one major design flaw; this being that natural gas is vented to the atmosphere whenever the valve is being operated. Not only does the venting of natural gas to atmosphere create environmental issues, it is also expensive and wasteful to operators. Furthermore, in systems powered by sour natural gas, significant care has to be taken to eliminate the possibility of personnel being exposed to the toxic gas during venting. SSCEH vent no natural gas during operation.

**SULZER**

In January 2016, Sulzer completed the acquisition of the Ensival Moret pump business and brand from the Moret Industries Group.

Although Sulzer already possessed a comprehensive pump portfolio, a clear message was communicated from large end users that they increasingly favour working with trusted suppliers who have the ability and proven operating experience to cover the maximum number of pumping services on large projects. This strategy greatly helps to reduce complexity in project management, service support and spare parts inventory. The addition of Ensival Moret, with its complementary portfolio and geographical presence, will significantly benefit the company’s customers with a larger selection of pumps, process expertise and further extended service network.

Within the oil and gas industry, the acquisition will allow the integrated Sulzer and Ensival Moret tendering offices to offer full-line supply for many major projects where previously both companies supplied separate, non-competing project packages due to focus on different processes. Following the integration, Sulzer can now provide the optimum technical and commercial offer, which simplifies the tender process, technical clarifications, contractual terms and important aftermarket care.

Ensival Moret is one of the world’s leaders in the manufacture of pumps for the polyethylene (PE) and polypropylene (PP) industries, with particular expertise in axial loop reactor and API slurry pumps. Slurry and gas phase process pumps are operating worldwide in PE and PP installations, proven over a period of more than 30 years, where high reliability and high efficiency are essential to overall life cycle costs and customer satisfaction. Further niche, but highly important, portfolio enhancements include molten sulfur pumps and sulfuric acid pumps. These services are extremely challenging due to the nature of the pumped fluids. Ensival’s long-term process knowledge and experience in designing and supplying these products is highly valued.

Product development is a continuous process within Sulzer and the teams from both organisations are working together, as part of its global product development organisation, on the next generation of products that will leverage knowledge and experience from both companies to provide a superior customer experience.

**VALCO GROUP**

**VALVE TECHNOLOGIES**

The refining industry confronts some of the most difficult valve application challenges in various process units. Companies are becoming more focused on the safety of the plant, personnel, and meeting production goals. As a means to provide additional safety to workers within the unit, one refinery in Southern California looked to install a safety process interlock system. These systems are designed to ensure that valves follow a pre-determined sequence of operation for startup and maintenance in their delayed coking units.

In addition to the safety process interlock system, a motor operated valve package was required to conduct
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Velan is one of the world’s leading manufacturers of industrial steel valves. The company was founded by acclaimed inventor and entrepreneur A.K. Velan in 1950, and continues to leverage advanced engineering capabilities and innovation to create high performance valves that meet critical industrial needs in a diverse range of tough global applications.

Velan holds all major industry approvals, and is the brand of choice for many of the world’s major oil companies. In fact, the company’s valves are installed in over 170 refineries worldwide and the installation base in all areas of the global oil and gas industry – from production to distribution, to refining to petrochemicals – continues to grow.

Velan’s Securaseal™ metal seated ball valve product offering is built on over 40 years of experience in quarter-turn valves. Introduced in 1986 as a result of a partnership with Engineered Valves International, this product line now includes many sophisticated designs such as the coker. Today, Velan offers a complete range of high performance metal seated ball valves engineered to operate reliably in severe services. These valves are built to minimise the effects of clogging due to catalyst fines and coke buildup, and to resist the erosive effects of prolonged catalyst service at high temperatures. Velan has successfully installed metal seated ball valves in processes operating at over 3000 psi in temperatures over 1400˚F.

Manufacturing capabilities
- 14 manufacturing plants: four in Canada and the US, five in Europe, and five in Asia.
- Four stocking distribution centres.
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**PUMPS, VALVES AND SEALS REVIEW**

- Three R&D facilities worldwide, offering a range of testing capacities.
- Hundreds of distributors and service shops worldwide.

**VIKING PUMP INC.**

Since it was introduced only three years ago, a new series of rotary positive displacement pumps, in full conformance with API 676, have been applied in upstream, midstream and downstream oil, gas and petrochemical facilities globally. The XPD 676 Series rotary internal gear pumps, in steel and stainless steel, are from Viking Pump Inc., which was founded by the inventor of the internal gear pump more than 100 years ago. With 12 displacements offering capacities from 5 – 1600 GPM (1 to 363 m³/hr) at differential pressures to 200 psig (14 bar), they are operating on offshore platforms, FPSOs, gas fields, bulk terminals, oil refineries and major petrochemical facilities around the world.

While many rotary positive displacement pumps claim API 676 conformance, many can only accept Category 1 seals, which were designed to fit ANSI/ASME B73.1 seal chambers, and they list many deviations to the standard. Viking Pump’s XPD 676 Series was designed to accept the larger API 682 Category 2 and 3 seals, and satisfy all other criteria of the standard, from an additional 3 mm corrosion allowance on pressure-containing parts to a minimum 25,000 hr bearing life, with no deviations. Conformance to this standard helps ensure maximum safety and reliability in critical services.

With their unique ability to handle viscosities from 0.5 to 500,000 cSt, some recent applications have included diesel generator and heli-fuelling, sour crude and refined fuel sampling, railcar and ship transloading, solvent deasphalting, methanol hyrocracking, ethane crackers, hydrocarbon terminals, and manufacturing of lubrication oils, plasticisers, linear low-density polyethylene (LLDPE), polyols and synthetic rubber.

While sold and serviced by independent distributors worldwide, projects are supported internally by Viking Pumps’ engineering, procurement and construction (EPC) group, which oversees project management from specification through manufacturing, non-destructive evaluation (NDE) and certified testing to ensure superior communication between the supplier, EPC firm and the user.

**XPD 676 PUMPS**

**Capacity**
15 to 1,600 GPM (3 to 363 m³/h)

**Pressure**
to 200 PSI (14 BAR)
Higher pressures with factory approval

**Viscosity**
28 to 2,000,000 SSU (1 to 440,000 cSt)
With special construction

**Temperature**
-20°F to +650°F (-29°C to +340°C)
With special construction

**Typical Applications:** Crude Oils, Refined Products, API 614 Lubrication Systems, Petrochemical
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Diesel oxidation catalysts (DOCs) can reduce carbon monoxide emissions in diesel engines by as much as 90%.

In 2015, US greenhouse gas emissions decreased compared to 2014 levels, driven by decreased emissions from fossil fuel combustion.

Daniel G. Nocera has invented the Raistonia eutropha bacteria to consume hydrogen and CO₂ and convert them into adenosine triphosphate (ATP) to produce alcohol for biofuel.

In 2015, China reduced its CO₂ emissions by 0.7% compared to 2014.

Nigeria has reduced flaring to less than 8 billion m³ in 2015 (down 18% since 2013).

A selective catalytic reduction (SCR) system can reduce NOₓ emissions in diesel engines by 75 - 90%, hydrocarbon emissions by up to 80%, and particulate matter emissions by 20 – 30%.

Total greenhouse gas emissions reported to the Greenhouse Gas Reporting Program (GHGRP) fell from 178.2 million t CO₂e in 2011 to 175.6 million t CO₂e in 2015 in the refineries sector.

Global CO₂ emissions from fossil fuel combustion, cement production and other processes decreased in 2015 by 0.1%.

Carbon capture and storage (CCS) could account for 13% of the required reduction in greenhouse gas emissions by 2050, according to the IEA’s 2°C scenario.

Without greenhouse gases and the Greenhouse Effect, the Earth’s temperature would be near to -18°C.

The World Bank has introduced the ‘Zero Routine Flaring by 2030’ initiative to eliminate routine flaring by no later than 2030.

Without greenhouse gases and the Greenhouse Effect, the Earth’s temperature would be near to -18°C.

Plants, soil and water take up CO₂ when stored for a long time (this process is known as carbon sequestration).

CO₂ emissions in Russia and Japan decreased by 3.4% and 2.2%, respectively, in 2015.

Carbon Capture and Storage (CCS) could account for 13% of the required reduction in greenhouse gas emissions by 2050, according to the IEA’s 2°C scenario.

Methane is the second most prevalent greenhouse gas emitted in the US from human activity.

Without greenhouse gases and the Greenhouse Effect, the Earth’s temperature would be near to -18°C.
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