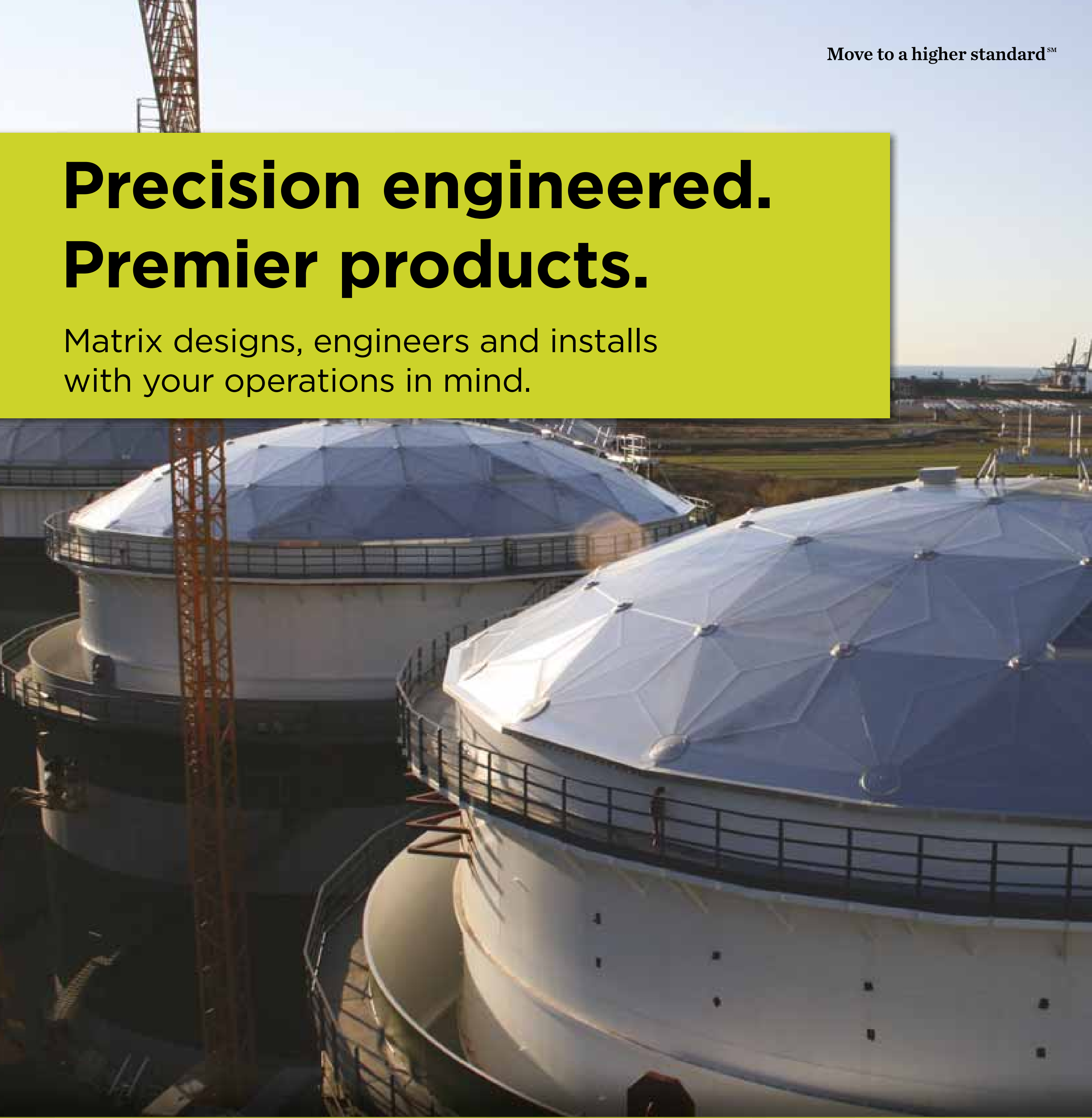
TANKS & TERMINALS

A SUPPLEMENT TO HYDROCARBON ENGINEERING



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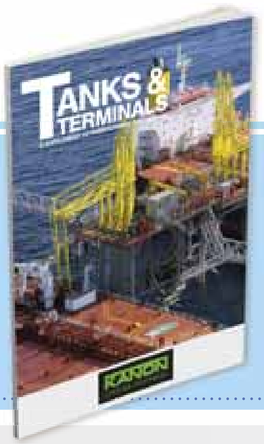

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TANKS & TERMINALS

CALLUM O'REILLY
EDITOR

There have been some encouraging signs at the start of this year that the oil price is beginning its long overdue recovery. OPEC members appear to be coming good on their promise to cut production throughout the first six months of 2017. The International Energy Agency (IEA) has reported a record initial compliance rate of 90%, with OPEC production estimated at 32.1 million bpd in January 2017. This has had a positive knock-on effect for the oil price, with Brent crude hovering around the US$55/bbl mark (at the time of writing).

This is good news for the oil and gas storage industry, which has been feeling the impact of recent uncertainty surrounding the price of oil. A new survey of 171 decision makers in the bulk liquid storage sector revealed that 46% of respondents believe that the oil price is a crucial issue that impacts the success of the industry, affecting both investment and cash flow.[1] In Africa, one in five of the survey participants suggested that fluctuating oil prices had the greatest impact on job security, while its consequences for environmental advances were the main concern for more than one in five respondents in the Middle East.

Environmental standards were named as a top priority going forward for 27% of respondents to the survey, which was conducted by the organisers of StocExpo Europe. Interestingly, there were key regional differences on the topic of environmental sustainability, with 40% of respondents in Europe and 62% in North America listing environmental standards as a key issue for the storage industry. In comparison, just 14% of respondents in the Middle East saw it as one of their top three priorities, while the figure stood at a lowly 11% for those based in Asia.

The survey also revealed that cost reduction is the number one goal for operators going forward. Nearly half of all respondents (49%) listed cost cutting as their top priority for 2017, followed by increasing efficiency (44%) and boosting profitability (35%).

Tanks & Terminals magazine aims to provide a broad range of in-depth technical articles and case studies to help the global oil, gas and petrochemicals storage sector achieve its goals in the months and years ahead. Whether your priority is reducing costs, increasing efficiency, boosting profitability, adhering to environmental standards, or improving safety, we have a range of articles that are certain to prove valuable. This issue of *Tanks & Terminals* – the first of four that we will be publishing this year – covers a range of topics including emergency response, level gauging, vapour recovery, alternative storage solutions and measurement, control and instrumentation. Gordon Cope also provides a detailed analysis of the North American storage sector, starting on p. 12.

If you have a story to tell or a topic that you would like to see covered in one of our upcoming issues, please get in touch. And if you're picking up this magazine from StocExpo Europe or one of the other leading events that we are proudly partnering in 2017, why not sign up for a subscription to the magazine? In addition to this quarterly supplement, you'll also receive a copy of *Hydrocarbon Engineering* – the leading publication for the downstream oil and gas industry – each month. More details can be found on p. 52.

1. 'New Research Reveals Reducing Costs and Environmental Standards are Key Priorities for the Global Tank Storage Industry', Artexis Easyfairs, (3 February 2017).

WORLD NEWS

USA | Sprague completes terminal purchase

Sprague Resources LP has announced that its wholly owned subsidiary, Sprague Operating Resources LLC, has completed the purchase of Capital Terminal Company's refined product terminal asset located in East Providence, Rhode Island, US, for US$23 million in cash, in addition to payments for other customary items. This terminal had been leased exclusively by Sprague since April 2014 and has a combined storage capacity of just over 1 million bbls.

A total of US$11 million in expansion capital will also be invested as part of this acquisition, as well as the subsequent optimisation with Sprague's Providence terminal.

This follows the recently announced purchase of L. E. Belcher, Inc.'s refined product terminal assets in Springfield, Massachusetts, US, for US$20 million in cash.

USA | JGC wins contract for proposed ethylene export terminal

The JGC Group has announced that its wholly-owned subsidiary, JGC America Inc., has been awarded a basic engineering services contract by Odfjell Terminals for the possible development of an ethylene export terminal at its facility in Seabrook, Texas, US.

Under the contract, JGC will provide front-end engineering and design (FEED) services for Odfjell Terminals project.

The proposed ethylene export terminal will be located adjacent to Odfjell's existing liquids terminal, which is positioned nearby major ethylene pipeline corridors. The new terminal will allow for faster turnaround of customer offtake carriers than currently available terminals.

Takehito Hidaka, President of JGC America Inc., said: "Leveraging our industry leading cryogenic terminal and ethylene experience, we will work closely with Odfjell to develop and deliver a cost efficient execution strategy. We look forward to supporting Odfjell Terminals achieve its growth strategy through its Texas-based facility."

South Africa | Royal Vopak to expand activities

Royal Vopak and Reatile have taken an investment decision to expand their activities in South Africa. This investment aims to enhance Vopak's infrastructure to help meet South Africa's increasing demand for petroleum products.

The expansion comprises a new 100 000 m^3 inland terminal in the Gauteng province (Johannesburg) connected to Vopak Terminal Durban via the Transnet Multi Product Pipeline, as well as an expansion of Vopak Terminal Durban with 130 000 m^3.

The new inland terminal will be built in Lesedi. The terminal will consist of six tanks of, in total, 100 000 m^3, eight truck loading bays with a vapour recovery system, and a pipeline connection to the state-owned New Multi Product Pipeline (NMPP) for refined petroleum products. The NMPP is running from the Port of Durban to Gauteng. Vopak Terminal Durban and Vopak Terminal Lesedi will be the first major open access independent tank terminals connected to the NMPP.

The expansion of Vopak Terminal Durban will comprise 10 new tanks with a total capacity of 162 000 m^3, as well as the demolition of 38 older small tanks. The net increase in capacity will be 130 000 m^3.

Russia | Linde awarded LNG plant contract

Gazprom and SRDI Oil & Gas Peton have selected the Linde Group as the licenser for a mid-scale LNG production, storage and shipment complex in Portovaya, located in Russia at the Baltic Sea.

The plant will liquefy natural gas coming from the nearby compressor station, which is part of Gazprom's Nord Stream pipeline. The LNG terminal will use Linde's LIMUM® technology.

Under the contract with Peton, Linde will perform basic engineering for the process plant and supply the equipment and related bulk material for the cryogenic units of the plant.

Both companies are currently cooperating on other projects, such as the Amur Gas Processing Plant (Amur GPP), located in the far east of Russia.

Professor Dr Aldo Belloni, CEO of Linde AG, said: "Gazprom's Portovaya LNG Project, which was jointly developed with the Russian engineering holding Peton, is of utmost importance for us as it represents another milestone for the successful strategic cooperation between Gazprom and Linde in the area of cryogenic natural gas processing and liquefaction."

WORLD NEWS

IN BRIEF

SAUDI ARABIA

Saudi Aramco has announced that construction is progressing well at its Jazan Economic City (JEC) and refinery and terminal projects. The refinery complex is now approximately 70% complete. The refinery complex will be equipped with a state-of-the-art port and a 4 GW power plant that will make the refinery entirely self-sufficient and provide power to locally owned manufacturing and service companies.

IRAN

Iranian Oil Terminals Company (IOTC) has reported that Iran's crude oil storage capacity has increased by 10 million bbls, following the inauguration of a new storage project in Bandar Ganaveh. The total volume of Iran's oil storage capacity has now increased to 38 million bbls.

USA

Plains All American Pipeline and Noble Midstream Partners have entered into definitive agreements to form a 50/50 joint venture to acquire Advantage Pipeline, which owns a 70 mile, 16 in. crude oil pipeline and combined crude oil storage, located in the southern Delaware Basin. The Advantage Pipeline has a capacity of 150 000 bpd, originating in eastern Reeves County, Texas, running through Pecos and Ward Counties, to Crane County, Texas. The Advantage Pipeline also includes approximately 490 000 bbls of combined crude storage at three separate trucking stations.

CROATIA

Jadranski Naftovod (Janaf) has announced that it has signed a deal with MOL for transportation and storage at its Omisalj and Sisak terminals. The company has also inked a three-year contract to provide oil storage capacity to Glencore at the Omišalj terminal.

UK | GAC UK inks deal with Valero Logistics

GAC UK has announced that it has signed a terminal and marine services deal with Valero Logistics UK Ltd.

Under the three-year agreement, which started on 1 February 2017, GAC UK will manage and support the discharge of 12 – 14 million t of clean petroleum products each from up to 180 tankers a year at the ports of Cardiff and Plymouth, UK. It will also use its jetty operation services at Avenmouth from 1 April 2017.

GAC UK will provide a range of terminal services including secure and safe manning of berths, ship/shore safety checks and connecting shore cargo lines to vessels' manifolds. It will also conduct value adding cargo sampling at three stages: from the vessels' tanks before discharge; from shore lines during the operation; and from the trucks. The results, including gauge readings before and after discharge, will be fed back to Valero.

GAC UK also recently announced that it will support Shell UK's operations at Braefoot Bay in Fife, Scotland.

Panama | VTTI continues expansion

VTTI B.V. has announced that it has acquired a 230 000 m^3 facility in Panama, resulting in a joint venture between VTTI and Global SLI.

This deal sees VTTI take a 75% interest in PetroAmerica Terminal, S.A. (PATSA), which is strategically located on the Pacific side of the country, close to the Panama Canal, with a wide range of refined products storage.

In addition to this acquisition, VTTI has closed the recently announced transaction with Energia Naturalis Holding (ENNA), comprising 70% of the newly built Adriatic Tank Terminal (ATT) in the Port of Ploce, Croatia.

In 2016, ATT completed the construction of 50 000 m^3 of clean petroleum product storage. A second stage of development is now expected to commence to deliver a further 200 000 m^3 of liquid product capacity, as well as up to 60 000 m^3 of LPG capacity.

Pakistan | Excelerate to deliver second FSRU

Following negotiations with the consortium of Engro, Fatima, and Shell, Excelerate Energy has announced that it is prepared to help the consortium deliver a proposed floating LNG terminal and second FSRU to the Pakistan market. The fast track FSRU project will supply much needed natural gas to Pakistan to help mitigate the supply shortfalls that the country is currently facing.

Excelerate will use its experience to help the consortium meet the aggressive delivery schedule required for the terminal. Most recently, Excelerate successfully commissioned GASCO's Ruwais Floating LNG terminal in the UAE, which was implemented in less than 12 months.

The consortium's project site is located just across the Port Qasim channel and the country's first LNG import terminal, which utilises Excelerate's floating regas technology.

When the consortium's project comes online in 2018, the total regasification capacity from Excelerate's two FSRU's at Port Qasim will be significantly over 1 billion ft^3/d, which is enough natural gas to support over 6000 MW of power generation.

WORLD NEWS

IN BRIEF

GERMANY

Roth and VARO Energy (VARO) have announced an agreement to transfer the storage terminal Hanau in an asset deal from VARO Energy Tankstorage GmbH (formerly Petrotank) to Adolf Roth GmbH & Co. KG. The terminal, which opened in 1961 and has a total capacity of 9700 m^3, is used for heating oil and diesel. This transaction complements Roth's geographical positioning and optimises the utilisation of the terminal's capacity. For VARO, the divesting of this asset is part of the ongoing development of the company's portfolio.

BELGIUM

The port of Antwerp has announced that liquid bulk volume through the port expanded during 2016 by 3.8% to 69 224 501 t. Oil derivatives were up by as much as 7.1% to 51 310 284 t. The amount of chemicals also grew by up to 1.1% to 13 592 806 t. However, imports and exports of crude oil fell over the course of the year, finishing down 17.4% at 3 977 722 t.

FINLAND

Neste has announced that it has sold its terminal in Pietarsaari to Wibax Ab. Neste said that it had not used the terminal for its own operations in many years. This is due to the fact that the tanks and other facilities are not suitable for storing oil products without investments. Neste did not disclose the sales price.

SOUTH KOREA

Excelerate Energy has executed a Letter of Intent (LoI) with Daewoo Shipbuilding and Marine Engineering (DSME) for the delivery of up to seven floating storage and regasification units (FSRUs). The LoI gives Excelerate the ability to order one FSRU in 2Q17. The agreement affords Excelerate the ability to respond to increasing market demand for natural gas as its existing fleet of nine FSRUs become committed to long-term projects.

India | AG&P signs MoU with Hindustan LNG

AG&P (Atlantic, Gulf and Pacific Company) and Hindustan LNG (HLNG), have signed a Memorandum of Understanding (MoU) to supply tolled gas-to-power stations in the East Godavari region of Andhra Pradesh, India. Under the agreement, AG&P will provide an integrated solution to deliver regasified LNG through a new LNG import terminal that it will design and build at the port in Andhra Pradesh.

The MoU has launched a fully integrated solution for delivering tolled gas in India, including design, construction, financing, operations and maintenance of the new terminal, which will ensure a reliable and low cost supply to power producers, fertiliser plants, cold storage and other industries in Andhra Pradesh, as well as other markets along the east coast.

AG&P will be responsible for designing and building all the required facilities for the import terminal, including a floating storage and mooring system, regasification terminal, related utilities and the provision of tolled gas-to-power plants and other users. AG&P will also carry out any necessary conversion works and, upon commissioning, ongoing operations and maintenance activities.

Canada | AltaGas reaches FID on export terminal

AltaGas Ltd has reached a positive final investment decision (FID) on its Ridley Island Propane Export Terminal, having received approval from federal regulators. AltaGas has executed long-term agreements securing land tenure along with rail and marine infrastructure on Ridley Island, and will proceed with the construction, ownership and operation of the Ridley Export Terminal.

The terminal is expected to be the first propane export facility on Canada's west coast. The site is near Prince Rupert, British Columbia (B.C.), on a section of land leased by Ridley Terminals Inc. from the Prince Rupert Port Authority. The locational advantage is very short shipping distances to markets in Asia, notably a 10 day shipping time compared to 25 days from the US Gulf Coast. The brownfield site also benefits from excellent railway access and a world class marine jetty with deep water access to the Pacific Ocean.

Mexico | JV to build refined products terminal

Kansas City Southern (KCS), Watco Companies LLC and WTC Industrial have announced a joint venture (JV) investment that will facilitate and expand the exportation of liquid fuels from the US to Mexico. The project will include the construction of a unit train liquid fuels terminal located in the WTC Industrial Park in San Luis Potosí, Mexico. The facility will be solely rail served by Kansas City Southern de Mexico (KCSM).

The JV comes as a direct result of energy reform legislation passed in Mexico in 2013. Recognising that it lacked the refinery infrastructure necessary to meet its growing demand for refined energy products, Mexico developed legislation that put into motion a process that will culminate by 2018 in the country's energy markets being fully open to foreign investment and the importation of refined energy products, including gasoline and diesel.

The JV partners will invest approximately US$45 million in this phase of the project, which has an anticipated completion in 2Q17. It is projected that the terminal project will eventually include a storage facility that would provide retail fuels for the population of Central Mexico.

WORLD NEWS

DIARY DATES

21 - 24 March
Turbomachinery Laboratory
Houston, Texas
turbolab.tamu.edu

28 - 30 March
StocExpo Europe
Rotterdam, the Netherlands
www.stocexpo.com

04 - 07 April
Gastech
Chiba, Tokyo, Japan
www.gastechevent.com

18 - 20 April
NISTM 19th Annual International Aboveground Storage Tank Conference & Trade Show
Orlando, Florida, USA
www.nistm.org

26 - 27 April
StocExpo Middle East Africa
Dubai World Trade Centre, UAE
www.stocexpomiddleeastafrica.com

12 - 14 June
ILTA 37th Annual Operating Conference and Trade Show
Houston, Texas, USA
www.ilta.org/aocts

09 - 13 July
22nd World Petroleum Congress
Istanbul, Turkey
www.22wpc.com

27 - 28 September
Tank Storage Asia
Singapore
www.tankstorageasia.com

29 - 30 November
Tank Storage Germany
Hamburg, Germany
www.tankstoragegermany.com

13 - 14 December
StocExpo China
Shanghai, China
www.stocexpochina.com

Shell | LNG outlook

In its first 'LNG Outlook', Shell notes that LNG demand growth kept pace with supply, as greater than expected demand in Asia and the Middle East absorbed the increase in supply from Australia.

China and India were two of the fastest growing buyers, increasing their imports by a combined 11.9 million t of LNG in 2016.

Total global LNG demand increased following the addition of six new importing countries since 2015: Colombia, Egypt, Jamaica, Jordan, Pakistan and Poland. They brought the number of LNG importers to 35, up from around 10 at the start of this century.

Shell expects LNG prices to continue to be determined by multiple factors, including oil prices, global LNG supply and demand dynamics, as well as the costs of new LNG facilities. In addition, the growth of LNG trade has evolved into helping meet demand when domestic gas markets face supply shortages.

LNG trade is also changing to meet the needs of buyers, including shorter term and lower volume contracts with greater degrees of flexibility.

Shell believes further investments will need to be made by the industry to meet growing demand, most of which is set to come from Asia, after 2020.

StocExpo Europe | Storage industry concerns

A survey of 171 decision-makers in the bulk liquid storage sector has revealed that their key priorities include boosting capacity, reducing costs and meeting environmental standards, as the oil price slowly rebounds and demand for more specialist storage grows.

The survey revealed that participants viewed cost reduction as the number one priority (49%), followed by increasing efficiency (44%) and profitability (35%).

The International Maritime Organisation's decision to reduce the content of sulfur fuels by 2020 is the latest environmental regulation to impact the industry. Meaning operators place an increased focus on more environmentally sustainable operations. Environmental standards were listed as the top priority by 27% of survey participants.

In Europe, 40% of respondents listed environmental standards as a key issue. However, 14% of respondents in the Middle East and 11% in Asia see it as one of their top three priorities. In North America, 62% of respondents see environmental demands as a key storage issue.

Port of Rotterdam | Crude oil throughput drops

Throughput of crude oil at the port of Rotterdam fell by 1.2% in 2016 to 101.9 million t.

Although refinery margins fell slightly, they remained buoyant whereby the level of crude oil input stayed at the upper end of the historical spectrum. Following a rise of 18% in 2015, the input and output of oil products increased by a further 0.3% to 88.8 million t. There was less throughput of fuel oil but more gas oil, diesel, kerosene, petrol and naphtha was handled.

Throughput of LNG dropped by 26.1% to 1.7 million t following an increase of over 90% in 2015. The port cited less arbitrage relating to LNG prices. The other liquid bulk category rose by 1.5% to 31.2 million t.

FINDING THE CAPACITY

As the US shale boom continues and OPEC has agreed to a cut in production output, **Gordon Cope, Contributing Editor,** examines the expansion of oil and gas plays in North America during a period of falling demand, and explains how this has created ample opportunities for the storage industry.

Over the last decade, North America has seen tremendous growth in both new and existing oil and gas plays. At the same time, demand has languished and opposition to pipelines has created situations where existing networks are running at full capacity. All of these factors have created opportunities for terminals and storage throughout the continent.

US oil

In the US, crude production has risen dramatically. Output in the lower 48 has almost doubled in the last 10 years, thanks to new shale oil plays in the Bakken in North Dakota and the Eagle Ford and Permian plays in Texas. Official statistics show that US crude production reached 9.3 million bpd in March 2015. Since then, drilling has tailed off dramatically, and output has slipped by 800 000 bpd, averaging approximately 8.5 million bpd in October 2016. The US Energy Information Administration (EIA) expects the declines to continue.

That still leaves a lot of oil. Much of the output from the Bakken is shipped to Cushing, Oklahoma, where it joins the tide of heavy oil marching south from Alberta. Cushing is the major storage facility for the US Midwest, serving refineries throughout the PADD 2 region. In 2011 it had 60 million bbls of capacity, which has since expanded by 30 million to 90 million bbls.

Pipeline operators have major plans to expand transportation south to the US Gulf Coast (USGC), but Cushing will need further storage to meet growing oilsands production bottlenecks. Plains All American Pipeline recently completed three storage tanks with a total capacity of 810 000 bbls, and is adding another tank of 540 000 bbls.

Cushing has been in the news of late due to a series of earthquakes in the region. In September, a 5.6 tremblor, one of the strongest ever to hit Oklahoma, occurred near Pawnee, 50 km north of the storage facility. In November, Pawnee was again struck by a 4.5 magnitude event. Both earthquakes caused walls to shake and items to move about in homes, though no casualties were reported.

In early November, a 5.0 quake, almost directly under Cushing, caused extensive damage to buildings in the city. Storage tankers are routinely surrounded by containment moats capable of holding the tank contents should a rupture occur. Although no damage to storage tankers was reported, several pipeline operators shut down activities. Enbridge reported that it had launched an emergency response plan to check tanks, pipes, motors, pumps, and other equipment.

State officials ordered nearby water injection wells to be shut down, but seismic geologists noted that it may take years before the incidence of major quakes related to water injection subsides.

In the meantime, residents of Pawnee have launched a class-action suit against energy companies that have been injecting wastewater.

While some shale oil plays, such as the Bakken, have slowly declined, the Permian basin in Texas moves from strength to strength. The price of oil has stabilised around US$50 for the last several months, and operators are fielding more rigs. As of November 2016, the count for rigs operating in all of the US stood at 450, with slightly under half of those (218) located in the Permian basin. In October, output climbed by 30 000 bpd, pushing it over the 2 million bpd mark for the first time.

Shale oil plays in Texas have the advantage of being close to the immense refinery and petrochemical complexes in the USGC, but the light tight oil (LTO) being produced is not best suited to Gulf Coast refineries, which were engineered to handle heavier feedstocks from Mexico and Venezuela.

Operators were relieved when in December 2015, Congress lifted the 40 year ban on crude exports; by September 2016, US crude exports averaged 692 000 bpd. While crude storage capacity at major USGC ports totalled almost 100 million bbls, new facilities are being built. Occidental Petroleum recently added 300 000 bpd of crude and condensate processing capacity at its Vicki Hollub facility in Corpus Christi, Texas. The company expects the terminal additions to be fully operational by early 2017.

Still, immense surpluses hang over the continent. The EIA reported in late 2016 that the total estimated inventories (excluding the Strategic Petroleum Reserve) sat at 511 million bbls, a historic high.

Storage companies in the Houston region have been working to expand capacity; Phase 1 of Fairway Energy Partners' Pierce Junction crude oil storage facility is set to come online at the beginning of 2017. Three caverns capable of holding 10 million bbls will add to the 30 million bbls of total crude storage capacity in the Houston area, and the company is planning 10 million more. Enbridge is committing US$5 billion to build three new oil terminals between Louisiana and Houston, while Phillips 66 is doubling crude storage capacity to 16 million bbls at its Beaumont, Texas, terminal.

Canadian oil

The oilsands hold over 170 billion bbls of recoverable oil. For the last decade, tens of billions of dollars have been poured annually into mining and in-situ projects; many of those projects, including Imperial's Kearl Oilsands expansion and Suncor's new 180 000 bpd Fort Hills mine, are keeping bitumen production in an upward trajectory. Although capital spending has been largely curtailed over the last two years, the International Energy Agency (IEA) still expects oilsands output to rise from 2015 levels of 2.4 million to 3.1 million bpd in 2020.

Canada lacks major pipeline routes to tidewater, however. Although Enbridge was originally given approval by the National Energy Board (NEB) to construct the Northern Gateway pipeline, which is designed to move up to 525 000 bpd to the deepwater port of Kitimat, British Columbia, the federal government under Prime Minister Justin Trudeau recently moved to kill the viability of the project by banning the sailing of large crude tankers off the west coast of Canada.

On a more positive note, the federal government approved the Trans Mountain pipeline expansion; a project that would see the tripling of capacity of an existing line to Vancouver, to almost 900 000 bpd. It also approved Enbridge's Line 3 replacement. The CAN$7 billion project will see capacity on the line running from Alberta to Wisconsin almost double from 390 000 to 760 000 bpd.

Eastwards, Enbridge has also been given approval by the NEB to reverse Line 9B, which delivers crude from Quebec to Sarnia, Ontario. The reversal will allow the company to deliver up to 300 000 bpd of heavy oil and lighter Bakken crude to refineries in the Montreal region. But TransCanada's Energy East Pipeline project – which seeks to repurpose part of its mainline gas transmission system running from Alberta to Ontario, and then extend it to tidewater with a new-build – is running into significant opposition, and the CAN$12 billion 4500 km pipeline might not see the light of day for years.

One pipeline proposal received a surprise boost with the recent US election. In late 2015, the White House under President Obama announced that the Keystone XL project, a 590 000 bpd pipeline designed to deliver heavy crude directly from Alberta to Gulf Coast refineries, was rejected. When President Trump took office in January 2017, he signed an executive order to accelerate approval of the project. TransCanada subsequently submitted a new Presidential Permit application to the US Department of State.

Currently, however, pipelines are running at capacity and, even with the growth of crude by rail, storage opportunities abound. There are two major crude storage hubs in Alberta: one in Edmonton and one in Hardisty. The Edmonton region is a combination of caverns and tanks. In 2013, Edmonton had approximately 11 million bbls of storage, with most of the usage related to gathering conventional and oilsands output from regional lines in order to serve nearby refineries and petrochemical plants. Hardisty is located in southeast Alberta at a junction point for major lines heading east and south. In 2013, it had approximately 20 million bbls of storage capacity.

Now both centres are seeing dramatic increases in capacity. Gibson Energy announced plans to construct 900 000 bbls of new capacity in Hardisty and another 800 000 bbls in its Edmonton Terminal. Keyera and Kinder Morgan intend to add up to 6.6 million bbls in Edmonton. TransCanada and Enbridge also have plans for expansion. In all, Alberta is expected to see at least 10 million bbls of new capacity, an increase of over 30%.

Mergers and acquisitions

While the oil and gas industry as a whole has suffered the last two years due to depressed commodity prices, storage and related activities are one of the bright spots. Inter Pipeline, for instance, which is a storage, NGL extraction and transportation company operating in Alberta, posted revenues of CAN$829 million and net income of CAN$222.5 million in the first six months of 2016, a 16% increase over the same time in 2015. Christian Bayle, President and Chief Executive Officer of Inter Pipeline, noted that this is the right environment for the organisation – with a balance sheet such as theirs and a stable business profile – to look to enhance their overall suite of assets through accretive acquisition.

Inter Pipeline is not alone in those sentiments. In October, NuStar Energy paid US$93 million to Martin Midstream Partners to acquire 900 000 bbls of crude storage and 250 000 bbls of refined storage, in the Port of Corpus Christi, Texas. The

Latest News

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CRESTWOOD DEVELOPING RAIL-TO-TRUCK NGL TERMINAL

Crestwood Equity Partners LP is developing a greenfield rail-to-truck NGL terminal in Montgomery, New York, US. The terminal will increase propane supply reliability across the Northeast markets. The terminal, which is expected to be placed into service in the summer of 2017, will be supported by product controlled by Crestwood from multiple producers in the Marcellus and Utica regions.

GTT WINS FSRU ORDER

Gaztransport & Technigaz (GTT) has received an order from Daewoo Shipbuilding & Marine Engineering (DSME) to equip a floating storage and regasification unit (FSRU) with its NO96 cryogenic membrane containment system. The FSRU will be built at DSME's shipyard in Geoje, South Korea, on behalf of Maran Gas Maritime. This will be the first FSRU to be added to the Maran Gas Maritime fleet. Delivery is scheduled for 2020.

NEW LEADER AT BURNS & MCDONNELL

Randy Schmidt has been named Managing Director of the Burns & McDonnell Terminals and Pipelines group, replacing Ted Born, who is retiring. Schmidt's promotion was effective 1 January 2017. Under Born's leadership, the terminals and pipelines group has contributed significantly to Burns & McDonnell's growth in recent years by successfully executing a number of large projects for major oil and gas industry companies.

DOE TO SELL CRUDE OIL FROM SPR

The US Department of Energy's (DOE) Office of Fossil Energy has announced that it will commence a sale of crude oil from the Strategic Petroleum Reserve (SPR) in late February 2017. The SPR is the world's largest supply of emergency crude oil. The federally-owned oil stocks are stored in underground salt caverns at four storage sites in Texas and Louisiana, US.

For further information go to:
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purchase now gives NuStar more than 3.6 million bbls of total storage in the region.

As part of the US$127 billion merger between pipeline companies Enbridge and Spectra, announced in September, the newly created giant will have over 30 300 km of liquids pipelines, 84 million bbls of liquids storage and 415 billion ft^3 of natural gas storage.

Natural gas

Over the last two years, the pace of drilling in the US has fallen dramatically. Monthly production in the lower 48, which peaked at 82.5 billion ft^3/d in September 2015, dropped to 80.6 billion ft^3/d in June 2016. Some unconventional plays are still growing, however.

While gas consumption has risen in North America, it has not kept pace with production, so new markets are necessary in order to soak up the glut. Cheniere Energy has been building four liquefaction trains in the Sabine Pass region of Louisiana. Two trains totalling 9 million tpy have been completed, and the first shipments recently left for Europe.

In Canada, there are currently over a dozen proposed projects to liquefy and ship up to 14 billion ft^3/d to markets to Asia, most of which would be located in the British Columbia tidewater ports of Prince George and Prince Rupert. The most advanced is Petronas' CAN$36 billion, 12 million tpy Pacific NorthWest LNG project; first production is projected after 2020.

The gas market in Mexico is growing at a rapid pace. Comisión Federal de Electricidad (CFE), Mexico's former electricity monopoly, is converting most of its bunker fuel burning generators to natural gas. Exports from Texas are currently exceeding 3.5 billion ft^3/d, and as a new network of pipelines extends ever deeper into the interior, Mexico's gas demand is expected to almost triple.

A warm winter from 2015 – 2016, and a lagging economy, have kept inventories high, however. Gas storage capacity is primarily composed of depleted conventional reservoirs and salt caverns. The US alone possesses approximately 10 trillion ft^3 of space; storage volumes generally peak at around 3.8 trillion ft^3 in November, then drain by approximately 2.1 trillion ft^3 through the winter. In November 2016, Canada's natural gas storage stood at 745 billion ft^3, virtually 100% of capacity. In the US, storage stood at 4.2 trillion ft^3, around 10% higher than the five year average.

Gas storage became front page news in October 2015, when a leak occurred at the Aliso Canyon storage site near Los Angeles. Thousands of residents living in the Porter Ranch subdivision had to be evacuated over health concerns. It took Sempra, which operates the facility, 16 weeks to plug a faulty well. The state is worried that the closure of the facility, which is the largest in Southern California, will hamper electricity supplies and could lead to blackouts this winter. The federal government established the Interagency Task Force on Natural Gas Storage Safety in the wake of the leak; in late 2016, it issued a report with 44 recommendations covering the 400 underground gas storage wells in the US.

Refined product

Between late 2014 and September 2016, the retail price of gasoline fell from over US$3/gal. to US$2.22/gal., and diesel tracked from US$2.90 to 2.39. According to the EIA, drivers responded with increased mileage, and gasoline consumption hit a record average high of almost 9.3 million bpd in 2016.

Exports have also grown. In 2010, the US exported 296 000 bpd of gasoline; by November 2016, that number had grown to over 1 million bpd. The largest single buyer is Mexico, with over 500 000 bpd in 2016. Most of the fuel is shipped by tankers, but NuStar recently announced a joint venture with Pemex to build a pipeline that will transport LPGs and gasoline from Houston to Nuevo Laredo and Burgos-Reynosa, in Mexico.

In spite of increased consumption and exports, demand for refined storage is high. US gasoline inventories in late September stood at 238 million bbls, or 94% of the total storage capacity of 252 million bbls. For most of late 2016, significant amounts of the inventory have been shifted by tanker from over-supplied regions on the East Coast to other PADD destinations and export markets.

Natural gas liquids

NGLs, including ethane, propane and butane, are stripped from natural gas at processing plants. In 2013, the US produced 2.61 million bpd of NGLs and by May 2016, total NGL supply stood at 4.5 million bpd.

NGLs are used in the petrochemical industry to produce plastics, fibres, resins and a wide range of industrial materials. Prior to 2014, the US had approximately 1.1 million bpd of processing capacity. This is now expected to expand to 1.9 million bpd by 2018.

NGL storage capacity has increased dramatically over the last five years to handle peak seasonal highs; in September 2011, peak storage for propane stood at 65 million bbls. By September 2015, that number had climbed to slightly under 100 million bbls.

Exports and terminal capacities have also increased dramatically. In 2011, NGL exports stood at 200 000 bpd, the limit of terminal capacity. By 2016, exports were averaging slightly under 1 million bpd. The dramatic increase in exports has been matched by increased terminal capacity expansion. Targa added 120 000 bpd to its terminal in Galena Park, Texas; Sunoco commissioned a 200 000 bpd facility in Nederland, Texas; and Enterprise expanded its Houston Ship Channel plant by 227 000 bpd.

The future

In the short-term, North America's upstream oil and gas sector will continue to be pummelled by low commodity prices. However, decreasing shale oil production and increased alternate uses for natural gas should firm up prices in 2017. Midstream companies are expected to maintain positive balance sheets through consolidation, increased efficiencies, and strong demand for storage.

What might the long-term hold? In late 2016, the US Geological Survey announced that the Wolfcamp shale formation in the Permian basin in Texas held an estimated 20 billion bbls of recoverable oil – three times the size of the Bakken formation in North Dakota – and an additional 16 trillion ft^3 of gas. It is safe to forecast that there will be a sufficient supply of unconventional hydrocarbons in North America to encourage production for decades to come. Furthermore, it is safe to predict that several billions of dollars of new investment will be needed to meet the storage needs of new producing regions, tank farms and terminals.

Dennis W. Boehm, Hayward Baker, Inc., USA, explains why tank capacity, design and construction should not be restricted by the pressure that aboveground storage tanks exert on the ground.

ON SOLID GROUND

The design capacity of aboveground storage tanks depends on many factors. These involve available site footprint, required customer capacities, as well as environmental and safety considerations. The main factor that controls the design capacity of most tanks is the pressure they exert on the ground they are built on. Proposed tank sites can have weak soil conditions or be built in close proximity to waterways. Both dictate that the tank design engineer uses lower bearing pressures for tanks to control settlement, bearing capacity and edge shear failures. The distortions created from settlement of the tank perimeter shell, floor plate and out of roundness are represented in Figure 1. These distortions are considered to be a result of differential settlement of the tank foundation. This is due to exceeding the bearing capacity of the ground that the tank is built upon. Filling and emptying cycles during normal operations can cause distortions that take months or even years to manifest themselves. This results in loss of product capacity, expensive repairs that involve relevelling and recommissioning the tank or, worst of all, the failure of the tank.

On sites where the existing ground conditions are not capable of surface support of the tank, deep foundations are used. This often results in a much stiffer foundation than is needed and can be costly and time consuming to build. Over the past 15 years, tank foundation design engineers have turned to ground improvement to support tanks. This trend has resulted in more economical foundation solutions, increased capacities, and smaller footprints. In many cases, the ground improvement support for tanks take less time and as little as half the cost of deep foundations. In recent years, sophisticated foundation modelling techniques have produced even more efficient and economical designs. The use of ground improvement (GI) techniques for the support of tanks have been successfully used all over the world.

This article will discuss three case histories where aboveground oil storage tanks have been supported on GI solutions.

22 tanks in Golden Pass, Louisiana

This terminal represents a classic case of large diameter tanks built on very soft deltaic deposits. Since 2001, fifteen 310 ft dia. x 50 ft high tanks, as well as seven 243 ft dia. x 50 ft high tanks, have been built and put into service at the site. Originally designed to be founded on 160 ft deep driven piles and a concrete mat foundation, the foundation system was redesigned using GI, providing significant cost savings to the owner. The tanks and foundations were constructed over a 15 year period with significant performance data collected over the years, verifying the designs.

The GI method chosen for the site was a combination of soil mixing, wick drains and placed surcharge (Figure 2). This foundation solution provided deep soil mixed (DSM) columns installed on a square grid pattern within the planned tank area. The space between soil mixed columns was occupied by vertical wicks, which were installed through the softest soil layers to a depth of 70 ft. Soil surcharge was then placed on the GI prepared ground tank foundations. The surcharge remained in place until sufficient settlement had occurred and the remaining settlement would be within the acceptable limits. Settlement during surcharging was measured by ground surface surveying and ground instrumentation installed on site. The consolidation settlement for these foundations was measured at over 5 ft (Figure 3). Once settlement was complete, the surcharge was removed, the tank pad regraded, and the tank constructed. The whole process per tank took over eight months to complete. While the design was cost effective, the time for tank construction and use of the asset for the terminal was too long. The design was later modified to accelerate the construction process while still providing the same long-term tank.

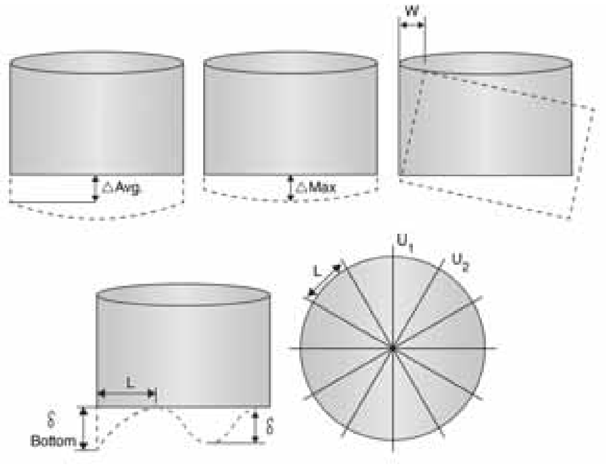

Figure 1. Design requirements for tank settlement tolerances.

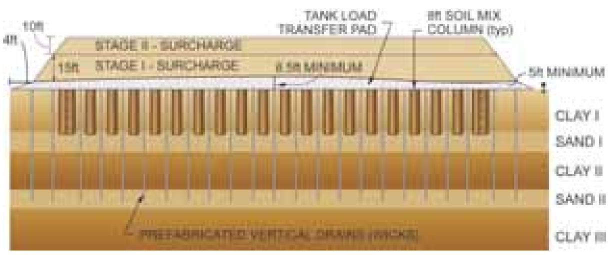

Figure 2. Surcharge solution for proposed tank foundation.

Table 1. Performance specifications for tanks

Series	Tank dimensions	Total edge to centre dishing	Planar tilt	Total settlement post hydrotest
200	155 ft dia. x 60 ft high	4 in.	12 in.	3 in.
100	110 ft dia. x 60 ft high	2 in.	9 in.	3 in.

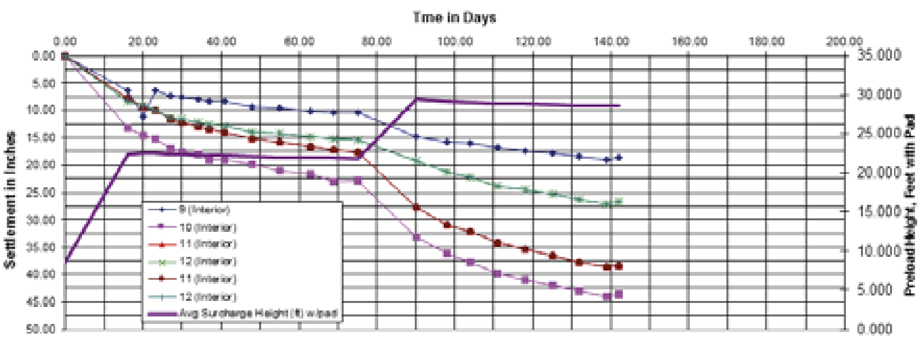

Figure 3. Settlement plot from surcharging tank foundation.

The new GI solution provided significant cost savings and quicker asset turnover. This allowed the terminal to meet customer needs sooner. The new design used deeper soil mixed columns, and a significantly stiffer surface pad to support the weight of the proposed tank. Construction time for this solution was reduced by two thirds. Long-term tank performance also improved over the surcharge solution. An additional time saving solution for the project was provided by the use of recycled material pads, constructed under the perimeter of the tank. This solution is more economical and quicker to implement than the typical concrete grade beam or ring wall used to support the edge of the tank on many other projects.

15 tanks in Deer Park, Texas

Variable ground conditions challenged the terminal designer of a proposed terminal in Deer Park, Texas, along the Houston Ship Channel. The ground conditions consisted of both newly placed and older dredge fill deposited over decades. The variable strength of the dredge fill material provided minimal support for ground supported tanks constructed on ring beams. The design height of the tanks founded on the oldest fill was 60 ft with a design diameter of 105 ft. The design height of the tanks planned for construction on the recent fill was 60 ft with a design diameter of 155 ft.

Several options for tank foundation construction were analysed, including removal and replacement of the fill and deep foundations, both of which were cost or time prohibitive for the project. The foundation design engineers chose GI solutions, utilising stone columns for support of the tanks on the older fill and DSM for support of the tanks on the recent fill. The design parameters for the tanks are shown in Table 1. The use of GI solutions provided a cost effective alternative for the terminal owner, who utilised the savings to build more tanks at the site.

Stone column foundations were designed to improve and reinforce the older dredge fill material. The columns provided a stiff enough foundation to control long-term settlements and increase bearing capacity. Stone columns were installed using the bottom feed technique due to the high water table and other environmental considerations. The stone columns were installed on a square grid pattern to variable tip depths into an underlying stiff clay layer. A load transfer platform (LTP), constructed of crushed rock

Table 2. Performance requirements for tankers

Tank dia.	Total settlement at edge	Differential settlements		
		Sag	Circumferential	Tilt
dia. ≥ 82 ft	12 in.	dia./300	0.5 in./33 ft	dia./200
82 ft > dia. ≥ 33 ft	6 in.	dia./300	0.5 in./33 ft	dia./200
dia < 33ft	2 in.	dia./300	0.5 in./33 ft	dia./200

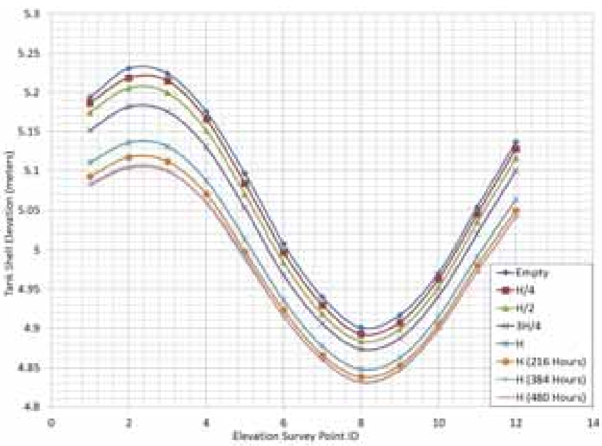

Figure 4. Ringwall survey during hydrotest.

Figure 5. Soil mixing carried out at the project site.

Figure 6. Completion of the perimeter ring berm.

and geogrid, was built on top of the installed stone columns. Given its close proximity to the Houston Ship Channel, a perimeter ring beam and liner was also added to meet environmental restrictions placed on the site.

DSM ground improvement was designed to transfer the loads from the tank into competent bearing stratum below. Large diameter DSM was chosen for the ground improvement using an appropriate design strength to prevent crushing of the elements from the imposed load of the tank. Installed on a regular grid pattern under the entire footprint of the tank, the DSM columns provided adequate bearing capacity and long-term settlement control for the planned tanks. Upon completion of the DSM columns, the LTP – consisting of dredge sand and geogrid – was constructed. The tank pad construction was completed with a ring beam and liner similar to the other tanks at the site .

Staged hydrotests were performed for each tank prior to putting them into service. The hydrotests were performed to verify the tank integrity, the foundation stability, and to reduce long-term in service settlements. Each stage of the hydrotest was held for a minimum of 24 hours. The final full stage was held for approximately two weeks. The complete test of each tank required 20 – 25 days to complete. Ring wall settlements were recorded in accordance with API at the end of each filling stage and at holds during the full fill of the tank. An example of one of the surveys is shown in Figure 4.

12 tanks in Vietnam

Soil conditions at a proposed refinery in Vietnam challenged the tank foundation design engineers to incorporate varying solutions to support the tanks. The refinery complex is located in the Mai Lam area, Tinh Gia District, Thanh Hoa province. The refinery is the second and largest project in the country. In total, 61 tanks were proposed for the site, varying in diameter from 78 to 292 ft with a design height of 65 ft. The soil conditions varied from sandy silt to stiff clay, which provided a unique use of different foundation solutions for the site. In one area of the site, the tanks were constructed on conventional ring wall foundations, providing a solution that economically met the performance requirements shown in Table 2. In another area of the site, weaker soil conditions required that the soil be improved using ground improvement techniques.

A total of 12 tanks were installed using dry bottom feed stone columns on a regular grid pattern, extending to 10 ft outside the tank perimeter. Treatment depths for the stone columns were as great as 60 ft. Crushed stone, with geogrid, was placed over the top of the perimeter stone columns to provide a ring berm. Granular fill was used to complete the filling of the tank footprint and complete the LTP.

Conclusion

Ground improvement used for tank foundations has been used on projects all over the world. GI has been used to meet the performance requirements even on sites with variable soil conditions. Providing a more efficient and economical solution for the support of tanks in today's world economy is challenging and GI solutions meet that challenge. The ground should no longer dictate tank capacity. T&T

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PLAYING IT SAFE

Natalie Iovino, MSA - The Safety Company, USA,
discusses correct responses to gas and flame emergencies in the oil, gas and petrochemical storage industry.

When an emergency event occurs at an oil/gas/petrochemical facility that involves leaking gas or fire, the consequences of failing to respond correctly can be devastating. The course of action taken within the first few seconds and minutes can make the difference between a successfully avoided accident and a fatal tragedy where lives are lost, equipment is damaged and more.

Unfortunately, once an emergency is in progress it is too late to put in place the safety regime and monitoring equipment that are necessary to protect a facility and avoid such an accident. Implementing a culture of safety within a company and its operations is the only way to ensure that any facility or team of employees will be ready for the emergency events that can occur in hazardous industries.

Protecting terminals and tank farms

Marine terminal and tank storage operations are no less immune to accidents than upstream production sites and petrochemical refinery operations. They do, however, present some different safety challenges that, when managed inappropriately, have the potential for catastrophic events.

Such facilities are frequently large in size, with highly dense operations involving multiple petroleum products. Transferring crude oil, refined petroleum products or natural gas from ship to shore for tank storage and then distributing them to the end customer/consumer is a complex process, with ample opportunities for fatal spillage and leaks.

The infrastructure at terminals and tank farms is often a maze of docks, pumping stations, pipelines, storage tanks, rail car terminals and tracks, truck loading stations, operations centres and more. The scope of diverse activity taking place makes safety management both the highest priority and one of the toughest jobs.

Fixed gas and flame detection

The primary safety threat at terminal and tank facilities is the potential leak of various combustible or toxic gases and flames. The major sources of these nuisance gases and flames are the products passing through the facility:

- Crude oil.
- Fuel oil.
- Diesel.
- Gasoline.

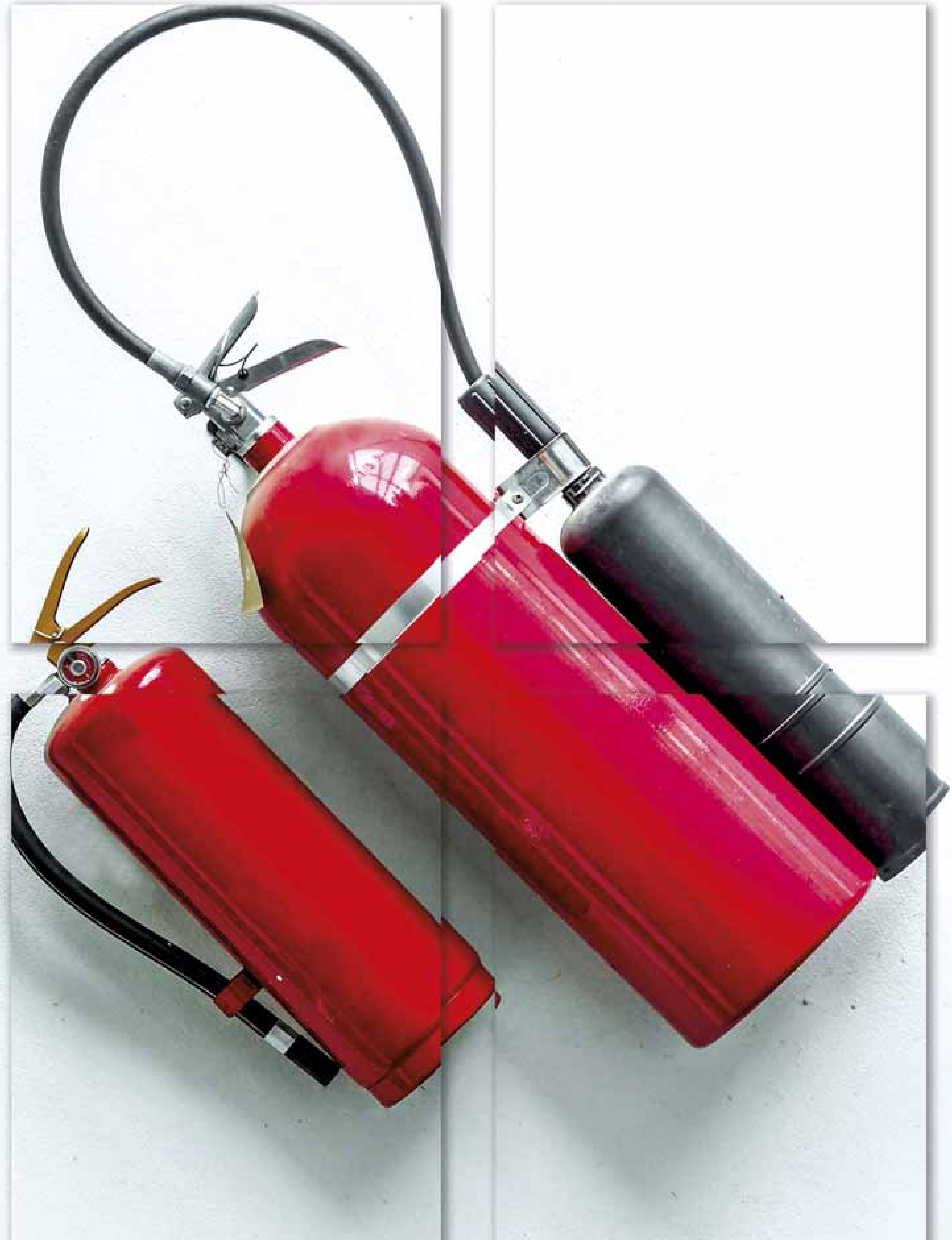

Figure 1. MSA GM Fixed Gas & Flame Safety System.

Figure 2. MSA ALTAIR 5X portable gas detector.

- Jet fuel.
- LNG/LPG.
- Various chemicals.

Hazardous gas leaks and flame incidents can potentially occur almost anywhere throughout the facility and require extensive fixed gas and flame detector monitoring. Equipment types where leaks and flames are usually found include pipelines, tanks, valves, pumps and hoses.

Employees involved in operations and maintenance activities must also frequently carry portable gas detectors. These are potential life saving devices when entering, inspecting or maintaining equipment where fixed gas detection is not necessarily desirable or practical.

Multi-layer sensory model

It is unsurprising, with the many challenges to reliable gas and flame detection, that a new strategy is emerging to improve safety in hazardous industries. What if all of the portable and fixed hazard detection sensor technologies were combined together and then layered where they fit best in terms of their reliability in each unique plant layout (Figure 1)?

Gas and flame detection sensing technologies mimic the senses of people, and the people who invented them. For example, catalytic bead sensors 'sniff' gases, infrared (IR) and optical type sensors 'see' gases and flames, and ultrasonic sensors 'hear' gases. What if these detectors behaved more like people, reacting based on their intelligence and retained past memories?

Layering portable and fixed sensor technologies throughout the plant, where they fit best in terms of their reliability, achieves a human sensory chain of defense against hazardous gases and flames. To better understand this new model of human sensory gas and flame detection, each type of sensing technology should be evaluated and then discussed.

Electrochemical cells

Portable and fixed gas detectors are now designed with highly effective electrochemical cells, which measure the concentration of a specific gas by oxidising it with an electrode and measuring the resulting current. Different types of cells have been developed for specific toxic gases, such as carbon monoxide, chlorine, ammonia, etc., and combustible gases.

Catalytic bead (CB)

Catalytic bead gas detectors employ catalytic combustion to measure combustible gases in the air at fine concentrations. As combustible gas oxidises in the presence of a catalyst it produces heat, while the sensor converts the temperature rise to a change in electrical resistance, which is linearly proportional to gas concentration. A standard Wheatstone bridge circuit transforms the raw temperature change into a sensor signal.

Point infrared (PIR)

Two wavelengths are used in PIR detection: one at the gas absorbing 'active' wavelength and the other at a 'reference' wavelength not absorbed by the gas. Neither wavelength is absorbed by other common atmospheric components such as water vapour, nitrogen, oxygen, or carbon dioxide. In PIR detectors, the concentration of hydrocarbon gas is measured via the IR absorption of an optical beam, known as the active beam. A second optical beam, known as the reference, follows the same optical path as the active but contains radiation at a wavelength not absorbed by the gas.

Open PIR (OPIR)

In OPIR detection, the path of the IR beam is expanded from less than 10 cm, typical of PIR detectors, to greater than 100 m. These devices use separate IR transmitters and receivers that are housed in different enclosures. There are OPIR detectors available that monitor in both the lower explosive limit-metre (LEL-m) and parts per million-metre (ppm-m) ranges to detect both small and large


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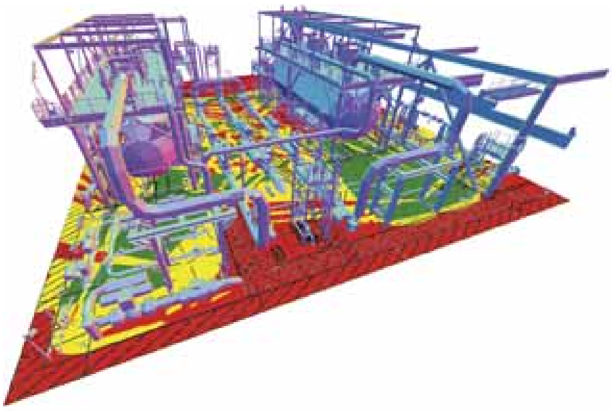

Figure 3. 3D gas and flame safety mapping software.

leaks. They cover large open areas, along a line of several potential leak sources such as a row of valves or pumps and also for perimeter monitoring of leaks.

Ultrasonic (UGLD)

When considered in comparison to conventional gas detectors that measure %LEL, advanced ultrasonic gas leak detectors with neural network technology (NNT) include a pattern recognition capability that responds to the ultrasonic noise created by a pressurised gas leak. This ultrasonic noise provides a measurement of the leak rate and establishes warning and alarm thresholds. Gas does not need to reach the sensing element as the detector 'hears' the gas leak. They are best suited for outdoor installations and indoor spaces with high ventilation rates.

Ultraviolet/infrared (UV/IR)

By integrating a UV sensor with an IR sensor, a dual band optical flame detector is created that is sensitive to the UV and IR radiation emitted by a flame. The resulting UV/IR flame detector offers increased immunity over a UV-only detector, operates at moderate speeds of response, and is suited for both indoor and outdoor use.

Multispectral infrared (MSIR)

The advanced design of MSIR flame detectors operates with an IR-based sensing array combined with NNT intelligence. This NNT intelligence provides pattern recognition capabilities that help train the detector to differentiate between real threats and normal events, thus reducing false alarms. MSIR technology allows area coverage up to six times greater than that of more conventional UV/IR flame detectors.

Integrated emergency response

An integrated approach to process and plant safety at terminals and tank farms, which includes emergency response, offers a number of advantages. The plant operations and process engineering teams are brought together to review potential hazards across the entire facility.

What is currently in place, including fixed gas and flame monitoring systems, portable gas detectors, respiratory apparatus, fall protection and safety gear (e.g. hats, gloves, goggles and more) are then reviewed. The needs of onsite emergency fire departments that deal with accidents when all else fails must be carefully considered.

For example, when plant safety teams are not aware of the full effects of likely hazards, they need to ensure that they are using an appropriate portable gas detector (Figure 2) or sensing technology for the potential threat. Some compounds can represent both a combustible and toxic threat. Although a combustible/LEL sensor may pick up explosive levels at the %LEL or %volume levels, toxicity may occur at much smaller levels, measured in ppm, so a different sensor or technology may be needed; a good example of this is benzene.

New 3D facility mapping software tools (Figure 3) can help process and plant engineers to optimise flame and gas detector resources without guesswork, in order to maximise system accuracy while minimising cost. For gas mapping, the software's algorithms combine hundreds of gas release and dispersion scenarios that could occur and gas detector sensitivity.

To map flame hazards, the software's algorithms consider the flame detector's field of vision (FOV), its sensitivity settings, the radiant heat output (RHO) of the target flame, its obstructions and obstructed flame plumes. The software's modelling results are displayed in graphical colour-coded coverage maps, which indicate the extent of flame and gas coverage.

The software's multi-stage mapping process first shows a plant map with 0% protection, then shows the incremental placement of detectors to achieve 60, 90 and 99% coverage. The final result is a complete 3D rendering of the plant, optimised with all detectors in place for greater safety and reliability.

Conclusion

Protecting terminals and tank farms from the potential consequences of the hazardous gas leaks and fires of today, requires an integrated approach to safety and emergency response. Once an accident event is in progress, it is too late to implement a safety regime; safety is a continuous process that requires total personnel participation to ensure success.

Establishing a culture of safety through assessment and training is the first step. Completing an integrated review of facility safety, with both the plant and the process teams, will identify potential problems before accidents occur. Working with safety professionals who offer 3D facility gas and flame mapping, with the next generation of highly intelligent multi-sensory detectors, provides the 'state of the art' in safety monitoring. T&T

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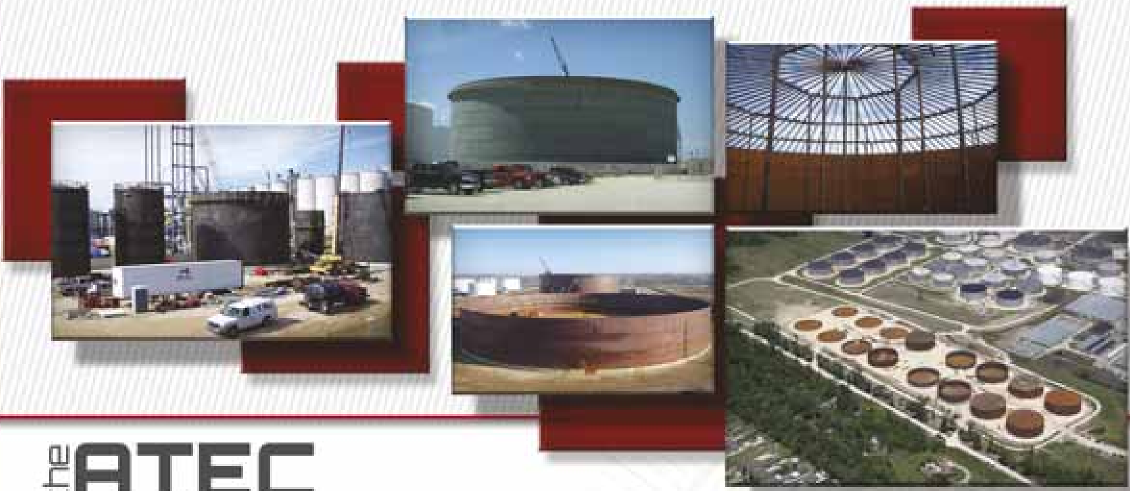

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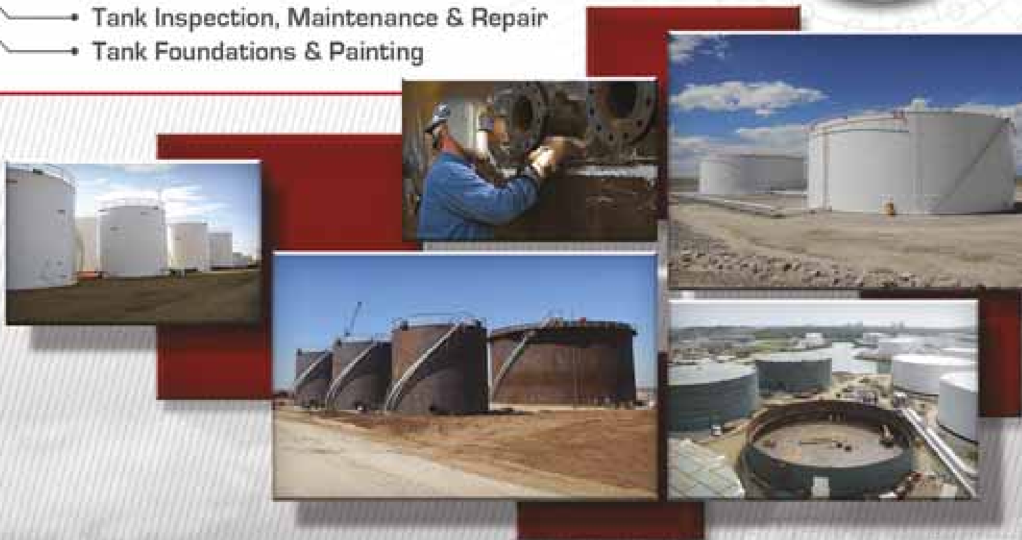

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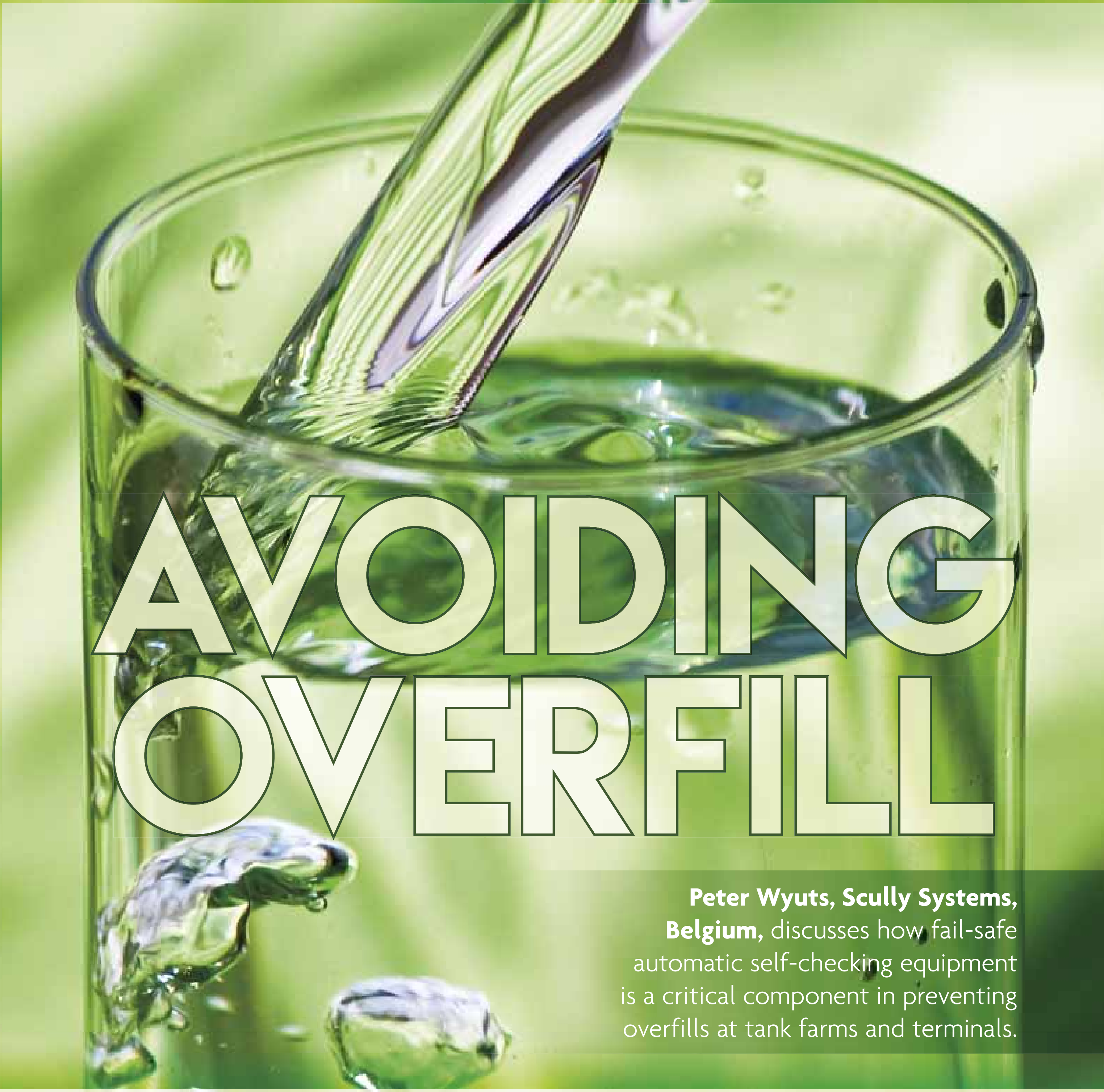

AVOIDING OVERFILL

Peter Wyuts, Scully Systems, Belgium, discusses how fail-safe automatic self-checking equipment is a critical component in preventing overfills at tank farms and terminals.

There is no doubt that even a small spill of hazardous petrochemicals can have a disastrous effect at any terminal or tank storage facility. From environmental, operational and human safety and legal liabilities to public relations implications, spills must be avoided and all terminals should be designing an absolutely fail-safe approach to liquid handling safety. As many experts and numerous industry associations and taskforces have extensively pointed out, this is not simply a matter of complying with local and federal regulations, there is also corporate operations training, procedures and industry recommended practices – though all of these are equally important. It is this fundamental mindset and corporate culture shift that, when coupled with the right equipment and solutions providers, enables terminal operators to efficiently and safely manage hazardous fluid transfer without the fear of spills.

If one looks at the major spills that have occurred at terminals worldwide, it comes down to a series of combined faults that create a catastrophe; human error combined with equipment failure, lack of information or negligence. This is the reason that the API*, CEN** and other organisations emphasise the need for an overfill management system (OMS), which is a series of systems including procedures, continuous improvement, failure analysis and trained personnel. However, despite written procedures and training, personnel are fallible and the risk associated with handling hazardous liquids is too great to accept any failures. This is why understanding what a truly fail-safe solution consists of can make the difference. A great deal can be done by the terminal to improve the chances that any one piece of equipment or

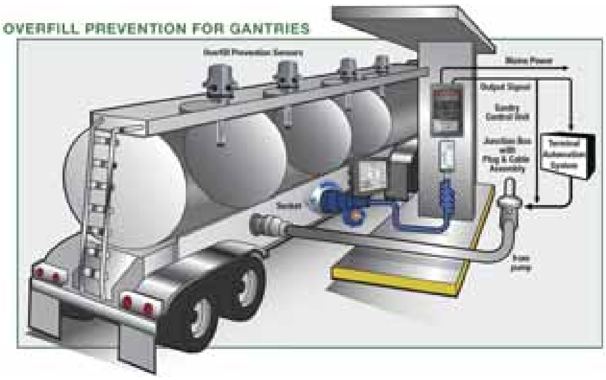

Figure 1. Typical overfill and earthing control system at bottom-loading gantry.

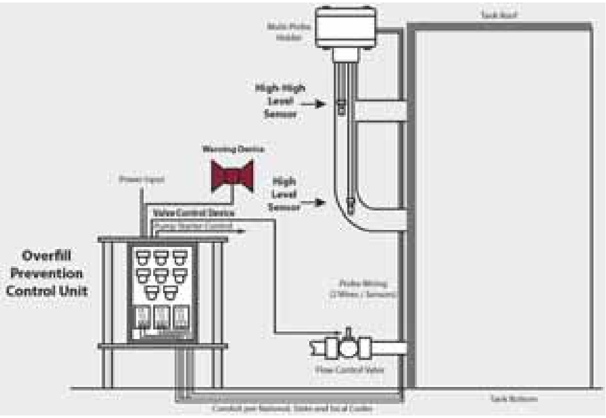

Figure 2. Automatic, electronic storage tank overfill prevention system includes a control unit hard-wired to a variety of self-checking optic or thermistor sensors – usually a high-high emergency level and a high level warning level. A floating roof application shows thermistor sensors mounted in a still well. Other options are available.

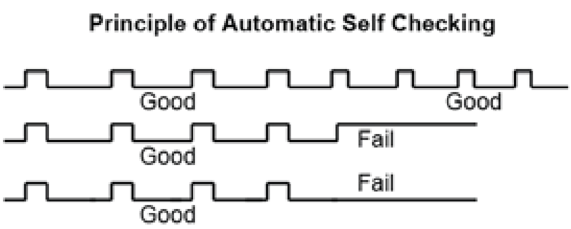

Figure 3. The Scully self-checking circuitry switches between a normal and fault condition 30 times/sec. When a fault is detected, the system enters a non-permissive state and shuts down the loading operation.

human error cannot cause a spill. The problem is that most spills result from a combination of faults. Even with the best training and procedures, highly advanced metering and continuous gauging systems, there is always a chance of error. The independent high level detection and overfill prevention equipment and automatic valves then become the last line of defense in averting a disaster.

There are generally two levels of liquid transfer control that occur when transferring petrochemicals. The primary control for terminal to road tanker filling is usually a preset meter or control system. This provides a positive means of selecting and loading a pre-determined quantity of products via a control valve or pump. Where there are no presets, primary control is achieved by human interface using a 'dead man' control and monitoring of the meter. With overfill prevention equipment, most terminals also employ a secondary control that is independent of any metering system and responds to a signal from a separate instrument. This is because meters and continuous gauges are not generally designed to be fail-safe, their primary role is accurate measurement. For petroleum and some chemical road tanker loading operations, most terminals worldwide use a pre-set meter, where the driver enters the number of litres/gallons for each compartment. In many cases, this is verified through the terminal automation system based on the known size of each compartment in their database. In the chemical or other fluid industries, the first line of defense may be weighing the tank vehicle or using continuous level gauges with visual indication or even manual/visual inspection of top loading vehicles. For storage tanks, the primary measurement system is a continuous level gauge – using various technologies from mechanical tape, to magneto-restrictive, ultrasonic, or radar. As technologies have improved, redundancy incorporated and advanced inventory management is tied to terminal automation and process control systems, overfills have decreased. However, there continues to be the chance of human or equipment errors. Thus, many in the industry feel that there is a need for a completely separate, automatic, continuous, self-checking, secondary emergency alert and shutdown system for all tank vehicles and storage tanks that store and transport hazardous materials.

For tank vehicles, this secondary emergency shutdown system, mentioned in the API RP1004 recommended practice/EN13922 and in use in most countries around the world, is an electronic control unit on the gantry/loading rack, which connects via a plug and cable to the overfill prevention system on the vehicle that consists of an electronic optic sensor mounted in the top of each of the tank vehicle compartments (Figure 1). For top loading vehicles, such as railcars that are not equipped with permanently mounted sensors, there is the option of a portable sensor, which is connected to the loading rack control unit and that temporarily clamps onto the man lid of the tank vehicle compartment, signalling the valves to shut down if the product reaches a critical level.

For storage tanks, the emergency alert and shutdown system has traditionally been separate from the gauging system and consists of either an electronic sensor float device or an electronic sensor that alerts the terminal operator when the tank level is reaching an overfill situation. API 2350 (Section 1.3.4)/EN15169


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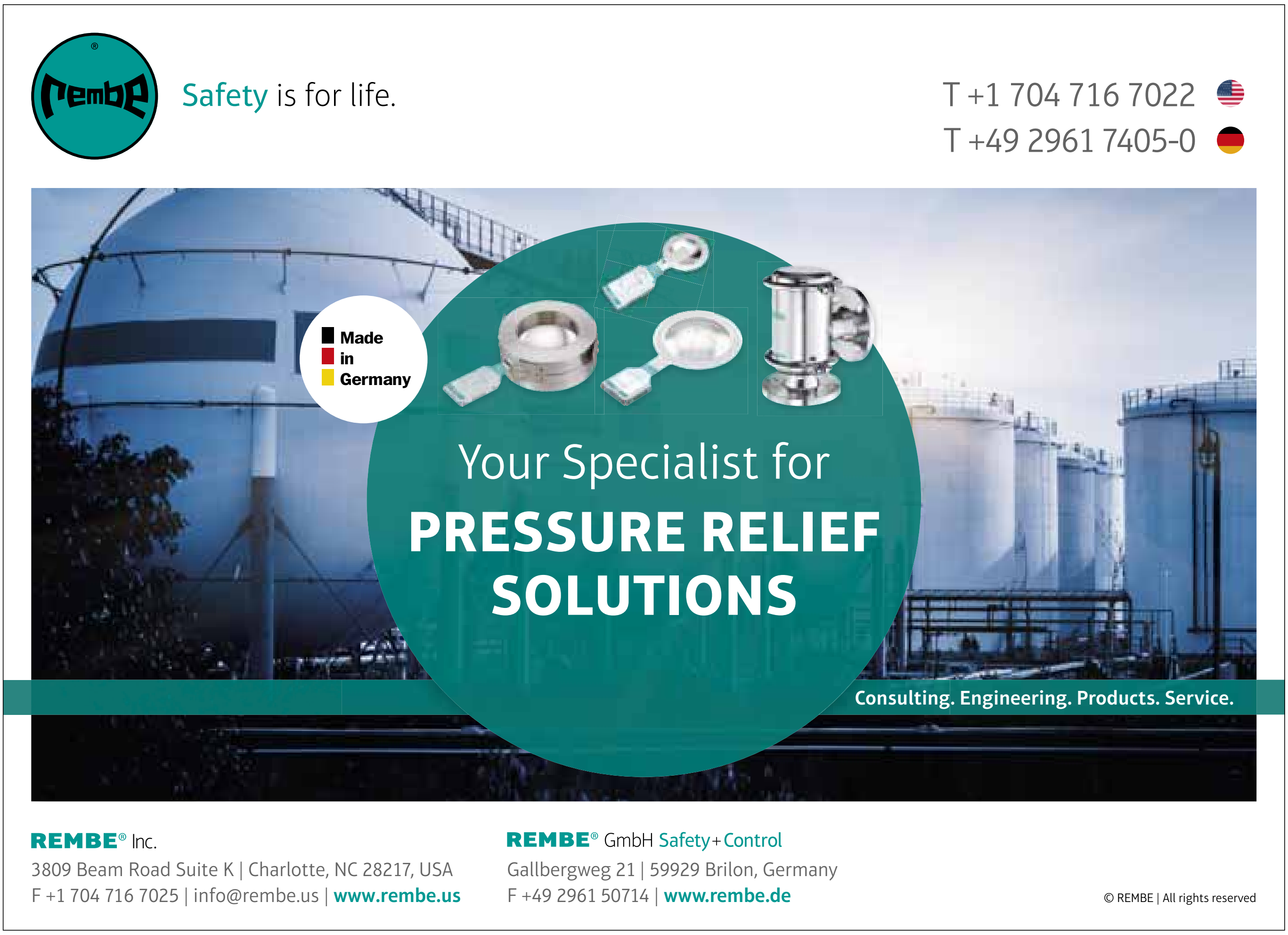
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Figure 4. A fail-safe concept ensures that all system components and wiring are constantly checking their own operation to ensure that the system fails in a safe state, before spills can occur.

Figure 5. Terminal and storage facility in UK with meters and overfill/earthing control unit on the gantry.

recommends that overfill prevention systems are completely independent. It states "high-high level detectors in single state and in two state detector systems shall always be independent detectors". For this reason, many terminals insist that the continuous gauging and overfill systems are separate. In addition, AP2350 Section A recommends that the automatic overfill prevention system (AOPS) "shall not rely on wireless communication to initiate diversion or termination of receipt", which in most cases means that the AOPS should be hardwired to ensure proper alarm and valve shutdown in emergency overfill situations. Other important standards include IEC 61508 and IEC 61511, which relate to functional safety. IEC 61508 covers the development, function and lifecycle of electrical, electronic, and programmable electronic equipment from the perspective of a safety instrumented function (SIF) where a failure affects the safety of people or the environment. A safety instrumented system (SIS) generally consists of a sensor, logic solver/controller and actuator and, therefore, automatic overfill prevention systems would be classified as such. Under these standards, the reliability of this system with regard to its capability to reduce risk, is assessed using a safety integrity level (SIL) rating (SIL 0 – 4). Options for automatic overfill prevention systems include individually mounted point level sensors or multiple sensors at different heights in one holder that are wired to a control unit (Figure 2).

The need for a truly fail-safe emergency overfill prevention shutdown system was something that Scully Signal Company determined when it began designing its first control monitors in the 1960s. The company's engineers defined the fail-safe concept as a situation where if any component of the system fails, it puts the system in the same state as if it were to detect the hazardous condition it is designed to prevent. Thus, engineers designed circuitry that checked its own operation by rapidly switching between a normal and fault condition, ensuring that the overfill prevention equipment would shut down the product transfer if there were any faults detected in the internal components or wiring. This patented design was a new concept and the resulting equipment was adopted by many oil companies in order to prevent the chance of any possible overfill conditions (Figures 3 and 4).

Unlike the terminal tank truck loading, the storage tank overfill prevention approach has varied more from country to country. Some local authorities require automatic tank gauging along with independent, automatic, self-checking overfill systems. Others allow for float devices that are manually checked by operating personnel on a regular basis. Generally, electronic overfill systems on tanks have a minimum of two sensors mounted in the tank – one for a high level and a second for the high-high emergency level (Figure 2).

European terminal

A European terminal started loading chemical products two years ago and was looking for an overfill prevention and earthing safety solution. The terminal was loading the road tanker trucks on a weight bridge. Operators were required to weigh the vehicle, determine the amount of product in the vehicle tank, and then enter the correct amount into the loading meter. This could lead to miscalculations and cause the potential for overfills and resulting spills. The terminal searched for a solution that could improve the safety and efficiency of its operation by ensuring proper earthing verification and overfill prevention. The Scully Intellitrol SIL 2 capable system was able to address both needs in one unit, which offered advantages to the pre-existing system.

The terminal operators reduced the amount of time it took to load each vehicle through just one connection for both earthing and overfill protection. The electronic control monitor and sensor provide a method of preventing spills by detecting not only overfill conditions but also faults in its own circuitry. An electronic sensor is mounted on each vehicle at a pre-determined emergency high level. Should the meter be set incorrectly and the sensor wetted, the control monitor sends a signal via the terminal automation system to shut down the loading operation. This causes valves to be closed automatically before a spill can occur. In addition, to ensure proper earth verification, a special 'smart' ground bolt (with internal diode) is fitted on each of the road tankers, and once the overfill and earth plug are connected, a signal is sent back to the loading terminal control unit to prove that the earthing connection has been made and allows product transfer to commence.

The terminal invested in this equipment and provided training to all personnel on the new procedures to ensure that loading could not begin without the proper earthing and overfill prevention measures in place. The system checks its own operation and prevents loading unless the sensors are dry, there are no opens or shorts in the writing, and all components of the system are operational.

RUBIS terminal

A terminal in France, operated by RUBIS, has separate earthing and overfill prevention controls for loading road tanks, but it operates in a similar way, providing a secondary emergency shutdown system. In order to improve safety during the automated loading process, the RUBIS terminal developed a prevention system for overfill control. Combining automated plate identification reading, database registering of all tank-trucks and communication with an advanced API sensor overfill control unit, the system will only authorise loading if all conditions are fulfilled, in particular the integrity (non-bypassed, idle and permissive signal) of each compartment sensor.

Conclusion

For transfer of potentially explosive liquids or those that could be hazardous to people or the environment, there should be a proactive, comprehensive plan by each terminal and tank farm to eliminate any possibility of an overfill. At facilities like those operated by RUBIS, this includes an overfill plan that includes management's full involvement, easy-to-follow operating procedures, proper training, and an investment in controls and equipment that not only safeguard the operation but have the intelligence to monitor themselves. Similar self-checking electronic automatic overfill prevention systems have been successfully installed on aboveground storage systems and gantry/loading racks for over 20 years with no un-safe failures.

Notes

*API is the American Petroleum Institute and RP1004 and 2350 are recommended practices.
**CEN is the European Committee for Standardisation.

GOING SEPARATE WAYS

Albert E. Ortega and Erin S. Carter, Cerex Advanced Fabrics Inc., USA, evaluate the separation efficiency of spilled oil from water using a fence made with nylon 6,6 non-woven fabric.

Industrial oil spills from tanks, pipelines and other sources can have detrimental effects on streams, lake and river environments, or groundwater. Spunbond nylon 6,6 fabric has been fabricated into bags and deployed as a fence along the coast of the Gulf of Mexico and other parts of the US to separate spilled oil and oil waste from contaminated water. This article discusses liquid chromatography studies that have shown a separation efficiency of over 99% of Louisiana sweet crude from oil-in-water emulsions. The deployment of spunbond nylon fences, by oil spill first responders, continues to demonstrate the ability of this material to contain the oily contaminate while allowing water to flow through. The oleophilic and hydrophilic nature of nylon makes it an effective material to separate oil from water in small streams. It is also effective in protecting shorelines, either by keeping spilled oil from reaching fragile shorelines or by keeping spilled oil on the ground from entering environmentally delicate bodies of water. The nylon traps oil droplets within the fabric or on the surface, while water is free to flow through the fabric.

Accidental spills of petroleum products can be catastrophic to the environment, especially if the spilled material is dispersed in water as an oil-in-water emulsion. In cases of accidental spills during transport or storage, surface run-off to watershed drainage systems can contaminate nearby bodies of water, further spreading the hydrocarbon contaminate. Many industrial processes generate oil-in-water emulsions as waste products. Oily wastewater must be stored and treated to remove oil contaminates and to mitigate the environmental impact of the oil-in-water emulsions.[1] Tanks and transport containers can also spill or leak these materials into the environment.

Mechanical recovery of petroleum contaminants that sometimes utilise a natural or synthetic oleophilic fabric, to contain and/or remove oil from water on or near the water surface, is the most commonly used oil spill response technique practiced to remediate emulsified or bulk oils with a wide range of viscosities.[2, 3] In addition, mechanical methods such as skimming, gravity settling, and filtration through porous membranes are commonly used for treating oily wastewater.[4] These porous fabrics act as sorption media for the oil as the water passes through them. Many different materials, such as superoleophilic membranes, multi-component graft polymer filters, and nanoporous graphene membranes, have been investigated as the next generation of oil and water separation materials, but these materials have the disadvantages of high cost, low scalability, and complex synthesis.[5 - 8] Currently, common media used for oil containment, separation, and filtration tend to be oleophilic, non-woven fabrics produced from polymer precursors.[9]

Ortega et al[10] investigated the use of spunbond nylon as a material for separating oil-in-water emulsions. Nylon 6,6 is a crystalline polymer containing oleophilic hydrocarbon chains connected by hydrophilic functional amide groups. Nylon 6,6 is known to rapidly wet in a wide range of liquids.[11] Hydrogen bonding between the polyamide chains results in high tensile strength and strong filament to filament bonding without the use of low melting copolymers or adhesives in nylon spunbond fabrics.[12] Spunbond nylon fabric in basis weights ranging from 0.3 to 4.0 oz/yd^2 comprises continuous fibres, which exhibit no fibre migration into bodies of water when the fabric is deployed. The fabric's basis weight (area mass density) can be finely controlled by

controlling the linear mass density and the thickness.[13] Nylon 6,6 is also known to be amphiphilic.[10, 11] Measurements of contact angle for water and oil on the nylon 6,6 spunbond fabric, by Ortega et al, indicate that the material is both hydrophilic and oleophilic. The nylon spunbond fabrics were previously found to sorb oil following a power function of the basis weight or the fabric density in this same study.[10] Ortega et al[10] also previously discussed the critical oil exposure volume (COEV) of the nylon spunbond fabric and discuss the mechanism driving the oil separation efficiency first hypothesised by Briscoe et al.[14] They go on to review the surface energy of nylon in an n-alkane/water system and present a detailed mechanism for the separation of oil from an oil in water emulsion using the nylon spunbond fabric.[10]

These characteristics make spunbond nylon an excellent material for oily water remediation and purification. Ortega et al[10] found that a nylon-based spunbond fabric, when used in a separation system for oil-in-water emulsions, effectively removes approximately 99% of high viscosity oil from an oil-in-water emulsion, while absorbing/adsorbing more than 1000% of its weight in both high and low viscosity oils. This article reviews the chromatography methods employed to further quantify the oil separation efficiency by the nylon spunbond fence fabric.

Figure 1. Laboratory apparatus used for chromatography analysis to determine oil separation efficiency by nylon spunbond fabric.

Table 1. Oil filtration efficiency determined from chromatography analyses

Water flow (ml/min)	150.0	150.0	75.0	75.0
Oil injection rate (mg/min)	40.0	60.5	40.0	60.5
Pre-filtration oil concentration (ppm)	267	403	533	807
Post-filtration oil concentration (ppm)	1.07	4.43	4.26	1.61
Filtration efficiency (%)	99.6	98.9	99.2	99.8

Figure 2. Deployment of spunbond nylon fabric used to contain spilled oil in Mooringsport, Louisiana.

Materials and methods

Preparation of oil samples and oil-in-water emulsions

Louisiana sweet crude oil, supplied from a private well, was dissolved in methyl ethyl ketone (MEK), 10% weight by volume in 2 butanone, before injection into the water flow with a calibrated kd Scientific syringe pump to simulate an oil-in-water emulsion commonly encountered as a result of an oil spill.

Separation efficiency using chromatography

A modified version of US Environmental Protection Agency (EPA) method 8015M was used for analysis via gas chromatography (GC).[15] A Hewlitt Packard 5750 gas chromatagraph located at the University of West Florida was used courtesy of Dr. Frederick Hileman of the University. The dissolved oil-in-water emulsion was passed once through a 4 oz/yd^2 fabric disc that is 34 mm dia. held perpendicular to the horizontal water flow. A peristaltic pump was upstream from the oil injection port and the filter holder. Pulse dampening was accomplished by installing a flask between the peristaltic pump and the inlet of the glass specimen holder. Water was analysed after the injection of the oil solution. Two samplings were taken to determine the decrease in oil concentration after the oil-in-water emulsion passed through the 4 oz/yd^2 nylon spunbond specimen. One sample was from a port immediately upstream from the fabric specimen and the other was from a port immediately downstream from the fabric specimen. The entire laboratory apparatus is shown in Figure 1.

Experimental methodology for chromatography studies

A 2x2 factorial experiment was designed to evaluate four conditions, simulating combinations of two levels of oil contamination and two levels of water flow. Water flow levels were 75 and 150 ml/min. These rates are typical water flows encountered in rivers and streams. Oil

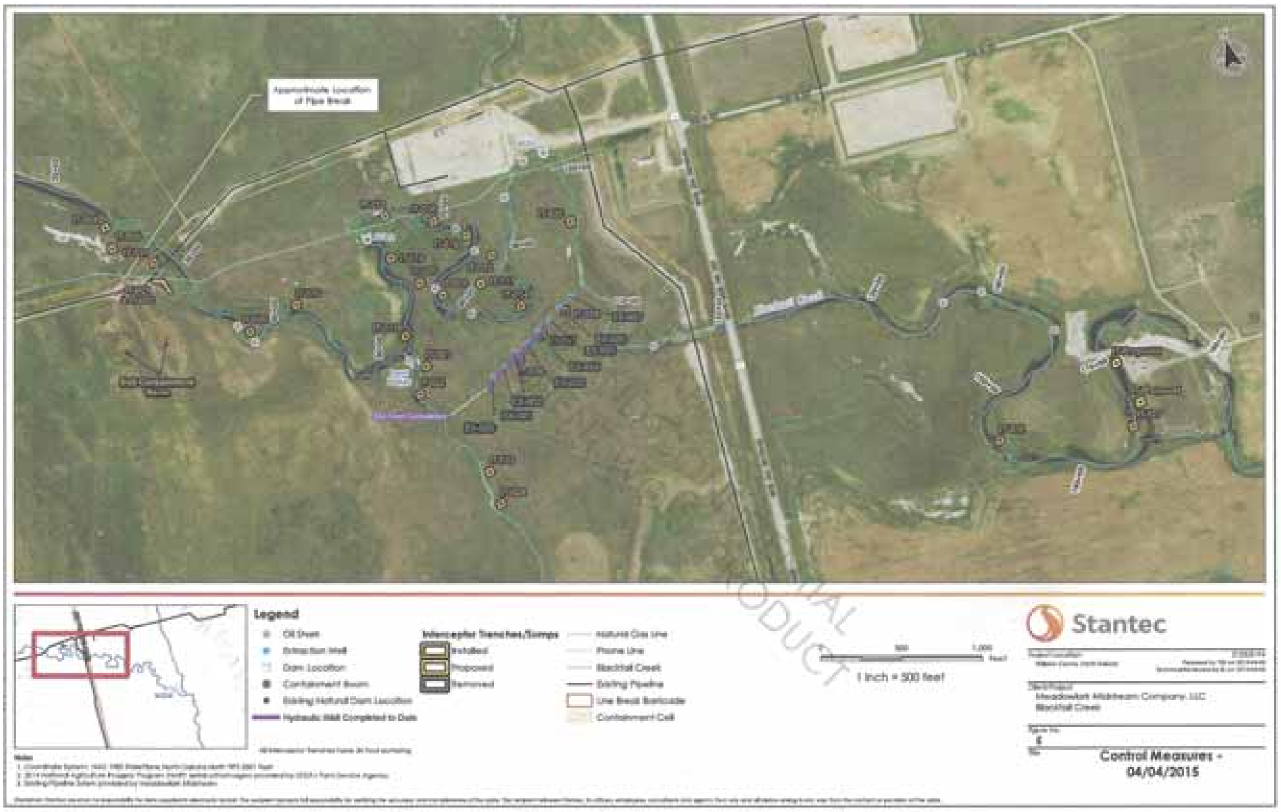

Figure 3. Control measures map of the Black Tail Creek spill, showing deployment of Oil Shark nylon spunbond fence fabric.

injection rates were 40 and 60.5 mg/min. Three iterations were run for each combination of settings. Efficiencies were calculated using the pre and post filtration oil concentrations determined from the average chromatograph analyses for each combination.

Recent emergency response field use

Oil spills can occur in many ways, including leaking transfer pipes, a leaking or ruptured storage tank, an accident involving a railcar or transport truck, or leakage from offshore sources. Regardless of the source and method of an oil spill, clean up and remediation efforts can be similar. In many cases, fencing using 4 oz/yd^2 Oil Shark® nylon spunbond fabric was installed by first responders to contain crude oil and further contamination of watershed drainage systems. For example, recent deployment of the nylon spunbond fabric as a fence has been carried out by first responders under the authority of the US EPA as an emergency response. On 13 October 2014, the Mid Valley pipeline had a crude oil release from a 20 in. pipeline that occurred near Mooringsport, Louisiana.[16] The release was estimated at 4000 bbls. On 6 January 2015, a line break was reported that released approximately 70 000 bbls of produced water, including oil from a water disposal 4 in. pipeline. The release impacted a small creek (Blacktail Creek), a tributary to the Little Muddy River north of Williston, North Dakota.[18]

In both cases, nylon fabric was used by emergency first responder personnel to contain the environmental contaminates and to filter contaminated groundwater. Field deployments did not involve any endangered or protected species.

Results and discussion

Table 1 presents the results of the chromatography studies. Filtration efficiency of oil from the oil-in-water emulsion was above 99% in all conditions except for the high oil injection rate, 60.5 mg/min, and the high water flow rate, 150 ml/min. The efficiency of this combination was 98.9%.

The results in Table 1 support the conclusion that the nylon spunbond fabric is very effective in separating oil from water at varying conditions. These observed efficiencies are similar to the efficiencies determined by Ortega et al in other experiments.[10]

Recent fence deployments following oil spills

Figure 2 illustrates the deployment of 4 oz/yd^2 spunbond nylon fence fabric in Mooringsport, Louisiana. Figure 3 is a control measures map of the Black Tail Creek spill in Marmon, North Dakota, showing a dozen locations of the deployment of the 4 oz/yd^2 spunbond nylon Oil Shark fence fabric. In both case studies, nylon spunbond fabric was successfully employed as part of a remediation programme to remove the spilled oil.

Conclusion

The unique properties of nylon spunbond fabric make it an effective material to use to separate oil from water in an oil-in-water emulsion. Experiments supported by chromatography analysis has provided more evidence that spunbond nylon can be used effectively to contain oil spills in aqueous environments. The oleophilic and hydrophilic nature of nylon spunbond fabric provides an optimal material to separate oil from water in an oil-in-water mixture. This provides first responders with a new material to remediate spilled hydrocarbons and other organic fluids such as crude oil by containing, collecting, and removing these fluids from the environment. T&T

Notes

The authors wish to thank Bart Warner for donating light Louisiana sweet crude oil from a private well. The authors would also like to thank Ryan A. Ortega for previous analysis of research data and providing editorial comments and support for the manuscript.

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John-Michael Carolan, Willowglen Systems, Canada, reviews why measurement reliability is paramount to the efficient functionality of the tank and terminal industry.

MEANINGFUL MEASUREMENT

Within the tank and terminal industry, and more specifically for flow measurement and control, reliability is not only sought after but required, resulting in a need for measurement devices and practices to provide this functionality. One method of initiating this improvement is system duplication, or dual redundancy. Redundancy is the duplication of critical components or functions of a system with the intention of increasing the reliability of the system. This allows for different instruments to be connected to separate flow computers to perform the same calculations on the same flow simultaneously. The result is an overall improvement in system reliability, and fulfils this principle industry requirement.

Two flow computers can be connected to the same field input/output (I/O) and operate together simultaneously while recording I/O and completing calculations independently. The analogue inputs can be read as 1 – 5 V by both electronic flow measurement (EFM) devices, while digital and pulse inputs can be easily split and sent to both flow computers. Both EFM devices need to share information, and each flow computer generates separate batch and prover tickets, ensuring seamless failover of control functionality in the event of a failure. Using more than one meter allows for redundancy in metering, reducing downtime. It is becoming more commonplace to size a metering skid with one additional meter to allow for servicing without negatively impacting operations. This additional meter can be used as an alternate to allow wear levelling between the different meters. Using the spare meter periodically allows the meter to be verified as operational, and helps to prolong the life of the remaining meters.

A key to securing this redundancy is ensuring that the instrument placement is considered at the design stage. How does the location of sensors affect the overall system? It essentially allows tradeoffs of accuracy vs redundancy. If one looks at the effect friction points have on temperature, it can be seen that strainers are a common source of friction, and flow rate through meters can increase temperature. Similarly, pressure drop over a length of pipe can occur, causing different sensors at different locations to give measurements that are different. The longer the distance of pipe between the meter and the pressure

Figure 1. Flow computer for a rail loading pipeline.

Figure 2. Flow computer with three manifolds, 12 m, and full valve and sampling control.

Figure 3. Unisen flow computer (2216).

measurement, the larger the pressure gain/drop can be compared to what the meter is seeing.

Another method of improving system reliability and securing redundancy is by taking the power sources and monitoring into consideration. With a single power source for multiple devices, a power failure could be detrimental. If an uninterruptible power supply (UPS) fails, what is the backup? Even a partial power failure would have a large impact on the measurement accuracy, especially if many devices are relying on this power source and no alternatives are available. Are the devices fused properly? Moreover, how is a power failure logged? By taking these issues into consideration and including multiple power devices in the system design initially, overall system reliability and safety will be improved – also leading to a reduction in maintenance costs.

Coriolis meters

When efficiency is essential, accuracy and subsequent analytics are at the forefront of the requirements list. While determining the best meter type for an overall project design, it is best to anticipate its long-term functionality and improvement on system reliability and return on investment (ROI). Coriolis meters are more commonly being used in measurement, not only for metering, but also for density and flow direction.

Based on the principles of motion mechanics, when paired with a modern flow computer, the Coriolis meter can provide multi-variable results over Modbus that not only increase accuracy, but can provide additional diagnostic information. Coriolis meters measure density as a manner of operation, and this density value can be used as a backup density value to the liquid densitometer:

(Mass flow rate/density = volumetric flow rate)

On a Coriolis meter, pulses are generated as a result of calculations on the meter's controller/transmitter. The frequency and units of volume for these pulses are often selectable.

A Coriolis meter boasts many measurement advantages over turbine and positive displacement (PD) meters. Not being dependent on any moving parts, there are no obstructions in the fluid path, long-term measurement drift is minimal and maintenance costs are reduced. This is further emphasised in a liquids application with fluids that can have some contamination. There are minimal effects by abrasives and corrosives, and Coriolis meters are not susceptible to damage by gas slugging. Its direct mass and density measurement is suitable for lower viscosity fluids, minimally affected by viscosity changes and allows for registering of a near zero flow rate. With many diagnostic functions available, a Coriolis meter does not typically require flow conditioning. Just as notable is the collection of communication features of the modern Coriolis meter, including multi-variable communications/diagnostics, analogue outputs, discrete

inputs/outputs, frequency outputs, HART, Profibus and Modbus RS-485.

There are various features available from leading Coriolis meter manufacturers, further enhancing the capabilities of the meter. From batch configuration to slug detection, where slugs of water/air can be detected and compensated for if functionality is turned on and configured. Certain meters have certification from measurement regulatory organisations, allowing for the lockdown and sealing of transmitter flow calculations to meet requirements. Since no flow conditioning is required, the flow rates detected by the Coriolis meter can be 'noisy' and flow damping can be enabled to 'smooth' out the flow rates at the penalty of a delay between what the Coriolis meter detects and when the action occurs. Empty pipe detection can eliminate 'ghost pulses' or 'ghost flow' that may occur from when no fluid (or the presence of only gas) can be detected and no flow is shown. Certain types of Coriolis meters can also compensate for pulsating flow, depending on the type of flow identified, and typically have advanced diagnostic registers to acquire details about sensor failure or other problems.

Some challenges exist, including communication from redundant devices to the Coriolis meter, measurement information capture methods, and prioritising the information collected. It is also important to note that when using Modbus for multivariable reads/writes, all manufacturers have a different Modbus register mapping. Meter factors for volume and density correction can be entered into the Coriolis transmitter; however, this is not auditable. It is recommended to use a dedicated flow computer that can track changes for API 21.2 compliance. Furthermore, it is worth noting that proving can be minimised by monitoring the structural integrity and internal diagnostics of the Coriolis meter, and additionally can be automated by a modern flow computer.

Uncertainty-based proving

There are two known setbacks with meter proving that can potentially incur additional time, effort and associated costs. The first setback is that the time involved in performing the industry recommended required runs can consume a significant portion of an operator's workday, and proves may not be possible with the industry trend of shortening batches. Without being able to prove meters in a timely fashion, these short batches may decrease overall accuracy, potentially leading to money lost in custody transfer. Secondly, meters with artificially generated pulse trains, such as ultrasonic or Coriolis, can be difficult to prove and often do not work well with the traditional proving algorithms. One method of alleviating these issues is by performing uncertainty-based proving and ensuring a valid meter factor has been obtained. Uncertainty-based proving allows for a smaller (or larger) number of proving runs to be used to validate if a prove is acceptable. Typically, the repeatability calculation is used to verify that the proving runs are producing a valid, stable meter factor. Comparatively, the uncertainty calculation attempts to determine if there is a 95% certainty that the new meter factor is accurate. Assuming a properly functioning proving system is in place, what improvements does the uncertainty equation produce?

When time constraints are an issue and an operator is working with small batch sizes, another option is to reduce the proving runs using the uncertainty-based proving method. For example, the quantity of runs can be reduced from five to three, while ensuring each meter proving run takes no longer than two or three minutes, as shown below:

3 runs x 3 min. x 6 m = 54 min.

Compare this to the five runs required for a repeatability-based prove, which is more traditionally used in the industry:

5 runs x 3 min. x 6 m = 90 min.

This equates to a saving of 36 min. for a single manifold (or 40% less time) using ideal numbers for the prove timing. By significantly reducing resources needed for the meter proving in a control centre with multiple pipeline manifolds, for example, a significant portion of the operator's day can be reassigned to other tasks, therefore increasing productivity and overall efficiency. Incorporating the uncertainty calculation into the proving operation can provide significant time savings by reducing the number of proving runs required for stable pulse trains.

When a modern ultrasonic or Coriolis meter is installed, their artificial pulses are known to be variable frequency and non-linear at times. These variations can cause difficulties with proving or obtaining a valid meter factor, especially when using the standard repeatability method of five runs within a specific time frame.

Incorporating the uncertainty calculation into the proving method for these modern meters can ensure a broader tolerance and increase the prospect of obtaining acceptable proves, from which to pull a valid meter factor that satisfies the uncertainty acceptability criteria. By allowing for more than five useable runs, a prove with more volatility in its flow rate can still meet the uncertainty criteria.

Conclusion

By implementing the suggested measurement approaches, such as system duplication, or dual redundancy, the expected result is an overall improvement in system reliability and efficiency. Ensuring a modern meter type, such as Coriolis, is chosen at the design stage of a project will allow for many measurement issues to be anticipated and potentially avoided. By ensuring a valid meter factor is obtained, through practicing methods such as uncertainty-based proving, the continuous improvement of processes is a goal that can be achieved. These measurement options can certainly contribute to the success of projects, applications and requirements in the tank and terminal industry. T&T

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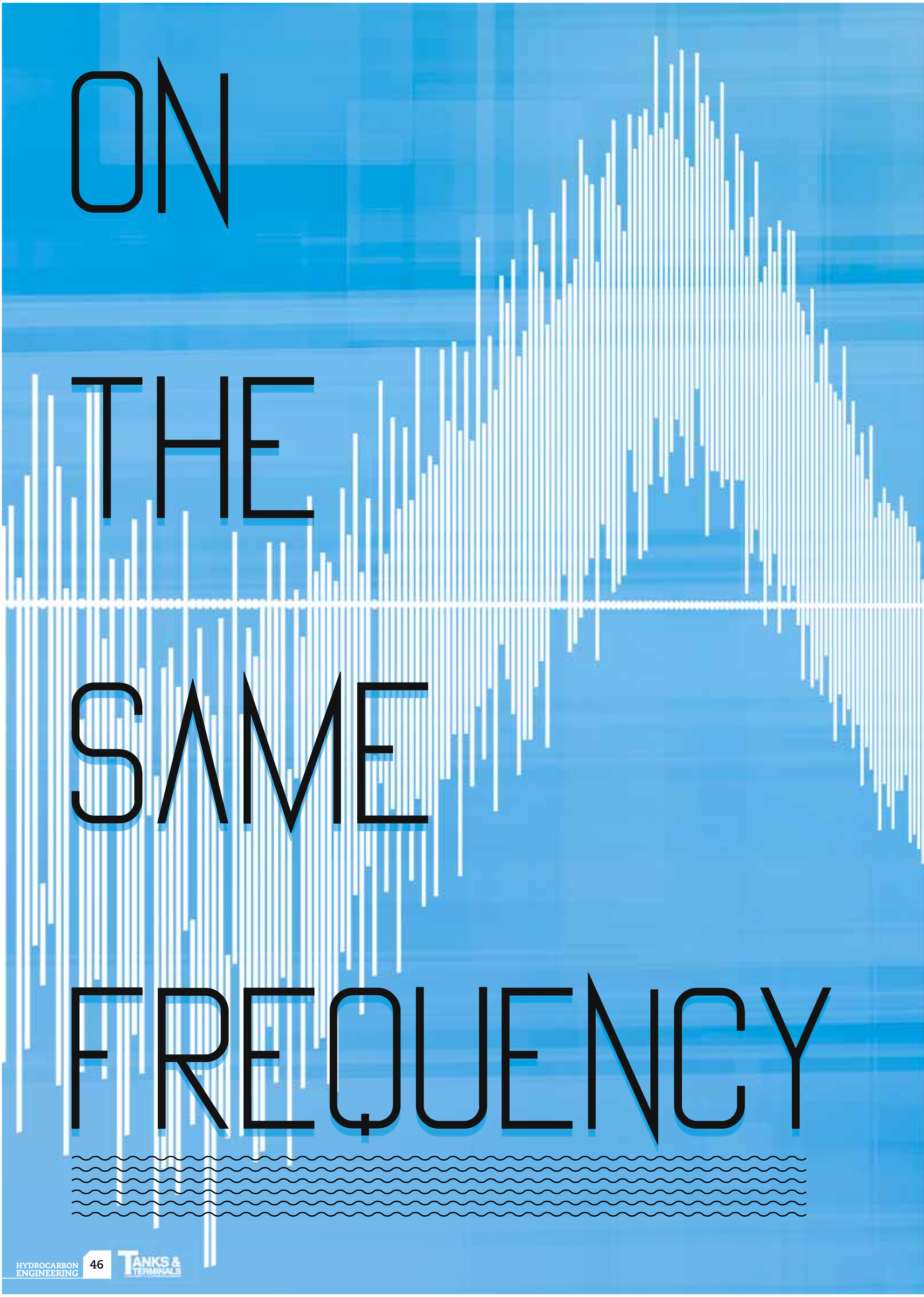

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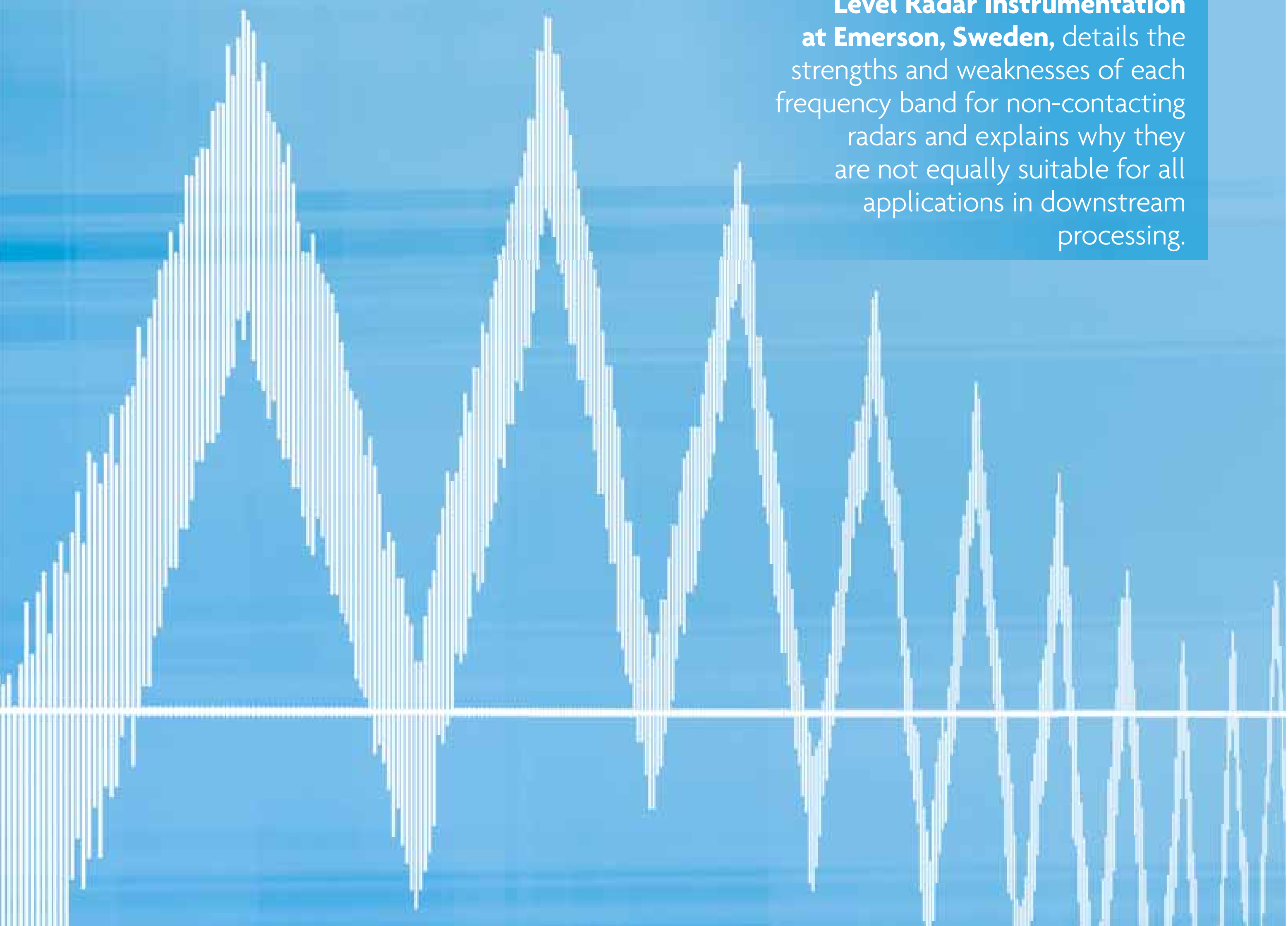

Per Skogberg, Rosemount Process Level Radar Instrumentation at Emerson, Sweden, details the strengths and weaknesses of each frequency band for non-contacting radars and explains why they are not equally suitable for all applications in downstream processing.

The accuracy and reliability of radar has made it the preferred technology for level measurement in many of today's industrial applications. However, when selecting a non-contacting radar solution, it is important to understand that different devices transmit a variety of microwave frequencies, and different frequency bands are required to solve different problems. To select the right device, it is therefore essential to understand which frequency band they use, the strengths and weaknesses of each frequency band, and which level measurement applications they are best suited for.

Radar technology has been continually developed for level measurements over the past 40 years. For non-contacting radars, the microwave frequency transmitted by the device is an area in which there have been some interesting recent developments. Traditionally, three different frequency bands have been used to provide accurate and reliable level measurements in industrial applications – the 6 and 10 GHz low frequency bands and 24 – 29 GHz mid frequency band. Now radars using high frequency (75 – 85 GHz) have been introduced as a further option.

The emergence of 75 – 85 GHz radars has been driven by the development of automotive radar applications such as driving assistance. However, within process industries, the use of high frequency devices is still at the infant stage and when choosing non-contacting radar technology, it is important to take into account that different frequency bands are not equally suited to all applications.

Frequency and wavelength impact

Radar instruments emit microwaves to measure the distance to a surface, and the wavelength is inversely proportional to the microwave frequency – the shorter the wavelength, the higher the frequency. Frequency is a fundamental property of any radar since it directly affects measurement performance due to laws of physics. High frequency microwave signals suffer more attenuation

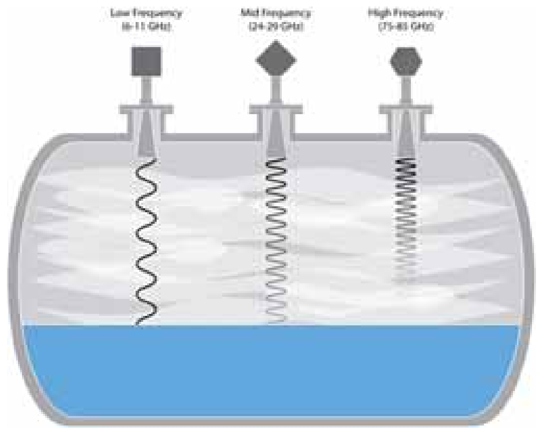

Figure 1. When propagating through a media, radar signal are absorbed and signal strength decreases. High frequency signals suffer more attenuation than mid and low frequency signals.

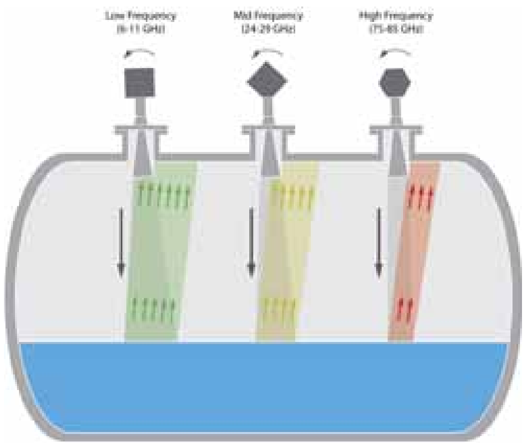

Figure 2. A small deviation from the plumb line can lead to weak signal return if the beam angle is too narrow.

(i.e. they are absorbed to a greater degree) when propagating through a medium, resulting in a weaker signal return. For a simple analogy, think of when a neighbour is playing loud music; a low frequency sound (i.e. bass) will travel long distances and can be heard clearly even through walls. However, high frequency sounds (i.e. treble) are quickly absorbed and do not carry over long distances or through objects.

When it comes to level measurement, high frequency radars will have most problems with foam, condensation, vapour, build-up on the antenna and dust. Low and mid frequency signals are less affected by these kinds of challenges and more able to pass through them unaffected.

Another important effect of the frequency is that it impacts the antenna beam width and angle, i.e. how focused the microwave propagation is. The beam angle and beam width are determined by the antenna design in combination with the microwave frequency. High frequency signals can achieve small beam angles with small antennas. Equally, small beam angles can be achieved with low frequency radars, but this requires larger antennas, so users would need to consider what fitting sizes they have on their vessels. The benefit of a small beam angle in level measurement is that it can make it easier to avoid hitting installations in the tank. However, a beam width that is too narrow can also be a disadvantage. For example, if there is an obstruction directly below the radar, a narrow beam will be completely blocked, whereas a wider beam would be only partially blocked and could still measure the level within the vessel.

Waves and ripples on the surface of a liquid are common in industrial applications and can cause problems for radar level measurement. Instead of reflecting back up towards the antenna, microwaves hitting a turbulent surface can scatter and disperse. That can mean up to 90% of the signal strength being lost, creating problems in obtaining an accurate and reliable level measurement. However, if the wavelength is larger than the ripple size, microwaves remain unaffected by surface irregularities such as turbulence. As a direct consequence of short wavelengths, turbulence particularly affects high frequency signals. For example, the signal return of high frequency radars are scattered by surface movements as small as 3.8 mm, whereas signal returns from mid frequency radars are unaffected by turbulence up to 2.5 times as large. As such, it is clear that the frequency has a major impact on the type of application a non-contacting radar is best suited to.

Strengths and weaknesses

Low frequency radars have several advantages. They can handle obstacles in their line of sight; they are least attenuated by conditions such as condensation, vapour, foam, build-up and dust; they are least affected by waves or ripples; and they perform very well in still-pipes. However, they require a larger antenna and nozzle, and have more difficulty in measuring very short ranges.

Mid frequency radars can also handle obstacles in their line of sight, and are also reliable in unfavourable conditions and when there are waves or ripples in a tank. They can also be fitted in the small nozzles commonly present at process plants. Their weaknesses are that they are affected by extreme vapours, such as anhydrous ammonia or vinyl chloride monomer, and dense foam, such as latex or molasses.

The plus-points of high frequency radars are that they have a narrow beam that can help avoid obstacles and they support antennas for very small nozzles. However, their narrow beam needs a free line of sight as they, and surface conditions, should be calm. They are the most sensitive to unfavourable conditions, most affected by waves and ripples, sensitive to inclination of the gauge, and not suitable for use in still-pipes and chambers.

Some examples of typical radar level measurement applications, with an indication of which frequency band would be most suited to them, are outlined below.

Dirty and contaminating applications

Dirt and contamination build up on the antenna over time and this affects the strength and direction of the radar signal. Low and mid frequency signals are less sensitive to this contamination and can pass through the build-up more or less unaffected. However, with high frequency signals, more of the energy is absorbed by dirt covering the antenna and the direction of the beam may be diverted. A deposit of uneven thickness covering part of the antenna can redirect the beam by approximately 1.5˚. For a radar with a narrow beam angle, this can cause problems because the return echo will not be directed straight back at the antenna, leading to a loss of signal strength. Low and mid frequency technology is therefore more suitable.


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Figure 3. A Rosemount 5300 guided wave radar level transmitter on a sphere tank in a gas processing plant.

Tanks with condensation and/or vapour

Condensation and vapour is sometimes a challenge for radar level measurement. Water reflects microwaves much more strongly than most industrial liquids. Condensation and vapour can therefore cause the reflection from the product surface to be obscured by 'noise' from water droplets. This is more of a problem for high frequency signals because their shorter wavelengths also reflect strongly from very small particles, such as steam and aerosols. Low and mid frequency technology is therefore a better choice in these applications. However, it should be noted that the design of the antenna is also critically important for condensation. Antennas with flat, horizontal surfaces should always be avoided in these applications.

Applications with turbulence, waves and ripples

In general, low and mid frequencies perform best in these applications. Small ripples on the surface of the process liquid are especially detrimental to high frequency measurements. The short wavelength of high frequency devices means that the signal reflection will be scattered by small surface movements, causing a loss of returning signal strength. The longer wavelengths of low and mid frequency devices are reflected as if from a flat surface, making them better suited to these applications.

Applications with foam

Similar to dirt and condensation, a layer of foam on top of the liquid will absorb the radar signal and make accurate measurement more difficult. Foam can have very different properties depending on which product it comes from, but lower frequency generally provides better measurement accuracy and reliability. For dense and thick foam, such as from beer, molasses or latex, low frequency works best. For lighter foam, mid frequency performs very well. High frequency technology, though, should be avoided in foam applications.

Bulk liquid storage tanks

In very large tanks, such as those used for bulk liquid storage at tank terminals, the size and placement of nozzles is typically unrestrictive when it comes to radar device selection. Obstructions and disturbing objects in the tank are usually not an issue either. However, due to the vessel size, waves and ripples are often present on the liquid surface. Condensation is also common. As previously explained, both of these issues cause problems for high frequency technology.

Many bulk storage vessels use floating roof tanks requiring level measurements to be performed through still-pipes. Low frequency radars are preferred for these applications because they are less sensitive to build-up on the pipe wall, slots, and pipes that are not completely straight. High frequency radars have difficulties in such situations.

Furthermore, bulk storage tanks often have significant roof movements due to sunlight and shade, wind, and tank bulging. This causes problems for high frequency radars because their narrow beam width makes them very sensitive to tilting if the axis moves from the vertical plumb line. Tilting can result in the reflected signal missing the antenna opening, making the installation of high frequency radars challenging as they must be installed absolutely level in order to perform correctly. Low frequency technology is therefore the most appropriate choice for this kind of application.

Small to medium-sized vessels

Small to medium-sized vessels, typically up to 20 m high, are among the most common in process industries. Conditions inside the tank are often difficult for level measurement, with challenges such as condensation, contamination, turbulence and foam. Mid frequency technology is a good choice in this kind of tank due to its versatility, it combines small antennas with good reliability in difficult conditions. Low frequency radars may be less suitable due to their small nozzles, while high frequency technology would struggle to cope with the tough process conditions.

Small tanks/buckets

In very small tanks (approximately 0.5 – 1.5 m high), the size and placement of nozzles can be a limitation. The short measuring range and the need for small antennas means that high and mid frequency technology are attractive options for these applications. However, previously mentioned challenges, such as condensation, contamination, turbulence and foam, must be considered where applicable.

Solids

For measuring the level of solids, the best frequency to use is very much application dependent. Low and mid frequencies are able to cope with dust, condensation, and coarse solids, whereas high frequency works well with very fine powders. Condensation is generally challenging for high frequency radars, but another problem arises with solids, as when condensation combines with certain solids it can cause rapid material build-up. This will quickly clog small nozzle openings and cover the small antennas of high frequency radars.

Conclusion

Microwave frequency is an essential consideration when choosing non-contacting radar technology, as each frequency band has its advantages and disadvantages, meaning that it may or may not be well suited to a certain application. The recently introduced radars, using the 75 – 85 GHz frequency range, are a good choice for tanks with only very small process connections. However, the fundamental suitability of low and mid frequency technology for accurate and reliable level measurement cannot be overlooked.

High frequency technology will usually perform well in less challenging process conditions, but is less suitable when the going gets tough. In contrast, low and mid frequency technology was developed specifically to meet the toughest level measurement challenges, and when connection size is not a limiting factor, it continues to provide the most accurate and reliable level measurement in the most demanding industrial applications.

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ON THE RADAR

Brian Howsare, Endress+Hauser, USA, reviews frequency modulated continuous waveform and pulsed time of flight radar level technologies for tank gauging in custody transfer applications.

Measuring the level of tanks that are used to hold fluids for custody transfer can be expensive. This is not due to the cost of the measurement instrumentation, but due to what inaccurate measurements can cost a terminal or tank farm operator.

For example, consider an operator with 10 oil tanks each filled and drained once a week. If the level instruments have ±3 mm accuracy per the manufacturer's technical specifications, and each tank holds 2 million gal., the uncertainty in the measurement is approximately 554 gal./week. At US$45/bbl, that represents an error of US$600. In one year of operation, that equates to US$31 200/y. Scaled up across 10 tanks, the error could potentially represent US$312 000/y in unnecessary losses due to less accurate inventory measurement.

Compare that loss to level instruments with 0.5 mm accuracy. The possible error is only 93.25 gal./week, for a total cost of US$52 000/y. Installing better level instruments could save the company US$260 000/y in reporting unnecessary losses due to more accurate inventory measurement.

In many applications, higher accuracy measurements are required to protect the customer from over-billing and the supplier from under-billing. Common products requiring this level of accuracy are typically oils, fuels, edible oils and alcohols. In the oil and gas industry, this requires a system called automatic tank gauging (ATG), as defined by the American Petroleum Institute (API) standards.

For this same reason, groups around the globe either make recommendations or dictate the equipment accuracies needed when using level-based (static) inventory accounting for custody transfer, trading products or tax payment evaluation. Some of these groups, standards and guidelines are NMi, PTB, OIML R85 and API 3.1B. In general, these groups require a level instrument with better than 1 mm level accuracy.

Frequency modulated continuous waveform (FMCW) and pulsed time of flight (ToF or PToF) are the two technologies used in modern radar-based tank gauging instruments, and there is often confusion about which is best. In reality they both perform to the specifications for custody transfer determined by the groups above. Both technologies have been on the market for well over 20 years and are proven in many applications, so in essence, both technologies meet the stringent requirements for <1 mm high accuracy level measurement.

This article provides an overview of the differences between FMCW and ToF radars used for custody transfer.

Figure 1. FMCW radar sends a continuous wave that reflects off the surface and returns to the antenna. The shift in frequency determines the level in the tank.

Figure 2. Pulse radar sends radar pulses that reflect off the liquid surface. The time of flight (ToF) determines the level of the liquid.

Level sensing

An FMCW radar (Figure 1) transmits continuously, with the radar signal reflecting off the liquid surface received by the radar antenna. The shift in the frequency of the return signal is then used to calculate the distance to the liquid. FMCW uses a range of frequencies and it is typically listed as the middle frequency.

The calculations are:

1) $\Delta f \approx \Delta t$

Where running time (t) is a function of the change in frequency (f).

2) $d = \frac{t * c}{2}$

Where d = distance between instrument sensor and surface, t = running time, and c = speed of light.

ToF radar (Figure 2) transmits energy in the form of a pulse, which reflects off the liquid surface and is received by the antenna. The time it takes for this to happen is then used to calculate the distance to the liquid.

The level calculation is much simpler than FMCW as it is based on actual time:

$$d = \frac{t * c}{2}$$

Selecting the proper instrument

A supplier selling one type of radar instrument but not the other might make various claims that could have been true in the past, but are not any longer. Some of these pitches include:

- FMCW requires more power to operate than ToF, and needs a four wire connection – this is no longer true as FMCW can be powered by a two wire 4-20mA connection.
- FMCW is more expensive than ToF – this is no longer true as pricing is now approximately the same.
- FMCW is more accurate than ToF – both technologies meet the API Custody Transfer accuracy.
- FMCW has temperature stability problems – this is no longer true (in the past FMCW radars used analogue components requiring a stable temperature to produce a linear output, but today digital components have solved the problem).

Essentially, there are no significant differences between the two technologies except for the algorithm


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used to calculate level. Selecting a radar level instrument, then, is more about the beam angle and the intended application.

The beam angle

As shown in Table 1, the beam angle – the amount of spread in the radar signal – is dependent upon the size of the antenna and the frequency of the radar signal. For example, the largest spread of 23˚ is produced by a low frequency 6 GHz radar and a 6 in. antenna. The smallest spread of only 3˚ is produced by a high frequency 80 GHz radar with a 4 in. antenna.

The beam angle is important because it determines how close the radar instrument can be installed to the tank wall (Table 2). The beam should never reach the tank wall because it will interfere with the radar signal. For example, when a radar instrument with a large beam angle is installed too close to the side wall, this causes non-linear inaccuracies throughout the measurement range.

A narrow beam angle enables the instrument to be installed close to the tank wall and makes it easier to find a location where it will not get a reflection off obstacles in the tank such as heating coils, fill/drain pipes or mixers.

But a wide beam angle has its advantages. For example, a 6 GHz radar instrument has a lower, broader frequency than an 80 GHz instrument, so it is better at penetrating steam and vapour. Wide beam angles are also beneficial in tanks with waves or agitation, as it provides more of an average representation of the liquid surface, and a 6 GHz frequency is better when radar is used in stilling wells. For custody transfer storage tanks, the surface is calm so factors such as steam, agitation, waves, etc., are not an issue.

Antenna size is important because it determines the size of the opening needed in the top of the tank. A drip-off lense antenna is preferred because condensed water or oil will drip off the antenna and not coat it.

Ideally, a radar instrument should be installed as close to the tank wall as possible, given the limitations imposed by the beam angle and the size of the hole needed to mount it. Mounting it close to the tank wall minimises the need for maintenance technicians to walk on the top of the tank when servicing the instrument, thus reducing safety hazards.

Also, the farther away from the sidewall of the tank, the less stable the radar's gauge reference height (GRH) will be. Rain, ice, snow, temperature changes or personnel walking on the roof to gauge the tank can easily cause several millimetres of deflection, which in turn changes the GRH of the instrument. Mounting the instrument close to the tank wall allows installation on the most rigid part of the roof, where the instrument is less affected by tank distortions.

For floating tank roofs, one solution is to mount the radar sensor inside a stilling well that is not affected by the roof moving up and down. Some companies mount a lower accuracy radar 5 – 10 ft out from the side to measure a reflection off the roof itself, but that brings inaccuracies due to the roof tilting, or water/snow accumulating and changing the buoyancy.

When selecting a radar level instrument, variables such as vessel height, the presence of obstructions, mounting distance from the side wall, available nozzle sizes, and other considerations, may require testing by an instrument supplier and the end user to determine which solution is best for each application.

A significant development in ATG applications is the 80 GHz FMCW radar level instrument (Figure 3). Its narrow beam angle of 3˚ is the smallest available, allowing it to be mounted closer to the tank wall than lower frequency models. The antenna size of an 80 GHz instrument is 2 – 4 in. dia., so it can be mounted in existing and smaller diameter nozzles, such as those used for older level instruments or locations where a company performs manual hand gauging.

FMCW technology has been around for many years, but it was cost prohibitive in some applications until component and material costs came down. This is why 6 GHz or 26 GHz pulsed ToF radar was mostly used for level measurement. However, converting from analogue to digital components not only brought down the cost of FMCW instruments, it also allowed suppliers to add more capability to the instruments.

For example, Endress+Hauser's 80 GHz device performs predictive measurements with its on-board microprocessor and alerts operators when problems arise.

Table 1. Beam angles vary according to the frequency of the radar signal and the antenna size

Antenna size	6 GHz	10 GHz	26 GHz	80 GHz
2 in.	---		18˚	4˚
3 in.	---		10˚	3.5˚
4 in.	---	21˚	8˚	3˚
6 in.	23˚	15˚	5˚	---
8 in.	19˚	10˚	4.4˚	---
10 in.	15˚	8˚	3.3˚	---
18 in. (17 in.)	7˚	(6˚)	---	---

Table 2. The distance the radar sensor can be mounted from the wall depends on the beam spread and height of the tank

Distance (m)	Distance to wall (m)						
	6 GHz	26 GHz	26 GHz	80 GHz	80 GHz	80 GHz	80 GHz
	4 in. horn	8 in. horn	8 in. antenna	10 in. antenna	4 in. antenna	3 in. antenna	2 in. antenna
5	1.2	0.9	0.35	0.2	0.25	0.3	0.5
10	1.8	1.8	0.7	0.5	0.6	0.8	1.2
15	3	2.7	1.05	0.75	0.95	1.3	1.9
20	4	3.6	1.4	1.05	1.3	1.8	2.6
25	5	4.4	1.75	1.3	1.65	2.3	3.3
30	--	5.3	2.1	1.6	2	2.8	4

Figure 3. An 80 GHz radar instrument, such as this Endress+Hauser Micropilot NMR81, provides 0.5 mm accuracy, can be mounted closer to the tank wall, and its antenna requires only a small hole in the tank roof of 2 – 4 in.

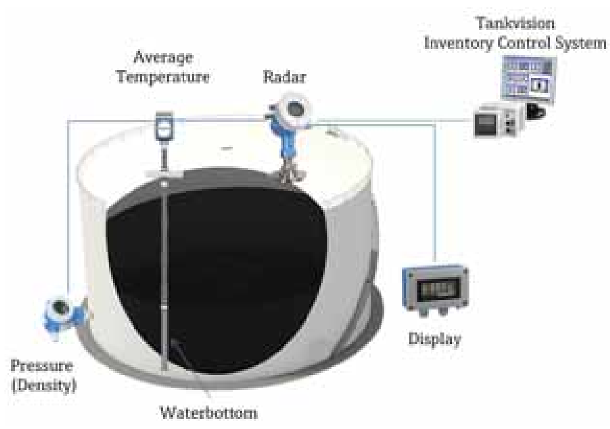

Figure 4. A complete tank gauging system needs level, temperature, waterbottom and pressure (when measuring mass) instruments, as well as inventory control software to process the data.

Figure 5. Radar level instruments have the necessary accuracy for custody transfer applications.

Diagnostic software checks electronic's temperature, voltage inputs, near-field/by-antenna measurements and relative echo amplitude to determine the strength of a returning signal. These algorithms and diagnostics can be used to predict process upsets before they occur.

Ensuring accuracy

Most installations will include either a spot temperature or – for better inventory accountability – an average temperature based on up to 16 resistance temperature detectors (RTDs) that measure temperature at various levels in the tank. The temperature is used to carry out volume correction based on the API tables.

Some applications require compensation for changes in density when making a mass measurement. For these applications, a pressure instrument is included to provide the average mass measurement of the vessel contents.

In many vessels it is also necessary to measure water accumulated in the bottom of the vessel, called waterbottom (Figure 4). Most of the accumulation comes from water that drops out of petroleum and oil-based liquids, but water can also come from vents in the vessel and gaskets on floating roof tanks. The water separates and sinks to the bottom of the vessel and must be accounted for to calculate the net standard volume (NSV) of product in a vessel.

One obvious reason for measuring the waterbottom is so only the desired product is measured and paid for in custody transfers, not the water. The measurement allows deduction of water from the NSV as part of the tank gauging system. Removing water is also carried out for maintenance reasons to prevent rust on the tank floor, which can lead to leaks and resulting environmental hazards. Waterbottoms are typically measured using a capacitance level instrument that can detect the interface between water and oil.

Calculating level, mass and volume from oil level, waterbottom level, pressure and temperature instruments in accordance with various regulations is usually accomplished by using specialised tank inventory management software, which provides the corrected volume and/or mass using embedded API tables.

Conclusion

Custody transfer and other critical tank gauging applications require a level instrument with extremely high accuracy. Both ToF and FMCW radar instruments provide the necessary accuracy to meet all regulations in the oil industry. The recent availability of 80 GHz FMCW radar level instruments makes it possible to install level instruments closer to the tank wall for improved operations and stability, and allows companies to potentially use existing, smaller diameter nozzles, where traditionally they were too small for the available tank gauging level sensors on the market.

GETTING THE MEASURE

Bart Wauterickx and Bas Hermans, The Sniffers, Belgium, highlight the importance of flaring and vapour recovery measurements for tank farm operators.

In an environment of increased storage capacity, ageing assets and increasing safety and environmental regulations, tank farm operators are confronted with several challenges. Adequate emission measurement and vapour recovery unit (VRU) effectivity measurements are essential to the management of storage tanks, and allow a tank farm to benefit from good brand reputation, excellent incident figures, high asset availability and low insurance fees.

The Sniffers, headquartered in Belgium, was founded in 1991 and operates its core business within oil and gas plants, and the chemical and petrochemical industry. The company assists operators with measuring emissions to the atmosphere, detecting and quantifying energy leaks, and maintaining the integrity of pipeline networks. This support and advice helps operators to reduce emissions, save energy and prolong the lifetime of critical assets

Storage tanks are used to hold product for brief periods of time in order to stabilise flow between production and pipeline, and distribution through trucking or shipping. During storage loading and unloading, and during daily or seasonal temperature changes, light hydrocarbons vapourise, including methane and other

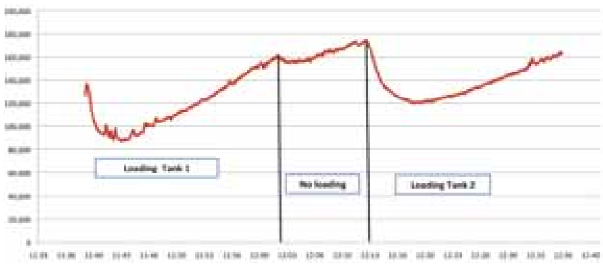

Figure 1. PPM value from exhaust VRU during loading of tank.

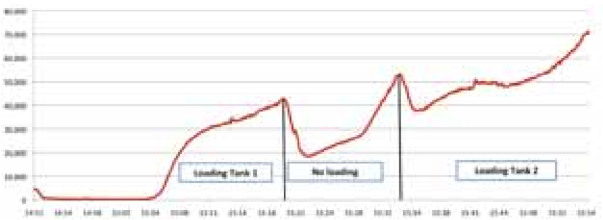

Figure 2. PPM value from exhaust VRU during loading of tank with new carbon filters.

Table 1. Example one of payback flare loss reduction programme

		Number of leaks		Loss (kg/y)	
Source	**Number of sources**	**Before SD**	**After SD**	**Before SD**	**After SD**
Safety valve	7	2	2	16 488	9686
Gate valve	10	2	2	3379	3524
Control valve	2	4	3	231 951	56 863
Brake plate	1	0	0	0	0
Total	20	8	7	251 818	70 073

Table 2. Example two of payback flare loss reduction programme

Valve type	Number of sources	Number of leakers	Leak rate (%)	Emission loss (kg/y)
Control valve	14	1	7.14	1.982
Hand valve	41	0	0	0
Relief valve	34	8	23.53	17.182
Total	89	9	10.11	19.164

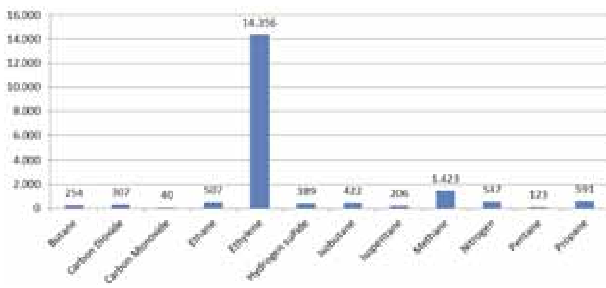

Figure 3. Emissions per chemical product (kg/y).

volatile organic compounds (VOCs), hazardous air pollutants (HAPs), such as benzene, toluene and xylene (BTX), and many others. These gas vapours collect in the space between the liquid and the fixed roof of the tank. During loading of the storage tank, these gases are often vented to the atmosphere or flared. One way to prevent the emission of these light hydrocarbon vapours, and yield significant economic savings, is to install VRUs on storage tanks. VRUs are relatively simple systems that can capture approximately 95% of the vapours for return of the valuable gases to the production process, or to remove environmentally hazardous gases.

The installation of VRUs has generated significant savings through recovering and marketing the valuable vapours, while at the same time substantially reducing VOC and HAP emissions. When the volume of vapours is sufficient, installing a VRU on one or multiple storage tanks can result in a payback of around three months.

Environmentally unfriendly gases can be captured using VRUs. Methane is a greenhouse gas with a much higher capacity to absorb heat compared to carbon dioxide, and hence an underestimated and significant global warming potential. VRU capture of methane prevents release into the atmosphere.

VOCs emitted to the atmosphere react with the NO_x present and form O_3 ozone and particulate matter (PM). Due to the negative impact on breathing air quality, VOC emissions must be prevented. HAPs, such as BTX and many others, are often regulated by local or regional authorities. Effective VRUs can capture these carcinogenic vapours.

Effectivity of a VRU

Given the important financial and environmental objectives of a sufficient working VRU, regular monitoring of its performance is inevitable. Sampling of emissions at the end exhaust reveals the performance of the total system.

The following case study concerns a storage tank containing a carcinogenic product. The end exhaust of the recovery was equipped with active carbon filters, and the residual vapours were vented to the atmosphere. Company employees and neighbours began to complain about an offensive smell, so a thorough investigation became necessary. Outstanding legislation requirements, permit thresholds and social responsibility objectives were in doubt.

Using continuous flame ionisation detector (FID) measurement, the concentration of the exhaust vapours was logged during different tank operating conditions. A specific test was prepared to visualise the effectiveness of the VRU unit.

The graph in Figure 1 shows the increasing concentration of the carcinogenic vapour during loading, reaching a level above 10%. This concentration remained high during 'no loading', therefore it was suspected that the carbon filters were saturated.

For this reason, a second test was executed with an improved carbon filter configuration (Figure 2). During the first 15 minutes, the parts per million (ppm) value of the

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Figure 4. Active carbon filtration.

Figure 5. Exhaust to atmosphere.

carcinogenic vapour was almost zero. However, following that initial 15 minutes, the ppm level increased again, and after 1 hour a value of 7% was reached.

Urgent action was required as the saturation level was reached very quickly. It became obvious that the design dimensions of the existing VRU were inadequate for the current gas vapour generating conditions in the storage tank. A new VRU with a larger capacity and larger active carbon filter was required to ensure the safety of the workers in the plant. The continuous logging of exhaust emissions during several different operating conditions of the storage tank can ensure the correct operation of the VRU.

Flaring on storage tanks

Pressure relief valves, ball and gate valves, control valves and other external equipment are part of a complete storage tank installation. These components are ideally closed in normal conditions, but in reality this is not the case. Internal leaks in this type of equipment occur, and this uncontrolled product loss is routed to the flare to be burned. Local legislation can mandate a VRU or a combustion unit to completely burn off these losses;

Figure 6. Ultrasound measurement of internal leakage safety valve.

however, in reality, due to safety reasons, flaring will still go on as a backup.

Factors such as the visible flame at the flare stack, the losses of raw materials, unreliable stream balances and the environmental consequences have created an important awareness. Companies should monitor and manage their flare losses; in the absence of a flare loss monitoring and reduction programme, these losses are the single most significant cause of raw material losses resulting from plant activities. The total number of flare-connected pieces of equipment, and thus possible leaking sources, is typically less than 1% of the total number of fugitive emission sources. Nevertheless, even when only a few leaks are found, this will result in a significant payback opportunity.

Within a storage tank at a European refinery producing light end products, such as liquefied petroleum gas (LPG), ethylene, propane, methane and hydrogen, around 20 components were found to be suspicious. All of the tank equipment should close completely in normal conditions. A monitoring programme using ultrasonic leak detection measuring equipment was executed to identify and quantify the product losses. The sound intensity (dB) measured on the suspected equipment, the density of the product and the pressure difference over the valve are parameters to calculate the product loss.

Of the 20 sources measured, eight were identified as leaking, with a total loss of 251 t of product every year. After shutdown (SD) a reduction of more than 70% was achieved by repairing only one control valve, and reducing the leakage of one of the safety valves (Table 1).

Measuring the storage tank equipment identifies the leaking components, quantifies the amount of lost product per component in both kilograms and value, and enables companies to prioritise maintenance activities. Adding the cost of repair to the total project cost, a company could expect a payback time of three to six months for a flare loss reduction programme. In this case – only repairing one piece of equipment and replacing another – a cost saving of more than US$200 000 was achieved.

Another example of a flare loss reduction programme concerns a large petrochemical site with a tank farm (Table 2). Only 89 potential leaking components were identified after examining the equipment for a full tank farm, which is relatively simple to manage. After identifying nine leaks on the total of 89 using ultrasonic leak detection (a 10% leak rate), quantification revealed a loss of 20 tpy of product. Eight relief or safety valves were detected as leaking, and could be repaired through maintenance work. The measuring programme makes it possible to limit the maintenance efforts on safety valves, instead of testing all of the safety valves. In normal circumstances, all the valves had to be dismantled and installed on a test bench for a full functional test. The time and cost reduction realised due to condition-based information for these valves was extremely valuable for the maintenance team and accelerated turnaround activities.

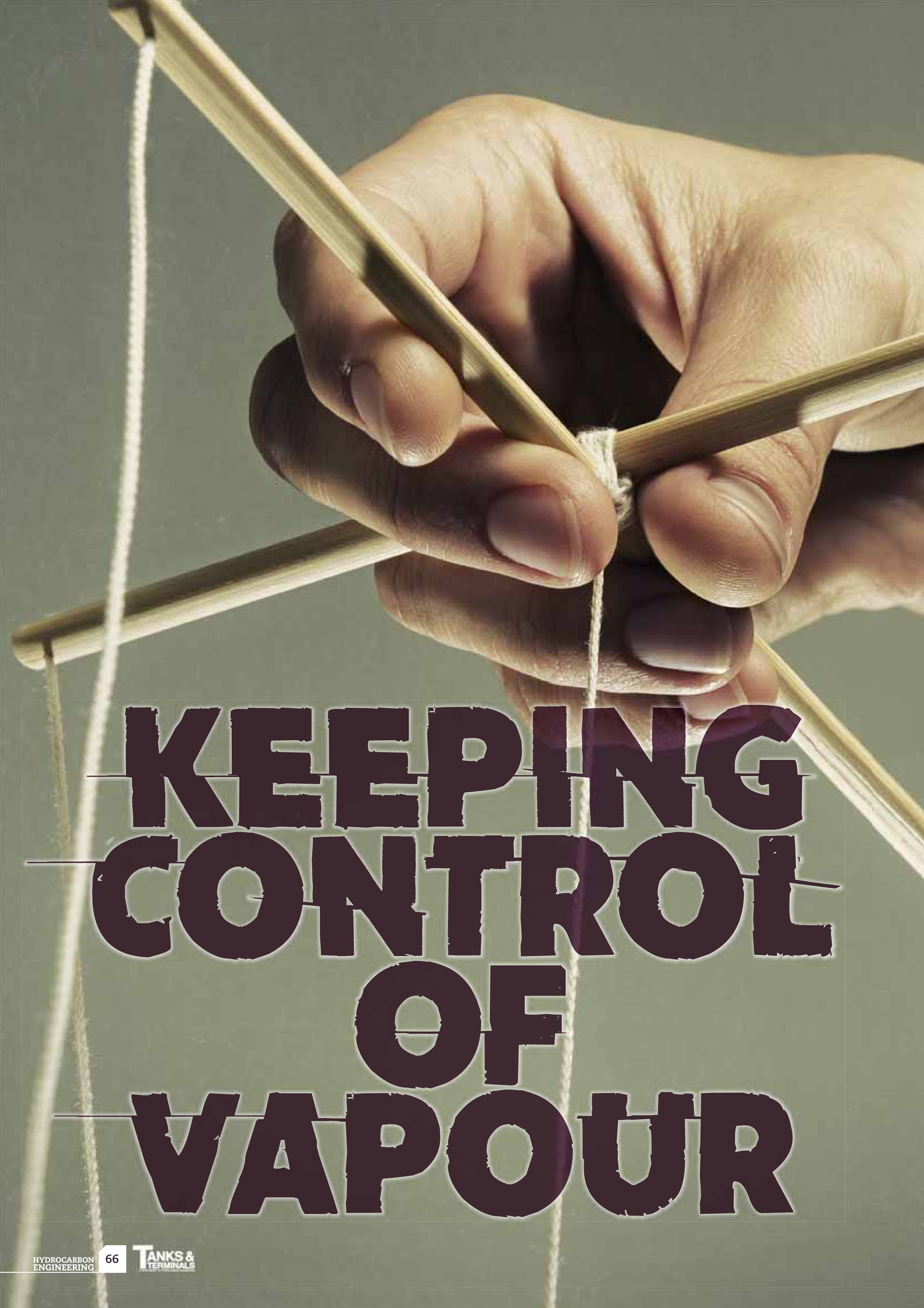
A proper flare loss reduction programme also reports on the individual chemical products routed to the flare and burned into the atmosphere. In the graph shown in Figure 3, the main contributor to the losses is ethylene. Even in situations with losses of mixtures, state-of-the-art software calculates the loss per chemical product. This enables easy environmental reporting and financial loss and benefit calculations.

Conclusion

Over the past few years, emission reduction programmes in refineries, crackers and chemical plants have been mandated by local authorities. This resulted in significant reductions from the industry, contributing to the 50% fall in non-methane VOCs over the past 13 years in the EU-28. A strong improvement in air ozone levels was a clear and direct effect of this legislative work.

More regulations have now been issued to manage emissions from tank farms, as their release to the atmosphere must be minimised. The Sniffers is able to measure direct emissions to the environment using PID/FID equipment or optical gas imaging devices, as well as internal leaks using ultrasonic or thermographic measuring equipment. Services such as this help operators to manage all possible leaks on tanks with both fixed or floating roofs. Eventually, the minimisation and prevention of leaks can allow tank managers to achieve a low environmental impact, low energy consumption figures, a good brand reputation, excellent incident figures and high asset availability.

KEEPING CONTROL OF VAPOUR



Simon Shipley, Zeeco Europe Limited, UK, discusses the decision between two common vapour control technologies, recovery or combustion, in tank and terminal applications.

Around the globe, vapour control systems are a common sight at storage terminals handling the transfer of hydrocarbon products. Though traditionally vapour control systems were only required for gasoline distribution terminals, today the number and types of applications where vapour control systems are considered a requirement is expanding to include controlling hydrocarbon emissions from truck loading, tank storage, and ship loading operations.

Vapour handling requirements for capacities from 10 000 to 40 000 m^3/hr are not uncommon in crude oil applications. In controlling hydrocarbon emissions for crude oil applications, operators have essentially two options: either recover the hydrocarbons or destroy (combust) them.

Vapour recovery

Although there are a number of alternative vapour recovery technologies available, activated carbon adsorption vapour recovery units (VRUs) remain the preferred technology for most applications. These systems provide operators with maximum flexibility because they are capable of handling an extensive range of products and feature a wide turndown ratio capability, from 0 – 100% of the design flow and inlet concentrations.

Activated carbon VRUs are readily able to attain emission standards to 150 mg(HC)/Nm^3 in a single stage system. The lower requirements of Germany, the Netherlands, and Oman, however, require two stage systems; where the first stage is an activated carbon VRU, followed by a second stage oxidiser of either a catalytic thermal oxidiser (CTO) or regenerative thermal oxidiser (RTO) design. The two stage approach can meet the obligation that VOC emissions be recovered, often a requirement of the emissions control permit, whilst meeting the most stringent overall emissions limit through the second stage oxidation of the final few grams, that would otherwise be vented from the VRU.

Such systems are used in a wide variety of applications, including truck, rail, ship loading, and tank venting. The range of vapour flows are wide, from the smallest truck loading applications at 100 m^3/hr to the two largest vapour recovery systems in the world, using activated carbon adsorption with vapour flows of up to 40 000 m^3/hr.

Figure 1. A typical Zeeco vapour recovery unit.

Destruction or combustion?

Vapour destruction systems typically employ vapour combustion units (VCUs), which are a mix between a simple thermal oxidiser and a temperature controlled enclosed flare. Key features of VCUs include:

- Soft refractory lining to protect the combustion chamber from the heat and to handle quick swings in temperature.
- Anti-flashback burner tip and flashback protection in the upstream line via a detonation arrestor or liquid seal drum.
- Full temperature control of the combustion chamber, utilising assist gas, air assist blower, and automated external air dampers.

Destruction efficiencies for VCUs vary depending upon operating temperature, but typically range from 98 to 99.9%. For applications in which higher destruction efficiencies are required, a thermal oxidiser may be the best solution. These differ from a VCU in certain design features, and are able to attain destruction efficiencies up to 99.9999%. VCUs are able to control emissions that are not easily handled in a VRU, including methane emissions and vapours with some H_2S content. VCUs or thermal oxidisers can offer a viable solution in cases where a VRU would present particular operating problems.

There are a number of options available under each of the two primary control paths, vapour recovery or vapour combustion, when selecting a solution to manage a particular application. To select the most appropriate technology, a range of factors should be considered, including the following:

- Legislative requirements.
- Emission requirements.
- Available utilities, including electric power and assist gas.
- Equipment capital cost.
- Return on investment (ROI).

Legislative requirements

Environmental pollution legislation is – almost without exception – the driver behind most operators' decisions to install a VCU. Operators choose VCUs to meet permitting requirements and to provide cleaner local environmental emission controls and a safer working environment. Legislators often dictate whether vapour recovery technologies must be adopted or whether destruction/combustion technologies may also be considered.

Emission requirements

Legislators worldwide are demanding tighter emission control capabilities. Emission requirements have been, and will continue to be, regularly tightened, with levels in some parts of the world as low as 35 mg(HC)/Nm^3. System providers must adapt designs and continue to innovate to ensure operators can meet new regulations and demands.

While emission standards vary somewhat throughout the world, many are based on either European Union (EU) or US Environmental Protection Agency (EPA) standards. Both the US and European market areas have a well developed installed base of vapour recovery technologies. In EU countries, volatile organic compound (VOC) emissions may not exceed 35 g(HC)/Nm^3, measured in the vent of the VRU for gasoline. EU member countries have varying emission requirements, but generally require that the VOCs do not exceed either 10 or 35 g(HC)/Nm^3. A number of countries outside the EU do not exceed 150 mg(HC)/Nm^3, while in the US, the standard is usually not to exceed 35 g(HC)/1000 l or 10 g(HC)/1000 l – with the notable difference from European standards that emissions from the VRU are measured relative to the product volumes being loaded instead of in the vent line.

Currently, Germany and the Netherlands require the lowest emissions applicable to VOCs at 50 mg(HC)/Nm^3, while Oman has enacted the most extreme emission requirement overall at 35 mg(HC)/Nm^3.

Other emissions limits may also be applicable. Permitting requirements may restrict nitrous oxide (NO_X) and sulfur oxide (SO_X) emissions as well. Fuel-bound NO_X in the inlet vapour stream is not uncommon in ship loading applications. Meeting NO_X emissions requirements is a consideration in the selection of a vapour control technology given that NO_X is naturally produced in the combustion process. NO_X developed during the combustion process is referred to as thermal NO_X, and any thermal NO_X produced would be added to fuel-bound NO_X in the inlet vapour stream. SO_X emissions may become a concern in applications where the vapour stream contains sulfur-bound compounds, i.e., H_2S and or mercaptans, commonly found in crude oil vapours.

Available utilities

Vapour recovery and vapour destruction technologies are dependent on available utilities. Both types of systems require electric power, but vapour destruction units require fuel gas as well. Electric power can become a challenge when existing feeders are not adequate for the additional load required by the vapour control system. For VRUs, the main power users are the vacuum pumps used in the regeneration process. The power required can range from the relatively low requirements of small systems, ranging from 20 to 50 kW, to the very large requirements of ship loading systems, which can reach 1 MW plus. Higher power requirements are commonly associated with VRUs, for example, currently the largest VRU in the world has a connected power requirement of 3.5 MW.

VCUs require fuel or support gas. They are used for running the pilots and acting as an assist gas during pre-heating of the stack or during the enrichment of low heating value vapours. In some terminal applications where a gas supply is not available at the terminal, this requirement can pose a challenge. In the simplest of cases, such as a small gasoline truck loading operation where the emission requirements are at the higher end of the emissions spectrum (35 g/Nm^3), a bottled propane supply may be adequate to fuel the pilots. For larger applications, in particular where emission standards are tighter, relatively large gas supplies may be required, for example, a recent ship loading application required fuel gas rates of up to 1000 Nm^3/hr. The lack of a gas supply may therefore be a factor in the selection of a vapour control technology.

Equipment capital cost

One important factor most operators consider is the capital cost of the equipment. For identical applications, a VRU typically has a capital equipment cost of 3 – 5 times that of a VCU. In moving to larger systems for marine applications, the difference in capital cost grows.

ROI

Beyond the environmental advantages VRUs offer, the potential economic benefit from the recovery of a highly valuable product cannot be ignored as an additional positive outcome in any operating analysis regarding the installation of a VRU.

Vapour combustion offers no recovery, whilst adding to the overall environmental emissions footprint through the addition of CO_2 and NO_X emissions. Vapour recovery systems are not entirely emissions free since they add to the CO_2 footprint through their electric power requirements. However, in general, recovery of hydrocarbons is seen as a more positive environmental strategy compared to combustion. Recovery rates vary significantly depending on the product or mixture of products being handled. However, for gasoline truck loading applications, recovery rates of between 1 – 2 l/1000 l loaded are not uncommon. For gasoline truck loading applications where the operator is able to reclaim duties and taxes paid on the loaded product, full ROI – including operating costs – is possible within a year of installation. In cases where duties and taxes are not reclaimable, the ROI might extend up to three years.

For larger marine vapour recovery systems, a full return on the capital investment is rarely possible because of two main factors: frequency and flow rate. The frequency of loading at these types of facilities is often a few times each month, which results in the system only recovering product during these times (vs a truck loading terminal, which sometimes runs 24/7). The vapour flow rates for marine units are very large, resulting in the need for very large and costly capital equipment investment when compared to VRUs sized for truck terminals. It is common for the operating costs of a marine VRU to be covered through the value of the recovered product, even though the capital equipment cost is rarely recovered.

Conclusion

As legislative emission requirements tighten, truck, rail, ship loading, and tank operators will continue to seek more efficient ways to manage their vapour emissions. Making the decision to employ a VRU, a VCU, or a combination of technologies is typically based on a variety of factors, including regulations, available utilities, equipment capital cost, and ROI.

GOING UNDERGROUND

D. J. Evans and J. Busby, British Geological Survey, UK, discuss underground gas storage and its relevance to the UK's security of energy supply, together with risks of varying nature.

From a position of self-sufficiency in gas supply during the late 1960s to the early 2000s, when the UK's natural gas production peaked, the UK became a net importer of gas in 2004. By 2015, the UK was importing approximately 50% of natural gas, and it is predicted this will rise to 80 – 90% by 2020. The shift from domestic gas surplus to import dependency could leave the UK more vulnerable to supply interruptions and gas price fluctuations, and the government has been moving to ensure gas security of supply. This has been achieved by negotiating long-term gas supply contracts (involving constructing new pipelines from Europe), increasing LNG import capabilities and also approving the construction of underground gas storage (UGS) facilities (Figure 1, Table 1). Due to their huge capacity and the fact they can store many times the volumes of conventional tank farms, economically and with less risk, UGS facilities, both onshore and offshore, will be key to delivering strategic storage capacity.

What is UGS?

Natural gas may be stored in a number of different ways, perhaps the most commonly known type being aboveground tanks storing either liquid or gas. However, it is also stored at high pressure underground in three main types of facilities, with each storage type having its own physical characteristics (porosity, permeability, host rock thickness, etc.) and economics (site preparation and maintenance costs, deliverability rates, and cycling capability), that govern its suitability for particular applications (Figure 2).

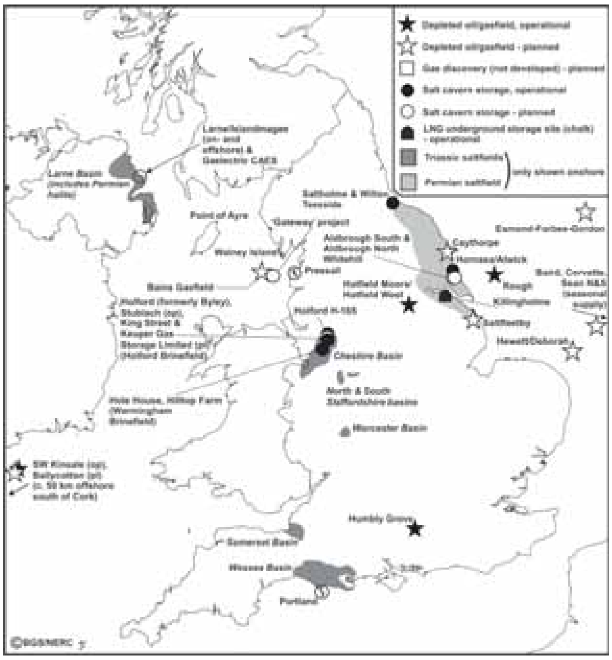


Figure 1. Sketch map of UK operational and planned underground gas storage facilities.

Porous rock

Gas is pumped (injected) underground to be stored in the pore spaces of suitably porous and permeable reservoir rocks in two main scenarios (Figure 2a – c):

- Depleted natural gas or oilfields, which have held gas under pressure for millions of years and provide the highest number and greatest volumes for UGS in the US and Europe. One of the benefits of converting a field from production to storage is the existing infrastructure (wells, gathering systems and pipeline connections). However, careful site investigations are required to ensure reservoir depletion has not caused movement and fracturing of the overlying strata (caprock), or reservoir damage.
- Aquifer (saline water-bearing) storage sites, which not having been proved to store hydrocarbons are more expensive to develop as they require the proving of a trapping structure and suitable caprock and usually require more base (cushion) gas*, with less flexibility in injecting and withdrawing gas. Deliverability rates may be enhanced by active water drive, which supports the aquifer reservoir pressure through the injection and production cycles.

Salt caverns

Salt caverns may be created in both bedded salt (halite or rocksalt) deposits and major diapiric salt structures (Figure 2d – f). Rocksalt is a very low permeability material and impermeable to gas. Although it is a rock, it is visco-plastic and undergoes gradual creep (flow). This leads to self-healing properties and upon burial, with increased load and heat can, by the process of halokinesis, lead to the development of major domes and walls several kilometres in height. Salt caverns are created to very high specifications by a carefully controlled process called solution mining (leaching). A borehole is drilled into the salt beds and water pumped down, dissolving the salt with the resulting brine pumped out and replaced by water (Figure 2e – f). Salt cavern storage facilities are developed from depths of around 250 m below ground level to the deepest at around 2000 m. They can operate in brine compensated (constant cavern pressure, variable volume) or uncompensated (constant cavern volume, variable pressure) mode. In order to avoid damage and failure, they operate within set minimum and maximum pressure ranges, dependent upon their depth and rock mechanical properties. A minimum pressure and volume of gas (cushion gas) is required to support the cavern walls, avoiding creep, closure and possible failure. They provide very high withdrawal and injection rates relative to their working gas capacity (total gas volume stored minus cushion gas).

Gas storages have also been constructed in abandoned coal mines in the US (Figure 2g) and mined voids (with or without water curtains** for containment). Regardless of the storage type, gas is injected and withdrawn via a well connecting the storage reservoir to the surface facilities. It is stored under pressure; the higher the pressure, the more gas can be stored, the limiting factor being the lithostatic (overburden) pressure. This increases with depth and to ensure the rock is not overpressured and fractured, compromising storage integrity, storage pressures are kept below this pressure by a safety margin dependent upon depth and rock properties. The first gas storage experiment was made in a gasfield in Welland County, Ontario (Canada) in 1915, whilst the first gas storage facility in a depleted reservoir was built in 1916, using a gasfield in Zoar near Buffalo, New York (US). Solution-mined salt cavities for liquefied petroleum gas (LPG) and other 'light hydrocarbons' storage have been used since the 1950s in North America and some European countries, including on Teesside in England since the late 1950s. Salt caverns engineered for gas storage were constructed in 1963 in Saskatchewan (Canada), and were followed in 1970 by two gas caverns in the Eminence Dome, Mississippi (US).[1] Many examples now exist of salt and mined rock caverns being used for the storage of crude oil, liquid hydrocarbons and high pressure gases including methane and more rarely, hydrogen, helium and compressed air. The three storage types outlined above represent the main options in most countries around the world. However, in regions lacking suitable reservoir rocks or rocksalt deposits, e.g. Scandinavia, other forms of storage include mined rock caverns in hard rocks and even rock caverns, with steel linings being considered. It should be noted, however, that incorrect operation or maintenance of these facilities can lead to problems with leakage and loss of product. In rare cases, this could have catastrophic consequences.[1, 2]

In terms of operation, porous rock storages tend to provide seasonal storage, with injection during low demand (off peak) summer months and withdrawal over the increased (peak) demand winter period. Salt cavern storages offer greater flexibility, with the potential to perform several withdrawal and injection cycles each year. Indeed, caverns are now increasingly being designed and constructed for rapid, daily to weekly storage cycles.

Table 1. Summary of UK UGS facilities, current status, and their operational parameters (from numerous sources)

Status		Storage type	Facility (operator)	Location	Working gas (million m³)	Injectability (million m³/d)	Deliverability (million m³/d)
Operational		Depleted field	Rough (Centrica Storage)	Offshore Yorkshire	3650	~30	43
			Hatfield Moors (Scottish Power)	Yorkshire	117	4.2	5.1
			Humbly Grove (Humbly Grove Energy)	Hampshire	262	8.5	7.3
		Salt caverns	Hornsea (Scottish and Southern Energy)	East Yorkshire	325	2	18
			Aldbrough I (Statoil & Scottish and Southern Energy)	East Yorkshire	325	30	40
			Holford H165 (Ineos Enterprises)	Cheshire	3.83	N/A	N/A
			Hole House (EDF Trading)	Cheshire	75	11	11
			Hilltop Farm/Hole House ext. (EDF Trading)	Cheshire	100	15	15
			Holdford (EON Gas Storage UK)	Cheshire	160	16 – 22	22
			Stublach (Storengy)	Cheshire (full operation expected in 2018)	400	30	30
Planned/underconstruction	Consented, under development	Depleted field	Hatfield West (Scottish Power)	Yorkshire	~40	N/A	N/A
	Consented, awaiting FID, likely to be droppped		Caythorpe (Centrica)	East Yorkshire	200	8.5	8.5 – 4.7
			Saltfleetby (Wingas)	Lincolnshire	715	4.2 – 2.36	9
	Consented, construction underway	Salt caverns	Preesall (Halite Energy Group)	Lancashire	324	28	28
	Consented, awaiting FID		Gateway (Gateway Gas Storage)	Offshore, East Irish Sea	1500	38	38
			Islandmagee (InfraStrata plc)	Northern Ireland	> 500	14	24
	Consented awaiting FID, likely to be dropped		King Street (King Street Energy Development)	Cheshire	348 – 630	32	32
			Whitehill (EON Gas Storage UK)	East Yorkshire	400	13	13
	Awaiting Planning Inspectorate decision		Keuper Gas Storage (Keuper Gas Storage Ltd)	Cheshire	500	34	34

Ideally, a country's storage portfolio would comprise facilities of both types to meet both short-term fluctuations in supply and provide longer-term supply.

UGS in the UK

A number of UGS facilities operate in the UK, providing some 5.5 billion m^3 of working gas – small compared to main European countries and the US (Figure 1). The first storages were for town gas, constructed in small former brine and later purpose mined caverns on Teesside in the late 1950s. The Hornsea/Atwick facility was the UK's first major underground natural gas storage facility, developed by the British Gas Corp. and which commenced operation in 1979.[3-5] A total of nine storage caverns were constructed by solution mining in the Permian Z2 Fordon Evaporites (c. 260 million years old), and the facility is currently operated by SSE Energy (SSE). Onshore salt cavern storages form the majority of UK facilities, but the largest is the depleted Rough Gasfield, about 31 km (20 miles) offshore from Withernsea on the East Yorkshire coast. Currently operated by Centrica, Rough was converted to storage in 1985. It represents approximately 70% of the UK's gas storage volume and is capable of supplying around 10% of Britain's peak demand.

At the present time, the UK has 10 operational UGS facilities, with a further eight consented and awaiting development. In addition to Rough, there are the Hatfield Moors and Humbly Grove depleted field facilities, with the remaining storages being salt cavern-hosted. The UK has no aquifer gas storage facilities, but a facility operates at

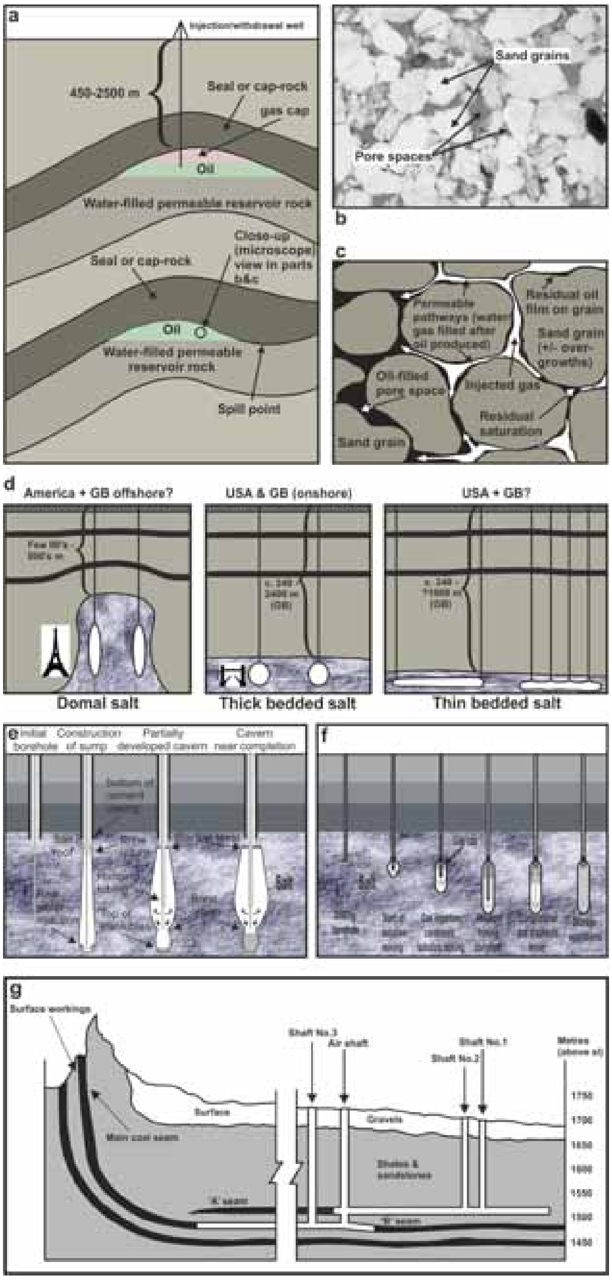


Figure 2. Schematic representations of the main UGS types and processes: a) cross section of oil and gas fields trap with hydrocarbons in permeable reservoir rock; b & c) illustration of pore spaces in a reservoir rock and into which gas is injected for storage; d) various salt formation types with caverns created in for storage – Eiffel Tower and Tower Bridge for scale; e & f) creation of salt storage caverns by solution mining method; g) example of former gas storage in abandoned Leyden Mine, US.

Killingholme storing LPG (butane and propane) in caverns mined approximately 200 m below ground in the chalk.

The Rough and Humbly Grove storages operate in a more seasonal mode (Figures 3a and b) and initially, the Hornsea salt cavern storage facility was designed for seasonal storage and perhaps two or three cycles per year (Figure 3c). However, between June 2013 and November 2014, Humbly Grove showed increased cycling. Increasingly, new salt cavern storages are being designed for more rapid, weekly and even daily cycles as illustrated by the Holford salt cavern facility (Figure 3d).

Issues when planning and developing UK UGS

Not unexpectedly, developers of UGS facilities face various hurdles when planning and applying to develop UGS sites. The majority of onshore facilities have gone through lengthy and costly planning applications, facing public objections, with many having faced Public Inquiries. All this with no certainty of gaining planning permission. At a time when concerns were growing over energy security of supply, the government established, with the Planning Act 2008, the Infrastructure Planning Commission (IPC): a non-departmental public body with the responsibility for examining and making the decision on proposed nationally significant infrastructure projects (NSIPs) in England and Wales. The IPC began operating on 1 October 2009 and closed on 1 April 2012, its functions being transferred to a new Infrastructure Planning Unit within the Planning Inspectorate. UGS facilities fall into the NSIP category and the first application for a development consent order (DCO) to go through the examination process was that by Halite Energy Group Ltd for the proposed UGS facility at the Preesall Saltfield, Lancashire. The process started in December 2011, with consent eventually awarded in July 2014 following a legal challenge and redetermination by the Secretary of State. A second project for a facility near existing UGS sites in Cheshire has since gone through the examination process with a decision expected in 2017 (Table 1).

Time taken to gain consent is a significant factor in terms of developing and financing the initial project. However, the issue of financing construction is also a major concern, particularly since the UK government announced in 2013, that it would not intervene to incentivise further gas storage.[6] Some projects previously under investigation have been withdrawn, including those of the offshore Hewett/Deborah, Bains, Corvette and Baird depleted field sites and the consented Aldbrough Phase II (East Yorkshire) and Portland (Dorset) salt cavern sites. Others are awaiting final investments decisions (FIDs), but are likely to be withdrawn, further reducing the UK's projected storage volumes.

Another major concern of UGS is safety, particularly for local communities concerned about potential gas leakage and migration. The behaviour and crystal structure of the salt and the size of the gas molecule is such that salt formations are very tight and self-sealing, whilst depleted fields have a proven capability to retain hydrocarbons at pressure for long periods of geological time (millions of years). These facts cannot be relied upon, however, as salt formations contain interbeds and may be faulted or subject to natural dissolution and collapse. Also, reservoir depletion can cause formation damage and movement of the overlying strata, leading to fracturing of both the reservoir and caprock. Additionally, UGS involves the repeated injection and extraction of gas into and out of the storage formation. This may be once or twice a season in

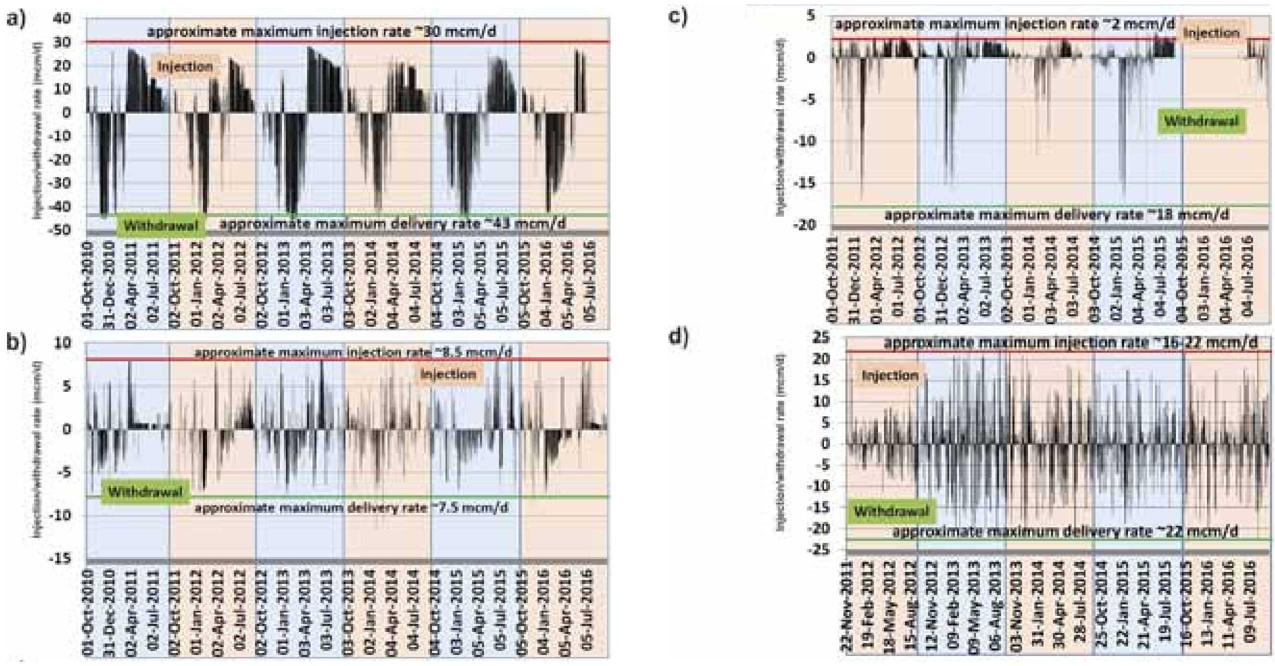


Figure 3. Withdrawals and injection cycles for four UK underground gas storage facilities, illustrating the differing operational modes for depleted field and salt cavern storages (data from National Grid[7]). a) Rough gas storage field operations from 2010 to present; b) Humbly Grove depleted field storage operations from 2010 to present; c) Hornsea salt cavern storage facility operations from October 2011 to present; d) Holford salt cavern storage facility operations from November 2011 to present (note: Holford became fully operational in February 2013).

depleted reservoirs, but more frequently (sometimes daily) in salt caverns. Pressure cycling and the associated thermal effects, therefore, need to be carefully assessed when considering likely rock responses to the stresses imposed during gas storage. Formation integrity is, therefore, a major concern, and each UGS proposal requires careful and rigorous safety, environmental and geotechnical assessments of the geometry and geomechanical properties of the storage formation. It includes careful evaluation of the possibility for gas escape, both from the formation and from wells, potential migration pathways in the overburden (natural or man-made), and the possible impacts on people, buildings and water resources. This requires expertise in geophysics, regional geology, reservoir, petroleum and engineering geology, geomechanics, cavern design and risk analysis. Safety and the likely environmental impacts and/or mitigation of any UGS development also have to be considered carefully.

Conclusion

UGS represents a mature technology, with many hundreds of facilities constructed in porous media (depleted hydrocarbon fields and aquifers) and thick halite deposits (salt caverns), mainly in the US and Europe. A number of storage facilities of both types are already operational in the UK, the development and operation of which in the UK is overseen by the Health and Safety Executive. As the UK moves towards a low carbon economy, gas will continue to be an important component of the energy mix into the 2020s. The demands to meet peak electricity generation are most likely to come from gas-fired power stations. As North Sea oil and gas reserves further deplete, meeting the UK's renewable energy targets and ensuring energy security supply will be more difficult without the deployment of energy storage technologies, with gas storage currently providing the greatest volumes.

Notes

This paper is published with the approval of the Executive Director of the British Geological Survey.

*The volume of gas that is intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season, or to maintain minimum pressure in salt caverns to ensure cavern stability.

** Water curtains enhance the storage capacity of compressed gas in unlined rock caverns by increasing hydrostatic pressure to above that of the gas stored.

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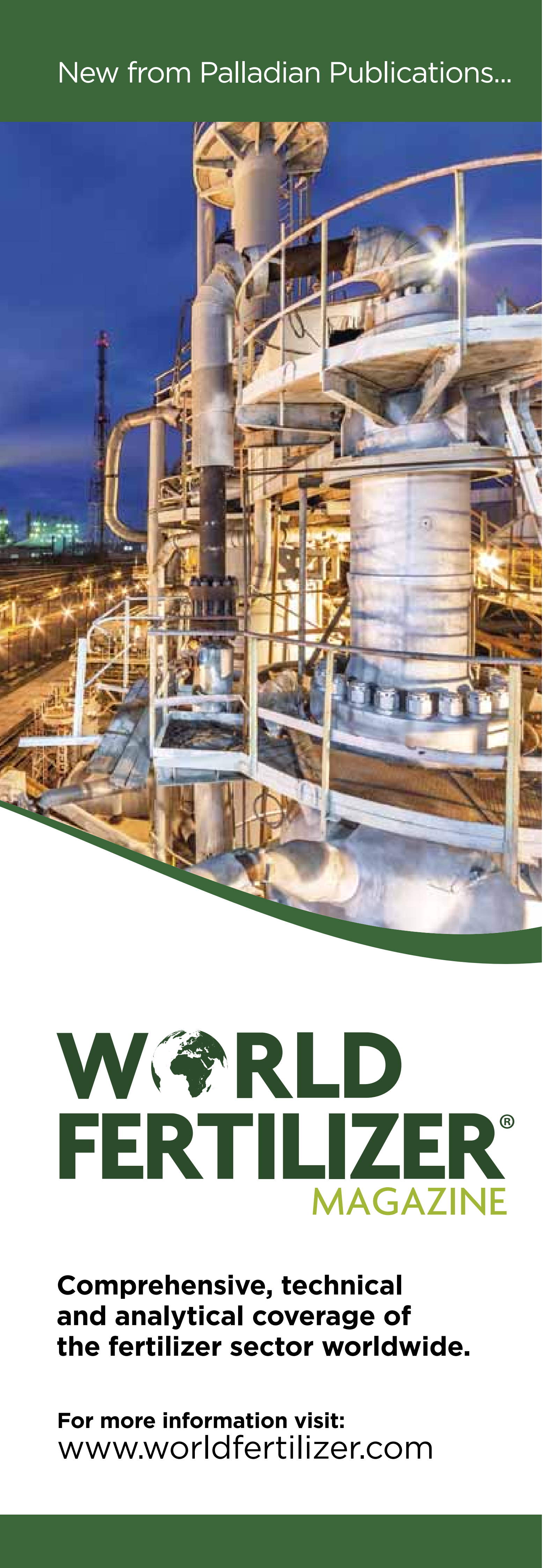
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FOLLOWING THE TREND

John White and Mark Rowley, partners in the Global Projects Group of Baker Botts L.L.P., Russia and UK, examine the developing LNG to power projects trend, with a particular focus on the evolution of FSRUs and geographical opportunities in Africa.

In recent years there has been a significant increase in the number of LNG to power projects in development. A variety of different yet equally important factors have contributed to this growth; including the falling cost of LNG and the global shift away from oil and coal-fired power generation. A third factor, which this article considers in more detail, is the technological improvements and growth of the floating storage regasification unit (FSRU) industry.

Evolution of FSRU

Since 2001, when El Paso Global LNG Co. unveiled its plans to install regasification units onboard three existing LNG vessels and one newbuild, the FSRU industry has gone from strength to strength. The El Paso milestone was followed in 2007 by Petrobras when it contracted the world's first converted FSRU vessel from Golar LNG, the *Golar Spirit*. At present, there are over 20 chartered FSRUs in operation and this rapid growth shows no signs of slowing down. At the time of writing, the most recent announcement was that Höegh LNG (Höegh) had entered into a contract with Global Energy Infrastructure Ltd (GEIL) to provide an FSRU for GEIL's LNG import project in Port Qasim, near Karachi, Pakistan in what will be Pakistan's third FSRU.

Fundamentally, the FSRU industry is based upon the premise that a vessel can receive, store and convert LNG offshore and deliver the gas onshore to the relevant purchaser more efficiently (in terms of speed and cost) than a land-based LNG regasification project. While the popularity of this project model continues to grow, countries are becoming increasingly aware of the need to diversify their energy mix, leading to an increased focus on 'LNG to power' projects. These projects typically have an integrated project model, whereby the project company constructs and finances the power

Figure 1. FSRU *Höegh Grace* in Cartagena, Colombia.

station as well as the LNG and gas related assets. Whereas, traditionally, the offtaker in an FSRU project purchases gas, the integrated LNG to power approach has seen a shift towards offtakers purchasing power instead.

Geographical opportunities

Many of the most notable LNG to power projects have been in Africa; borne in part out of the region's chronic undersupply of power and lack of gas grid infrastructure, which makes the adoption of FSRU technology an obvious solution.

In Egypt, two FSRU vessels have recently been chartered and a third project is also being considered. South Africa is also considering the development of an FSRU project. Elsewhere in Africa, Senegal has plans to convert its Cap des Biches power plant to run on LNG and, in Ghana, there have been recent announcements about the provision of an FSRU to supply gas to the local power market. Morocco is also considering a large land-based LNG to power project. Outside of Africa, LNG to power projects are underway in countries such as Bangladesh, Chile, Colombia (Figure 1) and Malta.

Why LNG to power?

The demand for power correlates closely with GDP growth, and accordingly there is increasing demand for power in developing economies. In combination with that, COP21 and new Organisation for Economic Cooperation and Development (OECD) rules to be implemented this year (that limit the ability of export credit agencies to support coal-fired power stations), are likely to assist in the promotion and growth of gas-fired power generation.

Other relevant factors for LNG to power projects include:

- LNG suppliers are actively working to develop new markets and demand by providing a service and product that is tailored to the demands of these new customers. In addition to the increasing volumes of 'spot' LNG cargoes available, LNG suppliers in recent transactions have offered additional flexibility on certain key terms, including volumes and delivery schedules, to address varying or seasonal demand, and the requisite level and form of buyer credit support.
- Hydro, solar, wind and other alternative energy sources are not sufficiently reliable to provide the entirety of the base load power requirement. Accordingly, thermal power capacity will continue to be required as part of any comprehensive energy portfolio.
- More generally, that LNG to power projects provide indigenous power generation industries with a highly reliable and clean fuel supply to meet projected power and industrial needs over the mid to long-term future.

Floating LNG regasification

The benefits of floating LNG regasification include the following:

- Eliminating land-based LNG storage and regasification facilities reduces project development time and cost.
- The regulatory regime for a floating regasification project is typically less onerous than a land-based project.
- Reduced project CAPEX – as FSRUs are typically hired on a charter basis, LNG project CAPEX is thereby reduced by the amount of the capital cost of the assets chartered and financing costs.
- More optionality and flexibility, including timing (short, medium and long-term), capacity, volumes and redeployability.
- The technical and operating risks associated with floating regasification have been significantly reduced, as a result of successful implementation in many previous projects around the world.

In addition, there have been significant developments in relation to floating regasification and FSRUs that may help to increase the relative viability of a floating solution over a land-based solution; including the following:

- An increase in the size and capacity of the FSRUs and floating storage units (FSUs) mitigates capacity concerns. Furthermore, the floating option is proving to be flexible, e.g. using large FSRUs in conjunction with an additional FSU for storage.
- The now proven reliability of FSRUs and the increasing body of experience among operators has further reduced potential project risks.
- Operational and technical developments in the ship-to-ship transfer of LNG, including by flexible hose, permits the use of floating regasification in locations that otherwise may not have been considered. This may also eliminate the need for certain infrastructure (such as a terminal or pier across which LNG would be transferred), thereby reducing project CAPEX.
- An increasing pool of FSRU owners has potentially increased competition in the market.
- The scalability that an FSRU provides allows for an increased capacity in response to increasing demand. It also provides the flexibility to manage volatility in power demand and fluctuations in domestic gas supply, while mitigating the effect of unpredictable weather conditions on a country's power balance, particularly on the African subcontinent.

Project alignment issues and risk allocation

The fundamental economics of any LNG to power project must be aligned for it to be viable. Alignment on economic matters creates 'natural' or positive economic incentives for performance. However, alignment on important legal concepts is also imperative for the success of any project. This can be assisted by including balanced and clear contractual provisions as to each party's responsibilities, with sufficient leverage to ensure compliance therewith. Contractual devices such as take-or-pay, deliver-or-pay, liquidated damages and performance warranties are important tools in this respect. However, such contractual devices are not intended to keep each counterparty up and down the value chain whole, in terms of downside risks. Instead, they are intended to be relative and proportionate to the contribution of each party, and within their respective economic means to bear.

There will likely be many additional alignment issues to be addressed in the many different forms of LNG to power projects. For example, in an integrated project structure, the circumstances in which availability payments are made to the power seller under the power purchase agreement, and the circumstances in which the FSRU owner receives capacity payments (or charter hire) under the FSRU time charter party, will require careful attention and, ideally, alignment. In addition, developers of integrated projects will need to pay particular care to fuel supply issues, and the structuring of the entire fuel supply chain, as fuel supply ultimately underpins the entire project revenue stream. Although non-integrated projects differ from integrated LNG to power projects, similar issues are experienced by the various participants of each at every link in the value chain, and lenders to any participant will be concerned to ensure that the value chain as a whole is appropriately structured and stable over the long-term (or at least the tenure of the debt).

Government support

Typically, the relevant gas or power offtaker's ability to perform its contractual obligations will be critical to the project's viability and 'bankability'. In developing economies, there is almost certainly going to be government involvement in the LNG to power value chain, and for this reason, government support is likely to be required in such projects.

Specifically, government support may also be required by any LNG to power project in relation to certain factors outside the project's control, such as in relation to regulatory approvals, fiscal policy, foreign exchange availability, change in law, and other political matters. The availability of such support will vary based on the particular circumstances of each project. However, the required level of government support is typically directly related to the country's risk profile – such that governments are generally required to assume more risk in more economically and politically challenging environments, and less risk in more favourable environments.

Project financing

Assuming the project agreements are bankable, non-recourse or project financing of an LNG to power project can be arranged with the appropriate level of government support. Key to such financing is the credit support of the relevant gas or power offtaker's payment obligations, under a bankable offtake agreement. Such financing may be structured using various commercially available credit support devices. In such case, the obligations of the (government) offtaker to the credit support provider may be covered by a multi-lateral development bank or similar entity, who in turn is typically indemnified by the sovereign government.

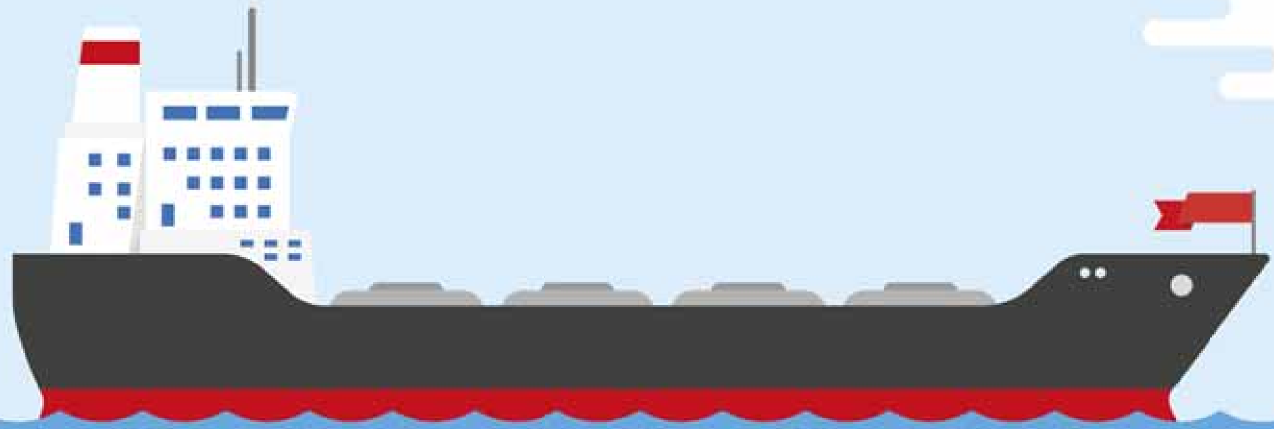
Importantly, there are many terms and conditions that will be required in the project contracts for the project to be bankable, and the above is only a broad outline of how project financing could be implemented.

In an integrated LNG to power project, it is imperative that the relevant gas or power offtake agreement cannot be terminated by the offtaker prematurely for seller default or force majeure, thereby leaving the project without revenues to service debt. As protection against such risk, lenders will require assurances that the project debt will be repaid on or before any such termination.

Furthermore, many host countries are under pressure (from the World Bank and other multi-lateral organisations) to reduce the level of direct credit support to 'private' projects. In this context, project 'put and call' options may be used as a mechanism to transfer (state-owned) offtaker payment risk directly to the state. The put option permits the gas or power seller to require the state to purchase all relevant project assets at a pre-determined price upon the occurrence of certain events – primarily termination. The call option works in the opposite way, permitting the offtaker to require the power seller to sell all relevant project assets to the state at a pre-determined price upon the occurrence of certain events. Such put and call structures are being actively promoted in certain African jurisdictions, in place of a more traditional form of state credit support.

Conclusion

The driver for LNG to power projects, particularly in developing economies, is clear – the need to provide additional power supply as efficiently as possible. The use of floating LNG regasification in any such project is premised on the flexibility, speed and cost effectiveness of FSRUs, when compared to land-based solutions. In any LNG to power project (whether integrated or non-integrated), careful consideration of alignment issues up and down the entire value chain is imperative, with an awareness of local 'host' state issues, and required government support. Finally, each project is unique, and requires a bespoke solution. There is no 'cookie-cutter' or 'one size fits all' solution when developing LNG to power projects. T&T



Patrick Janssens, ABS, USA, explains how design, storage and loading innovations in gas carrier newbuildings are supporting the US' expanding gas export market.

SHAPE UP & SHIP OUT

Having entered the US ethane export trade in 4Q16, the 35 000 m^3 capacity *Navigator Aurora* is the largest semi-refrigerated ethane/ethylene capable liquefied gas carrier serving the global market.

The first in a series of four versatile newbuildings ordered by Navigator Gas from Shanghai's Jiangnan Shipyard, at a price per vessel of approximately US$80 million, *Navigator Aurora* will carry ethane cargoes of up to 20 000 t per voyage.

When in service, the vessel will be capable of carrying all types of natural gas liquids except LNG. Its dual fuel, two stroke propulsion machinery enables the engine to burn either natural gas or marine gas oil (MGO), ensuring compliance with the most stringent emission controls in US and Northern European waters.

Delivery of the *Navigator Aurora* will be followed by three additional vessels in the series – *Navigator Eclipse, Navigator Nova* and *Navigator Prominence* – all of which will be constructed to ABS class.

Long-term employment

Austrian chemical group Borealis has chartered *Navigator Aurora* for a minimum of 10 years to transport ethane from the Marcus Hook complex in Pennsylvania, US, to the Borealis petrochemical plant at Stenungsund on the west coast of Sweden, north of Gothenburg.

An upgrade of the Stenungsund refinery's flexible steam cracker and construction of ethane storage and unloading facilities is underway in preparation for the start of the new feedstock import traffic.

Drilling company Antero Resources will provide raw ethane originating in the Marcellus and Utica shale formations in the Appalachians to the Sunoco Logistics operated Marcus Hook deepwater terminal, near Philadelphia, for shipment to Sweden.

Ethane exports began from Marcus Hook in March 2016, when the 27 500 m^3 multi-gas carrier *INEOS Intrepid* loaded a full cargo for the INEOS refinery at Rafnes, Norway.

Figure 1. *Navigator Aurora* is the first of four newbuildings ordered by Navigator Gas from Shanghai's Jiangnan shipyard.

Figure 2. *Navigator Aurora* is designed for the mid-size gas carrier market, but with an increased cargo intake level.

Innovative design

The transport of LPG and similar chemical cargoes calls for a precise combination of innovative thinking and practical experience. For its new generation of ethane/ethylene carriers, Navigator was careful to select project partners that could support its position as owner and operator of the world's largest fleet of handysize liquefied gas carriers.

The principal challenge for Navigator was to design ships that are suitable for the mid size gas carrier (MGC) market. In making the ships MGC capable, the company was able to improve the tank design to increase intake level and still stay below 180 m length overall. This kept the design within the profile of most fully refrigerated MGCs carrying propane and ammonia.

While a conventional design would be for ships that are narrower and longer, the Navigator vessels are slightly wider, with optimised bow and stern shapes to make them as fuel efficient as possible. Jiangnan Shipyard used a combination of computational fluid dynamics (CFD) and tank model testing to verify that the vessels could reach the desired service speed and fuel consumption targets from this design.

Designed for partial operation in emission control areas (ECAs), the ships are able to consume MGO as well as LNG, with the option to burn conventional fuel on ocean voyages. Approximately 2000 m^3 of LNG can be loaded for main engine propulsion or for powering auxiliary engines. When the ships are burning conventional bunker fuel, the gas fuel tanks can be used to load additional cargo, increasing the ship's total intake to 37 000 m^3.

The MAN two stroke main engine installed on *Navigator Aurora* is a six cylinder unit of the S50ME-C8.2-GI type, manufactured under license by Hyundai Heavy Industries and rated for a power output of 8100 kW. LNG fuel will be stored in a tank on the after part of the weather deck, and fuel gas will be supplied to the main engine under high pressure.

This unit is designed for ultra low fuel consumption and is slightly larger than normal for this type of ship, with reduced rotations per minute (rpm) and a larger propeller fitted with a propeller boss cap fin to further increase fuel efficiency. For the ships to be commercially attractive to charterers in the MGC trades, it was important that this 'ecoship' had extremely good performance, as well as low fuel consumption.

Storage and loading technology

Navigator Aurora is fitted with three bi-lobe tanks, the two largest of which have capacities in excess of 12 000 m^3. Developed by German cryogenic specialist TGE Marine Gas Engineering, these Type C independent units are designed to carry liquefied gases at temperatures down to -104°C, necessary for the transportation of liquefied ethylene.

The containment system can also transport ethane, which is conveyed at -89°C, and a range of other liquefied cargoes, including propane, butane, butadiene, propylene, vinyl chloride monomer, and ammonia.

The gas system designed by TGE features a 'direct' reliquefaction plant with piston compressors. The plant also features a refrigeration system that allows the reliquefaction plant to operate in cascade mode, normally used to liquefy cargoes below -50°C.

An unusual feature of these ships is that the refrigeration plant can be used to load warm petrochemical cargoes, such as propane, butadiene and CC4, chilling them using PPL/R-1270 coolant to -40°C before the cargo enters the tanks.

This provides the advantage that the ships will be able to load cargoes such as propane at +20°C, which will already be cooled down to +5°C before it reaches the primary cooling plant. This arrangement means that the ships are able to take on more cargo and chill it more quickly, resulting in potentially shorter times at the loading berth.

This is a technology that was first used approximately 20 years ago, but to some extent has been neglected in modern cargo operations. All ethylene capable ships feature a cascade plant, which is normally only used for ethane and ethylene. However, where the cargo is propane or butane, this can be loaded warmer than its boiling point.

Proven yard capability

Navigator built its first ships at the Jiangnan shipyard in China, and having worked with this yard for 15 years, the company was confident that it would be able to deliver to the stringent technical requirements of the new fleet additions. During the latest newbuilding project, Navigator has maintained a dedicated site team at Jiangnan to bring insight from the previous project, as well as fresh insights.

Its fleet still includes five Jiangnan-built ethylene/LPG/ammonia carriers of 22 000 m^3 capacity, completed in 1999 – 2000. The new ships are fundamentally a scaled-up version of the previous series, with similar cargo tanks and equipment – a decision taken to provide better redundancy and to make it easier for crew members to move between vessels, as well as simplifying the ordering of spare parts.

Over the last decade, Navigator has also built a series of eight 20 500 m^3 LPG carriers at South Korea's Hyundai Mipo Dockyard, and much of the knowledge gained in building and operating these ships has been incorporated into the Jiangnan vessels.

Navigator's decision to construct the ships to ABS class was based on a positive view of the class society's experience in LNG and LPG shipping, as well as its proactive approach to problem solving and providing solutions to technical issues.

Looking ahead

Even while its series of new ships is under construction, Navigator Gas is already considering how a future generation of vessels might be designed to take advantage of regulatory changes to be even more efficient.

Main engine manufacturers are looking at new gas-fuelled engine designs that would enable them to use propane or ethane as fuel. Under the IGC Code, if an owner can provide evidence through hazard identification (HAZID) and hazard and operability (HAZOP) studies that using these gases is as safe as burning methane, it could be possible to receive flag approval to use them.

Figure 3. Navigator built its very first ships at the Jiangnan shipyard in China and has now worked with the yard for 15 years.

Navigator is already discussing projects for larger ethane/ethylene vessels, which will also be built to ABS class. Since propane and ethane are currently cheaper than other gas fuels and are equally environmentally friendly, there is interest in exploring the choice of which to use. The company will continue to work with ABS to determine how this could be applied to the design of future vessels.

In the coming years, ABS expects to see many more projects being developed to service the expanding gas export market from the US. As well as fulfilling demand in Europe, natural gas will play an increasingly important role in the future energy mix of Asian countries. This creates new trades in ethane, ethylene and LNG, with increasingly strong LNG flows out of the US Gulf following the opening of the expanded Panama Canal. T&T

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