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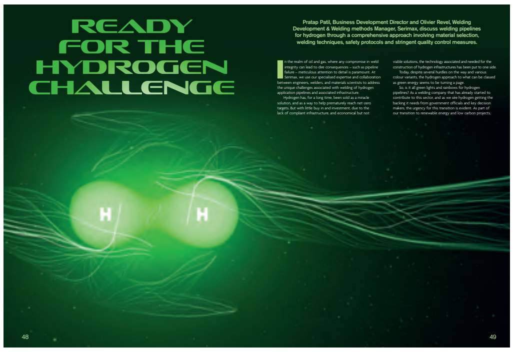

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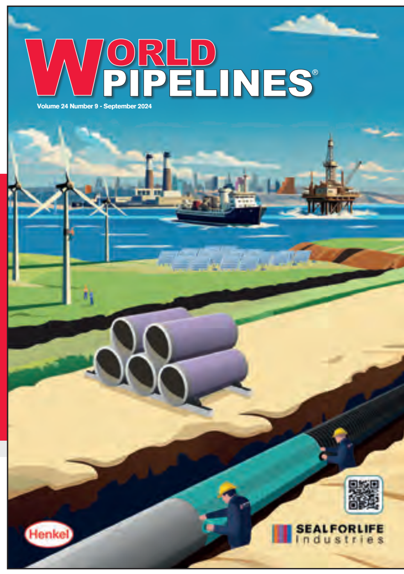

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At the end of August, ExxonMobil published 'Global Outlook: Our view to 2050', which offers the oil major's perspectives on energy supply and demand over the next 25 years.[1] The report imagines a world which is vastly different from today, in which a global population of 10 billion people use 15% more energy, less than half of which will be generated by oil and natural gas. Rapid growth in wind and solar will challenge the energy sector as the energy mix evolves, and carbon emissions will fall for the first time in 2030. Much of the forecast is as you'd expect: renewables will be the fastest growing sector in the energy market; the coal sector will decline the most; and oil and gas remain an essential part of the picture. But the report also includes a juicy bit about what would happen if the world stopped investing in oil and gas.

In this imagined scenario, oil production falls by 15% annually (global oil supplies would fall by more than 15 million bpd in the first year), and within one year the world would experience a severe energy shortage. By 2030, oil supplies would fall from 100 million bpd to less than 30 million bpd. Oil prices would be expected to rise by more than 400% as a result of the shortfall, and within 10 years of no investment unemployment rates would likely reach 30% (higher than during the Great Depression of the 1930s).

The verdict is that global oil and natural gas supplies would virtually disappear without continued investment. It's a blistering indictment of the 'keep it in the ground' policy we hear about so often from industry detractors. To quote the executive summary of the report: "As this Outlook shows, sustained investment is needed to meet the world's demand for oil and natural gas – even as companies like ExxonMobil invest billions to lower the greenhouse gas emissions associated with its own operations and help other industries lower theirs."

In this issue of *World Pipelines*, Umicore argues that pipeline operators have the chance to become instrumental in solving the emissions problem (p. 65): "Acting now on gas will have significant short- and long-term benefits for energy operators. From reducing greenhouse gas emissions, to protecting employees from harm, investing in gas detection devices will reduce the harm that this sector causes, while improving the international understanding of how severe emissions are. Only with this understanding will businesses position themselves to protect their people, benefit their bottom lines, and safeguard the planet".

Our North American keynote this month hears from Contributing Editor Gordon Cope, who writes about US and Canadian pipeline projects, for transporting fuels both old (oil, natural gas) and new (hydrogen, CO_2). In addition, two contributors offer their expertise when it comes to compliance with the US Gas 'Mega Rule': Penspen writes about digitising to keep up with the demands of the new regulations; and T.D. Williamson considers integrity threats from dents, and gouge classification under the latest portion of the 'Mega Rule' to be enforced.

September sees two significant oil and gas shows taking place on North American soil: Gastech is first up, in Houston, followed by IPCE, in Calgary. Much business will be done at these huge events, as participants continue to invest time, energy and money into meeting the increasing energy demands of the world, facilitating the safe transport of oil and gas, and supporting economic growth – being mindful to reduce emissions as they go.

1. https://corporate.exxonmobil.com/sustainability-and-reports/global-outlook#Keytakeaways

WORLD NEWS

Halliburton hit by cyberattack

Reuters reports that US oilfield services firm Halliburton was hit by a cyberattack on 21 August.

Halliburton said it was aware of an issue affecting certain systems at the company and was working to determine the cause and impact of the problem. The company was also working with "leading external experts" to fix the issue, a spokesperson said in an emailed statement.

The attack appeared to impact business operations at the company's north Houston campus, as well as some global connectivity networks.

The *Financial Times* reports that cybercriminals are launching more ransomware attacks on the oil and gas, water, and mining sectors.

High-profile examples include a 2021 ransomware attack that shut down the Colonial Pipeline, which provides fuel to a large part of the US east coast, and, later that same year, a leak of data from oil group Saudi Aramco, which was followed by a US$50 million ransom demand.

Rystad Energy: subsea global spending to exceed US$42 billion by 2027

The subsea market segment, which includes players involved in production and processing systems such as subsea umbilical risers and flowlines (SURF), trees, wellheads, manifolds and other components, is poised to experience a significant influx of capital. Driven by rising operator expenditure on equipment and installation services, Rystad Energy projects a 10% annual compound growth rate (CAGR) from 2024 to 2027, with total spending anticipated to exceed US$42 billion by the end of this period.

Investment activity has been particularly robust in regions such as South America and Europe, where major projects are making significant progress and attracting new investment. Brazil, notably, remains a focal point due to its vast pre-salt reserves, driving strong demand for subsea equipment and SURF. Anticipated expenditure in Brazil is set to surge 18% from the previous year, to US$6 billion in 2024. Meanwhile, in Europe, Norway is experiencing a resurgence in activity, fuelled by favourable market conditions and technological advancements.

Cumulative spending is expected to reach US$32 billion by the end of 2024, representing a 6.5% increase from the previous year. This growth is driven by strong activity across services, equipment and SURF, largely fuelled by significant investment in deep and ultra-deepwater projects. The subsea sector is also expanding beyond traditional oil and gas applications. The push for carbon capture and storage (CCS) is creating new opportunities for suppliers and spurring research and development in this emerging market. Consequently, suppliers are leading the way in developing more efficient subsea production systems, which are set to see broader adoption.

"The subsea market has rebounded robustly from the impacts of COVID-19, which caused a significant 20% drop in expenditure in 2020. By 2021, the industry began to recover, with spending increasing by 5% to reach US$23 billion. Looking ahead, we anticipate steady growth in the subsea sector, fuelled by advancements in deepwater exploration and carbon capture and storage (CCS). This recovery highlights the industry's resilience and suggests a promising trajectory of consistent progress." says Sanwari Mahajan, Analyst, Supply Chain Research, Rystad Energy.

Deepwater developments are set to dominate the sector, accounting for 45% of the market from 2024 to 2028. Significant greenfield projects include Barracuda Revitalization in Brazil, Johan Castberg and Breidablikk in Norway and Golfinho in Mozambique. Key brownfield initiatives include Balder Future, Gullfaks South and Schiehallion in Norway and the UK.

Ultra-deepwater projects, driven by major floating production, storage and offloading (FPSO) initiatives in Brazil and Guyana, are projected to capture 35% of the market. South America is expected to lead globally with 500 subsea tree installations over the next five years. Upcoming ultra-deepwater greenfield projects (beyond 1500 m) include Yellowtail, Tilapia and Redtail in Guyana, alongside Buzios VIII, Buzios IX, Sepia and Atapu in Brazil. Notable brownfield projects are Trion in Mexico, Egina in Nigeria, and Argos (Mad Dog Phase 2) in the US.

The subsea sector has made notable strides since 2022 amid more sanctioning activity for deepwater and ultra-deepwater developments.

Pemex gets approval for expansion of natural gas project

On Thursday 22 August 2024, Mexico's hydrocarbon regulator approved a request by state energy company Pemex to expand a natural gas project in the Gulf of Mexico, which requires extra investments of just over US$400 million, reports *Reuters*.

The Lakach field has been hailed as a potential gateway to a new deepwater Mexican gas frontier. Pemex had requested to update the field's production strategy with the recovery and termination of wells, the management of production, and the commercialisation of hydrocarbons.

In addition, the project now contemplates the construction of gas pipelines up to the ground – instead of using boats to collect the gas and transport it, as previously planned.

Of the US$2.218 billion in costs that were approved for the years of 2024 and 2041 by the regulator CNH, US$1.667 billion are earmarked for investments and US$551 million for operational expenses. An earlier plan, authorised last year for 2024 to 2035, listed an estimated US$1.815 billion. Its production deadline was also pushed back from 2025 to 2026.

Recently, Grupo Carso owned by Mexican billionaire Carlos Slim, signed an exploration and extraction services contract with Pemex. It said it would invest US$1.2 billion.

Pemex has said that it has spent about US$1.400 billion on Lakach, a project that has been shelved twice before. Pemex and New Fortress Energy parted at the end of 2023 after they could not agree on terms.

CONTRACT NEWS

EVENTS DIARY

9 - 13 September 2024
IPLOCA convention
Sorrento, Italy
www.iploca.com/events/annual-convention

17 - 20 September 2024
Gastech 2024
Houston, USA
www.gastechevent.com

24 - 26 September 2024
International Pipeline Conference & Expo (IPCE) 2024
Calgary, Canada
www.internationalpipelineexposition.com

23 - 24 October 2024
Hydrogen Technology Expo Europe 2024
Hamburg, Germany
www.hydrogen-worldexpo.com

23 - 24 October 2024
Carbon Capture Technology Expo Europe 2024
Hamburg, Germany
https://www.carboncapture-expo.com

23 - 24 October 2024
Subsea Pipeline Technology (SPT) 2024
London, UK
https://sptcongress.com

4 - 7 November 2024
ADIPEC 2024
Abu Dhabi, UAE
www.adipec.com/visit/registration

20 November 2024
Global Hydrogen Conference 2024
ONLINE
www.accelevents.com/e/ghc2024

28 - 31 January 2025
Pipeline Pigging & Integrity Management Conference (PPIM) 2025
Houston USA
https://ppimconference.com/

EnerMech secures two major pipeline pre-commissioning contracts

EnerMech has been awarded two significant pipeline precommissioning contracts in offshore East Malaysia.

These contracts have been secured with two tier-one contractor clients, both of which are supporting the same multinational operator's developments in the region.

The first scope of work involves precommissioning operations at a depth of 1300 m in deepwater, and the second scope takes place in shallow waters.

EnerMech's multi-skilled team will carry out a range of highly specialised services for both clients including flooding, cleaning, gauging and testing, dewatering and nitrogen packing of subsea umbilicals, risers and flowlines.

The company has extensive experience in the region having successfully supported its customers' needs since its establishment in Asia in 2009. Over the last 15 years, it has expanded its geographical presence in Asia with subject matter experts located at its operational bases in Asia and further afield in Americas, Europe, Australia and AMEC regions. In Asia, EnerMech's focus countries are Singapore, Malaysia (regional HQ), Indonesia and China.

Charles 'Chuck' Davison Jr., EnerMech CEO said: "Asia is a key geography for the business as it has significant offshore oil and gas reserves that continue to attract investment. These two new contracts align with our strategic vision to expand our pipeline and subsea capabilities in the region to support the current sector's needs and the anticipated larger projects on the horizon."

Nigeria and Equatorial Guinea sign gas pipeline project agreement

Reuters reports that Nigeria and Equatorial Guinea have signed an agreement to establish and operate a gas pipeline.

Nigerian President Bola Tinubu met with Equato-Guinean President Teodoro Obiang Nguema Mbasogo in Equatorial Guinea during a three-day visit in August. Nigeria and Morocco agreed to build the pipeline in 2016 to promote regional integration and enhance energy security, while offering African gas an export route to Europe. That project, backed by the Economic Community of West African States (ECOWAS), is expected to cost US$25 billion and have a capacity of 30 billion m^3/y, to be completed in three phases as it links up to existing infrastructure.

The agreement with Equatorial Guinea covers legislative and regulatory measures for the gas pipeline, establishment and operation, transit of natural gas, ownership of the gas pipeline, and general principles.

Kent secures global commissioning services contract with Shell

Kent has been awarded a global three year enterprise framework agreement (EFA) by Shell to provide Commissioning and Start-Up Services (CSU) across various onshore and offshore projects. This contract encompasses a wide range of energy sectors, including oil, gas, and new energy initiatives, and reinforces Kent's opportunity to enhance project execution and efficiency globally.

ON OUR WEBSITE

- Norwegian pipeline gas exports could approach historic record
- Shell set to shut portions of Zydeco oil pipeline for maintenance
- Petronas, ADNOC and Storegga to assess CCS in Malaysia
- Brazos Midstream completes new gas processing facility and announces further expansion plans
- Miros supports pipelay operations for CCS project in Norway

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NAVIGATING NORTH AMERICA

***World Pipelines*' Contributing Editor, Gordon Cope, provides updates on North America's midstream landscape, exploring recent pipeline projects, the role of hydrogen and how the continent plans to tackle future challenges and opportunities.**

Over the last decade, Canada and the United States have tremendously expanded their O&G output. In the case of Canada, the advance in crude has been spearheaded by the oil sands of Alberta and the growth in unconventional gas in northeast British Columbia (BC), and northwest Alberta. In the US, shale oil in the Permian Basin in Texas has vastly increased crude supplies, and the development of the Marcellus Basin has boosted gas production.


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All told, the two countries produce 17 million bpd of crude and approximately 140 billion ft^3/d of gas. In order to deliver this immense amount to market, the continent's midstream sector has expanded accordingly.

Canada

Without a doubt, this year's seminal pipeline event has been the commissioning of the Trans Mountain Expansion (TMX) crude pipeline.

When it was first proposed by Kinder Morgan in 2012, the announcement of the expansion of the 300 000 bpd line that ran from Alberta to tidewater near Vancouver, BC, was met with little fanfare. The line, built in 1953, had been operating for over half a century; the CAN$5.4 billion project, designed to add 590 000 bpd of capacity, was generally considered a sound investment that would create a much-needed alternative Asian market to the existing lines that served the US.

But the project soon became mired in controversy. A succession of British Columbia governments demonised the project on environmental grounds; at one point, former Premier Horgan announced that his cabinet would "use every tool in our toolbox to stop the project from going ahead."[1]

Kinder Morgan, fed up with the political shenanigans, eventually walked away from the project, obliging the federal government to purchase the line. As opposition grew, so did the price-tag, reaching CAN$12.6 billion in 2020.

The TMX woes continued to mount; COVID, flooding and Indigenous opposition compounded, causing the eventual cost to balloon far beyond initial estimates. When the line finally entered service in June, 2024, the tab was estimated at CAN$34 billion, more than six times the original budget.

While Ottawa has vowed to cleanse its hands of the pipeline by selling it to Indigenous groups, there is little doubt that it is serving its purpose. China and other Asian markets have been buying shipments, helping to lower the traditional differential that plagued Alberta operators for decades. Oil sands operators have green-lighted a series of expansions, guaranteeing production growth for the rest of the decade.

In late 2023, TC Energy completed the Coastal GasLink pipeline. The 670 km, 48 in. line runs from northwest BC to the Pacific port of Kitimat, where it will supply up to 2.1 billion ft^3/d of natural gas to Shell's LNG Canada project. Construction of the line was dogged with controversy and challenges; at one point Indigenous protestors blocked workers, and erosion along the ROW impeded construction. The original estimated cost of CAN$6.5 billion more than doubled to CAN$14.5 billion. The line now offers producers the ability to export gas to Asian markets, heralding a huge boost to drillers.

Already, stakeholders in the sector are talking of the necessity of new pipelines to handle increased output; according to analysts, Canadian producers are expected to increase gas production from current levels of 17 billion ft^3/d to 23 billion ft^3/d by 2030. During that same time period, crude is expected to grow from 4 million bpd to 4.7 million bpd. That would require the equivalent addition of two new gas mainlines and a new TMX.

In May, 2024, Canadian Utilities announced it was building the Yellowhead Mainline, a CAN$2 billion natural gas pipeline that would run 200 km from the Edson, Alberta, to the industrial Heartland refining and petrochemical region near Edmonton. The line is expected to deliver up to 1 billion ft^3/d to new petrochemical facilities, including Dow's CAN$9 billion net-zero ethylene cracker, when it comes on-stream in 2027.

Other major pipeline operators, including Enbridge, TC Energy and Pembina, are all planning new, significant investments in infrastructure. During an investor's day conference in May, 2024, Scott Burrows, CEO of Pembina, expressed confidence in the future of Canada's O&G sector. "Pembina is poised to benefit from this growth given our extensive footprint, including a leading network of export, import and gathering pipelines with total capacity of three million barrels a day."[2]

United States

Thanks to new drilling technologies that have increased average well production, the US Energy Information Administration (EIA) predicts that crude output in the Permian basin will average 6.3 million bpd in 2024, and associated gas production will average approximately 24 billion ft^3/d.

The growth has pushed existing crude pipeline capacities to the limit; egress from Midland to Houston and Corpus Christie is estimated to be at 90% capacity. Enbridge has proposed to increase capacity on its 900 000 bpd Gray Oak line by 200 000 bpd through the use of drag reducing agent, but increased production in the Permian is expected to fill every square inch of pipe by mid-2024.

Gas infrastructure is also reaching its limits as pipeline companies move to deliver billions of square feet to new LNG plants. In March, 2024, Enbridge formed a joint venture with global investment manager I Squared Capital and US pipeline firms WhiteWater and MPLX LP to consolidate natural gas assets in the Permian basin. The JV, designed to deliver gas to LNG plants along the Gulf of Mexico, will include the Whistler pipeline, a 450 mile line transporting gas from Waha in the Permian to Agua Dulce, Texas, where it will connect to the 137 mile Rio Bravo pipeline project running to NextDecade's Rio Grande LNG project in Brownsville, Texas. The deal also involves the proposed ADCC pipeline, a 40 mile large-diameter connector from Agua Dulce to Cheniere's Corpus Christi LNG plant.

The Greenfield Matterhorn Express pipeline, owned by WhiteWater and partners, will enter service in 2024, adding 2.5 billion ft^3/d to Permian takeaway capacity. After that, Moss Lake Partners is proposing the 690 mile DeLa Express pipeline, which would move up to 2 billion ft^3/d from the Permian basin to Louisiana.

Hydrogen

In late 2023, the Biden Administration selected seven hydrogen hubs ranging from California to Texas as part of a US$7 billion plan to kick-start production, transportation and consumption of hydrogen fuel.

A commercial hydrogen infrastructure already exists in the US Gulf Coast (USGC). Over 1600 miles of dedicated pipelines move several million tpy of hydrogen from its sources of manufacture to consumers, primarily refineries and petrochemical plants. The multi-billion dollar system grew organically over the span of nearly a century to meet long-term supply contracts. In order to convert the network to low-carbon, hydrogen manufacturers need to

either build solar/wind farms and electrolysis plants or install carbon capture and sequestration (CCS) systems.

Air Liquide, which specialises in producing industrial gases, makes over 400 million ft^3/d of hydrogen at several plants in the USGC and operates over 500 km of the USGC hydrogen pipeline network. The company recently received a grant from the US Department of Energy (DOE) to study the viability of retrofitting carbon-capture to its steam methane reformer in its La Porte plant near Houston, Texas. (Air Liquide already successfully deploys a proprietary carbon-capture system in France, which allows it to capture up to 95% of produced CO_2). In June, 2024, Air Liquide and ExxonMobil announced an agreement in which the former will supply transportation infrastructure to the latter's planned hydrogen production facility in Baytown, Texas; when operational, the facility will produce 1 billion ft^3/d of low-carbon hydrogen and over 1 million tpy of low-carbon ammonia.

Air Products is building a revolutionary hydrogen energy complex in the Fort Saskatchewan industrial region near Edmonton, Alberta. The CAN$1.6 billion facility will create 1500 tpd of blue hydrogen using auto-thermal reforming (ATR), which enables the company to capture 95% of CO_2 emissions (up to 3 million tpy) for sequestration. The power plant is also fuelled by hydrogen, avoiding indirect emissions from the grid. The facility will use a dedicated 55 km pipeline to deliver blue hydrogen to Shell's diesel refinery, as well as to third parties and commercial fuel stations.

In October, 2023, the DOE awarded California up to US$1.2 billion for a regional clean hydrogen hub. As part of the initiative to promote the hub, Southern California Gas (SoCalGas) is developing Angeles Link, a dedicated, green hydrogen pipeline system that could deliver enough hydrogen to displace the equivalent of 3 million gal./d of diesel fuel. The pipeline would likely originate in the wind and solar-rich desert east of Los Angeles and terminate within the Los Angeles basin near current utility plants or the port of Los Angeles.

Challenges

The imbroglio surrounding Enbridge's Line 5 continues. The crude line has been transporting 540 000 bpd from Canada (and North Dakota) through Michigan to Ontario and Quebec for over 70 years. In late 2020, Michigan Governor Gretchen Witmer ordered Line 5 to shut down operations by 13 May 2021, due to the potential for spills where it passes under the Straits of Mackinac in the Great Lakes. Because it is an international pipeline, Line 5 is governed by the 1977 Transit Pipelines Treaty, which contains provisions guaranteeing uninterrupted transit of crude oil and natural gas liquids between Canada and the US. In October, 2021, Ottawa invoked Article Six of the treaty to instigate bilateral negotiations with the US federal government. Numerous challenges also arose where the ROW passed through First Nations lands, resulting in a lower court ruling calling for a US$5.2 million penalty to the Bad River Reservation and the closure of several kilometres of the line. In April, 2024, the Biden Administration issued an amicus brief through the US Department of Justice (DOJ) calling for a substantial penalty, but urging the court to reverse the pipeline shutdown ruling. The brief justified its position citing significant diplomatic obligations to Canada.

On a more positive note, the Mountain Valley project, a gas pipeline that is designed to move 2 billion ft^3/d from West Virginia to consumers in Virginia and the south Atlantic, has finally entered service. First proposed in 2018, the line was estimated to cost US$3.5 billion, but a 5 km stretch of the 488 km ROW passes through Jefferson National Forest and, in early 2021, the US Court of Appeals vacated the US Forest Service and Bureau of Land Management decisions to allow access. Joe Manchin, a Democrat senator from West Virginia, successfully lobbied the White House for support, and, after further political and legal wrangling, the project (whose budget had swollen to almost US$8 billion), was granted approval by the Federal Energy Regulatory Commission (FERC) in 2023.

The future

The government of Canada and the Biden administration have enacted a series of GHG emission regulations that provide a legally-binding roadmap to achieve net-zero emissions by 2050. In order to meet these targets, various sectors have instigated massive plans that call for CO_2 to be captured and sequestered. The Pathways Alliance is a consortium of oil sands producers in northern Alberta that is proposing a CAN$15 billion CCS network to capture up to 12 million tpy of CO_2 at facilities near Ft. McMurray and transport it via a dedicated, 400 km pipeline for permanent burial in a saline aquifer. If all goes according to plan, the project will commence operations by 2030.

In the US, Summit Carbon Solutions is proposing a dedicated CO_2 pipeline network to capture the gas produced in Iowa ethanol plants and sequester it in North Dakota. The 2000 mile network is estimated to cost US$2 billion; it would capture up to 12 million tpy (the equivalent of 2.6 million cars), significantly reducing the carbon footprint of the biofuel. In June, 2024, the Iowa Utilities Board approved the building of a 668 mile portion in the state. The board stipulated that construction cannot start until Summit Carbon Solutions has also received permission for related gathering networks in Nebraska and Minnesota, as well the sequestration site in North Dakota.

In the short-term, midstream companies need to increase both crude and gas capacity from the Permian basin to the USGC, as well as egress for growing crude and natural gas production in northern BC and northwest Alberta.

In the longer term, the rollout of the hydrogen economy will likely be conducted in fits and starts as governments cajole the energy, transportation, industrial and utility sectors to build electrolysis plants, establish bespoke ROWs, and convert plants and electricity generators into hydrogen-friendly mode. Likewise, CO_2 sequestration networks, governed by net-zero legislation, will require extensive subsidies and government credits to achieve fruition. Regardless, North America's midstream sector is poised to tackle the challenges and opportunities of both conventional and new pipeline networks for the coming decade.

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2. https://www.dobenergy.com/news/headlines/2024/05/17/pembinas-macro-outlook-bullish-confident-its-well

Louise O'Sullivan, Managing Director of Penspen THEIA, explains why Mega Rule is not as onerous as it might appear and should instead be seen as an opportunity to improve the efficiency of pipeline integrity management.

BEYOND COMPLIANCE:

the digitisation opportunities of Mega Rule

The Gas Mega Rule aims to improve pipeline safety and reduce the frequency of natural gas pipeline failures. This new regulation will require far more frequent and more intense integrity management than many operators have ever experienced.

The US has more pipelines than the rest of the world combined. In Texas alone, there are more pipelines than all of Europe. Many of these pipelines travel through medium and high consequence areas, near things like schools and densely populated areas. On top of this, pipeline operators are preparing for an energy transition which will see existing infrastructure converted to carry hydrogen, which behaves very differently to tradition oil and gas, LNG, mining slurry and water.

Naturally, with this added pressure, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has implemented the Mega Rule as a means to improve the safety of North America's pipelines. This regulation calls for far greater intensity in terms of pipeline safety, inspection, and reporting, as Penspen detailed in its recent white paper. Many pipeline owners who previously have not fallen under regulatory requirements will need to comply with Mega Rule's integrity management standards by as soon as 2035.

What this means in real terms is thousands, if not hundreds of thousands, of kilometres of pipelines in North America will now need more frequent and more rigorous inspections. This will cost pipeline operators millions of dollars every year and will inevitably cause downtime on their networks, especially as they get used to this new intensity of requirement.

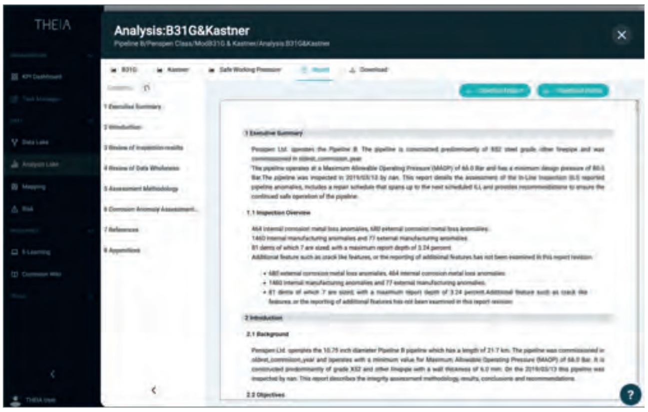

Figure 1. **Digitising the pipeline inspection process, through software platforms like Penspen's THEIA ensures regulatory compliance by consolidating historical and offers opportunities to optimise operations.**

Integrity engineers are no doubt anxious about the workload that will come with Mega Rule's new regulatory requirements, it may even feel like an impossible task. That's because they understand the complexity of pipeline integrity management.

The reality of the task ahead

Inspecting a pipeline is a matter of processing measurement data and making judgements and recommendations on the management of the pipeline. While simple in theory, the reality of this task is more challenging.

Firstly, there is the sheer quantity of data that needs to be collected and processed. Right now, the inspection data required for routine pipeline inspections would be close to maxing out the market-leading spreadsheet software, both in terms of size and the programme's processing power. But spreadsheets are, at present, the standard tool for integrity inspections.

This approach is slow and unwieldy, and the problem is only intensifying as technology improves; as inspection techniques become more sophisticated, the amount of data produced grows exponentially.

Secondly, there is no one source of data when it comes to pipeline inspections. The inspection data comes in different forms, from different software platforms, in different file types, and even from different suppliers. This means that integrity engineers are often spending more time crunching through data and manually trying to align disparate sets when they should be focussing on the actual insightful engineering they specialise in.

Finally, there is the issue of accuracy, or rather, a shortfall of accuracy. Data processing of the scale required for pipeline integrity management is naturally prone to human error, from the input stage right the way through to the final assessment. The work is simply too big for a human to do 100% precision and accuracy. But the stakes are high, and the consequences of such mistakes could potentially be devastating.

The prospect of drastically increasing the number of integrity inspections required on a pipeline is therefore understandably daunting. But, at Penspen, our view is that Mega Rule is the necessity that breeds innovation. This could well be the opportunity and impetus pipeline operators need to change how integrity management is done.

Digitising the process

Digitising the pipeline inspection process, through software platforms like Penspen's THEIA,

Figure 2. **THEIA brings pipeline integrity data together, processes it, and presents it visually, overlaid on asset maps, making the data easier to conceptualise.**

will not only ensure regulatory compliance by consolidating historical reports, but also offers myriad opportunities to optimise operations.

THEIA brings pipeline integrity data together, processes it, and presents it visually, overlaid on asset maps, making the data easier to conceptualise at a human level. It, and programmes like it, can consolidate and analyse all pipeline integrity data, past and present, from all suppliers, and deliver inspection reports to known standards within minutes, something that would take weeks using a spreadsheet. It is completely platform-agnostic, eliminating the need for data wrangling and, with the oversight of an experienced integrity engineer, it drastically improves the accuracy of integrity management reporting.

THEIA itself is also a proven and well-evidenced solution, that is backed by 70 years of expertise.

Case studies

Peru

For example, Penspen recently ran an ILI study for a natural gas company in Peru operating around 1500 km of natural gas and natural gas liquid pipelines, compressor plants and pumping stations in complex Peruvian geography.

We used THEIA to consolidate 58 ILI runs executed in previous years, using different technologies on different pipeline segments hosted in the client's system.

Analysing these large ILI inspection data sets, THEIA can calculate corrosion growth rate (CGR) for all sections of a pipeline. The corrosion rate estimation analysis pairs joints and correlating corrosion type indication through Penspen's multiple defect remaining life prediction (MDRLP) methodology, which is also hosted on the platform. THEIA also has a document repository, which provides a centralised location to store information with easy access to relevant live and historical data.

Ultimately, THEIA's corrosion rates distribution graphs supported the client in making maintenance decisions, including the establishment of optimal inspection intervals. The swift analysis of the pipeline's condition from all gathered data sets, meant that all deliverables were provided to the client in under three months.

Qatar

Another illustrative example of THEIA's ability to streamline the integrity management process was an FFS and corrosion investigation study on an offshore to onshore 20 in. crude oil pipeline in Qatar, which was suffering from heavy internal corrosion and had experienced leaks.

The pipeline was inspected annually by multiple vendors over a 14 year period, which presented a problem for the operator who wanted a detailed study with a short turnaround to urgently address the pipeline's issues.

THEIA was able to perform a critical assessment of 14 years' worth of data in record time, which got the asset integrity team ahead of schedule. With the platform, the team completed feature and anomalies matching for five pairs, and three pairs of ILI results runs for four sections of pipeline with twelve matching all sections, calculated corrosion rates for all matched ILI, and conducted deterministic future integrity calculations based on ASME b31G, DNVF1010 and Kastner method.

The operator commented that their team had previously spent one month conducting feature matching and corrosion rate calculations on a single pair of ILIs, while we delivered three pairs of ILI runs in one day using THEIA.

Seeing the opportunity

Digitisation is not just the solution to keeping up with the demands of Mega Rule, it is an opportunity to drastically improve the efficiency of pipeline integrity management. Widescale adoption of platforms like THEIA will save individual integrity engineers hundreds of hours of tedious admin tasks every single month, it will reduce downtime on operator networks, it will ensure compliance with regulation and, most critically of all, it will improve the safety and reliability of pipelines in the region. Which is the ultimate goal of, and intention behind, Mega Rule.

In terms of which software platform operators should choose to implement, that is strictly their prerogative, but it is our view that any solution should be backed by real expertise. With that in place, pipeline operators are free to see 2035 as the start of a new era, rather than a deadline to comply with an onerous piece of regulation.

Figure 3. THEIA is a proven and well-evidenced solution, that is backed by 70 years of expertise.

A new type of

Figure 1. PipePillo used for storage of 42 in. (1066.9 mm) OD pipe.

support on site

Meghan Connors, President, PipeSak Incorporated, Canada, presents an alternative to cribbing for above ground pipe support.

Traditionally pipelines are supported outside of the trench during the construction process using temporary wood or composite structures, referred to as cribbing. Cribbing is a technique where 4 x 6 in. (100 x 150mm) hard wood or composite blocks called skids, typically 4 - 6 ft (1.2 - 1.8 m) in length, are stacked in a predetermined pattern to support heavy loads during pipe fabrication, stringing and welding.

Cribbing is a time consuming and labour-intensive process which, if not done correctly, can pose serious and unnecessary safety risks to both workers and the pipe. Most experienced pipeliners have stories of dramatic, and sometimes catastrophic, cribbing failures, often caused by improper design, careless installation, rotting or damaged cribbing, temperature induced pipe movement, or a combination of the above. There is no universal industry standard for supporting the pipe outside of the trench and it is often left to the contractor or owning company to determine a cribbing configuration that will support the heavy pipe in varying terrains, climates and construction conditions.

Many contractors and owning companies in North America are using a more reliable, safer and cost effective solution that takes the guess work out of supporting large diameter pipelines – the PipePillo® structured pipeline support. The PipePillo was developed by PipeSak as an engineered, permanent solution for supporting pipelines in rocky trenches, replacing ad-hoc methods such as sandbags and foam. Contractors and owning companies quickly discovered that many of the features that make PipePillo the best option for in-trench support also make it an ideal alternative to wood and composite cribbing outside of the trench.

Load capacity

PipePillo supports are engineered and tested to standard load capacities. The patented dual frustoconical shape transfers extreme loads effectively through to consolidated or virgin soil beneath. The ultimate load capacity for a single PipePillo for 48 in. OD (1219 mm) pipe is 85 000 lb (38 500 kg) – similar to the estimated ultimate load capacity of a nine point cribbing stack (Figure 2).

90˚ of continuous support

Safe cribbing guidelines typically require wedges at the top of the stack to prevent the pipe from rolling. This is often done by 'crotching' skids to create a 'V' configuration at the top of the crib stack that the pipe is placed on. PipePillo are designed to provide a full 90˚ of uniform support, helping to ensure the pipe will not roll off the stack. When the pipe is expected to be supported for an extended period, the PipePillo is designed to limit ovality, especially in large OD pipes with a high D/t ratio. In areas where significant pipe movement is possible, the pipe can be tied to the PipePillo so it moves with the pipe, providing additional assurance.

Figure 2. Cribbing stack versus PipePillo® supporting 48 in. (1219 mm) pipelines.

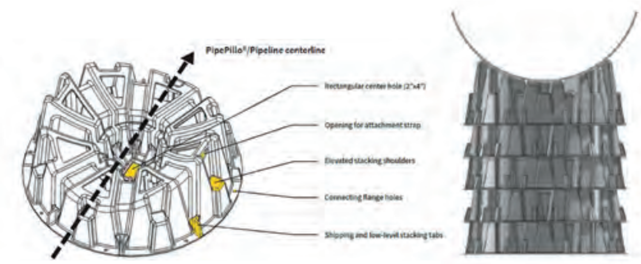

Figure 3. PipePillo design for extended stacked configuration.

Durability

It is imperative that wood skids are inspected regularly to ensure the safety and integrity of the cribbing. Wood is prone to moisture absorption, which can cause the blocks to swell, warp, or decay. In pipeline construction, where conditions are often harsh and damp, this deterioration compromises their ability to provide stable, reliable, and durable support – increasing the likelihood of jobsite hazards and potentially catastrophic incidents. PipePillo pipe supports are made from a proprietary polypropylene based material that will not absorb moisture and provides extreme strength, durability and UV resistance.

Adjustable height

PipePillo supports can be used in either a single or stacked configuration, giving the contractor the flexibility to easily change the support height as needed. For example, for a 36 in. (914.4 mm) OD pipe, a single PipePillo will support the pipe 8 in. (20.3 cm) from the ground. When PipePillo are stacked, the contractor can add either 3 in. (7.6 cm) of height in a nested stacked position or rotate the PipePillo by 22.5˚ and add an additional 6 in. (15.2 cm) of height per PipePillo. This is accomplished by incorporating elevated stacking shoulders into the design (Figure 3). In an elevated stacked position, the working load reduces by approximated 30% which is accommodated by slightly reducing the spacing between PipePillo stacks.

Ease of installation

Building a cribbing stack using wood or composite skids is a time consuming and labour intensive process. For example, to build a nine point cribbing stack to raise a 36 in. (914.4 mm) OD pipe 20 in. (51 cm) from the ground typically requires a crew of four to six labourers arranging 15 hardwood skids with a total weight of approximately 600 lb (272 kg) versus one to two labourers stacking three PipePillo with a total weight of 80 lb (36 kg).

Environmental considerations

Wood cribbing blocks are manufactured by cutting down mature hardwood trees – not the most environmentally friendly option for pipeline support. Wood can also absorb moisture, oil, salt water, and many different chemicals on the jobsite, in addition to harbouring insects and rodents. When cribbing is transported and reused there is a risk of bringing unwanted contaminants or pests with it. PipePillo are manufactured from environmentally inert polypropylene that is unaffected by environmental factors, ensuring consistent performance and structural integrity – even the harshest conditions.

Logistics, labour and unit cost

Compared to wood skids, PipePillo are lightweight and ship in a nested position, reducing the overall transportation costs. The support provided in one truckload of lightweight PipePillo supports is comparable to multiple truckloads of heavy wood cribbing.

The labour savings when installing PipePillo supports compared to wood skidding is substantial. Not only are far fewer labourers required to handle the lightweight supports, but they can be placed and stacked in a fraction of the time it takes to build a wood crib.

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The cost of hard and soft wood skids varies widely depending on the location of the pipeline and availability. The spacing required between wood cribbing supports versus PipePillo is also an important factor. In most instances, PipePillo supports can be placed farther apart, reducing the overall costs.

Case studies

Pipe storage and fabrication

The Mountain Valley Pipeline (MVP) project is a 42 in. (1067 mm) OD natural gas pipeline that spans approximately 294 miles (473 km) in the US states of West Virginia and Virginia. The project installed over 50 000 PipePillo in place of foam pillows and sand bags to support the pipeline in the trench. In addition to in-trench use, PipePillos were also used extensively outside of the trench to aid with pipe storage, fabrication, welding and stringing.

Standard practice is to use stacked wooding cribbing in the pipe fabrication yard to store the pipe and support it during fabrication and welding. The pipeline contractor wanted a lower cost solution that provided reliable and uniform support with multiple height configurations.

Figure 4. PipePillo used to support pipe during the fabrication and welding.

PipePillo supports were successfully used in the fabrication yard for pipe storage (Figure 1), inspection, fabrication and welding (Figure 4). Contractors were impressed with the durability of the PipePillos and were able to reuse them over and over in the yard. One of the contractors was quoted saying: "PipePillos have replaced skids for all of our pipe supports. The ease and stackablity makes it quick and easy to secure large bends. The durability of PipePillos is amazing – we reuse the same 24 for our daily bending" (Ray Stieg, US Trinity Energy Services).

Stringing

The Matterhorn Express Pipeline is an approximately 490 miles (789 km) of 42 in. (1066.8 mm) OD pipeline designed to transport up to 2.5 billion ft^3/d of natural gas from the Permian Basin to the Katy area near Houston, Texas.

The contractor utilised PipePillo for stringing due to the substantial cost savings in transportation, labour and installation. Single PipePillo supports were used to support each joint of pipe, replacing 25 skids. In uneven areas, the contractor placed the PipePillo on three skids to ensure stability (Figure 5). The contractor was able to re-use the PipePillo supports multiple times as the project progressed, resulting in further cost savings.

Integrity and rehabilitation

The Enbridge Dawn Compressor station in Southwestern Ontario, Canada, is one of four mainline compressor stations in the 140 miles (225 km) Dawn Parkway pipeline system and is a critical component to keeping natural gas moving.

A below ground tee and small section of pipe needed to be replaced with an elbow at the Dawn Compressor station. A 48 in. (1219 mm) OD above ground cross over and valve assembly, weighing approximately 30 000 lb (13 600 kg) needed to be supported approximated 10 ft (3 m) above ground during the replacement work. The support method used needed to

Figure 5. PipePillo used to string 42 in. (1066.2 mm) in conjunction with wood skids.

remain in place for several weeks until the replacement work was completed and backfilled. The initial plan was to support the above ground header using a crane until a custom manufactured support comprised of metal I-beams. Prior to designing such an expensive and time consuming solution, the project engineers contacted PipeSak to determine if PipePillo structured pipeline supports would be an option for this application.

PipeSak engineers designed a solution utilising 19 ea. PipePillos SPPs designed to support 48 in. (1219 mm) OD pipe. The SPP48 PipePillos were stacked up from a 1 in. thick steel base on virgin ground approximately 10 ft. (3 m) (Figure 6) . Two additional SPP48s were used to support the buried pipeline during tie-ins. Following completion of the welding, the replaced section was backfilled to grade – leaving the 19 stacked PipePillos in place until permanent concrete supports are installed.

Conclusion

PipePillo structured pipeline supports are an engineered, uniform solution for replacing wood cribbing in many above ground support applications. Contractors across North America are attributing substantial costs savings and increased safety when using PipePillo compared to traditional support methods. PipePillo is adaptable to most height and load requirements and are well-suited for use during transportation, storage, fabrication, stringing and welding as single or multi-stacked supports.

With five sizes currently available, PipePillo structured pipeline supports can accommodate a wide range of pipe diameters from 4.5 - 48 in. (114 - 1219 mm).

Figure 6. PipePillo used to support 48 in. (1219 mm) pipe 10 ft (3 m) from the ground.

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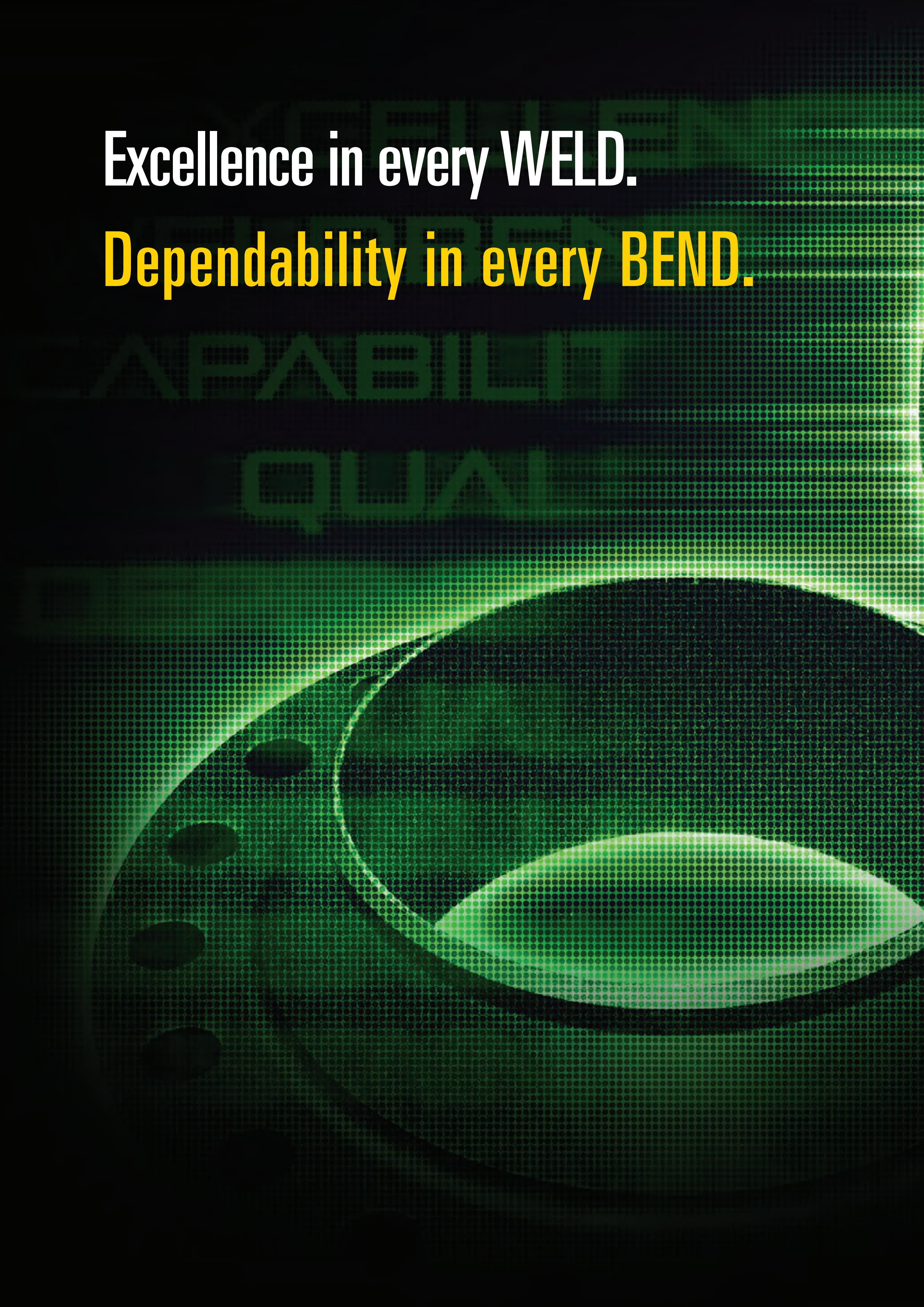

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REINFORCING REPAIR WITH COMPOSITE TECHNOLOGIES

Dr. Chris Alexander, PE, General Manager and Founder of ADV Integrity, Inc., provides an in-depth look at how composite materials can repair corrosion defects, including the basic design, cyclic pressure loading, and long-term strength performance.

As we enter our fourth decade of using composite repair technologies to reinforce corrosion features in the pipeline industry, there is no doubt as to the significant role this innovative technology has contributed to integrity management programmes around the world. When I started my career as a young engineer in the early 1990s the concept of using composite materials to reinforce pipelines was new and often viewed unfavourably by senior engineers. In the pipeline industry we often tend to be hesitant in adopting new and innovative technologies, especially when it comes to the long-term integrity

of our pipeline systems. Our cautiousness is often warranted as the consequences associated with pipeline failures are unacceptable. Before new technologies can be used, their performance must be validated.

Fortunately, over the past 30 years the pipeline industry in North America has made significant investments in validating

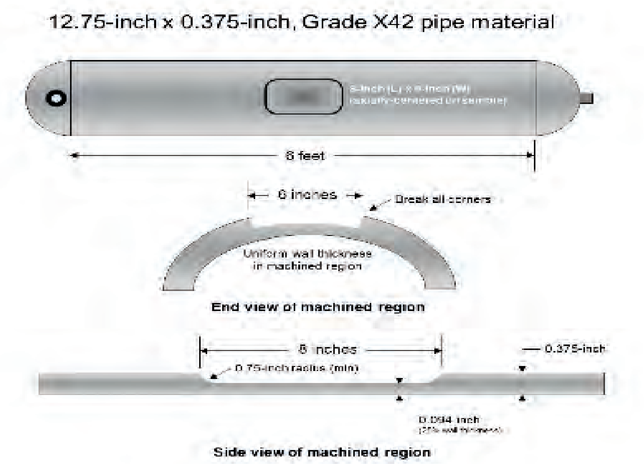

Figure 1. Schematic diagram showing 75% deep corrosion sample.

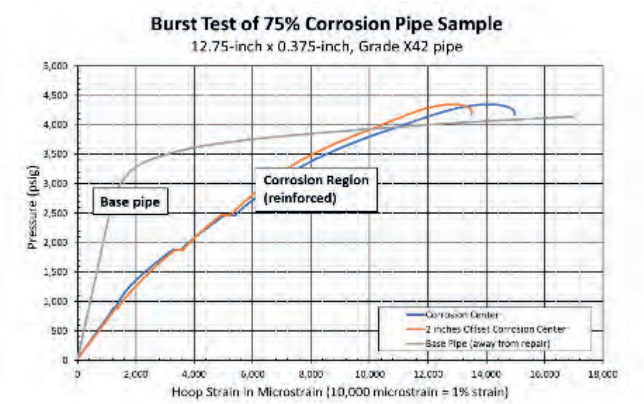

Figure 2. Hoop strain measured in a composite reinforced 75% corrosion pipe test sample.

Figure 3. Photograph showing burst failure in composite reinforced 75% corrosion sample.

the use of composite technologies for reinforcing a wide range of defects. What originally started as a repair technology for corrosion features has expanded to include the reinforcement of dents, mechanical damage, planar defects and axial cracks, branch connections, wrinkle bends, and defective girth welds. For numerous pipeline operators the integration of composite repair systems into their integrity management programmes have 'changed the game' in terms of their ability to repair pipelines safely and efficiently.

A lot has been written about composite repair technologies, including papers presented at pipeline conferences around the world. It is obvious that great interest exists in this subject. This article has been specifically prepared to provide readers with an in-depth look at how composite materials can repair corrosion defects, including the basic design, cyclic pressure loading, and long-term strength performance. Although full-scale testing has played a vital role in validating composite repairs, the 30 plus year history of their in-service use is also testimony to their performance capabilities in effectively reinforcing high pressure pipelines.

The basic design

The two internationally recognised standards for composite repairs are ASME PCC-2 and ISO 24817. Both standards employ a design method that includes an option for considering the combined strength of both the corroded steel pipe and reinforcing composite material. The design methodology employed by ASME PCC-2 is the one presented in this article, emphasising long-term performance and validation through extensive full-scale testing.

Although ASME PCC-2 provides three different options for design, the most common option used for repairing transmission pipelines is based on Equation 12 that calculates the minimum required composite thickness, t_s. This equation is as follows:

$$t_{min} = \left(\frac{PD}{2} - t_s S\right)\left(\frac{1}{f \cdot S_{lt}}\right)$$

Where:

P	Design pressure
D	Pipe diameter
S	Pipe yield strength
t_s	Corroded pipe wall thickness (remaining)
f	Service factor from ASME PCC-2 Table 401-3.4.5.1
S_{lt}	Long-term strength

A review of Equation 12 yields the following observations.

- Included as the contribution of the remaining pipe wall to the overall strength of the reinforced pipe is the product of t_s and S. The strength of this remaining ligament reduces the required composite thickness when compared to what would be required were the composite required to carry the entire reinforcing load.

- Not included in this equation is length of the corrosion, which for certain scenarios such as short corrosion features a thinner repair will be required. For shorter corrosion features some experts have argued that too much composite material is installed using Equation 12 when corrosion length is not included, resulting in an overdesign condition.

- Equation 12 includes long-term composite strength, as well as a service factor used to establish the design strength of the composite material. The service factor is the reciprocal of the safety factor. A safety factor of 2.0 is associated with a 1000 hour test period, while a 10 000 hour test period is associated with a safety factor of 1.5. The longer test period (i.e. 14 months for 10 000 hours versus 42 days for 1000 hours) compensates composite manufacture designs with a reduced wall thickness.

The backbone of the work to validate composite repair technologies has been full-scale testing. The author has conducted more than 2000 full-scale destructive tests since the mid-1990s to evaluate the reinforcement of defects and features including corrosion, dents, mechanical damage, vintage girth welds, planar defects, axial cracks, wrinkle bends, bends/elbows, and branch connections. Loading has included burst and cyclic pressure, along with axial tension and bending loads. Elevated temperatures have also been used for testing composite repairs. The most tested configuration is the 75% corrosion feature sample shown in Figure 1.

Provided below is a calculation used to determine the required composite thickness for a 75% deep corrosion test sample. On the test sample strain gages were installed on the base pipe outside the repair and in the corrosion region. Results for hoop strain as a function of pressure are plotted in Figure 2. The sample failed at 4,351 psig (176% SMYS) outside the composite repair as shown in Figure 3.

$$t_{min} = \left(\frac{(1{,}780\ psig)(12.75\ in)}{2} - (0.094\ in)(42{,}000\ psi)\right) \cdot \left(\frac{1}{0.5\ (24{,}000\ psi)}\right) = 0.616\ inches$$

Design pressure, P (72% SMYS): 1780 psig
Pipe yield strength, S: 42 000 psi
Pipe diameter, D: 12.75 in.
Corroded wall thickness, t_s: 0.094 inches (75% deep)
Service factor, f (Table 401-3.4.5.1): 0.5 for 1000 hour testing
Long-term strength, s_{lt}: 24 000 psi (based on 1000 hour testing)
Composite thickness (see below): 0.616 in.

Long-term strength performance

In the late 1980s and early 1990s research engineers who oversaw the development of Clock Spring under the auspice of the Gas Research Institute recognised the critical role that material degradation and creep would play on the long-term performance of composite repairs. Early research sought to quantify the reduced strength of the composite material over time through long-term creep testing up to 10 000 hours. Unlike the design of steel pipelines that employ safety factors between 1.5 and 3.0 relative to the ultimate strength of steel, composite repair designs often have safety factors based on ultimate tensile strength between 10 and 20. The larger safety factors with composite materials are required because of uncertainties in future material performance.

Provided in Figure 4 is a graph plotting inter-layer hoop stress measurements made as a function of layer using strain gages installed in a composite reinforcing system used to reinforce a 75% corrosion feature. The thickness for the repair was based on ASME PCC-2 Equation 12 and the corrosion feature was machined in a 12.75 in. x 0.375 in., Grade X42 pipe sample pressurised to a design pressure of 1780 psig (72% SMYS). The average measured hoop stress in the composite material at the design pressure was 3.6 ksi (25.2 MPa) as shown in the graph. Considering that the tensile strength of the E-glass composite reinforcing material was 56 ksi (386 MPa), the corresponding safety factor is 15.

In addition to the inter-layer pressure test, another 75% deep corrosion pipe sample with the same repair configuration was pressure cycled from 36% to 72% SMYS. This sample reached 165 127 before a crack developed in the corrosion feature. As discussed in a subsequent section, this experimental fatigue life is useful for quantifying the service life of a composite repair.

Circa 2010 another body of work sponsored by the Pipeline Research Council International, Inc. and 13 composite repair manufacturers involved the burial of composite reinforced corrosion samples for a period of 10 years (approximately 88 000 hours). Corrosion features machined into the samples had depths of 40%, 60%, and 75% of the pipe's nominal wall thickness. At the end of designated time periods (e.g., 1, 2, 3, 5, 7.5, and 10 years), pipe samples removed from burial were pressurised to failure. This study was completed, demonstrating that well-designed and installed composite technologies provide a long-term pipeline repair solution for reinforcing corrosion features.

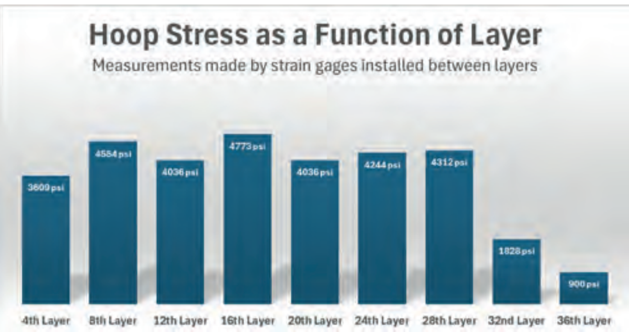

Figure 4. Measured hoop stress as a function of layer in a composite reinforcement.

Cyclic pressure loading

All transmission pipelines experience cyclic pressure loading, even gas pipelines that typically experience minimal cyclic loading on an annual basis. When evaluating and validating composite materials the role of cyclic pressure testing is important. First, the use of cyclic pressure loading is an ideal means to 'push' a composite repair system to the breaking point in identifying top performing technologies. It has been the author's observation that the top performing technologies are able to achieve high cycle counts (i.e. greater than 150 000 cycles at ΔP = 36% SMYS) before failure when reinforcing features such as severe corrosion, dents, and axial cracks.

Secondly, quantitatively determining a specific number of cycles is useful for establishing the long-term design life of a repair. The example below uses the fatigue life presented previously of the E-glass system used to reinforce the 75% corrosion sample that reached 165 127 cycles. For a "moderate" pressure cycle condition (Kiefner, 2004) a calculated service life for this repair is 98 years. This example problem is the exact type of calculation performed to establish the service life for a composite repair system considering cyclic pressure. This is especially important for those repair systems used to reinforce liquid transmission pipelines that might be subject to aggressive pressure cycling.

- Number of experimental cycles to failure: 165 127 cycles.
- Fatigue safety factor: 5.0.
- Number of design cycles: 33 025 cycles (165 127 cycles/5).
- Number of pressure cycles at ΔP = 36% SMYS 337 cycles per year (moderate cycle condition).
- Design life: 98 years (33 025 cycles/337 cycles per year).

Closing remarks

Even though composite materials have a successful history spanning more than 30 years, questions continue from pipeline companies and regulatory agencies concerning long-term performance. As stated previously, our natural tendency in the pipeline industry is towards cautiousness; however, the extensive experimental validation work and in-service success provides ample evidence towards broad adoption of composite reinforcing technologies.

Care is warranted in using composite materials to repair high pressure pipelines. The favourable results presented in this article and many other publications are based on high quality installations made in test labs. To achieve an equivalent level of field performance the same installation quality must be performed. Also, combined loading and elevated temperature conditions must be considered in design when applicable. Failure to consider these scenarios could result in failures, as observed in the test lab. As reflected in this paper, the key to ensuring in-service performance is accurately replicating field conditions in the test lab. With good test engineers and technicians, achieving elevated levels of performance is possible.

As an industry we continue to evolve in our use of composite reinforcing technologies. Our confidence and ability to manage the risk in their deployment has grown because of the pipeline industry's unwavering commitment to validate and explore new applications. Composite manufacturers continue to play a vital role by introducing innovative technologies and have also made significant financial and resource contributions to support the more than 30 Joint Industry Programs undertaken since 2005. The collaboration involving composite technology companies, regulatory agencies, pipeline operators, and researchers is a model for our industry to not only advance technologies, but ensure they are commercially deployed and viable.

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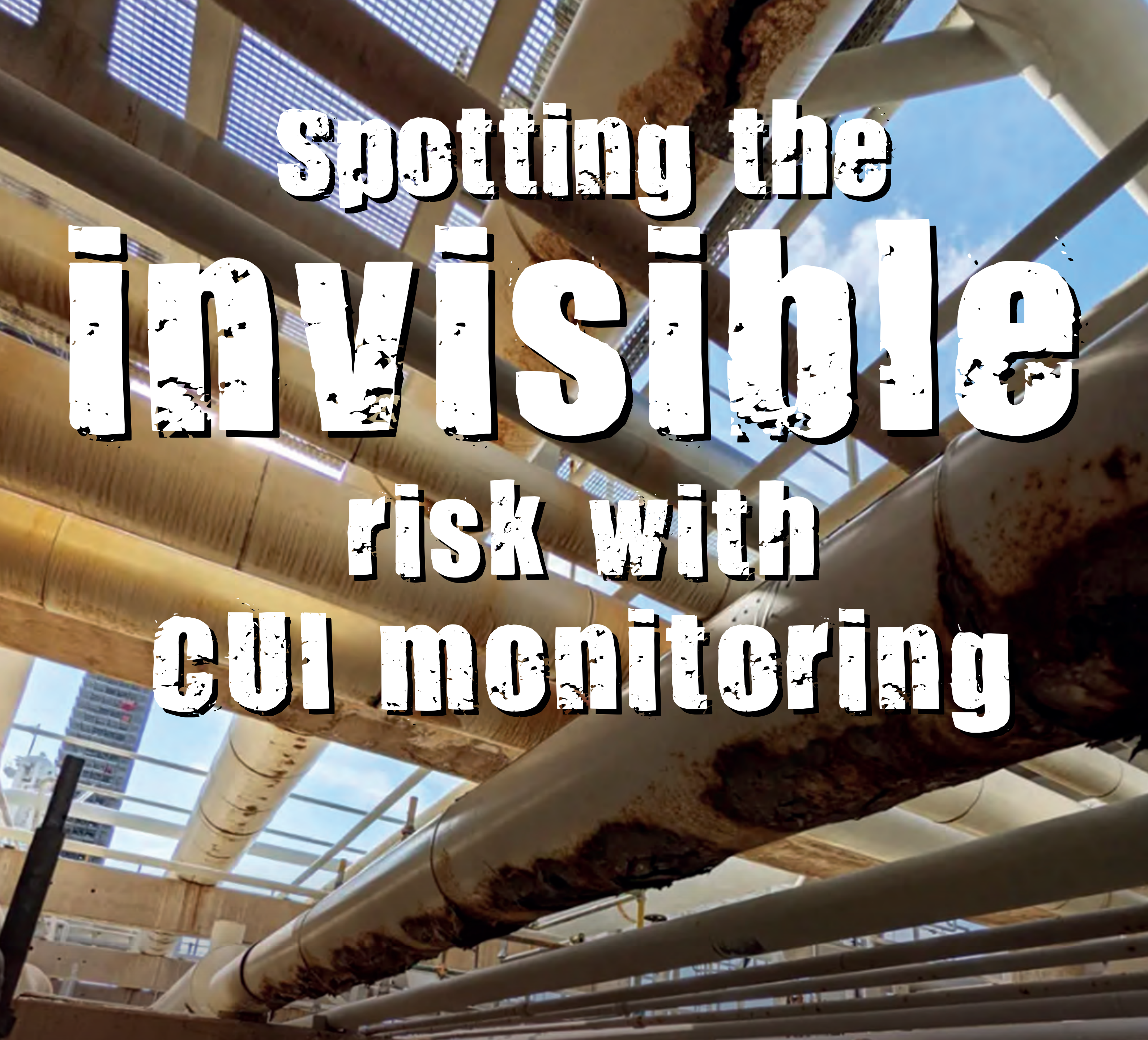
Spotting the invisible risk with CUI monitoring



Dr Prafull Sharma, Chief Technology Officer, CorrosionRADAR,
discusses issues surrounding the risk of Corrosion Under Insulation (CUI) on assets, and explains how new technology enables a 'predictive' approach through remote monitoring, significantly reducing failure risk.

It started when operators spotted a small pinhole leak in a 30 year old gas pipe. While they jumped to isolate the line, it catastrophically failed, narrowly avoiding a major gas release.

That's just one story about a pipeline failure. Many more have been reported. Remember, it was just a small pinhole from corrosion.

With sufficient oil and gas pipelines to circle the world 30 times, corrosion under insulation (CUI) is an immense challenge for the industry. And spotting at-risk areas has relied entirely on costly physical inspection – until now.

The risk of CUI

US$2.5 trillion annually: that's the amount revealed in the NACE Impact Study when considering the global cost of corrosion across all sectors and geographies. It is a staggering figure that puts the spotlight firmly on asset corrosion – not least in the oil and gas industry.

The sector insulates many pipes, pressure vessels and other components to safeguard the fluid inside and maintain its temperature. Insulation also protects nearby personnel from the dangers of extreme heat or cold. But insulation presents an 'invisible' corrosion risk. It's called corrosion under insulation.

Figure 1. Corrosion Under Insulation (CUI) present on pipelines on a refinery.

Moisture (due to process condensation, rainwater, or sweating of assets due to a specific temperature range) can find its way in and deteriorate the metal surface that's hidden away below the insulation. CUI accounts for 60% of pipeline failures in the oil and gas industry alone (as per NZTC UK).

Often undetected until substantial damage occurs, CUI can undermine asset integrity management when physical inspection methods alone fall short of reducing the risk. The sheer volume of surfaces to inspect can be overwhelming while many are almost impossible to reach without significant scaffolding.

Adding insult to injury, metals such as carbon steel can corrode up to 20 times faster under insulation than in normal aerated conditions where moisture can evaporate more easily. It's clear to see why CUI remains an immense corrosion risk to manage.

The impact of CUI risk

There are two types of cost from CUI: direct costs and indirect costs. Both can be significantly harmful to the industry.

Direct costs

When oil and gas equipment deteriorates – or even fails – due to CUI, the associated costs can be eye-watering. Repair work may be necessary in hard to access areas. And often urgent in nature, bills can scale ever higher. Meanwhile, downtime is never a desirable option.

Indirect costs

Production losses, hampered customer service, and a damaged reputation are just three indirect costs associated with CUI instances. Depending on the severity of the damage, they can quickly scale out of control.

It's clear the impact of CUI is a formidable challenge for asset integrity management. So much so that a step change in monitoring and identification techniques could make a significant difference. So, imagine the potential of unleashing a new dawn of technology.

Industry 4.0 changes the game for CUI monitoring

As technologies rapidly transformed, the industrial Internet of Things (IoT) in this era of Industry 4.0, disrupted sectors like nothing we've seen for a long time.

Today, it's possible to connect devices that sense, store, and communicate information through wireless networks. This generates meaningful insights from raw data that accurately inform decisions and make deployments rapidly scalable. For non-technical people, such information and functionality are often provided via a user-friendly dashboard. This is certainly the case for CUI monitoring.

Thanks to digitalisation fusing with CUI management, new technology can now enable smart sensors to provide timely insight and analysis. These sensors can monitor equipment 24/7 without physical inspection, providing data that informs a predictive CUI monitoring approach.

In other words, by spotting potential failures before they occur, both maintenance costs and downtime risks fall significantly. Asset integrity engineers can focus their resources on the highest priorities and lessen the risk of CUI catching them out unawares.

How predictive CUI monitoring adds value

There's no doubt smart sensors are providing a pivotal moment for the oil and gas industry. Being able to remotely collect data 24/7 to inform CUI risk intelligence is game-changing.

While this transition doesn't negate the need for physical inspection, it allows organisations to allocate maintenance resources to the right areas, mitigating the greatest risks before they develop into something more serious.

Remote monitoring enhances the inspection team's safety too. While sufficient scaffolding can help reach many areas, some surfaces are incredibly hard (and costly) to inspect physically. Far better to monitor them remotely and only access them if there's a CUI issue to resolve.

Predictive CUI monitoring provides value beyond cost efficiencies and safety, though. By using sensors to detect corrosivity rates and moisture under the insulation, asset integrity engineers gain data to define thresholds for critical CUI parameters. These may include factors such as the number of wet days and the temperature.

Armed with this data, they can establish a dynamic approach to risk assessment based on current conditions. In fact, monitoring data can help predict corrosion rates beyond what's suggested in literature, enhancing the accuracy of risk evaluation.

Figure 2. CorrosionRADAR: LR the end to end solution.

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Successful use cases of predictive CUI Monitoring

Aramco

One of the world's largest oil and gas companies, Aramco experienced CUI challenges, on some of its critical assets. Any downtime was unimaginable. And yet, with temperatures fluctuating between freezing and ambient, the risk of CUI is high for these assets operating in intermittent operations.

Aramco chose to adopt CorrosionRADAR's CUI monitoring system, installing numerous sensors on several kilometres of pipeline during a planned shutdown. CorrosionRADAR created an enhanced analytics dashboard using its Clarity software and LoRa connectivity.

Asset integrity and corrosion engineers now receive regular data insights meaning they're better equipped to make accurate decisions that mitigate CUI on the pipeline. Aramco also expects this technology to reduce the cost of future maintenance and shutdowns.

Figure 3. Aramco chose to adopt CorrosionRADAR's CUI monitoring system, installing numerous sensors on several kilometres of pipeline during a planned shutdown.

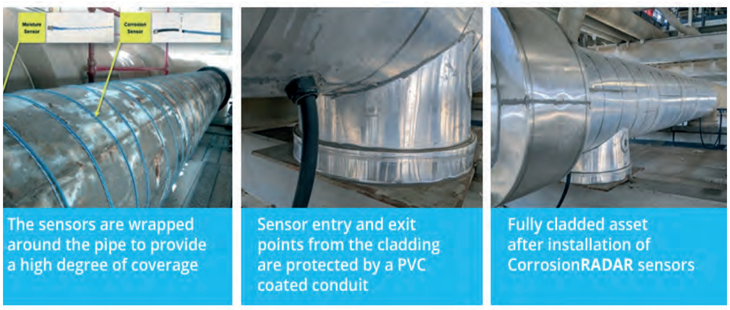


Figure 4. CorrosionRADAR: LR Installed on a propane refrigeration pipeline at an Aramco Site.

Dow Chemicals

One of the largest petrochemical companies in the world, Dow Chemical Company operates in more than 150 countries. It wanted a new approach to CUI monitoring.

Covered in closed cell insulation with a vapour barrier, operating in periodic thermal cycles, cracked gas dryers are at high risk of CUI. They also endure temperature extremes from minus 15°C to 180°C.

While Dow's main goal was to reduce risk by maintaining asset integrity throughout the life cycle, it also saves several hundred thousand US dollars on each dryer inspection cycle. The organisation has continued to work with CorrosionRADAR, installing sensors on other high-risk equipment around the world.

ADNOC

A major energy producer in UAE, ADNOC found maintaining its De-Ethaniser column (with a history of CUI) difficult and expensive. More than 30 m high, it required extensive scaffolding to safely inspect the column.

Embracing new technology, ADNOC approached CorrosionRADAR to install CUI monitoring on the column. Positioned on high-risk areas with sweating service and vapour-sealed insulation, the sensors continually informed a risk analytics dashboard.

The inspection engineer could now make data-driven decisions, only arranging physical access via scaffolding when, and where, they identified a likelihood of CUI. As a result, inspection costs fell dramatically, and employee safety improved.

INEOS

Based in the UK, INEOS wanted to reduce the inspection costs of the heat exchanger. A critical plant asset, the organisation approached CorrosionRADAR for help.

Using a helical installation method, CorrosionRADAR installed remote sensors to provide data to desk through a risk analytics dashboard. The sensors detected corrosivity rates and moisture within the insulation, highlighting weak spots before the problem became significant.

INEOS can now make data-informed decisions from the ground, planning inspection and maintenance schedules accordingly. Using sensors has reduced inspection costs while also reducing the risk of downtime from CUI.

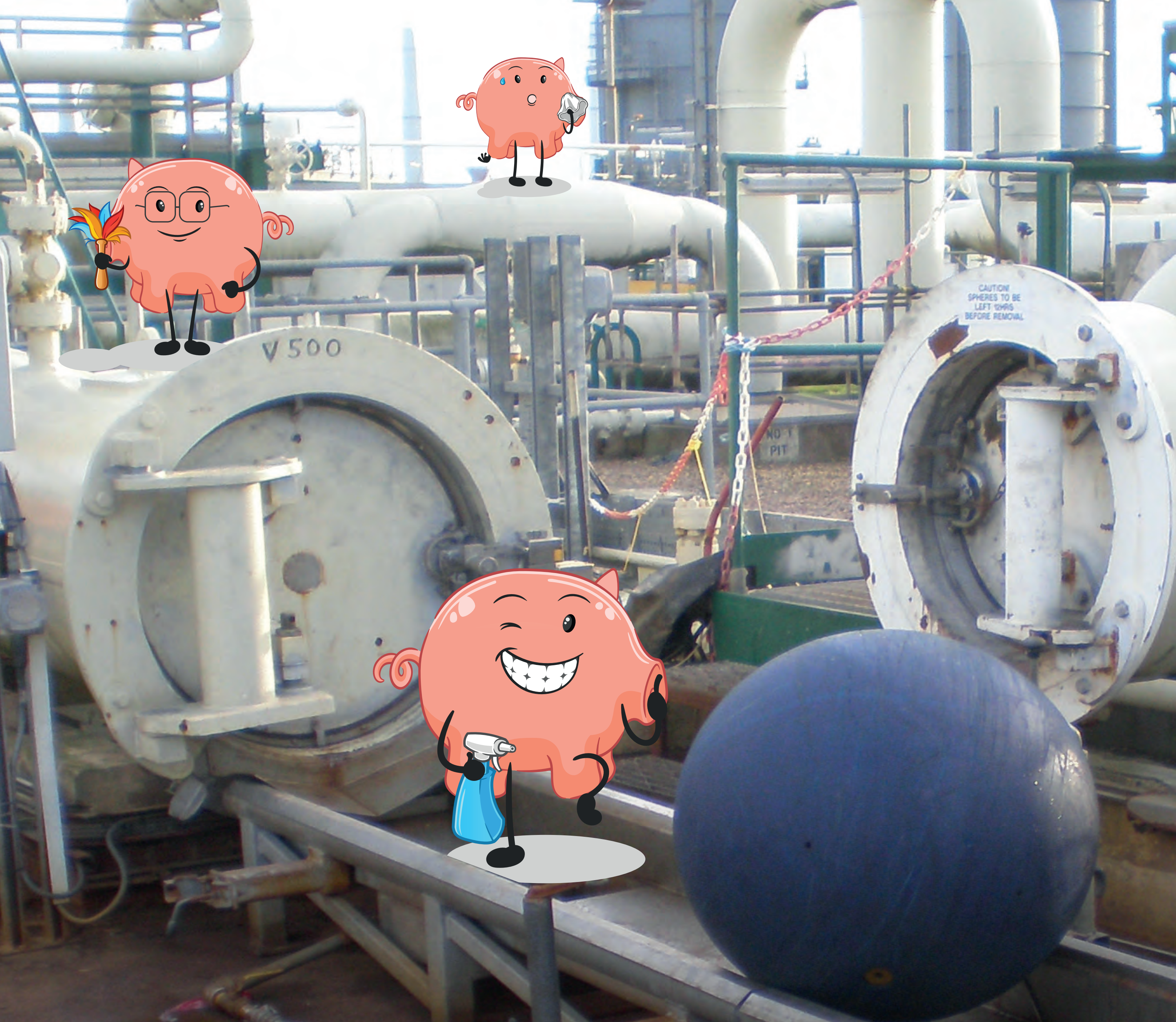
Industry 4.0 and CUI monitoring

Adoption of CUI monitoring during the era of Industry 4.0 has been a welcome development for the oil and gas industry. With immense risks evident from CUI, monitoring programmes must be effective at managing asset integrity.

Technology has provided the answer to this risk.

By spotting CUI early, and prioritising repair, maintenance teams can proactively address issues before failure and fluid escapes happen. This reduces the impact of oil and gas production on the environment while enhancing site safety.

With intelligent remote sensors enabling data-driven decisions, organisations that choose to adopt this innovative technology face an efficient and cost-effective future for CUI monitoring.



Cleaning pigs in action

Simon Bell, Managing Director, iNPIPE PRODUCTS, considers the various designs, and frequency, of pigging tools used over the pipeline life cycle.

It is generally accepted that pipelines offer the most cost effective and efficient method of transporting liquids and gases, however, this assumption depends upon achieving the required throughput, coupled with the lowest capital investment to achieve the lowest operating costs.

It is also accepted that in order to achieve continuous operation, together with the required payback, is based

Figure 1. Sphere loading tray.

upon ensuring that the optimum flow is achieved with the minimum amount of maintenance. Cleaning to remove substances which may damage the pipeline, disrupt or reduce the flow should be conducted with purpose designed cleaning pigs. The calculation of these projected costs can be further complicated by the fact that flow rates, and consequent deposition, can vary dramatically over time which means that the design of the pig type and/or the frequency of cleaning can change over the projected lifetime, and consequent pay-back, by a number of factors. The anticipated lifetime of asset may be extended by many years due to the development of new extraction techniques has significant extended production

Figure 2. Sphere storage/transport racks.

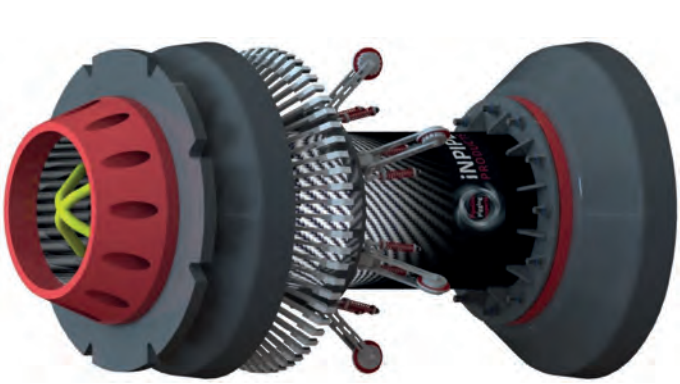


Figure 3. Debris mapping tool.

but at the same time altered the pigging requirements of mature reserves.

Subsea deepwater pipelines further exacerbate pigging variables which impact upon cleaning frequency and consequent pig design. Cold seawater temperatures can lead to increased deposition on the pipe-wall, with paraffins and hydrates of particular concern. The use of flexible pipe for connection jumpers, risers and flowlines is prevalent in subsea pipelines which can mean pigs need to be designed to run in multiple diameters. Further potential complications for pig design include valves, bends, multiple offtakes and wyes all have implications upon the pig design. For example, tight bends will reduce the pig body length however wye pieces will dictate a longer pig body length and the use of both may dictate an articulated pig design. Often the most cost-effective pigging solution is to pig from a launcher topside through to a receiver on land. One of the most expensive pigging solutions is the use of remote subsea production systems which may need extra expensive flowlines to create a pigging loop from the surface or through an even more expensive subsea launcher at the production site which will require periodic intervention by a surface supported system.

An example for changes in the relevant cleaning tool is a 36 in. offshore to onshore gas transporting pipeline which originally used inflatable magnetic polyurethane spheres for the removal of condensate. The preferred pigging tool then subsequently changed to a bi-directional pig. However, the volume of condensate being pigged out increased beyond the capacity of the slug-catcher. Consequently, a cup pig was designed to control the amount of condensate removed by the cleaning tool which proved very successful. It was then decided that the client wanted to increase the frequency of pigging and to semi-automate the existing very old launcher to minimise wear and tear on the isolation valves and closure. This requirement necessitated a conceptual redesign around a removable cassette followed by full scale testing to ensure the successful launch using either water or air as a launching medium with client witnessed testing with the production pigs.

Pipeline pigging phases throughout pipeline life

Various designs of cleaning tools or pigs are used over the course of the pipeline life cycle, although the function and design can vary greatly. Life cycle phases include:

- Construction and pre-commissioning – typically removing construction debris and mill-scale followed by water filling, hydrotesting and then pipeline drying.
- Pipeline operation – including pipeline cleaning of waxes, sands, hydrates, scale, condensate, water and black powder.
- Pipeline inspection – pipeline cleaning prior to internal inspection predominantly looking for corrosion, pitting, cracks and laminations.

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- Pipeline renovation/rehabilitation/isolation – specialised cleaning pigs dependent upon type of deposition and cleanliness required.

Figure 4. Mini integrated light and camera pig.

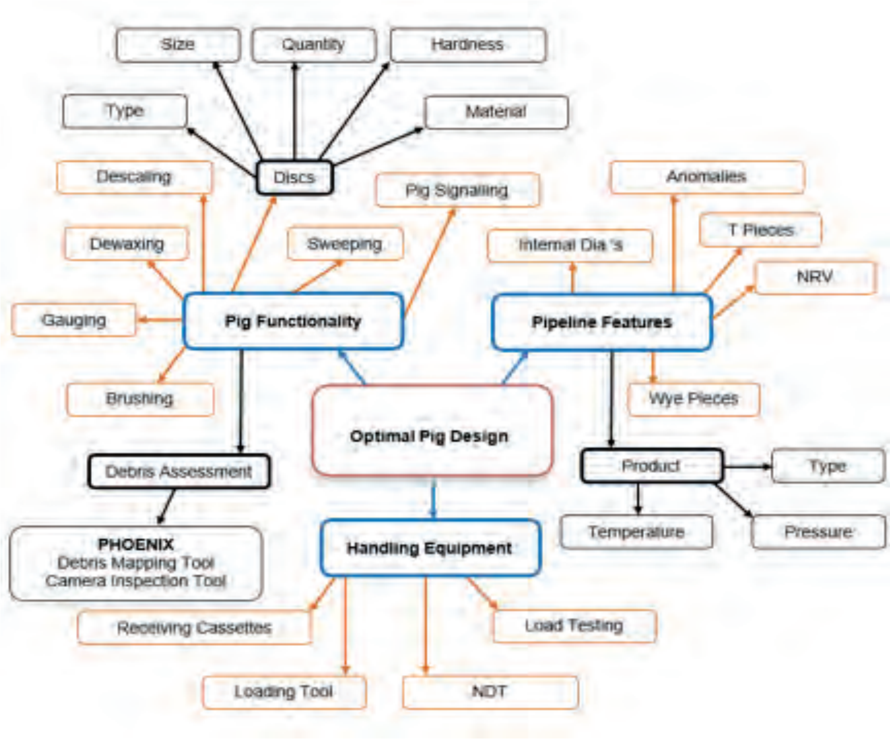

Figure 5. Pigging functionality App.

- Pipeline decommissioning – pipeline cleaning to remove potentially large amounts of waxes, sands, hydrates, corrosion, scale, condensates, water and black power prior to decommissioning. Decommissioning could entail simply plugging the pipeline and leaving in situ or cutting up and complete removal.

Pigging frequency remains subjective and historically based, however, one of the most reliable means to determine the utility pigging frequency required is to initially pig frequently, while monitoring pigged materials removed from the pipe wall and received into the receiver. Obviously, production fields, however, change in pigging requirements during field life cycle. A more scientific approach to understanding the nature and volume of deposits is to use a debris mapping tool which can be used to understand the location of deposits together with rate of deposition. This accurate data then allows for the frequency of pigging and the type of cleaning tools to be reliably determined to ensure optimum flow together with a clean pipeline. A clean pipeline is particularly important when running ILI tools to ensure optimum accuracy of results.

It should also be born in mind that an Operator or contractor can develop a significant inventory of tools over the course of the lifetime of the pipeline, often supplied by various suppliers for various functions. The functionality of these should be reviewed periodically to ensure that the correct tools are being run at the optimum speed and frequency to achieve the desired results. iNPIPE PRODUCTS Aberdeen Service Centre has conducted such reviews for Clients and has developed a logical approach which provides Clients with 24/7 access to their pigging tool register via an online based system. This can provide weekly or even daily reports, inspection and test reports emailed direct to the Client. It can also provide full customer historical data, commercial data and dashboard highlights of recent refurbishment activity and status at the push of a button. Provision of such accurate data ensures that the customer is provided with time and cost savings on project management. Time and cost saving benefits on identifying pigging tool locations, condition and configurations are also an added customer benefit and all available online at any time or via a mobile App. The close working relationship between Operator, pigging contractor and designer helps to provide shared knowledge from pig runs offers the ability to streamline the pig fleet to reduce costs and optimise pigging tool capabilities against current pipeline conditions.

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UNCOVERING THE TRUE NATURE OF DENTS

The industry's first gouge versus metal loss classifier lets operators better understand integrity threats and meet Mega Rule requirements says Matt Romney, Product Line Director, T.D. Williamson.

SOLVED

When the US Pipeline and Hazardous Materials Safety Administration (PHMSA) began enforcing the latest portion of the so-called Gas Mega Rule in late February 2024, it signalled a stricter regulatory environment for the American natural gas pipeline industry and the need to adhere to a more risk-based, rather than prescriptive, requirements.

In line with the industry's evolving direction, industry expectations compel gas transmission pipeline operators to implement robust processes for identifying, evaluating and repairing dents and other mechanical damage that could result in a stress riser or other integrity threats. The expectation is that operators be able to identify and evaluate potential threats to the pipe segment in the vicinity of the dent anomaly or defect. Those threats include ground movement, external loading, fatigue, cracking and corrosion.

In addition, the new regulation requires operators to look for damage in the dent area by reviewing a variety of inline inspection (ILI) data – high-resolution magnetic flux leakage (HR-MFL), high-resolution deformation (HR-DEF), inertial mapping and crack detection – then performing pipeline curvature-based strain analysis using the HR-DEF inspection data.

In the end, Part 192.714(d)(ii) identifies a dent located top of the pipe (between the 8 o'clock and 4 o'clock positions) and associated with metal loss, cracking, or a stress riser as an immediate condition for remediation, unless an engineering critical analysis performed demonstrates critical strain levels are not exceeded.

How dents are different

The actual integrity threat – and the warranted level and timing of a response – depends on what caused the metal loss: coincidental corrosion or material being mechanically removed from the pipe wall, resulting in a gouge. There's a significantly different threat to pipeline integrity between the two, and the updated regulation allows operators to assess this risk via engineering critical assessment.

Figure 1. **Pipeline mechanical damage gouge anomaly on the external surface of the pipe wall.**

Figure 2. **MDS Pro inspection platform. Inspection technologies left to right: drive, spiral MFL, ultra res axial MFL, low-field MFL, geometry, and mapping.**

For one thing, corrosion typically attacks the metal over a broad area of the pipe surface while gouges are localised. The concentrated, mechanical removal or smearing of the pipe wall metal, results in cold working (deformation that increases brittleness) (Figure 1). In turn, cold working can lead to residual stresses and trigger additional integrity issues, ultimately culminating in increased susceptibility to cracking.

We also know dents containing gouging are considered an interacting threat, meaning the combined presence of both the dent and the gouge together poses a greater risk to pipeline integrity than a dent, gouge or metal loss would individually. Dents with gouges are also often known as mechanical damage anomalies. For many years, mechanical damage anomalies have been a confirmed leading cause of significant pipeline incidents globally.

A game-changing approach

Though the US gas transmission regulation says that factors like gouge depth and length must be part of the integrity assessment, there's no specific gouge acceptance criteria. That means there's no consistent benchmark for gouge severity, which could lead to inconsistencies in how gouges are evaluated and addressed.

But what if an operator could know with confidence that the metal loss associated with a dent is less than 10% deep low-level corrosion, which is widely accepted as not being an immediate integrity threat? Or that a shallow dent associated with gouging and axial crack-like features warrants immediate attention? Having the ability to accurately classify dents with coincident gouging and validate depth sizing performance for both gouge and non-gouge metal loss located within a dent would be game-changing.

Global pipeline services provider T.D. Williamson (TDW) has given operators that capability. To tackle the complex problem of differentiating coincident corrosion from gouging, the company has combined the comprehensive data-capturing capabilities of its MDS® Pro platform, with cutting-edge machine-learning models (Figure 2).

The result of this innovative work is the first gouge classifier backed by an industry-compliant performance specification.

The multi-technology advantage

The process of gouge formation can be fairly straightforward. In a common top-side mechanical damage scenario, an indenter – a backhoe, excavator, piledriver or similar equipment – creates a dent in the pipe wall while mechanically removing or smearing pipe wall material. As the indenter retracts, the pipe wall rebounds to a final geometry. This creates localised strain in both the original and final dent geometries.

Bottom-side mechanical damage anomalies can be created as the pipe inadvertently rests on a protruding rock or uneven hard surface. Over time the pipe is pressed against the rock surface denting the pipe and gouging the pipe wall. However, unlike many top-side dents, the


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BAUMA

indenter (the rock) remains in place holding the pipe wall in a more stable dent shape.

Like other types of interacting threats (and mechanical damage in general), gouges have historically been difficult to identify and measure using single technology ILI systems. Because those systems were adapted to detect, classify and size a specific threat, they struggle to assess interacting features such as mechanical damage, wrinkle bends, puddle welds and selective seam weld corrosion (SSWC).

This technology gap resulted in overly conservative approaches to pipeline management. For example, pipeline operators have excavated their pipe to perform a direct assessment of identified anomalies only to determine that the anomaly in question is a stable feature that poses a low risk to the integrity of the pipeline. However, the act of excavating and exposing the pipeline induced potential new risks.

By contrast, combining technologies onto a single tool train such as the MDS Pro platform (Figure 2), allows the simultaneous assessment of multiple independent data streams. This enables the most comprehensive characterisation of pipeline anomalies, especially complex interacting features.

For example, while axial magnetic flux leakage (MFL) can detect and characterise general volumetric metal loss and pitting on its own, by itself it can't properly characterise metal loss associated with a dent as either corrosion or gouging. However, analysing MFL data simultaneously with dent geometry enables the precise identification of a metal loss anomaly relative to a dent.

In addition, leveraging multiple high-field MFL technologies that have different magnetic orientations provides enhanced details about metal loss morphologies, that is, shapes, patterns or textures that develop due to deterioration, including uniform thinning, pitting and grooving. Finally, adding low-field MFL (LFM) technology helps classify the anomaly's impact on localised material permeability (how the pipe wall reacts in the presence of a magnetic field). The localised material permeability can be sensitive to variations in stress and cold working, which are often associated with gouging.

Reducing gouge calls

The topic of gouge classification – specifically, how to differentiate coincident metal loss from gouging – is constantly being discussed in the industry. The need is to overcome gaps in past technologies and give operators a classifier solution that would help them answer the question, is this metal loss anomaly a gouge or not?

Today, the validated classifier entails three components:

- An advanced ILI tool capable of providing comprehensive inspection data.
- Subject matter experts to extract and develop relevant and applicable features.
- A machine learning model capable of producing accurate results to successfully guide remediation.

Machine learning models assist in making assessments based on quantitative features extracted from empirical data. Machine learning is particularly useful when the volume of data is of sufficient size that more conventional or manual methods struggle given the complex interactions of said data. These types of models can find interactions that may not be obvious to the naked eye and thus produce meaningful predictions to enhance a decision-making process.

In this case, experienced data scientists used field-provided dig feedback as truth data to identify key insights into what ILI features best describe gouge and corrosion features associated with dents. These qualitative features were converted to quantitative values and included things like dent orientation, dent shape, and MFL, SMFL and LFM signal characteristics.

TDW used MDS Pro dent data from 60 unique inspections to train the machine learning model and to ultimately develop and statistically validate the gouge identification process (that is, the classifier). The broad dataset spanned various diameters, wall thicknesses, product mediums and operating conditions.

While these test datasets best represented future examples, the universe of future samples is, of course, extremely large. TDW is continuing to monitor classifier performance using historical data, following the qualification requirements standard in API-1163 section 6.3.

More recently, the gouge classification process and model were utilised on a 65 km (40 mile), 24 in. diameter pipeline that had been inspected by the MDS ILI system. Leveraging the classifier, gouge calls were reduced by 33% by reducing false calls or corrosion as gouges without increasing the probability of missing gouges. The ability to reduce the number of reported gouges provided relief to the remediation efforts and allowed the operator to focus resources to the most critical integrity threats.

In addition to the classification performance, TDW also investigated the performance of coincident feature depth sizing. While the ability to accurately size a metal loss feature within a dent is dependent on how well the metal loss sensors track the dent profile, the performance of the MDS Pro platform proved successful for both gouge and non-gouge anomalies.

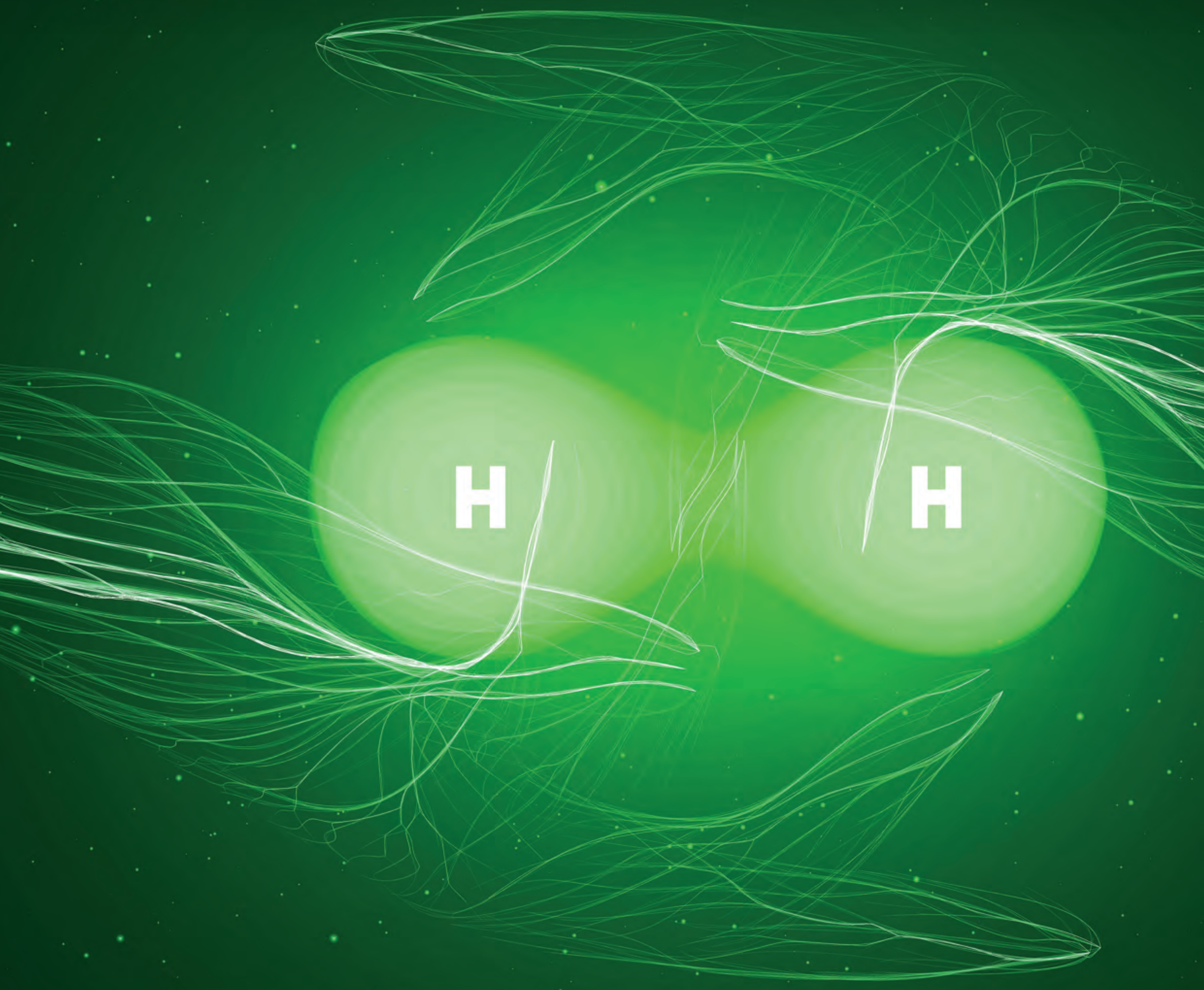
Continuous improvement, more compliant

Like everything else in the energy industry, ILI is subject to continuous improvement. Increased sensor resolution provides better data; when that data is analysed by experts, it lets operators manage more complex anomalies with greater confidence.

The gouge versus metal loss classifier is being continuously improved as well. To ensure its efficacy and further increase accuracy, TDW reviews and revalidates it annually.

By leveraging the classifier's ability to reduce the number of reported gouges, operators can mitigate true pipeline defects, directly focus resources on critical integrity threats and comply with recent and future regulations.

READY FOR THE HYDROGEN CHALLENGE



Pratap Patil, Business Development Director and Olivier Revel, Welding Development & Welding methods Manager, Serimax, discuss welding pipelines for hydrogen through a comprehensive approach involving material selection, welding techniques, safety protocols and stringent quality control measures.

In the realm of oil and gas, where any compromise in weld integrity can lead to dire consequences – such as pipeline failure – meticulous attention to detail is paramount. At Serimax, we use our specialised expertise and collaboration between engineers, welders, and materials scientists to address the unique challenges associated with welding of hydrogen application pipelines and associated infrastructure.

Hydrogen has, for a long time, been sold as a miracle solution, and as a way to help prematurely reach net-zero targets. But with little buy in and investment, due to the lack of compliant infrastructure, and economical but not viable solutions, the technology associated and needed for the construction of hydrogen infrastructures has been put to one side.

Today, despite several hurdles on the way and various colour variants, the hydrogen approach to what can be classed as green energy seems to be turning a page.

So, is it all green lights and rainbows for hydrogen pipelines? As a welding company that has already started to contribute to this sector, and as we see hydrogen getting the backing it needs from government officials and key decision makers, the urgency for this transition is evident. As part of our transition to renewable energy and low carbon projects,

Serimax is heavily involved in welding hydrogen pipelines, offshore windfarm structures, CO_2 pipelines and certain elements from nuclear plants. This symbiotic relationship supports the transition to a sustainable energy system, reduces carbon emissions, and enhances energy security and is why Serimax is so keen to be involved in such pipeline structures. It looks like getting there could take some time but together, with repeatable solutions, skills transferals… it's clear that the industry needs to collaborate, discover and deliver it to make our heavy industry greener and in turn reach net-zero. As the hydrogen revolution is here, Serimax is ready to tackle all your welding challenges. Together with the skills transfer from the oil and gas industry the pace and weight for constructing the hydrogen infrastructure is upon us – we need to build what has previously been done in three decades in just one.

Collaborate

Working on key hydrogen challenges such as embrittlement, leakage and permeability, infrastructure, cost and collaborating to make this revolution happen is key; to delay the hydrogen revolution would be a mistake and to make possible a speedy delivery of infrastructure needs to be done collaboratively by industry experts working together to make this revolution possible. Previous experience and resilience are two core elements for success, bringing hydrogen transferrable skills will help increase the productivity of hydrogen projects. With over three decades of experience in providing welding services for heavy sour service projects with stringent technical demands in line with H_2 requirements means that we are poised to join the challenge and make the safe welding of hydrogen infrastructures whether pipeline or piping, possible. With our expertise, we're driving innovation in the energy transition, enhancing welding operations for unparalleled excellence.

With this in mind, we can manage the welding challenges that hydrogen infrastructures bring to the table. Identify and develop new assessment methodologies of hydrogen induced damage at microstructure level either for pipe girth welds and pipe material. Some of our work includes providing welds using our latest welding strategy to keep control of the hardness level. Our secret recipe of successful welding of hydrogen application pipeline and piping evolved from our experience of sour and severe sour service projects.

Below you can see some elements we have worked on to validate our findings.

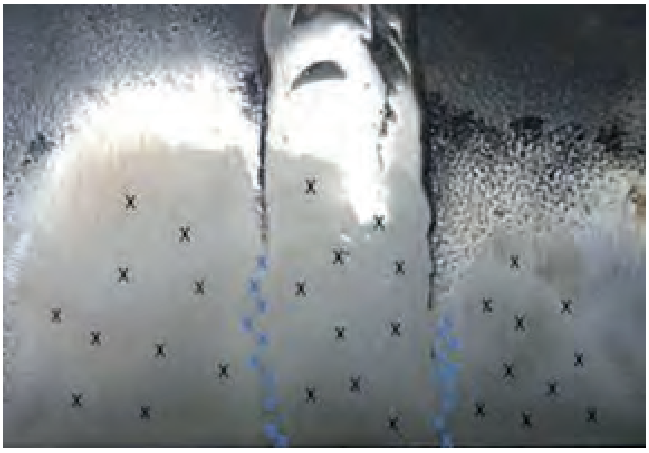


Figure 1. H_2 embrittlement challenges.

Figure 2. Saturnax 01 mechanised welding in action.

Risk: H2 embrittlement

Main drivers

- Pipe material and weldability.
- Filler metal.
- Residual stress.
- Modelling capability.

To reduce the residual stress induced by welding, Serimax applied a narrow gap bevel for its mechanised welding strategy for hydrogen pipelines. This allows also to improve the welding productivity compared to manual welding while resulting in the best quality joints.

Our track record of sour and severe sour service projects validates the filler metal used by Serimax is acceptable. For sour service project the weld is tested under H_2S environment to demonstrate its resistance to hydrogen sulfide stress cracking. During this test, the weld is also exposed to H_2 embrittlement phenomena thanks to H_2S pressure (up to 16 bars during testing) and H_2 diffusion into the weld structure, allowing to validate that Serimax filler metal is compliant (supply according to our particular purchase specification).

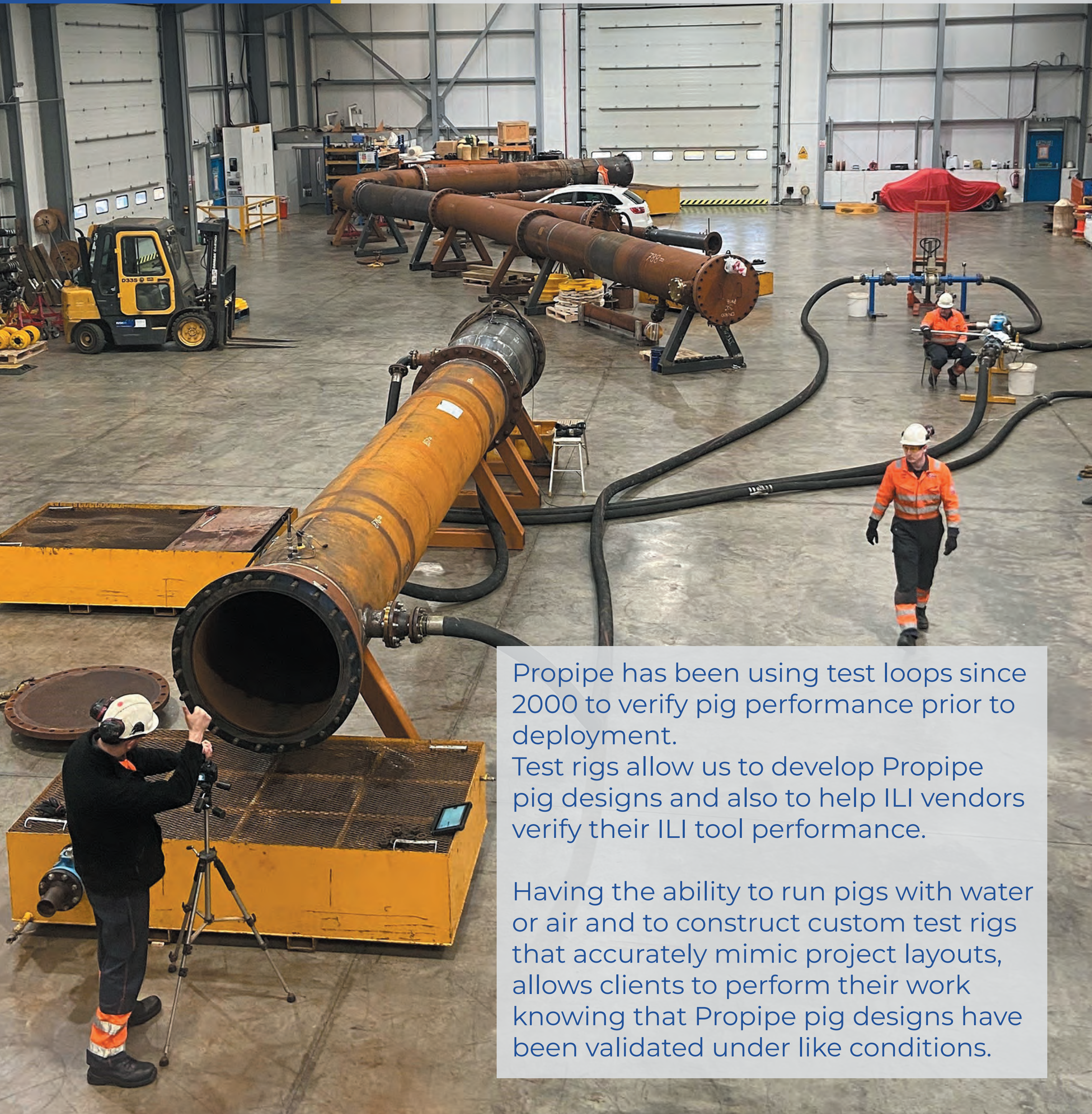
Risk: Root pass internally coated compliant (for hydrogen pipeline projects requiring internal field joint coating)

Main drivers

- Root pass profile and regularity.

PROPIPE
PIGGINGSMARTER

PIGGABILITY TESTING AND VERIFICATION



Propipe has been using test loops since 2000 to verify pig performance prior to deployment.
Test rigs allow us to develop Propipe pig designs and also to help ILI vendors verify their ILI tool performance.

Having the ability to run pigs with water or air and to construct custom test rigs that accurately mimic project layouts, allows clients to perform their work knowing that Propipe pig designs have been validated under like conditions.

Propipe Limited - www.piggingsmarter.com

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Tel: +44 1429 872927
Email: groupsales@propipe.co.uk

For North American Sales
Tel: +1 902 417 5075
Email: sales@propipenorthamerica.com

Serimax track record on internal coated welds (over 100 000 welds with internal coating already done in production) allow us to confirm the capability of our welding strategy to meet the specific requirements associated with this configuration.

"Our welding strategy of using mechanised GMAW-controlled short circuit (STT) combined with GMAW constant voltage process is field-proven, demonstrating its compatibility with stringent hardness requirements (welding strategy used for H_2S projects)."

Discover

As with all bricks in the energy transition, we need to work together to make this happen fast and as we work together, we can discover the benefits and how each solution fits together. Welding tends to be a last-minute decision, however with welding partners onboard from the off, the right decisions can be made in terms of material selection, welding processes... and project deadlines can be met. With our proven track-record we manage the welding for such projects, making projects run smoothly and removing any setbacks.

- Material selection: Choosing and using materials that meet strict quality and safety standards. With our extensive track record, we can help select the best jointing/material combination.
- Weldability testing: Testing at Serimax Welding Technology Centre provides project pipe weldability testing using operational welding procedures to ensure required performance.
- Welding processes: Selecting the right welding process for your chosen pipe material and applicable specifications for the best performance in H_2 environments.
- Mechanised welding: Welding with Serimax easy-to-use machines ensure robust, repeatable welds, to achieve full pipeline integrity.
- Internal inspection: Inspecting and measuring the internal weld and fit-up alignment is key to managing the Hi-Lo and internal weld profile; promoting firing line efficiency.
- Data monitoring: Documenting all welding data during and after the project; CleverWeld, Serimax data tracking solution is your ally to ensure long term integrity.

Deliver

Delivering implies big things, and investing for investing sake isn't key to project success. By using solutions that are field-proven and ready to deploy the process becomes robust and repeatable, meaning increased productivity. Welding pipelines for hydrogen demands a comprehensive approach encompassing material selection, welding techniques, safety protocols, and stringent quality control measures to uphold the reliability and safety of the entire pipeline system. The integrity of welds in hydrogen pipelines is key to prevent potential leaks and ensure operational safety. Given the susceptibility of pipelines to hydrogen-induced embrittlement, the selection of welding processes and materials assumes critical significance. Which is why working with a welding partner having relevant experience and expertise to ensure the integrity of welds is crucial to meeting stringent quality and safety standards but to also get the job done, right first time and to deliver the job.

Leveraging our expertise to weld sour and extreme sour service pipelines whether it's onshore or offshore, we understand the intricacies required to guarantee reliability and integrity.

- Mechanical properties required for H_2 pipelines are very similar to H_2S sour/severe sour projects (i.e. hardness requirements).
- Strong Serimax track records on oil and gas H_2S service project with proven welding strategies.
- Continuous improvement on-going through our involvement in EU/International R&D programmes.
- Welding procedure and equipment H_2 ready for operation using pipes with internal coating.
- Pipe being a key component of the process control, pipe weldability for H_2 project is a must. The alloying strategy used shall be validated based on project requirements to ensure good HAZ behaviour.

We have been working in our R&D centre in Paris to deliver advanced welding solutions for hydrogen pipelines and support this new era of hydrogen as a low-carbon energy source. Even if a most suitable welding strategy is developed during welding procedure qualification stages, it is paramount to ensure its repeatability on the field, hence the need to organise and design the welding spread means adequately to warrant that all preset conditions are met allowing reaching that compliance goal (mechanical properties):

- Mechanised welding shall be used to reduce the human factor impact on final result.
- Full monitoring and traceability shall be applied at each production steps.

Serimax mechanised welding equipment integrates dedicated monitoring software that controls and records welding parameters impacting the weld mechanical properties. With cutting-edge welding tools and software, our highly qualified staff manage the welding and its documentation (via CleverWeld) in its entirety, enhancing project productivity while prioritising safety. Addressing all these challenges requires a collaborative effort across industries, governments, and research institutions to drive innovation, standardise practices, and build the necessary infrastructure for a sustainable hydrogen economy.

Hydrogen networks are an important requirement for the successful implementation of a secure and resilient hydrogen economy for the UK. Lewis Anderson, Head of Transformational Projects at Luxfer Gas Cylinders, looks at the role of virtual pipeline solutions in boosting hydrogen adoption.

VIRTUAL GAS PIPELINES: MOVING HYDROGEN TO WHERE IT'S NEEDED

The hydrogen sector in the UK is estimated to unlock over 12 000 jobs and up to £11 billion of investment by 2030. To deliver this thriving hydrogen economy and capitalise on the potential economic benefits it presents, industry must continue to invest in innovation across the production, distribution and consumption of hydrogen.

As positive and tangible progress continues to be made, the hydrogen landscape is shifting at pace. However, there are several barriers to widespread hydrogen adoption. Innovation is critical to overcoming these challenges, and to establishing the UK as a leader across the full hydrogen value chain.

Addressing the need for infrastructure

The widespread uptake of hydrogen is hinged on the development of fuelling infrastructure. The good news is that 27 GW of potential hydrogen projects have been identified in the UK alone, but continued efforts are required to create a comprehensive and accessible hydrogen infrastructure.

An area of great consideration is repurposing the UK gas network to transport hydrogen from where it is produced to where it is needed. The country has a world-leading gas network with around 300 000 km of gas pipes – enough to go around the world seven times.

Studies have shown that equipping the gas grid to transport hydrogen can be a low disruption, cost-effective way to deliver hydrogen to large scale storage and other end users including industry, transport and power. Of course, around 22 million homes and commercial properties, equivalent to approximately 23% of the UK's total energy bill, are already connected to the grid.

However, while pipeline transportation of hydrogen will undoubtedly form part of the country's long-term infrastructure, it requires a significant capital investment, takes time to build, and is limited in coverage. Additionally, according to a report by the Committee on Climate Change, the UK's hydrogen pipeline network won't fully serve industrial clusters until after 2030.[1] This is due to several factors, including the need for significant investment in pipeline infrastructure and regulatory hurdles.

Where no gas networks exist, bulk gas transportation systems (BGT) offer a solution as 'virtual gas pipelines', which can help connect the dots between hydrogen production and consumption by bridging the gap between the point of production and the point of use.

Innovation in hydrogen storage solutions

Virtual gas pipelines offer ease of deployment and the ability to reach the full range of locations where hydrogen is needed in a scalable way. Crucially, they offer a stepping stone until dedicated pipeline infrastructure is established and can provide either temporary or permanent solutions to delivery or capacity difficulties, such as ongoing access to users not connected to a pipeline.

A range of solutions have been investigated over the past two decades. Gas storage experts, such as Luxfer Gas Cylinders, have been exploring hydrogen as an alternative fuel for a significant period of time, building designs based upon compressed natural gas systems launched at the turn of the century. That's important because while the hydrogen economy may be in its infancy, the engineering know-how driving it is not.

Figure 1. Lewis Anderson, Head of Transformational Projects at Luxfer Gas Cylinders.

Moving vast quantities of hydrogen

Innovation has been led by forecasted demand for hydrogen across different sectors, industries and markets, which varies greatly.

Multiple Element Gas Containers (MEGCs) are designed specifically to meet the needs of large-scale requirements for hydrogen, allowing over 1 t of the gas to be safely stored and transported.

Available from Luxfer Gas Cylinders in 20 ft and 40 ft units, MEGCs will help extend access to the clean gas as the hydrogen economy continues to gather pace. By offering maximum capacity and energy delivery, they provide the best price per kilogram of hydrogen. Cost of ownership of these units is important, as well as operational considerations, such as the distance between source of hydrogen and intended destination. There are many moving parts, and scenario planning is crucial to best predict what operators will need.

Modular hydrogen storage solutions

Modular solutions play a vital role in driving adoption of hydrogen fuel. Systems comprising interconnected, stacked cylinders, known as multiple cylinder packages (MCPs), can store gas in a smaller footprint compared to other available options.

A practical and efficient storage solution, MCPs are used where hydrogen is required to be fed at a regular flowrate and pressure without any interruption. They reduce the need to manage cylinder stocks and eliminate time lost in cylinder changeover and handling, as well as gas wastage.

These cylinder packages come into their own for mobility and portability – they can generally be seamlessly slotted into an existing structure and onto trucks and trailers – enabling hydrogen to be transported via trucks, ships, or rail to different locations.

The technology especially suits marine applications, construction vehicles, running generators or even to fill test vehicles where a refueller or large storage may be deemed too costly for the small amount of gas required to check a fuel cell is working correctly.

Bulk gas transport: a global perspective

Around the globe, there continues to be a focus on the upstream development of hydrogen production sites and downstream advancements in industrial use cases of hydrogen. While there are plans for a great number of projects – the global industry had announced 1418 clean hydrogen projects as of October last year – many infrastructure initiatives and network expansion plans are still in the development phase.

As midstream infrastructure has not received as much attention, the question of how to safely and efficiently transport and store hydrogen to reach the businesses and operators that need it, is a global concern.

According to estimates, as of the end of January 2023, a total of 170 hydrogen projects had been announced in North America, accounting for approximately 15% of total announced projects globally. Some 135 of these are aiming to be fully or partially commissioned by 2030, representing US$46 billion of committed direct investment in hydrogen value chains.

While the European market is seeing demand for MEGCs, there is a focus on smaller capacity pods in the US as it has ample production resources, including over 1600 miles of hydrogen pipelines, three caverns that can store thousands of tons of product, as well as eight liquefaction plants spread nationwide.

Additionally, the US has announced a Regional Clean Hydrogen Hubs programme. It is expected to design and implement demand-side support mechanisms for unlocking the market potential of several hubs, laying the foundation for broader private sector off-take and by creating networks of hydrogen producers and consumers.

The role of cylinder technology

Another crucial consideration is how hydrogen is stored. Here, cylinder choice plays a significant role, with Type 3 and Type 4 cylinders the most commonly used. Each has different core benefits, with product selection based upon the application and the brief.

Type 3 aluminium lined cylinders are robust, faster filling due to heat dissipation and are non-permeable, which means they have been a preferred choice of pioneers and OEMs for many years. Plastic lined Type 4 cylinders deliver high storage volumes while remaining lightweight, offering a cost-effective hydrogen storage solution ideal for long range rail, boats and other vehicles.

Each has its merits based on application and what is most critical to users' operations – Type 3 cylinders are heavier, but Type 4 cylinders often require hydrogen to be chilled before filling as the heat produced in a fast-fill system can affect the polymer liner.

Figure 2. MCPs can store gas in a smaller footprint compared to other available options.

A safe, regulated solution

High-pressure hydrogen cylinders are designed to meet strict performance requirements and are tested against relevant regulations and engineering standards. It is vital that hydrogen gas cylinders undergo a stringent testing regime, including extreme temperature testing, drop and impact testing, gunfire testing, fatigue cycle, and burst testing.

Across mobility applications, there is currently also an absence of standardised regulations, which poses hurdles for development in the sector. As such, more needs to be done to put codes and standards in place, supported by the necessary guidance and information for all manufacturers to safely build, maintain, and operate hydrogen equipment, systems, and facilities.

Without addressing concerns related to safety, and without clear guidelines and regulations that apply across the entire supply chain, building confidence in hydrogen systems among companies who may be looking to invest in greener, more sustainable solutions will remain a challenge.

The promise for virtual gas pipelines

Ultimately, for the potential of hydrogen to be truly realised, we need better infrastructure. However, it will be a long time before physical pipelines are in place, making virtual gas pipelines critical to linking geographically diverse supply and demand, ensuring that sufficient hydrogen is available when and where it is needed not only in the short and medium terms, but also beyond.

The future of hydrogen transportation will likely involve a combination of physical and virtual pipelines, with each solution utilised to meet different needs across the supply chain. As such, virtual gas pipelines should be seen as a long-term investment which will still be relevant once a physical pipeline is in place, especially in terms of first and final mile delivery.

Recognising the substantial opportunity in virtual gas pipelines, Luxfer Gas Cylinders has invested in an alternative fuel production hub in Nottingham. The new purpose-built facility will see its first MEGC hydrogen solution – the G-Stor® Hydrosphere – hit the road later this year.

As hydrogen continues to gain momentum, the company is proud to be part of a number of groups and membership bodies – it most recently joined East Midlands Hydrogen, the UK's largest inland hydrogen consortium – all working towards the same goal: shaping the future of the hydrogen economy and driving adoption both in the UK and across the globe.

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Getting metrology fit for the hydrogen economy

Menne Schakel, Marcel Workamp, Jacoline Boonman, and Erik Smits, VSL National Metrology Institute, Netherlands, argue that lack of fit-for-purpose hydrogen measurement standards could potentially turn metrology into the bottleneck of the hydrogen economy.

In today's world, annual natural gas consumption stands at about 4000 billion m^3, valued at US$300 billion in 2021. It is gradually being replaced by renewable energy gases, such as green hydrogen produced from decarbonised, renewable energy. Reliable trading of large amounts of hydrogen requires accurate calibration of measurement equipment. This is made possible by accurate measurement standards developed and maintained by national metrology institutes such as VSL. While they are in place for the energy system based on natural gas, a huge effort is needed to ensure appropriate reference measurement standards for the hydrogen economy. As the shift towards a decarbonised economy takes place today, actions for getting metrology fit for the future have to be taken now.

Hydrogen economy

Against the background of decarbonisation of the energy system, dedicated hydrogen gas networks are currently under development in various countries and regions. The European Hydrogen Backbone unites energy infrastructure operators in a mission towards an integrated pan-European hydrogen gas infrastructure. A hydrogen gas network offers noteworthy benefits:

- It offers the highly needed storage capacity for renewable energy produced when wind and solar energy are abundant and cannot be handled by the electricity grid.
- An integrated gas grid enables the transfer of energy efficiently, to places where it is needed and when it is needed.
- Long-haul energy transport can connect regions of production to regions of end-use in similar fashion as liquefied natural gas is currently integrating natural gas infrastructure across the globe.

The hydrogen backbones that are currently under development make use of existing gas grid pipelines, illustrating their projected crucial role in the future energy supply system. In the short-term, mixing of hydrogen with natural gas (hydrogen enriched natural gas: HENG) is already taking place as economies are transitioning towards a fully decarbonised energy system.

Accuracy and fiscal risk

In today's natural gas based energy system, several calibration facilities enable to calibrate large flowmeters used in the transmission of natural gas through the gas network. These facilities are in place to avoid systematic errors of the flowmeters so that financial risk during natural gas trading by pipeline operators is minimised. A systematic error in the flowmeter of 1 % leads to the same impact in the amount of money invoiced. To minimise the impact and to support fair and reliable trade the accuracy of gas flowmeters, measuring the amount of traded gas should be proven by calibration with the actual gas.

Typical achievable calibration uncertainties for the calibration of natural gas flowmeters are listed in Table 1. The primary standard gas flowrates are limited by the nature of the installation. Consequently, calibration uncertainties are higher for larger flowrates as they build up from the primary level. VSL is in possession of a high pressure natural gas flow primary standard which it developed and maintained, using decades of experience, to achieve the lowest uncertainties as indicated in the Table 1. Natural gas transmission system operators require uncertainties at levels indicated in Table 1. A crucial component in achieving the lowest uncertainties is to perform intercomparisons with primary standards of independent, partnering national institutes in Europe. Preferably the partners in intercomparisons have comparable and low uncertainties. The intercomparisons guarantee that the systematic measurement errors lay within the claimed measurement uncertainties of the different institutes.

It is currently not possible to calibrate gas flowmeters measuring hydrogen with ranges and calibration uncertainties as listed in Table 1, since the primary level is lacking. Time is needed to develop metrological standards for the hydrogen economy with similar ranges and calibration uncertainties as is currently in place for the natural gas based energy system. Development efforts have to be undertaken such as developing dedicated hydrogen gas flow standards, performing intercomparisons, and proving validity of calibration results as established over time. Without the hydrogen standards, larger errors of hydrogen gas flowmeters may occur when

Figure 1. VSL's primary standard for the calibration of natural gas flowmeters on the left (see also Table 1), hydrogen cylinder bundle on the right. The primary standard was modified to the use of HENG in addition to natural gas.

Table 1. Typical natural gas flow calibration and measurement capabilities showing the lowest calibration uncertainties for gas flowmeter calibration. The coverage factor $k = 2$ indicates a coverage probability of approximately 95% (as applicable to a normal distribution)

Traceability level	Flowrate m³/h	Pressure range bar(a)	Calibration uncertainty ($k = 2$) %
Primary Standard (VSL)	5 – 200	4 – 64	0.06
Secondary Standard (VSL)	200 - 2000	4 – 64	0.10 – 0.12
Working standards (gas flowmeter calibration facility)	Up to 65 000	4 – 64	0.15 and above

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they measure the amount of transferred hydrogen. For illustrational purposes, a systematic error of 0.5% is taken on the total amount of annually traded natural gas, currently at 900 billion m^3 according to the Energy Institute's latest statistical review of world energy. The corresponding monetary equivalent, taking the natural gas price at €11/mmBtu (about 1 kJ) and setting its heating value at 47 000 Btu/kg, is estimated at €2 billion each year. In a hydrogen economy without suitable metrological standards, such costs may be paid on an annual basis and will eventually be charged to the end-users (consumers) of the hydrogen energy, obviously posing a severe financial risk. A further risk exists that lack of public trust in measured values poses a hurdle to the adoption of clean hydrogen as an alternative to natural gas.

Pan-European hydrogen metrology research

Significant progress in the metrology of hydrogen is made in the European metrology community, in close interaction with industry. A number of European research projects under EURAMET (the European Association of National Metrology Institutes) funding programs, have tackled challenges in hydrogen flow metrology. Significant progress was made:

- Understanding the effects of hydrogen and HENG on the performance (and longevity) of gas flowmeters in varying applications.

- VSL's primary standard for high pressure natural gas flow (the first realisation of the unit "m^3/h") was used successfully, for the first time, with HENG. It resulted in the first calibrations of gas meters with HENG establishing a direct traceability to the SI-unit 'meter' at pressures relevant to the gas grid. This standard will be compared to similar standard(s) across Europe, which is key to ensuring the quality of the provided reference values.

Further development towards a hydrogen primary standard for the calibration of gas grid flowmeters is needed. It is only partly undertaken as part of ongoing metrology research projects. The primary standard is needed to provide a direct link to the SI units of measurement under the conditions in which the gas flowmeter is operating in. Flow calibration facilities for pure hydrogen exist (for domestic gas meter to transmission pipeline gas meter calibration). Their links to the primary level SI units of measurements usually includes assumptions or models to predict a (reference) meter's performance on pure hydrogen while being calibrated with so-called surrogate or alternative gases. With a dedicated hydrogen primary standard, less models and/or assumptions are needed. A gas flowmeter calibration from a dedicated hydrogen primary standard will improve trust in measurements, and bring it to the level of trust as it currently exists for natural gas.

Metrology readiness for the hydrogen economy

VSL – the National Metrology Institute of the Netherlands – is working relentlessly with its partners and the government of the Netherlands, to meet the pressing metrology challenges of the hydrogen economy. The hydrogen economy is already being rolled-out, necessitating action today. Ensuring fit-for-purpose hydrogen measurement standards is a complex task, needing large investments. Measurement standards are serving all stakeholders in industry and the wider society. Without them, calibration facilities can't be made traceable to the SI units of measurement. Pipeline operators need them to minimise their financial risk and make correct invoices. Governments need them for tax purposes. Consumers need them for fair billing. Operators and citizens need them for safe handling of equipment.

Lack of fit-for-purpose hydrogen measurement standards can potentially turn metrology into the bottleneck of the hydrogen economy. Trust in measurement values leads to reliable billing and safe use of hydrogen. Lack of trust can lead to slower adoption of renewable hydrogen than needed for meeting energy transition targets. It can further lead to a larger measurement uncertainty, and concomitant financial risk, than what is technically conceivable. The current situation for LNG can serve as an example. It's significance is evidenced from its share in all globally traded natural gas which currently stands at about 59% according to the Energy Institute's latest statistical review of world energy. VSL's LNG calibration facility led to improved calibration of LNG flowmeters and composition measurement systems from the direct and complete link to the SI units of measurement. This link is established with the LNG primary standards embedded in the calibration facility. Yet, LNG measurements are not as accurate as they could be as the industry is reluctant to make the investments needed to upscale their measurement capabilities. In large LNG transfer systems determination of LNG quantity is typically done through volume measurement of tanks versus usage of calibrated LNG flowmeters. As a result, relatively large measurement uncertainties and concomitant exposure to financial risks are occurring in the day-to-day practice of LNG trading. The resulting costs are eventually paid by the end user, who takes the brunt of bad measurement in the chain.

VSL invites all parties to team up and ensure that large scale hydrogen transport measurement will be made possible within the required accuracies and proven by traceable calibrations as exists for natural gas, today. As stated above, the development of new, fit-for-purpose standards needs time. We need to act today to get metrology fit for the hydrogen economy already being implemented. Without action today, (financial) risk will be carried by the hydrogen pipeline operators tomorrow.

Sealing the future of hydrogen pipelines

Ian Kinnear, GPT Industries, USA, discusses understanding and overcoming the challenges of sealing and protecting hydrogen pipelines.

With every new development, there will always be unknowns and challenges that come along with making the development a reality. When exploring sealing and protecting hydrogen pipelines, GPT Industries has been able to identify many critical, unique challenges that will come along with it. These challenges will need to be addressed to make our systems as safe and known as possible as we progress into more of a hydrogen future. For the focus of GPT, this future is specific to looking into the transportation of hydrogen, specifically through pipelines. This article will delve into the future of hydrogen energy, specifically being transported through pipelines, and then detail the challenges in terms of sealing and protecting these pipelines and some possible solutions to overcome these.

Hydrogen is light, making it easier to transport and work with in general. It is storable, which is a critical factor when considering any form of sustainable energy. When used in a fuel cell, hydrogen is considered energy dense, meaning there is high energy content per unit of weight. Hydrogen produces no direct emissions of pollutants or greenhouse gases when used as an energy source (producing the hydrogen can be a different story). Lastly, hydrogen can be produced from diverse resources, as we know that it is abundant in our universe, meaning that we just need to be able to produce it effectively to form energy in a renewable way. Because of all these reasons, the forecast for hydrogen demand worldwide is exponential over the next 45 years. According to Statista, in 2019 the demand for hydrogen across various sectors was 71 million t. Come 2030 that will be 87.2 million t, 2050 287 million t, and 2070 519.1 million t. This is across the sectors of refining, power, buildings, synfuel production, ammonia production, transportation, and industry.

Future of hydrogen transportation

A critical factor to keeping up with this increasing demand for hydrogen to become an energy source will be the effectiveness of transportation. A huge plus of fossil fuels is that we can transport them extremely efficiently. The way this is most efficiently done is through pipelines. Regarding hydrogen, Energy.gov states that "Key challenges to hydrogen delivery include reducing cost, increasing energy efficiency, maintaining hydrogen purity, and minimising hydrogen leakage." These challenges are directly in line pipelines, which are the most efficient, lowest cost, and lowest emission way to traditionally transport energy sources. Continuing, Energy. gov states "Today, hydrogen is transported from the point of production to the point of use via pipeline and over the road in cryogenic liquid tanker trucks or gaseous tube trailers. Pipelines are deployed in regions with substantial demand (hundreds of tpd) that is expected to remain stable for decades." As seen by the forecast in Figure 1, there is sustainable hydrogen demand in the coming years, meaning that transport through pipelines is a likely means of hydrogen transportation. In addition to this, millions of kilometers of natural gas pipelines are already in place, so the infrastructure for this transportation already exists and can likely be utilised to make this means of transport more effective and efficient. Pipelines will be essential in the process of bringing hydrogen to be a new, reliable energy source, and thus needs to be considered in the process of hydrogen growth.

With this evidence present and movement happening before our eyes, the time to focus on this growth is now. As an industry, however, there are still huge roadblocks in front of us. Testing and regulation on hydrogen pipelines and sealing is very limited. It is always a challenge to have caught up on the regulation side before anything has been put into action. With hydrogen specifically, however, there are both real and perceived implications in terms of danger that must be strongly considered. The perceived dangers are based upon real incidents, such as the Hindenburg, that have highlighted the power hydrogen can produce. In the transportation of hydrogen, there is no leeway for something to go wrong.

Sealing hydrogen in pipelines is going to bring unique challenges that must be addressed and done so in a way that brings confidence, even before regulations have been set for hydrogen transportation. In working through many sealing applications, GPT has identified these challenges to sealing and protecting hydrogen pipelines specifically. Some of these are similar to what is faced in the traditional oil and gas markets, but some are very unique and new to be accounted for with hydrogen. Each of these challenges will be explained further throughout this paper. The first challenge to discuss is sealing capabilities, as hydrogen is incredibly difficult to seal. Next are the challenges that come from permeation, uniquely emphasised by hydrogen. Next is hydrogen's propensity for ignition, potentially leading to fire and explosion, a reason why there is danger with utilising hydrogen. Chemical compatibly is also a challenge, as we need to ensure the correct materials are being used for long term success. All of these are in combination at the same time as well, meaning solutions must check all the boxes to provide the safety required for these applications.

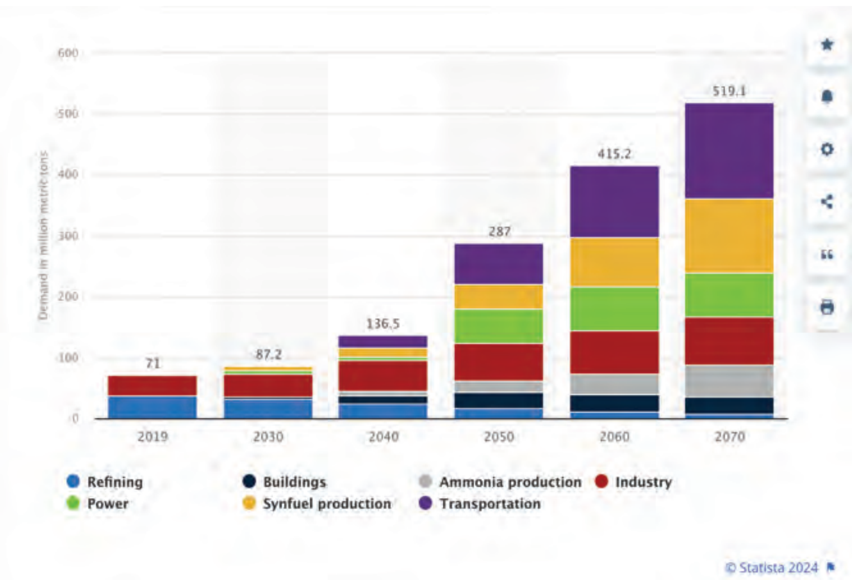

Figure 1. **Global demand for hydrogen by sector to 2070. (Aizarani, J. (2023, February 17). Statista. Retrieved 4 May 2023, from https://www.statista.com/statistics/760001/global-hydrogen-demand-by-sector-sustainable-scenario/)**

Main challenges of sealing hydrogen pipelines

Looking at the challenges around sealing capabilities, hydrogen has a much higher propensity to leak than traditional medias, especially the ones that the oil and gas industry traditionally deal with. The reason for this is because hydrogen uniquely provides low viscosity, very high diffusivity, a high likelihood of embrittlement (more on this later), all because it is the smallest molecule gas. When attempting to seal the smallest molecule gas, the margin for error will be at the lowest point. To understand this further, we can look at the diffusion coefficient of various common sealing materials when comparing methane and hydrogen to give further perspective. This coefficient is essentially how easily the media will move from a high concentration region to a low concentration region, something that cannot happen when achieving a seal. Through FKM Type 1 and traditional PTFE, two of the most common sealing materials, the diffusion coefficient for methane is 1.4 for FKM Type 1 and 1.7 for PTFE. When comparing this to hydrogen, the diffusion coefficient for FKM Type 1 goes to 14.1 and for PTFE goes to 11.3. This is a 907% increase in diffusion coefficient of hydrogen going through FKM Type 1 instead of methane, and a 565% increase for PTFE. As a pinch test, it is obvious that sealing a small molecule is going to be more challenging than larger molecules, but this is evidence for how traditional sealing materials will fare in this regard. The actual act of sealing the hydrogen media in pipeline connections will be a challenge in the future transport of hydrogen.

Permeation is the next major challenge specific to hydrogen. Speaking again on the point that hydrogen is the smallest molecule gas, this leads to it being able to permeate into and through materials much more frequently. In the world of sealing, permeation can lead to two major challenges. The first is that permeation can lead to a direct leak through the material itself, so that even if a proper seal is made, leaks are still occurring through the material. This is very similar to the diffusion coefficients that were recently shared, as diffusion and permeation are closely related. In traditional pipeline sealing, leaks due to permeation are already experienced, which is why metal cores have needed to be introduced to traditional isolation gaskets. This permeation leads to higher levels of emissions taking place, especially when dealing with hydrogen in the pipeline. Sealing materials that are not permeable will be critical, which typically leads to metals being used. However, metals can be challenging because of the next permeability point, which is the likelihood of embrittlement.

When hydrogen permeates into a metal, it can cause embrittlement, or the decrease of ductility of the material. The typical forms that this occurs from hydrogen are mechanical stress cracking, hydrogen included cracking, stress-oriented hydrogen induced cracking, and high temperature hydrogen damage. Diffuse hydrogen atoms can enter a metal's surface and then combine within causing cracking and brittleness within the metal. Embrittlement will most likely happen within metals and are more susceptible in some metals than others. The rub lies in that metallic seals are more likely to be used to avoid emissions from permeation through the material and diffusion through elastomers. However, these metals are now susceptible to embrittlement, where hydrogen is absorbed by the metal, reducing its yield strength, and leading to premature failure. Finding materials that can hold up to both permeation impacts is a challenge.

Figure 2. GPT's Evolution gasket.

The next challenge from transportation of hydrogen in pipelines is hydrogen's propensity for ignition, which can lead to fire and explosion. The reason that hydrogen provides such a concern in terms of fire and explosion is because of its very wide flammability range, making ignition or combustion easier. This is combined with a very low ignition energy and the possibility of spontaneous ignition. If this occurs, hydrogen can also burn with an invisible flame, making it even more dangerous. This leads to the need for a fire safe seal. With a pipeline full of hydrogen travelling through it, if an external fire happens to occur and the seals fail, hydrogen will begin leaking onto an already existing fire, which can lead to a very dangerous situation. A seal that can hold up in a fire for long enough time for the fire to either be extinguished or for the line to be shut off is essential for safety concerns when transporting hydrogen.

The production of hydrogen can come from various sources, highlighted by the different types of hydrogen, such as grey, blue, green, etc. With these various types of hydrogen production, there is the potential for hydrogen applications to provide various challenging medias in the process, leading for the sealing materials to be chemically compatible throughout. Hydrogen itself can be a challenging media when exposed in soak testing for various seal materials, as it can lower the material properties of many elastomers. Along with this, there are times where other medias such as CO_2, amines, steam, H_2S, ammonia, and others can be present in the process. These medias can cause major challenges with traditional sealing materials, whether they be metals, elastomers, sheet materials, or anything else that is used as a gasket.

Potential solution for sealing hydrogen pipelines

With all these challenges laid out, it becomes very challenging to find a seal that can meet all the criteria required. GPT Industries however feels that its Evolution gasket is created fit for purpose for hydrogen applications and can overcome the challenges that hydrogen transportation brings from a sealing perspective. Evolution utilises a metal core, so there is no permeable material for hydrogen to leak through and cause emissions. With this being said, there is also no exposed metal, as the gasket is completely encapsulated with coating, and the sealing occurs directly at the ID with a reinforced PTFE ID seal, leading to embrittlement also not being a concern. Evolution is a low emission sealing gasket, due to its two-seal, one metallic, one elastomeric design, which provides levels of sealing redundancy. This is shown in testing such as Shell Tightness Class A or Chevron Fugitive Emissions testing of only allowing 1 PPmv leakage. Much of this testing is done with small molecule gas, showing that Evolution will be the low emission seal needed for hydrogen. It is also inherently fire safe, passing multiple sizes and pressure classes of the API 6FB fire test. The reinforced PTFE ID seal provides chemical compatibility towards all medias discussed, with seal options that have been BAM testing in hydrogen storage, in both liquid and gas forms. This is the seal that is set to be the future of hydrogen transportation, providing the highest level of safety by checking all the necessary boxes. The future of energy will have hydrogen being high importance, and GPT is here to help.

Act now on gas emissions

Mark Naples, Umicore Coatings Services, UK, outlines how investment in gas detection can propel your success.

As the global demand for energy grows, the oil and gas industry needs to step up its record on gas detection.

The developing international economy has prompted a rise in energy consumption. In 2023, the world's electricity requirements grew by 2.2%, and this is expected to rise even faster to 2026 as demand from data centres and artificial intelligence expands.[1]

Despite the ongoing action towards cleaner energy sources, the oil and gas industry will continue to play an essential role in this landscape. Oil and gas suppliers have a duty to ensure that fuel supplies remain reliable and affordable, providing energy security to a world that is still dealing with ongoing international disruption.

However, this escalating requirement for energy presents a challenge. Growing public awareness of the

sector's environmental impact is increasing the urgency for oil and gas operations to get on top of their emissions problem. With the energy sector contributing approximately 40% of anthropogenic methane emissions – as well numerous other harmful gases – operators are under pressure to demonstrate real change if they are to continue supplying society's growing power requirements.

At the same time, although the environment is a critical issue for the oil and gas industry, it is not the only consideration. Worker safety, infrastructure maintenance, and financial competitiveness are all important concerns that must be managed as energy demands increase, and these all have one thing in common – they again rely on reducing emissions and minimising gas leak occurrence.

Rather than being seen as part of the emissions problem, energy operators have the chance to become instrumental in solving it. Achieving this will not be straightforward; advances in gas detection technology at last mean that change is within arm's reach. Investing in a comprehensive gas detection solution can help the energy sector make a real difference to some of the biggest challenges facing them today, and what is more, this solution could pay for itself.

Environmental issues

It is impossible to discuss gas detection in the energy sector without touching on the subject of emissions.

Greenhouse gas emissions are a perennial factor in the production, storage, transportation, and use of oil and gas. Substances like methane and carbon dioxide are common byproducts of these processes, and possess significant global warming potential, with methane in particular noted for its lasting impact on the climate. Oil and gas operations are responsible for around 15% of all energy-related emissions, equivalent to 5.1 billion t of CO_2e in 2022, and the international pressure from regulators demanding action is growing.[2]

Gas detection systems present a viable solution for addressing this problem. One of the main barriers to effective action on emissions in the energy sector is the lack of clear data as to the problem's true extent. Many oil and gas operators base their emissions estimates on factor-based computer modelling, but these often significantly under-estimate the true extent of the problem. According to the International Energy Agency (IEA), current annual methane emissions from oil and gas operations around 84 million t, but the figures reported to national governments by the UN Framework Convention on Climate Change (UNFCCC) are around half this amount.[3]

Improving the data that businesses hold on the extent of gas emissions and where precisely they are occurring is the first step towards addressing this problem. A clearer understanding of gas emissions enables maintenance procedures to be targeted at areas of greatest need, quickly repairing any leaks and even facilitating preventative maintenance to prevent leaks occurring in the first place. If oil and gas operators want to demonstrate a commitment to reducing their environmental impact, investing in gas detection technology should be their first consideration.

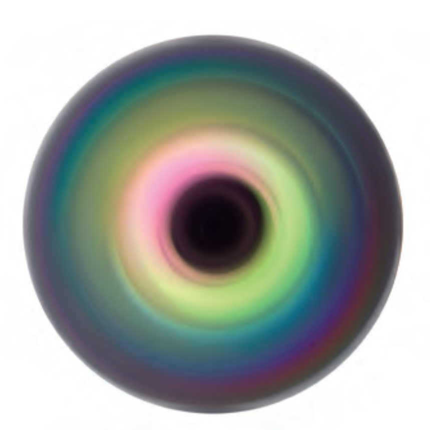

Figure 1. By exploiting the unique spectral features of each gas compound, IR sensors can accurately identify chemical species.

Detecting for safety

It may sound obvious, but gas leaks and build-up can present a serious threat to safety in this sector. Extraction, production, and transportation of fossil fuel produces comes with the risk of exposing workers to hazardous substances such as hydrogen sulphide, benzene, ammonia, or nitrates. Such exposure has been linked to long-term health conditions such as lung cancer, and sufficiently severe cases can result in death. Oxygen deficiency presents another threat, not to mention the explosive risk that can emerge when certain gases accumulate in high concentrations. Employee safety is not the only thing threatened by emissions – gas leaks can also cause critical damage to important equipment. For example, hydrogen sulphide is highly corrosive and may cause damage to infrastructure over prolonged exposure.

It is not enough to rely on human senses to identify when a threat to safety occurs. Although certain gases are detectable by smell, others can become impossible to notice at higher concentrations as exposure causes olfactory fatigue in employees, otherwise known as 'nose blindness'.

This threat reinforces the importance of a robust gas detection network. Today's technology can identify gases even at concentrations where human beings cannot, issuing immediate alerts to ensure safety. Installing fixed detectors in high-risk areas, and equipping employees with wearable gas detection technology when operating in confined spaces close to potential leak hazards, will provide early notification and ensure that any emerging problem is identified as soon as possible.

Financial benefits

Alongside environmental and safety benefits, investing in gas detection technology also has solid financial incentives for energy operators by helping them capture and sell a product that is otherwise being wasted.

For example, in the oil and gas sector, vast quantities of methane are released into the atmosphere through flaring and venting, alongside any that escapes from unintended leaks. Some estimates suggest that approximately 260 billion m^3 of methane vanish from oil and gas operations each year due to leaks or other unexplained activity.[4] Gas detection technology would enable most of this to be recaptured – potentially as much as 75% – and sold for profit.

The IEA believes that around 50% of all methane emissions from the oil and gas sector could be avoided at no additional cost to businesses because the cost of abatement measures is less than the value of the additional methane gas that could be sold. Although

inadequate infrastructure or institutional arrangements may complicate this process for some companies, meaning it may not be viable everywhere, it still represents a potential untapped value stream that should at least be examined.

Tracking progress

Given the myriad ways in which gas emissions can occur in the energy sector, there is a wide range of detection technologies available, all of which are best suited for specific circumstances.

Satellite monitoring technologies are one of the most advanced solutions being used in emissions detection. Last year, researchers used satellite technology to identify the largest methane leak ever recorded, spilling an estimated 127 000 t of the gas during a six month period. This plume was detected due to the use of short-wave infrared sensing an artificial intelligence, which can be used together to easily identify methane leaks in the atmosphere by their unique spectral fingerprint. This detection led to the company responsible being fined the equivalent of US$774 000.

However, although satellite monitoring technology is powerful, it is not always practical for everyday use, especially in smaller scale operations. Large single leaks such as the example above represent a major source of emissions and targeting them will go a long way towards addressing this problem. However, they only form a small element of the wider emissions picture. Often, smaller ongoing leaks and cumulative emissions from ongoing operations can be more significant, with everyday energy sector practices contributing the equivalent amount of emissions each day as some of the largest leaks on record.[5]

Instead, satellite detection is better served as one tool in the energy sector's arsenal. Drone technology offers another, smaller scale solution – sensor-equipped drones are increasingly being used for inspecting critical energy infrastructure in remote locations, as outfitting them with multispectral sensors enables gas detection in remote or otherwise hard to reach locations. The market for this technology is predicted to grow at a CAGR of 6.1% over the next 10 years to a value of US$7.8 billion.[6]

Fixed and portable gas detectors can also play a crucial role in an emissions detection strategy. Both systems have their own advantages and disadvantages. Fixed detectors offer continuous monitoring in their surrounding environment, whereas portable devices provide flexibility at the cost of 'always on' protection. However, equipping every employee with a portable detector is a time-consuming challenge that relies on employee adherence to be effective. These technologies will provide the greatest benefits when used in concert, and thanks to advances in infrared (IR) sensing capability, they are becoming more powerful than ever.

Infrared gas detection

The introduction of IR capability into gas sensors marks a major milestone for this sector. By making gas detection devices more powerful and reliable, this technology means there is now little excuse for not tracking emissions in oil and gas operations.

IR detectors are designed to continuously monitor for potential hazardous materials. Such devices can detect a wide range of potentially toxic or flammable gases and are instrumental to ensuring safety throughout energy operations. If the sensor detects the presence of gas, it triggers an alarm to alert workers and enable any required emergency procedures. Such technology can be connected to form a network of real-time insights into gas levels across a business's infrastructure. This ensures ready access to information on gas concentrations, instantly notifying businesses of potential leaks to help avoid dangerous events.

At the heart of IR devices sits optical laser technology. By passing an IR laser through the gas sample of interest to a detector, operators can quickly and reliably determine gas concentrations in the air with high degrees of sensitivity. This technology is based on monitoring the changes between the incident laser beam the light that reaches the sensor. Comparing the beam that passes through the sample to a reference beam will show portions of the incident beam have been absorbed. Because each gas has a unique absorption profile, this produces a unique chemical fingerprint that laser sensors can use to identify which gas is present. Methane, carbon dioxide, and other hydrocarbons all strongly absorb IR light, making it easy for these devices to demonstrate the required sensitivity – often in the range of parts per billion.

Using IR light has the additional advantage of exploiting the many spectral lines that characterise the profiles of these gases. This means multiple features within the spectra can be used to accurately chemical species, providing gas analysis sensors with a wealth of useful information.

As a specialist in IR filter and coating solutions, Umicore has seen the developments being made in gas detection technology first hand and works closely with customers to develop custom IR designs that balance performance and efficiency in equal measure. As a result, the company can offer a selection of bandpass optical filters idea for gas detection and analysis applications. These filters are central to IR laser absorption spectroscopy-based sensors, and Umicore's expertise in coating production results in the exceptional spectral performance required for IR sensing applications.

From lagging to leading

The oil and gas sector has not always had a stalwart reputation when it comes to emissions tracking. However, advances being made in IR gas detection technology mean that turning this around is becoming easier than ever. With the breadth of technologies available today, businesses can access monitoring equipment suitable for use in almost all locations, with varying degrees of cost, sensitivity, and performance.

Acting now on gas will have significant short- and long-term benefits for energy operators. From reducing greenhouse gas emissions, to protecting employees from harm, investing in gas detection devices will reduce the harm that this sector causes, while improving the international understanding of how severe emissions are. Only with this understanding will businesses position themselves to protect their people, benefit their bottom lines, and safeguard the planet.

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EVERY SECOND COUNTS

3t Training Services details its blended approach to emergency response training for pipeline incidents, helping industry prepare for the worst-case scenarios.

Imagine the scenario – you're working on an oil and gas pipeline in a remote location in the middle of nowhere when fire breaks out. Terrifying and potentially deadly. Would you know what to do?

Emergency response training is not just a tick-box exercise, it's a vital investment in safety, environmental protection and efficient crisis management. According to data from the Pipeline and Hazardous Materials Safety Administration in the US, between 1986 and 2013 there were nearly 8000 pipeline incidents, resulting in more than 500 deaths, more than 2300 injuries and nearly US$7 billion in damage. These statistics show that explosions and fires across oil and gas pipeline infrastructures lead to devastating consequences, such as the loss of human life, destruction of homes and property, and damage to the surrounding environment.

For example, in January 2019, the illegal tapping of an oil pipeline in the town of Tiahuelilpan, in Hidalgo, Mexico caused an explosion killing at least 137 people and injuring dozens more. The blast was particularly deadly because of the large crowds who had gathered to fill containers with the leaking gasoline.

Another high-profile gas pipeline incident went viral on social media in 2021 after video footage of a pipeline rupture emerged showing an 'eye of fire' on the ocean's surface in the Gulf of Mexico. This incident highlighted safety concerns around the thousands of miles of oil and gas infrastructure that exist in that area.

Although rare, these types of incidents can be reduced with safety measures such as technical insulation systems which protect pipework and regular, ongoing maintenance programmes. However, if an incident does occur, prompt and effective emergency response can limit the consequences.

A UK leading energy training provider, 3t Training Services (formerly known as AIS Survivex) recently opened its third

emergency response training centre in the UK. The County Durham-based centre in Northern England is a joint venture between 3t and Vital Fire Solutions, the trading arm of County Durham and Darlington Fire and Rescue Service (CDDFRS), following six-figure investment. The state-of-the-art centre replicates all the structures found on an offshore installation, including a full-size helideck, and helicopter simulator and extensive network of pipework. It was recently accredited by OPITO and is now able to offer all the emergency response courses required for the oil and gas industry.

Offshore emergency response is a mandatory requirement for offshore installations, with these structures requiring a minimum number of crew members to be trained in secondary roles as emergency firefighters to deal with potential emergencies onsite. Emma Howorth, General Manager for England at 3t Training Services, said: "We are delighted to receive OPITO approval for our Bowburn site in County Durham and would like to thank everyone for all their hard work in making this happen.

"This is 3t's third emergency response training facility in the UK and our second in North East England adding to our locations in Aberdeen and Newcastle Airport. We are focussed on bringing increased choice and more locations to our clients and this centre delivers just that. It is extremely convenient for the many offshore workers and companies in the Tees Valley and County Durham areas, who can now train much closer to home, as well as perfectly complementing our new Teesside Training Centre in Middlesbrough. Essentially any course you need for offshore emergency response, we can offer it.

"As well as being key to safety, emergency response certificates are highly desirable for employers in the oil and gas sector, and can complement any offshore worker's CV. This facility provides a valuable resource for the region and will no doubt attract people to the area from much further afield."

Figure 1. Offshore emergency response training.

Figure 1. Emma Howorth, General Manager 3t Training Services England and Rob Cherrie, Director, County Durham and Darlington Fire and Rescue Service – joined by three offshore fire and rescue expert instructors.

Realistic emergency response training – the only way to prepare workers for the worst

In emergencies, every second counts. Trained personnel can quickly assess the situation, activate emergency protocols and coordinate with the emergency responders.

It's easy to see why it's so important that teams can be self-sufficient. After all, when you are miles from anywhere, in a remote location, you can't just call on your local professional firefighting team to come and help. You need to have someone on hand with the right skills and a calm head to tackle the flames.

Only realistic training can prepare you for the genuine experience. 3t's emergency response training facilities are so realistic they feel like a live emergency call. As well as a ten-metre-tall PUMA helicopter simulator, which provides realistic simulated helideck fire-fighting scenarios, there are purpose-built facilities and pipelines to represent typical oil and gas infrastructure and assets. Within these facilities, delegates experience the heat and smoke conditions of a real offshore or oil and gas pipeline fire.

For some of 3t's bespoke courses, delegates are put on standby as if working on an actual oil and gas asset and are then called over a Tannoy system and briefed on a simulated incident in real time. The adrenalin starts running straight away and some people are physically shaking with nerves. They'll be sent into an area which is filled with smoke and extremely hot – upwards of 200 °C to 300 °C.

It feels real. The heat and the smoke make it impossible and uncomfortable to see. Course delegates are very much reliant to their sense of touch, so part of the training instils a sense of confidence in the PPE equipment they are using, specialist firefighters' techniques and the right procedure to follow. The breathing apparatus has a working time of around 36 minutes so the fire must be extinguished before that runs out adding to the pressure.

At the end of the course the difference in people can be astonishing. Even those who are extremely nervous and unsure of what to do in an emergency situation become confident and familiar with the equipment and techniques. Rare oil and gas fires, when they do occur, can be ferocious and are often in difficult to access areas such as confined spaces and pipework valves. Having experienced fire training that's as close to the real experience as it gets, oil and gas workers are well prepared for the firefighting task.

Virtual reality advances

In addition to practical face-to-face training, the growing use of virtual reality (VR) software in the oil and gas industry is playing a huge part in making training feel real and helping to improve personnel effectiveness when facing extreme situations.

VR technology such as the creation of digital twins is becoming more commonplace. A digital twin, in essence, is a digital representation of a physical object, room, or work site.

From a single space to a building, pipework infrastructure, FPSO vessel or an entire site – even Chernobyl – anything can be developed into a digital twin. There are no limitations. As well as a physical entity, digital twin technology can replicate your worksite procedures by using advanced analytical, monitoring, and predictive capabilities, test processes and services. This means a limitless range of scenarios can be developed to train and test your workers before they enter a live working environment.

To make its emergency response training more engaging, immersive and informative, 3t's digital team created a virtual reality digital twin of the emergency response training ground at 3t Training Services' Aberdeen site, including helideck and accommodation quarters.

As delegates await their practical training exercises, they are provided with an orienteering session via the digital twin to familiarise them with what to expect in their upcoming training, as well as a relevant emergency scenario to test and underpin knowledge.

This not only fills idle time while delegates wait for their practical training, but the activity enhances the overall delegate training experience at 3t and receives overwhelmingly positive feedback from delegates.

Emma Howorth, explains: "Making sure our delegates are fully engaged in the training process and will retain the information they receive and skills they learn is imperative. At 3t we have developed a Pre-course, On-course, and Post Course process or 'POP' to ensure every point in a delegate's training journey is the very best it can be. The VR exercise we developed in close conjunction with our digital team on our emergency response courses has significantly improved learner engagement and has helped to enrich the delegate's training experience."

Emergency response skills

OPITO has developed a wide range of skills courses in the area of emergency response. Some of these include: OPITO introduction to control room emergency response.

- OPITO control room operator emergency response competence assessment and coaching.
- OPITO further helideck emergency response team leader.
- OPITO further helideck emergency response team member.
- OPITO helideck emergency response team leader.
- OPITO helideck emergency response team member.
- OPITO offshore emergency response team leader.
- OPITO offshore emergency response team member.
- OPITO offshore emergency response team leader further.
- OPITO offshore emergency response team member further.
- OPITO major emergency management initial response.

Conclusion

Unfortunately, in high-risk industry's such as oil and gas, there will always be a need for emergency response training. Training people through engaging technology and proven techniques helps to ensure any response to a crisis is handled effectively, efficiently and with a cool head, preventing extreme situations from escalating to an even bigger crisis.

SEAL FOR LIFE

INDUSTRIES

A modelling approach for abnormal fracture appearance

Muhammet Sakonder, Offshore Pipeline Engineer, Genesis Energies, USA, writes about investigating abnormal fracture appearance in high-strength pipeline steels during drop weight tear tests.

Abnormal fracture appearance (AFA) in drop weight tear tests (DWTT) is an increasingly significant concern for pipe manufacturers and customers, particularly in next-generation high-strength pipeline steels where the likelihood of such occurrences is high. Investigating and understanding this abnormality from an engineering perspective is essential to mitigate its occurrence, ensure material quality, and guarantee the safe operation of pipeline networks. Specifically, AFA refers to unexpected and non-standard patterns of material fracture morphology during impact tests, where the initial ductile crack propagation suddenly turns into a cleavage fracture as the propagating crack moves across the sample's ligament. The statistical nature of this occurrence requires a deterministic approach to reduce its likelihood during experiments. To address this issue, a phenomenological continuum-level model has been developed to consider the ductile-brittle transition (DBT) behaviour of X65 Q&T and the strain rate effect, providing a platform to study the recurrence of reverse fracture morphology.

The main objective of this testing is to meet the design requirements for fracture propagation by considering the ductile to brittle fracture transition. Testing programmes before the 1970s did not include line pipes with Charpy energy higher than 50 J or higher fracture initiation energy. Recent line pipes have 5 - 10 times more Charpy energy than those from before the 1970s.[1] Based on this concept, pipes with higher Charpy energy leads to AFA in DWTT specimens.

Using pipes with higher Charpy energy provides greater fracture initiation resistance, making these pipes desirable in industry. However, higher Charpy energy also results in fewer inclusions for void growth and coalescence for ductile fracture, which are the sites for cleavage fracture initiation. Consequently, this behaviour invalidates DWTT results using the American Petroleum Institute (API) 5L3 standards.[2] The Recommended Practice (RP) API 5L3 standards offer economical and straightforward testing for DWTT specimens to qualify pipeline materials. The RP-API 5L3 standards aim to indicate the arresting capability of brittle fractures in the DWTT specimen. AFA is essentially the sudden transition of fracture ligament from ductile to brittle in DWTT. In other words, AFA is the observation of ductile fracture before cleavage fracture initiation, while pipes with lower Charpy energy typically exhibit cleavage fracture first. A comparison of AFA and normal fracture appearance in DWTT is shown in Figure 1. This concept is also known as inverse fracture, where the abnormal fracture region is the ductile initiation region from the notch. Today, AFA generally occurs in thermo-mechanical controlled process (TMCP) pipes.

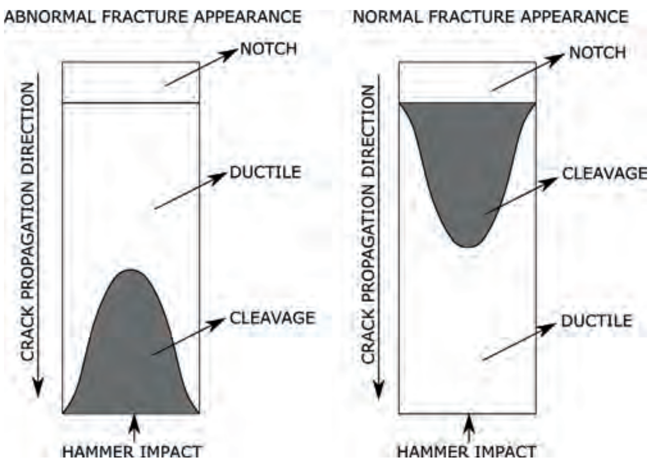

Figure 1. **Comparison of AFA and normal fracture appearance in DWTT.**

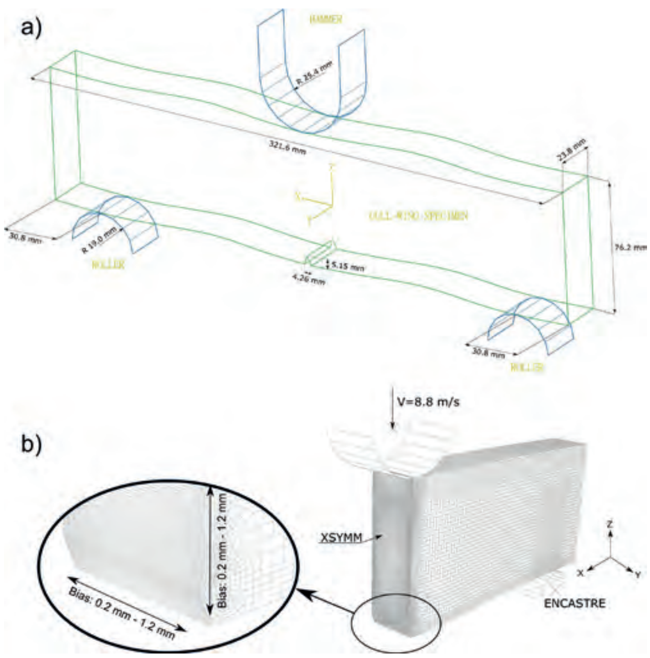

Figure 2. **Finite element model geometry and details, where a) Gull-wing DWTT configuration, b) finite element model boundary conditions and mesh details.**

Methodology

Ductile fracture model

The mechanical behaviour of X65 Q&T pipeline steel beyond the elastic limit is described by the quadratic yield function, incorporating von Mises equivalent stress and deformation resistance components. The von Mises equivalent stress represents the multiple loadings (tensile, compressive, and shear) acting simultaneously on the material. Deformation resistance, on the other hand, embodies the combined influence of strain rate, thermal effects, and plastic flow strain, considering Lüders strain through a multiplicative decomposition within the hardening response.[3] The plastic flow is determined based on the Lüders strain condition, which includes the Swift-Voce hardening model and a temperature-dependent parameter. The temperature dependency is expressed with material fitting parameters and homologous temperature, which is a function of melting temperature, reference temperature, and target temperature.

Rate dependency is modelled by incorporating the temperature softening function into the model, along with the strain rate hardening function, completing the classical Johnson-Cook model.[3] The ductile damage model quantifies the level of deformation a material undergoes during plastic deformation using a damage indicator. An uncoupled model based on this damage indicator is used to predict fracture initiation under dynamic loads. This indicator, represented in integral form, describes the onset of fracture. The fracture strain function is formed using experimental results that provide strain-to-fracture data and varies based on different triaxiality, lode angle, and strain rates.

The modified Mohr-Coulomb model,[4] a rate-independent model, describes stress state-dependent fracture initiation. As the simulation model increases in complexity, particularly with thicker model simulations, it becomes necessary to incorporate post-failure softening to enhance the model's efficiency and ensure more accurate outcomes. Post-failure softening accounts for the gradual development of local damage at the integration point, represented by a power law.

Brittle fracture model

The brittle fracture model is designed to incorporate desired probability inputs for the numerical simulation of the DWTT. This research employs the Weibull distribution, a commonly used probability distribution for characterising the lifetimes or failure times of various products and materials. The statistical model is based on the Weibull distribution and serves as the foundation for describing cleavage fracture in ferritic steels. This model requires the calibration of two micromechanical parameters, denoted as m and σu, which are typically considered intrinsic material properties. The Weibull stress model establishes a connection between the local first principal stress and the plastically strained volume, quantifying the probability of fracture. Beremin introduced a cleavage model that correlates the probability of fracture with the Weibull stress, as discussed in reference 5.

FE model

The DWTT geometry comes in two distinct variations, each determined by the diameter of the pipe from which the DWTT specimen is extracted. According to ASTM E436 standards, the required length of the specimen should be 304.8 mm with an allowable tolerance of ±19.05 mm. When the pipe diameter is too small to allow the extraction of a flat plate that meets this required length, a specialised configuration known as the gull-wing geometry is employed. This unique geometry achieves the necessary specimen length by bending both ends of the pipe section to align through the centres of the thickness.

In this study, the gull-wing DWTT specimen is utilised, as studied in previous works of the author.[6] This particular specimen features a length of 321.6 mm, a width of 76.2 mm, and a thickness of 23.8 mm, as depicted in Figure 2a. One side of the specimen is fashioned with a V-notch through the thickness using an indentation technique. The V-notch is characterised by a 45˚ opening, a depth of 5.15 mm, and a corresponding mouth opening of 4.16 mm. It is important to note that this specimen geometry necessitates modelling only half of the actual geometry due to its asymmetry along the longitudinal axis (x-axis). Consequently, half of the model is created along the through-thickness (y-axis), as demonstrated in Figure 2b.

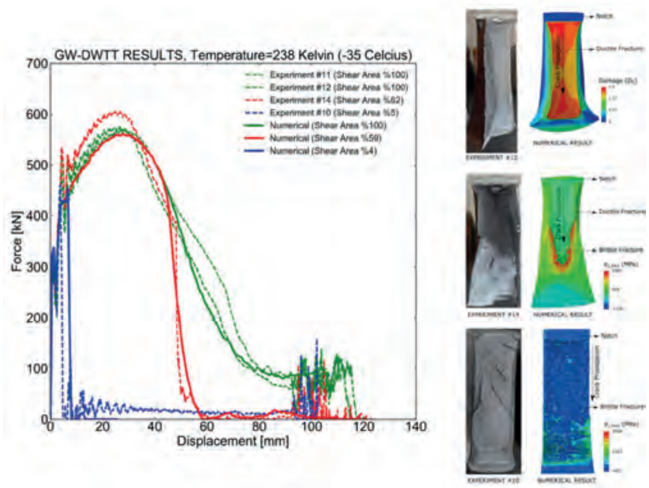

Figure 3. Comparison of the calibrated numerical model in different fracture ligament modes with the DWTT experimental results.

For the creation of the mesh in this model, linear brick elements with reduced integration (C3D8R) are used. A biasing technique is applied to the fracture surface, where the double bias size varies from 0.2 mm to 1.2 mm along both the y-axis and z-axis. Additionally, the roller and hammer impact areas are refined with a 1 mm mesh size, whereas other areas of the model use a mesh size of 3 mm. This meshing strategy is designed to reduce the total number of elements in the model, thereby saving computational time. Ultimately, the total number of elements in this model is approximately 175 000 C3D8R elements, which balances accuracy with computational efficiency.

Results and conclusion

The numerical model was validated by comparing its results with DWTT experimental outcomes. Experiments conducted at 35˚C produced three distinct fracture modes: fully brittle, fully ductile, and AFA. These outcomes, depicted in force versus displacement graphs in Figure 3, were compared with the numerical model results. Additionally, the fracture surfaces were compared to those predicted by the numerical model. Notably, the model accurately captured the AFA in both fracture surface characteristics and force-displacement results.

In conclusion, a numerical model incorporating ductile-cleavage temperature coupling and rate dependence has been developed and calibrated specifically for Q&T X65 pipeline steel. This calibration used an algorithm based on critical damage accumulation and critical Weibull stress parameters, enabling an accurate representation of reverse fractures in DWTT using the coupled numerical approach. The model's efficacy was verified by comparing DWTT experimental results at 35˚C, which included fully ductile, fully brittle, and reverse fracture scenarios. The numerical model precisely captured all three cases.

Furthermore, an exploration into the causes of reverse fractures involved analysing principal stress, plastic strain, stress triaxiality, and lode angle profiles at various deformation levels in the DWTT hammer impact region. These profiles revealed that plastic strain, stress triaxiality, and principal stresses increase as crack propagation approaches the hammer impact area during the DWTT experiment. This transition in loading conditions from tension to compression at the hammer impact region enhances the likelihood of AFA occurrence.

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BUCKLING UP FOR A DATA DEEP-DIVE

Ismael Ripoll, Advanced Analysis Lead, Xodus Group, analyses data on deepwater pipeline buckling, aiming to enhance understanding of its causes and consequences.

Earlier this year, I had an article published in *World Pipelines* based on a technical paper produced in partnership with TotalEnergies, titled 'Updating Pipeline Buckling'. Amongst other things the piece discussed the approaches to managing pipeline lateral buckling, putting forward an updated methodology that can be applied with few changes to DNV-RP-F110, a widely used industry recommended practice that gives design methodology and criteria to allow pipelines to buckle in a safe and controlled manner.

Our research aims to enhance the offshore sector's understanding of the causes and consequences of pipeline buckling, an issue that is of paramount importance to the safe and successful management of operational deep-water pipelines. These infrastructures serve as critical conduits for transporting hydrocarbons and other essential materials from offshore oil and gas fields to either onshore or floating processing facilities.

A solid grasping of the mechanisms, risks, and mitigation strategies associated with pipeline buckling is essential for ensuring the reliability, safety, and efficiency of subsea infrastructure. This knowledge not only enhances the design and maintenance of these vital arteries but also safeguards marine ecosystems, supports the sustainable production of oceanic resources, and, in the case of oil and gas, protects the sector's social licence to operate.

Further enhancing industry understanding of pipeline buckling

Since the publication of our last technical paper – entitled 'Lateral Buckling Design using the Friction Distributions at the Expected Buckles' – Xodus and TotalEnergies have been continuing to work together to further enhance knowledge about pipeline buckling and the associated risks.

Recently, we issued a new technical paper on the issue, 'Retrospective Analysis of the Lateral Out-of-Straightness (OOS) and Buckling Response of Operational Deep-Water Pipelines'. This paper examines the lateral buckling response of the pipelines in a deep-water field, including a retrospective probabilistic analysis as per the DNV-RP-F110 recommended practice, a review of the available survey data, and a comparison of the predictions of the analyses with the actual observed responses.

From the reviews of the records and the results of the comparisons, we identified aspects of the recommended practice that could be improved and make relevant recommendations. The paper also reviews the published pipeline OOS data and makes recommendations on how to improve it for use in probabilistic lateral buckling assessments.

Understanding the mechanism behind pipeline buckling

Deep-water pipelines operating under moderate or high pressure and temperature develop significant compressive forces. The natural response of these pipelines is to buckle, a form of structural instability, to relieve these forces.

The lateral buckling response of these surface-laid pipelines is highly sensitive to numerous OOS features. Some of these features are vertical, resulting from seabed bathymetry, or depth, while others are intentionally introduced, either vertically or horizontally, as mitigations to allow buckling at a specific location. These intentional features can be accounted for in the design process.

However, pipelines also exhibit numerous horizontal plane imperfections that are randomly introduced during the pipelay process. These small deviations from the theoretical route are unintended and thus cannot be predicted at the design stage. For pipelines laid on relatively flat seabeds, most OOS features, aside from intentional mitigation measures, arise randomly, contributing to significant uncertainty in the lateral buckling design.

To address this uncertainty, the industry employs probabilistic lateral buckling assessments, such as Monte Carlo simulations. This approach, detailed in DNV-RP-F110 and discussed in our last paper, involves defining probabilistic lateral buckling assessments for OOS features. Currently, the only published distributions of pipeline OOS are those in DNV's recommended practice, and it is important to know that the recommended practice advises that this information should be used "in the absence of more specific data" and "care should be taken in its application". Additionally, some installation contractors are compiling survey files to develop their own specific distributions.

Digging into the existing OOS data

In practice, the lack of other agreed-upon data and post-processing methodologies means that probabilistic lateral buckling assessments often rely on the OOS distributions provided in DNV-RP-F110. These assessments typically predict high probabilities of unplanned buckling in route curves with industry-standard radius of curvature. Additionally, when simple sleepers are used as buckle initiators, it is difficult to ensure that unplanned buckles on route curves do not replace the planned buckles at the sleepers. This arises because the critical buckling force distributions for unplanned buckles within route curves and for simple sleepers tend to overlap when using the OOS distributions from DNV-RP-F110.

To avoid unplanned buckles, designers are often forced to use buckle initiators with very low critical buckling forces, such as sleepers with pushing or pulling mechanisms or zero radius bends (ZRBs), both of which are significantly more expensive than simple sleepers. The choice of initiator is heavily dependent on the OOS distributions used in the assessments, which are, as mentioned, uncertain.

In validating the OOS distributions in DNV-RP-F110, we used and assessed information from pipelines in a large, deep-water field that has been operational for several years. This included 21 flowlines, totalling 130 km, comprising small-diameter single pipes and heavy PIP pipelines. Available statistics includes positional and embedment data collected during the as-laid and as-built surveys, and from two additional surveys conducted during pipeline operation.

These pipelines were designed before the development of probabilistic lateral buckling methodologies and the creation of the current OOS distributions in DNV-RP-F110. Blind assessments using these distributions were performed as they would be at the design stage, prior to pipelay. These probabilistic simulations predict the number and locations of likely buckles, which are then compared to actual observations from pipeline surveys. The analysis includes an assessment of the survey figures to evaluate the validity of the OOS data in DNV-RP-F110 and improve future designs.

The available survey records also included pipe embedments along the pipeline routes, correlating with pipe-soil interaction – a significant uncertainty in lateral buckling design. These embedments are assessed and compared to design predictions. The spatial variability of embedment and its impact on lateral buckling response is also considered, alongside end expansions recorded during operation compared to predictions from probabilistic assessments.

Conclusions

The objective of our retrospective analysis was to use the comparisons between the predicted and actual responses of the pipelines to identify areas for improvement in DNV-RP-F110. Particular emphasis was given to the OOS distributions required for probabilistic assessments.

During our work, Carlos Sicilia of TotalEnergies and I reviewed the publicly available OOS data and distributions, as well as the available methods to quantify the features assessed. It quickly became evident that peak curvature alone is insufficient to characterise OOS features. Instead, the most promising approach involves using finite element (FE) analyses on survey data to quantify the severity of the features by determining the level of axial force at which they buckle.

High-quality surveys are essential for assessing OOS features. Unfortunately, the pre-operation survey data available for the pipelines considered in the paper were not of sufficient quality to extract OOS features and develop distributions for comparison against those proposed in DNV-RP-F110. Despite this, the observed lateral buckling response of all the pipelines in the field was satisfactory. Buckles formed at all planned locations with sleepers, and although many unplanned buckles formed, mostly within route curves, the conditions at all these buckles were acceptable.

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However, some observed responses did not match the predictions of the retrospective analyses, leading to the following conclusions:

- The DNV-RP-F110 critical buckling force (CBF) distributions overestimate the buckling loads at sleepers, particularly for sleepers on route curves.
- The DNV-RP-F110 CBF distributions do not underestimate the buckling loads at unplanned buckles in route curves (as we suspected before this exercise was conducted). If anything, the distributions may overestimate the actual response.

The close proximity of some unplanned buckles and the observation of ridges at almost all buckles suggest that post-buckling forces at buckles and axial friction may have been underestimated in the retrospective analyses.

Using the best-fit OOS distributions for unplanned buckles in nominally straight sections underestimated the number of such buckles, highlighting the importance of running sensitivities to the lower and upper bound OOS distributions in DNV-RP-F110.

Recommendations

To further improve lateral buckling designs, we made the following recommendations.

Develop improved OOS distributions

For nominally straight sections, route curves, and sleepers (both in straight sections and route curves), the industry should collaborate to gather high-quality survey information and define an agreed methodology for processing this data using an FE approach. Data should include all relevant metadata to allow the creation of families of OOS distributions for specific scenarios (e.g., pipelay method, severity of metocean conditions). This exercise should be performed using shorter reference lengths than those considered in the DNV-RP-F110 data.

Consider lateral soil mobilisation

Develop a methodology to account for the influence of lateral soil mobilisation on the evolution of OOS features from initial placement to buckle onset, as this can impact the CBF.

Assess interaction of vertical and lateral OOS features

Develop a methodology to consider the interaction between vertical OOS features (created by seabed bathymetry) and lateral OOS features (created by the pipelay process) in probabilistic analyses. This should involve independently sampling vertical OOS (with large spatial variability depending on seabed roughness but small epistemic uncertainty) and lateral OOS along the pipeline route.

Combine OOS distributions with hydrodynamic loading

For pipelines not designed to be completely stable, develop methods to combine OOS distributions with the effects of hydrodynamic loading in probabilistic assessments.


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