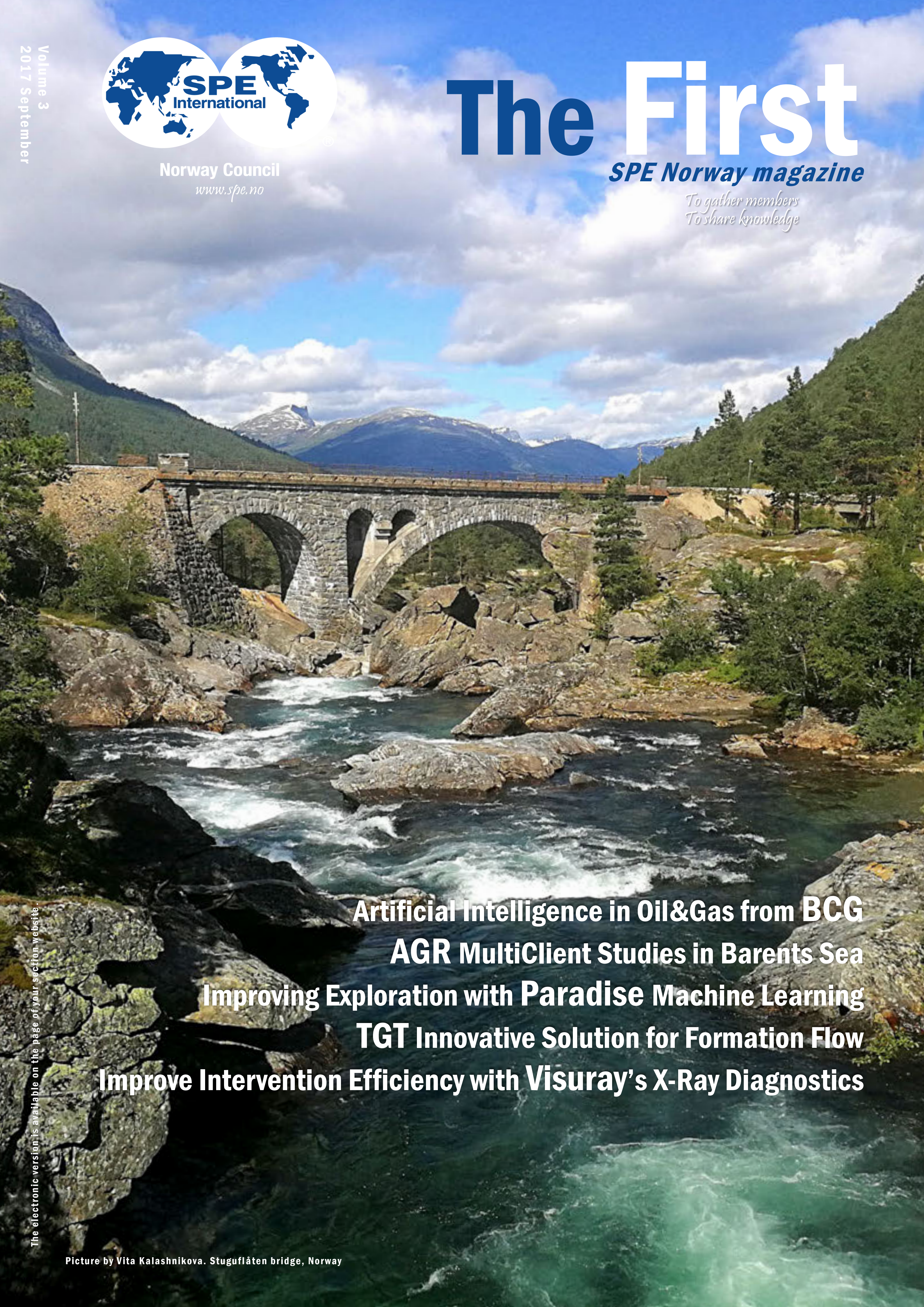

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SPE International
Norway Council
www.spe.no

The First

SPE Norway magazine

To gather members
To share knowledge

Artificial Intelligence in Oil&Gas from BCG

AGR MultiClient Studies in Barents Sea

Improving Exploration with Paradise Machine Learning

TGT Innovative Solution for Formation Flow

Improve Intervention Efficiency with Visuray's X-Ray Diagnostics

The electronic version is available on the page of your section website.

Picture by Vita Kalashnikova. Stuguflåten bridge, Norway

Inside this issue

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From SPE First editors

SPE The First Editorial team:

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Communications Manager, AGR

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QI Geophysicist, PSS-Geo AS

Innovative technology and digital transformation are buzz words that dominate our industry as we move into new season of the SPE community. Technical solutions and automated processes are however as good as we people learn to be good at using them. In order to achieve results from new innovations, we need to collaborate and communicate with each other. Luckily there are technologies in place which help us find ways how to better share information between various disciplines and how to make daily communication more efficient.
The collaboration between the Board of Directors in Norwegian SPE community has also improved a lot during the recent years. We think and breathe alike having the interests of our members as priority. The feedback from the recent visit of the SPE President, mrs Janeen Judah, was very positive and highlighted outcomes of this continuous collaboration. To remind, the SPE community has chosen to form a Norway Council which is managed by mr Igor Orlov and which assembles monthly to discuss the topics relevant to daily managing of the community.
SPE The First magazine serves the role of being the largest source for news, events and technical content to the SPE community in Norway. It's published quarterly and distributed electronically and in print to all our members. So if you have a story or innovation you would like to share with others in our industry, remember to send it to the editorial team of the magazine.
Wishing you a colourful autumn,

Maria Djomia
On behalf of SPE The First editorial team

Editorial content

Technical Articles

Artificial Intelligence

Exploration

Well Performance

Would you like to join the editorial team? Please contact the editors.

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SPE Offshore Europe is a chance to discuss the new North Sea

This article was first published by Big Partnership agency on behalf of SPE International in the light of upcoming Offshore Europe gathering in Aberdeen

An interest in geology shapes the background of Karl Ludvig Heskestad, the Society of Petroleum Engineers' regional director for the North Sea Region. The Norwegian has strong connections to the natural landscape and as a reservoir engineer understands the complexities of exploration and production activity in locations as diverse as the Norwegian Continental Shelf and the Barents Sea.
Karl Ludvig has moved into a business development role with a company that epitomises the collaborative, forward thinking approach required in a lower cost base oil and gas industry. Aker BP was formed out of established players Det norske oljeselskap and BP Norge.
As the voice of the North Sea on the SPE board of directors, Karl Ludvig is looking forward to the flagship home show that is SPE Offshore Europe 2017. He believes a lot has changed on both sides of the North Sea over the last two years but knows that now is a time to continue sharing advice and forward planning.
He explained his belief that Norway is slightly ahead of the UK in terms of emerging from the downturn, but said there are signs of a positive future for both areas. He said: "Phones are beginning to ring again and activity is picking up. I have been impressed with the way vendors have done their bit to reduce their costs and I know operators have appreciated that and are working closer with the supply chain. It has been a difficult time with small margins, but there is optimism.
"I hope SPE Offshore Europe will be a chance to communicate what is actually happening in the North Sea. There has been a rise in activity and I know the Norwegian Government is expecting a certain number of final investment decisions to be submitted with high capex estimates. If Norway is picking up, then I expect the green shoots to appear in the UK too."
In Karl Ludvig's day job with Aker BP he has witnessed the benefits of being a smaller, nimble operator with strong financial and operational backing. The firm has had an aggressive mergers and acquisitions policy from its outset, gaining production assets to offset a large capex programme. One of its big developments, Ivar Aasen came onstream in December last year and the partnership in the massive Johan Sverdrup field is reaping rewards too. The focus is evidenced by the share price which rose from $5 to $19 in a year in a low oil price scenario.
"I think it is important for us to continue to optimise efficiencies so that when the oil price does rise that the value gain for vendors and operators can be satisfyingly high. New discoveries are also adding to the positivity, and I hope there will be a chance to discuss these further at OE.
"The North Sea is still very highly valued globally, but there are other exciting discoveries and prospects regionally, for example off the west coast of Ireland and in the Barents Sea. With the OGA highlighting 30 billion barrels remaining in the UKCS and the Norwegian Petroleum Directorate forecasting 90 billion barrels there are many years left for our industry in this region."

Karl Ludvig Heskestad
SPE Regional Director North Sea 2016 - 2019
Business Development at Aker BP

Stavanger SPE Award Winners

was announced at the SPE BBQ held June 16th

Karl Johnny Hersvik (Oilman of the Year, CEO at Aker BP)

SPE Stavanger honored Karl Johnny Hersvik with the Oilman of the Year 2017 award at the annual Dance & BBQ Dinner June 16th. The award was given to Karl Johnny Hersvik (CEO, Aker BP), whom through his work and elected positions has contributed in bridging the gap between academia and the Norwegian petroleum industry. His colleagues describe him as visionary, curious, responsible, predictable and involved - similar to AkerBP's own corporate values.

As a leader of Aker BP, Mr. Hersvik has through innovation and in challenging times, developed "Det Norske Oljeselskap" into a Norwegian, independent and competitive upstream business with its own successful strategy on the Norwegian Continental Shelf. This has resulted in several well executed transactions involving Det Norske, Marathon Oil and BP Norway. With both fields in production and under development, and a staff highly competent in petroleum production, assumptions are in place to expect good results from Aker BP. The Aker BP operated field Ivar Aasen was delivered well within budget and time during very challenging times.

Mr. Hersvik assumed the position as CEO of Aker BP Mai 2014, after leaving the position as head of research in Statoil. Before joining Statoil in 1998, he was actively involved in founding several IT businesses. He has held several leading positions within Norsk Hydro and StatoilHydro.

Øystein Årsheim (Young Engineer of the Year, Reservoir Engineer at Shell)

The SPE Stavanger Young Engineer of the year is given to SPE members who are under the age of 35 and have been nominated by their peers in relation to their achievement and contributions to the petroleum industry.

Øystein is 28 years old and has a degree from NTNU in Trondheim. He is a member of SPE and the local board at NPF Young and currently holds a position as reservoir Engineer at Shell, working with the Ormen Lange field. The award is related to his contributions to better understanding the subsurface uncertainties at the Ormen Lange field.

Milad Khatibi (PhD - Philosophiae Doctor)

His current PhD research involves laser measurement and well-bore fluid dynamics. After working as a mechanical engineer at a methanol plant in Iran, Milad started his master degree at NTNU in 2011 and his doctorate degree at UiS in 2014. He is an intermediate level learner of Norwegian at the high school Bryne. Working as a PhD student at the university for the last three years, Milad possesses the rare combination of being a comprehensive and innovative researcher working on advanced equipment, while at the same time mastering numerical modeling, required theory and general duties as a PhD student. Milad is also very helpful to his fellow students.

Iris Kam Sok Yee (MSc - Master of Science Petroleum Engineering)

Iris came to Stavanger in 2015 and started her two years of petroleum engineering master studies with a drilling specialization. Before arriving in Norway, Iris worked as mechanical engineer for four years on developing production packers and other tools at Halliburton in Singapore and Texas. Earlier she had an internship as a procurement assistant at ExxonMobil.

Iris is a top A-student while at the same time working with IRIS as part of the Visual Arena project and with the university as a petroleum engineering graduate teaching assistant. In her master level research she investigated how nanoparticles can be used to better design drilling and completion fluids. Iris receives strong recommendations from petroleum engineering faculty members.

Sindre Langås Forsetløkken (BSc - Bachelor of Science Petroleum Engineering)

Sindre was part of the famous SPE PetroBowl team of 2016, earning the European championship for the Stavanger chapter! For the last three years he worked part time at the university as a mathematics and natural sciences mentor to inspire young people to choose this as a career. His student exchange semester took place in North Dakota and he has worked in India as an intern. He has achieved all A grades in his university course work.

SPE Stavanger Young Professional has newly elected a new board!

Gøran Åkesson
Board member

Aleksander Kristensen
Chairman

Sam Bremner
Board member

Kristian Solem
Treasurer

Get Involved, Get Informed, and Get Ahead as a SPE Young Professional!

Are you looking for new ways to get and stay active in the E&P industry?

Or maybe you are an industry newcomer and want to learn how to get ahead?

If so, SPE's Young Professional programs will help you. SPE offers you the opportunity to connect with practicing industry professionals; swap advice through the eMentoring and Ambassador Lecture Programs; and learn about the latest industry advances. You can even be nominated for awards, all by being an active SPE YP member.

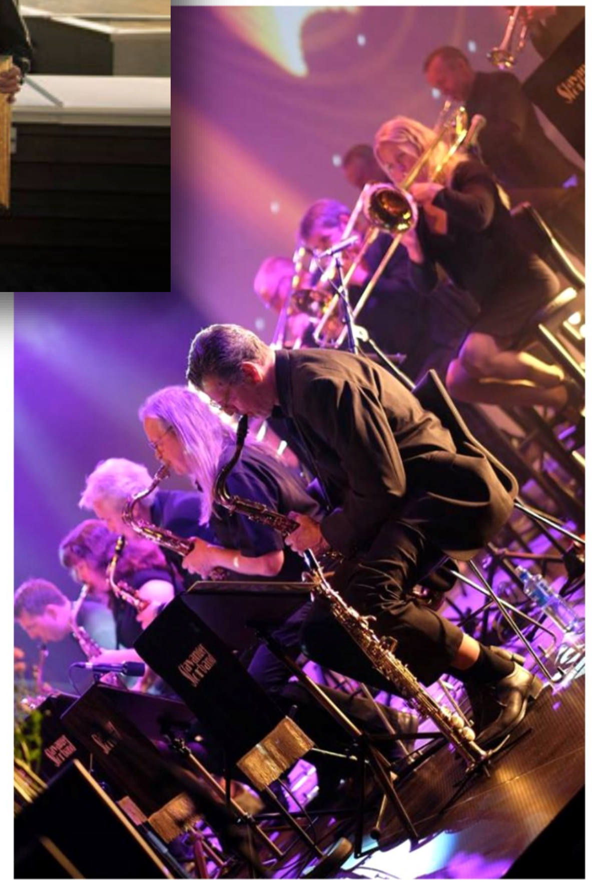
Event Calendar

The Award Winners

Back row from left: Milad Khatibi (PhD), Iris Kam Sok Yee (MSc), Sindre Langås Forsetløkken (BSc), Øystein Åsheim (Young Engineer)

Front row from left: Jeremy Mazzilli (SPE Stavanger), Vidar Strand (SPE Stavanger), Janeen Judah (SPE President), Karl Johnny Hersvik (CEO Aker BP), Frode Indreeide (SPE Stavanger).

The BBQ, June 16th. 210 guests!



News from SPE Bergen Section

SPE Bergen Section

welcomed the summer with the most popular event of the year – sailing with Statsraad Lehmkuhl. The evening started with presentation from Wintershall and ended with nearly 200 oil & gas professionals on board what is likely to be Norway's most beautiful ship.

We look forward to a busy autumn with many events already confirmed and encourage the companies across Norway to contact us regarding possibility to present at our TechNights.

SPE BERGEN SECTION EVENT CALENDAR

October: TechNight – Completions
November: TechNight – Focus on Fluids & Cement
& Yearly Lutefisk dinner

News from SPE Oslo Section

Sept. 6 2017 SPE Oslo Kick off event!

Olje- og energidepartementet

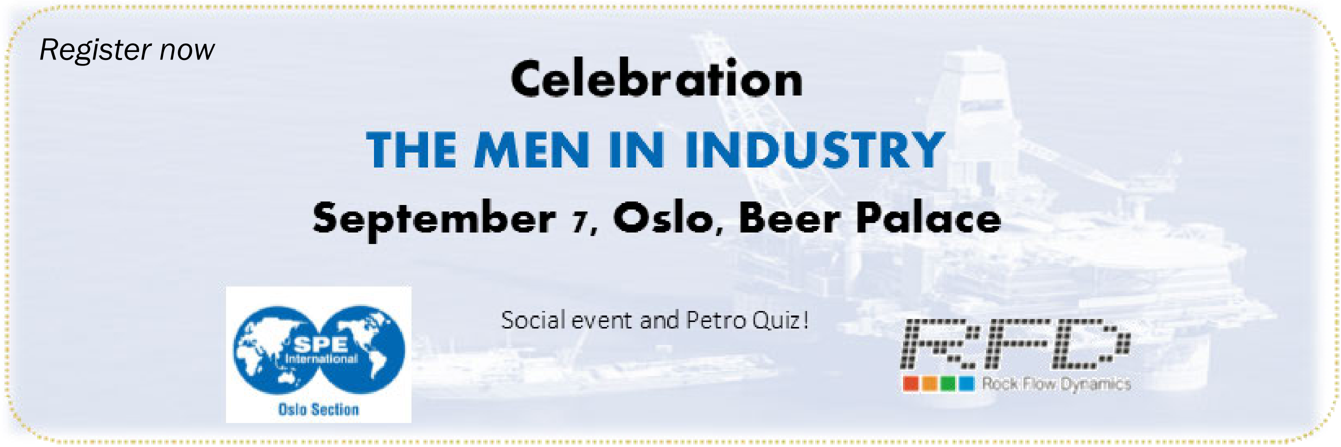
Society of Petroleum Engineers (SPE) Oslo Section would like to invite you for Season 2017-2018 Kick-off Dinner Meeting to take place at **Hotel Continental** on Sept. 6 2017 starting at 17:30.

50 Years of The Oil Industry in Norway

Speaker
Ingvil Smines Tybring-Gjedde, State Secretary from the Olje- og energidepartement (Ministry of Petroleum and Energy).

Register here

Sept. 7 2017 5 pm Social event and Petro Quiz!



Artificial Intelligence: The Ultimate Disrupting Force for Oil and Gas Companies

by Daniel Schlecht, Philipp A. Gerbert and Sylvain Santamarta; co-authors: Rohit Singh and Karen Schelb
THE BOSTON CONSULTING GROUP

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Artificial intelligence (AI) has exploded onto the scene in recent years, promising to change everything from how we live to the ways companies work, create value, and serve consumers. While the causes of this explosion—increasing processing and storage power, abundant data availability, and AI algorithmic advancements—are well known, the effects are not. Few organizations are "AI-ready."

In a joint study to be published in September, "Reshaping Business with Artificial Intelligence," BCG and MIT Sloan Management Review analyze the state of AI today and in the future in 21 industries. While very few companies have made great strides today, BCG expects a strong impact in the next two to five years. In addition, the upcoming BCG report "A Practitioner's Guide to Artificial Intelligence" will discuss cross-industry use cases that can spur competitive advantage and value creation.

In the O&G industry, several AI applications have already emerged. Other industries have also made advances that can be transferred to O&G. In this article, we examine the AI use case landscape specifically for O&G.

Upstream
AI will enable companies to optimize field development from exploration to production. O&G companies have been using advanced data processing and simulation technology for many years. These tools are now being augmented by machine learning and AI techniques. Recently, companies have started to experiment with autonomous underwater drones, which are seeing rapid innovation, similar to aerial drones. AI-enabled vehicles will bring a wide range of opportunities to the offshore O&G industry such as seabed surveys, metocean data gathering, oil spill detection, inspection, and underwater intervention. Compared to today's solutions, performance will be at a much higher level of precision and cost will just be a fraction of what we are seeing today.

In exploration, for example, AI can help to support better and faster interpretation of seismic data to identify hydrocarbon deposits. AI is also expected to help engineering firms and operators make better and faster design choices, integrating a broad set of parameters and involving a large number of companies. AI can effectively revolutionize project delivery by challenging the sequential project maturation process used by industry players today.

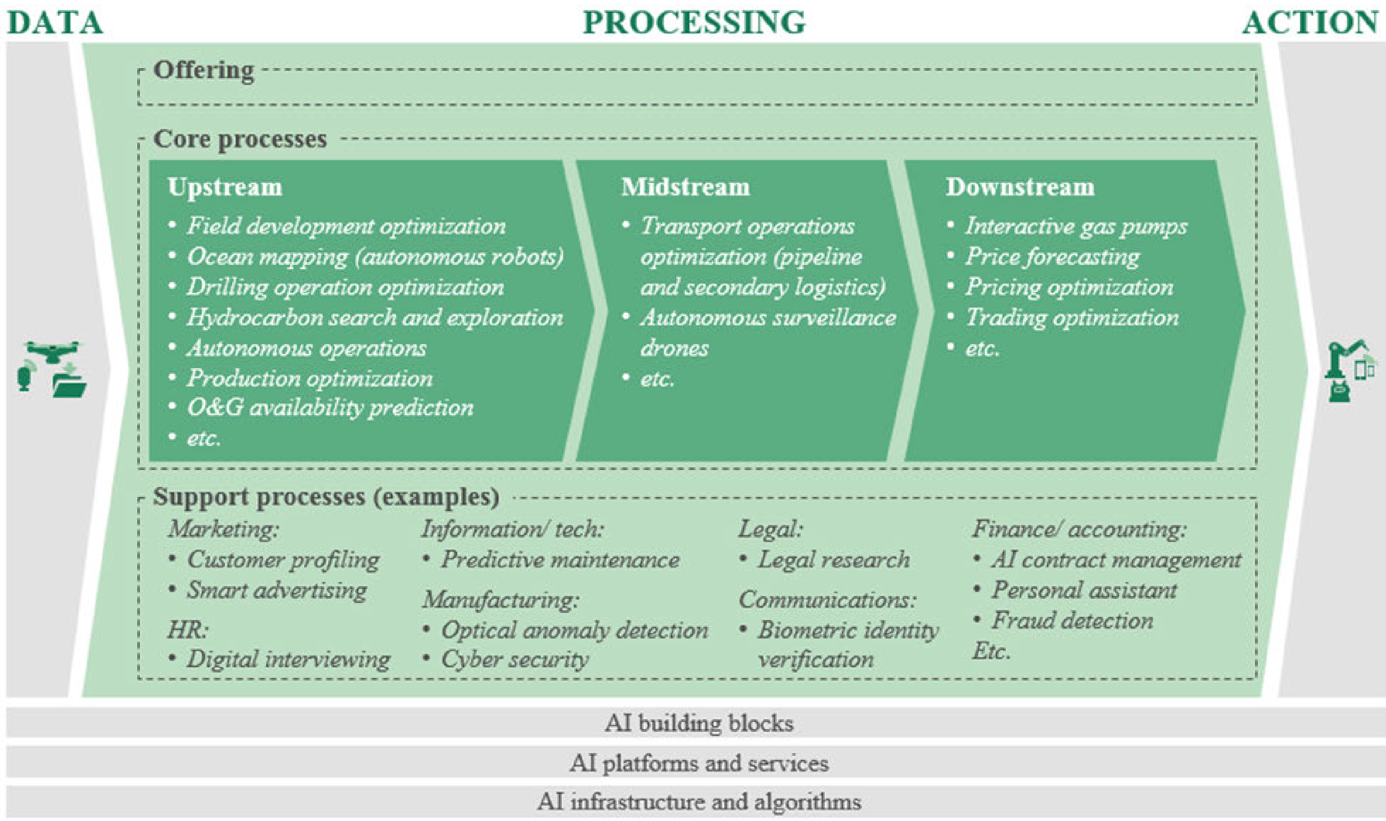
In drilling, AI can help to identify the best locations and optimize drilling operations. AI will likely play a valuable role in real-time modeling and prediction of drill bit and drill string performance. Overall, and also impacted by factors outside drilling, productivity improvements of AI-enabled processes can generate significant value for O&G companies.

In the mining industry, AI is already being used to help automate machinery and vehicles and minimize health and security hazards for autonomous operations. The ultimate goal in O&G is an unmanned oil platform.

We expect AI systems to play a key role in improving health, safety, and environmental (HSE) performance by minimizing direct interaction of humans with heavy equipment and by using image recognition systems to reduce hazardous situations. In addition, AI can help to ensure that the industry can leverage the experience of an aging workforce. For example, national-language processing systems can help catalog and mine the knowledge embedded in, for example, workers' notebooks, e-mails, and conversations.

Based on BCG client experience, operations optimization and predictive maintenance hold great potential. O&G companies and suppliers have already started to implement self-learning algorithms to improve optimization. They are also continuously integrating sensor and system data with predictive tools to improve real-time decision-making. Operation centers with AI capabilities can monitor operations, offer advice to engineers, and send alerts in case of identified risks. AI is also increasingly automating root cause failure analyses as self-learning AI systems move from description to prediction to prescription. As a result, engineers will have to spend less time on administrative or data-related work and can focus on value creation.

O&G companies can save millions of dollars by, for example, using AI to minimize unplanned downtime and production loss. According to Sloan Management Review, a medium-sized liquefied natural gas facility has an average of five down days a year, with an implied production loss of $125 million to $150 million. For an offshore platform, downtime losses can average $7 million per day. Especially in times of low energy prices, any reduction in operating costs is critical.



Graph 1: Relevant AI use case examples along the O&G value chain

Midstream
Companies can use AI to optimize transport operations including pipeline and secondary logistics. For example, AI will help to improve maintenance and inspection intervals of pipelines by analyzing and predicting the level of corrosion in combination with environmental and operational information. Technologies such as AI-powered surveillance drones can be used to gather the pipeline data needed for such analyses.

Downstream
In O&G trading, analytics technologies and AI are increasing the liquidity and availability of data and information and enabling advancements in pre-trade, trade, and post-trade activities. This is putting pressure on established O&G trading capabilities. Self-learning algorithms can absorb and analyze data far more thoroughly than humans and fundamentally transform O&G trading. Companies that do not enable their trading with AI are at risk. For a cross-industry perspective, BCG has published the study "Attack of the Algorithms: Value Chain Disruption in Commodity Trading."

AI is becoming increasingly important for refineries in downstream operations, especially in predictive maintenance. Machine learning helps to identify the causes of failures and unplanned outages, and suggests measures to extend machinery lifetime and load. It can also improve and optimize scheduled operation cycles. Even when only little or incomplete information is available, O&G companies can unlock multimillion dollar savings through these measures.

In the retail business, AI is improving customer service and customer interaction. Chatbots are available around the clock to answer common customer questions. Natural language processing has not yet been perfected but increasingly offers a human-like interaction. Virtual assistants can incorporate context-related information such as product or customer data to personalize answers or recommendations. These tools have the potential to increase customer satisfaction and cross-selling while reducing churn.

Data and AI building blocks
Regardless of how AI is used along the O&G value chain, it will be critical for companies to generate, capture, and clean contextual data and to give data a new meaning and new momentum. O&G companies can enable self-learning systems and create new insights and automation beyond human capabilities by leveraging large amounts of data which often already exist. This requires some effort and foresight since data sets are often in incompatible formats, unstructured, or incomplete and thus have to be cleaned and prepared for AI use. More generally, operators will already need to establish a clear data strategy today to systematically and efficiently leverage the power of large amounts of data generated by their operations.

In addition, different "building blocks" are essential for all AI systems. The upcoming BCG report "AI in Business: A Practitioner's Guide" further elaborates on the essential components of AI. They are more advanced than a single algorithm but not operational by themselves. All O&G AI use cases are based on single or sets of building blocks. The basic functionality of these blocks is often available in the market but needs to be tailored to individual needs.

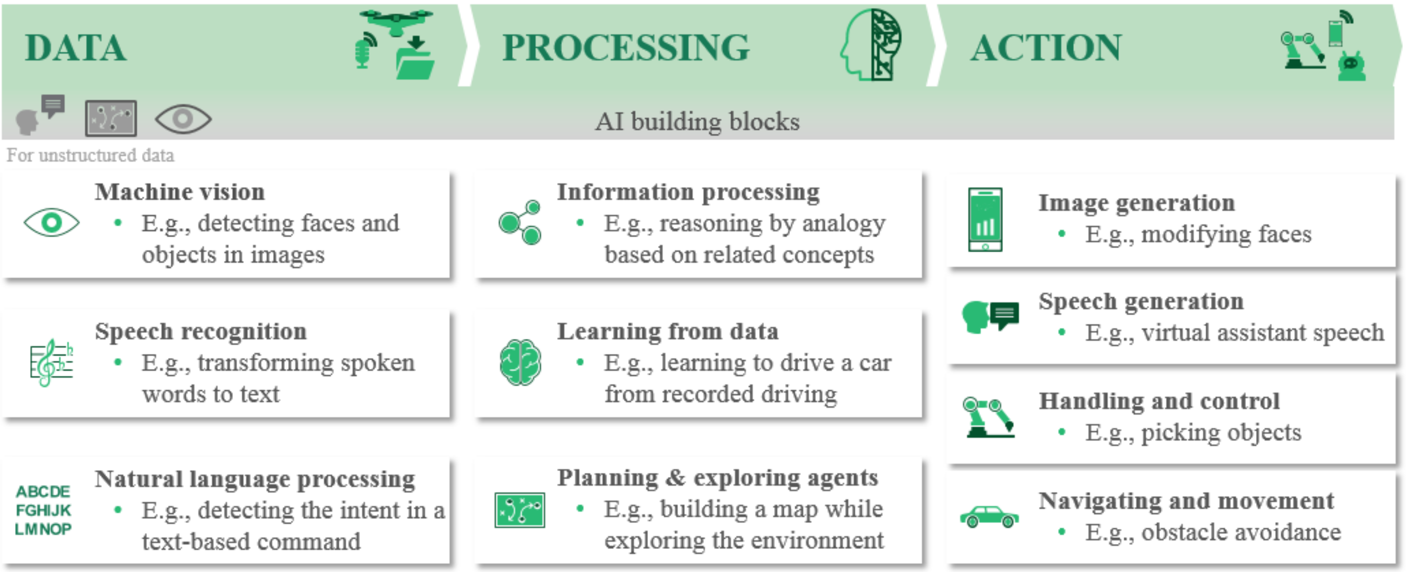
Machine vision is the classification and tracking of real-world objects based on visual and other signals, such as pictures and videos.

Speech recognition is the transformation of auditory signals into text. Siri or Alexa are consumer examples, while Nuance's PowerScribe for radiologists is a commercial example.

Natural language processing (NLP) is the interpretation of text. NLP is used to recognize spam, fake news, and sentiments such as happiness, sadness, and aggression.

Information processing covers methodologies to derive information from unstructured text and provide answers to queries.

SPE Norway — Oil&Gas and Artificial Intelligence



Graph 2: Breakdown of AI use cases into building blocks

Learning from data is essentially machine learning. It is the ability to predict values or classify information based on historic data and refers to the application of machine learning to new data. Anomaly detection used by cyber -security systems is an example of learning from data.

Planning and exploring agents are methods that identify the best sequence of actions to achieve a goal, such as self-driving cars navigating autonomously to their target destination.

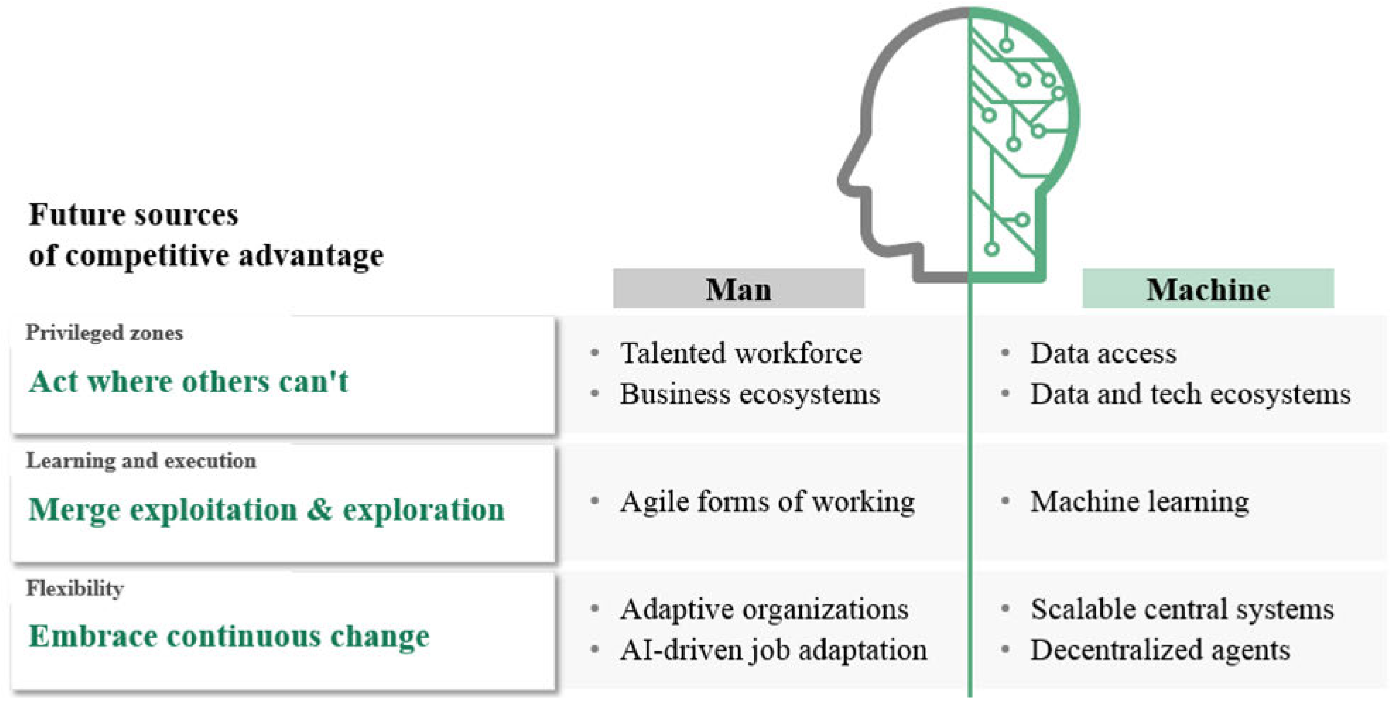
Image generation creates images based on models. It is the inverse of machine vision and can be used to complete images that have no background or transfer oil paintings to photo images.

Speech generation covers both text generation from data and the synthesis of speech and text. Chatbots and Alexa are examples commonly used today.

Handling and control refers to interaction of robots with real-world objects, such as robots autonomously picking up and delivering items within a warehouse without human interaction.

Navigating and movement describes robots moving through difficult, unstructured environments on legs, such as robots climbing stairs or mastering sidewalks. A second, independent task is that of navigation and localization.

Getting engaged in AI means that O&G executives have to think beyond individual use cases and across different dimensions, since the business implications and requirements of AI span the entire organization. Four lenses are especially helpful: customer needs, technological advancements, data sources, and (decomposition of) processes. The BCG report "Competing in the Age of Artificial Intelligence" discusses the question of how business leaders can harness AI to take advantage of the specific strengths of man and machine.



Graph 3: Future competitive advantage based on human-machine interaction

SPE Norway — Oil&Gas and Artificial Intelligence

A company's strategic direction will be significantly shaped by its ambitions and willingness to invest into prioritized AI opportunities.

A data strategy needs to be an integral part of any technology and transformation strategy. This data strategy should include data consolidation, cleaning, and acquisition, as well as priorities for new algorithms, systems, and required technologies. Finally, the company should establish a companywide data platform.

Companies will have to assess existing in-house capabilities and identify what new competencies they need to develop. This might include creating an AI and analytics team, hiring new technology specialists, or building AI competencies in product development, marketing, sales, or service.

In addition, they will need strategy- and service-oriented business models for dealing with vendors and partners. These third parties may be required for noncritical capabilities related to system optimization (for example, algorithms and platforms).
In order to turn quick wins into a long-term competitive advantage, O&G companies have to establish seamless human-machine interaction: They will need an AI-educated workforce, an enabling business ecosystem, AI-prepared data, and technology ecosystems. They should implement agile forms of working for both humans and machines. Finally, they need to create scalable, centralized AI systems and decentralized agents such as bots. All of this needs to be created in an adaptive organization that is able to embrace continuous change.

AGR develops MultiClient studies in Barents Sea prior to 24th Concession Round

Erik Lorange
AGR's Exploration Manager
Erik.Lorange@agr.com

AGR has developed several MultiClient studies in the Barents Sea that help the small and medium-sized E&P companies, but also majors, identify exploration prospects in a cost-efficient method.

AGR's MultiClient studies provide an entry tool for its clients to obtain a significant amount of interpreted key horizons and well data, supported by a complete public 2D and 3D seismic database on which to make sound planning and investment decisions.

One of the recent Studies the team has developed covers the Hammerfest Basin. **The Hammerfest Basin** is the most prolific area in the Barents Sea with two fields already operating and many discoveries made in the area. Yet, the Hammerfest Basin is still expected to have a great hydrocarbon potential of undiscovered resources within the Triassic and the Jurassic hydrocarbon plays (Pic. 1).

AGR's Hammerfest MultiClient study unlocks the potential of the Triassic play of the basin showing that Triassic sedimentary facies vary from marine turbiditic channels to meanders on a coastal plain.

AGR has detected several Early to Late Triassic third order stratigraphic sequences where delta fronts may occupy the western and southern part of the Hammerfest Basin. The deeper Fennoscandian derived delta fronts laterally change the direction of progradation from S-N to SE-NW through the time. Forced Regression System Tracts (ST), Low Stand ST, Transgressive ST and High Stand ST are fairly easy to recognise in seismic sections which allows detecting the best sandy reservoirs in each sequence. These possible reservoir sands have been buried deeper before the uplift, bearing witness of porosity and permeability preservation in the Early and Middle Triassic sands in the Hammerfest basin.

Unlocking the potential of the Finnmark Platform.

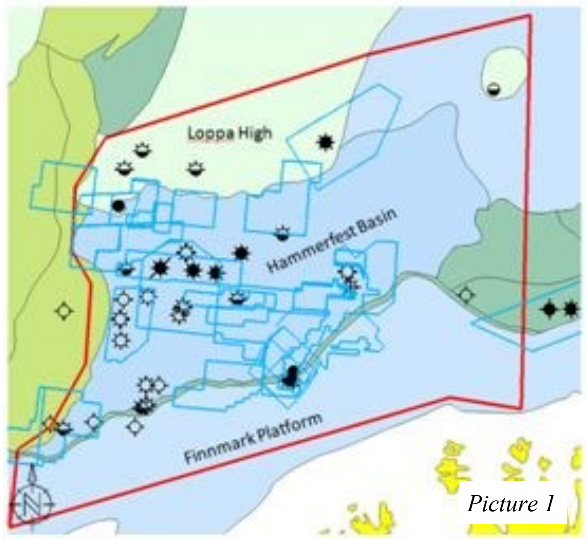
Another study AGR has been working on covers the area on the border between Norway and Russia. AGR's Finnmark Platform Study is based on the interpretation of regional released 2D and 3D seismic datasets, available wells and cores, previous commercial reports, published reports and publications.

Depositional environments are constructed based on the integration of the information extracted from new core descriptions, wireline log analysis and seismic interpretation, pointing at the potential reservoir rocks. Geochemistry and basin modelling analysis reveal target source rocks and their maturation in the area, peculiarly highlighting its possible partial Russian origin. Integrated facies analysis and basin modelling lead to the identification of more than a dozen of hydrocarbon leads within Carboniferous, Permian and Triassic sediments in the area, being up to the half of them structural traps.

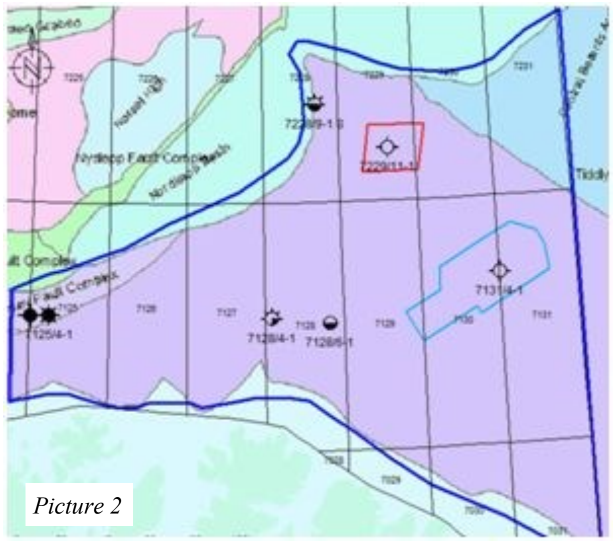
AGR's Exploration Manager, Erik Lorange, comments: "Our results from an integrated geoscientific evaluation of the Eastern Finnmark Platform reveal detailed Permian and Triassic depositional environments, unlocking the potential prospectivity in the area. We are especially looking at two periods of exposure during Permian and the gliding of Triassic sediments over the underlying basinal evaporites that create both reservoir potential and traps within the Eastern Finnmark Platform."

Picture 1. Hammerfest Basin is expected to have great hydrocarbon potential

Picture 2. Eastern Finnmark Platform covers complete interpretation of 2D and 3D seismic datasets, released commercial reports, available wells and cores and other public publications



Picture 1


Picture 2

Significant Advancements in Seismic Reservoir Characterization with Machine Learning

by Rocky Roden and Patricia Santogrossi, Geophysical Insights

Rocky Roden
Consulting Geophysicist,
Geophysical Insights

The application of machine learning to classify seismic attributes at single sample resolution is producing results that reveal more reservoir characterization information than is available from traditional interpretation methods. Two consequences of applying machine learning with several appropriately chosen seismic attributes include the discrimination of thin beds that are below conventional seismic tuning and the identification of Direct Hydrocarbon Indicators (DHIs). These capabilities enable a higher resolution interpretation of reservoirs and stratigraphy. An explanation of the machine learning methodology and its application to thin beds and DHIs is described briefly in this paper.

Machine Learning Methodology

Taking advantage of today's computing technology, visualization techniques, and an understanding of machine learning on seismic data, Self-Organizing Maps (SOMs) (Kohonen, 2001), efficiently distills multiple seismic attributes into classification and probability volumes (Smith and Taner, 2010). When applied on a multi-attribute seismic sample basis, SOM is a powerful nonlinear cluster analysis and pattern recognition machine learning approach that helps interpreters identify patterns in their data that can relate to inherent geologic characteristics and different aspects of their data. SOM analysis, which is an unsupervised neural network application, when properly applied has been able to reveal both thin beds and DHIs in appropriate geologic settings. Figure 1 illustrates a single seismic amplitude trace and seven different seismic attributes computed from the amplitude data. All of these traces are displayed in a wiggle-trace variable area format. This display represents 100 ms vertically and each horizontal scale line represents a sample (4 ms). Each of these attributes are at different scales and in some cases vastly different scales. It is evident from this Figure that each of the attributes measure a different component of the total acoustic energy at every sample. SOM identifies clusters where different combinations of attributes congregate to reveal significant information about

Patricia Santogrossi
Sr. Geoscientist,
Geophysical Insights

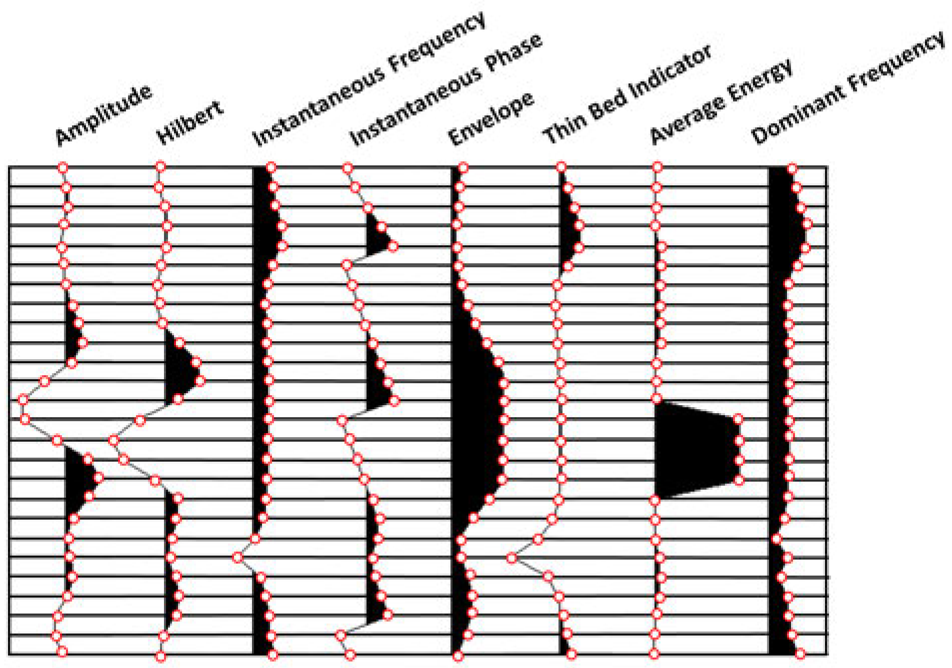


Figure 1. Wiggle-trace variable area display format of a 100 ms window of seismic data with the amplitude trace and seven associated traces of attributes. Each attribute trace is at a different scale and each horizontal scale line is separated by the sample interval of 4 ms. If all these traces were employed in a SOM analysis, each red circle along a timing line indicates samples that would be input as a multi-attribute sample

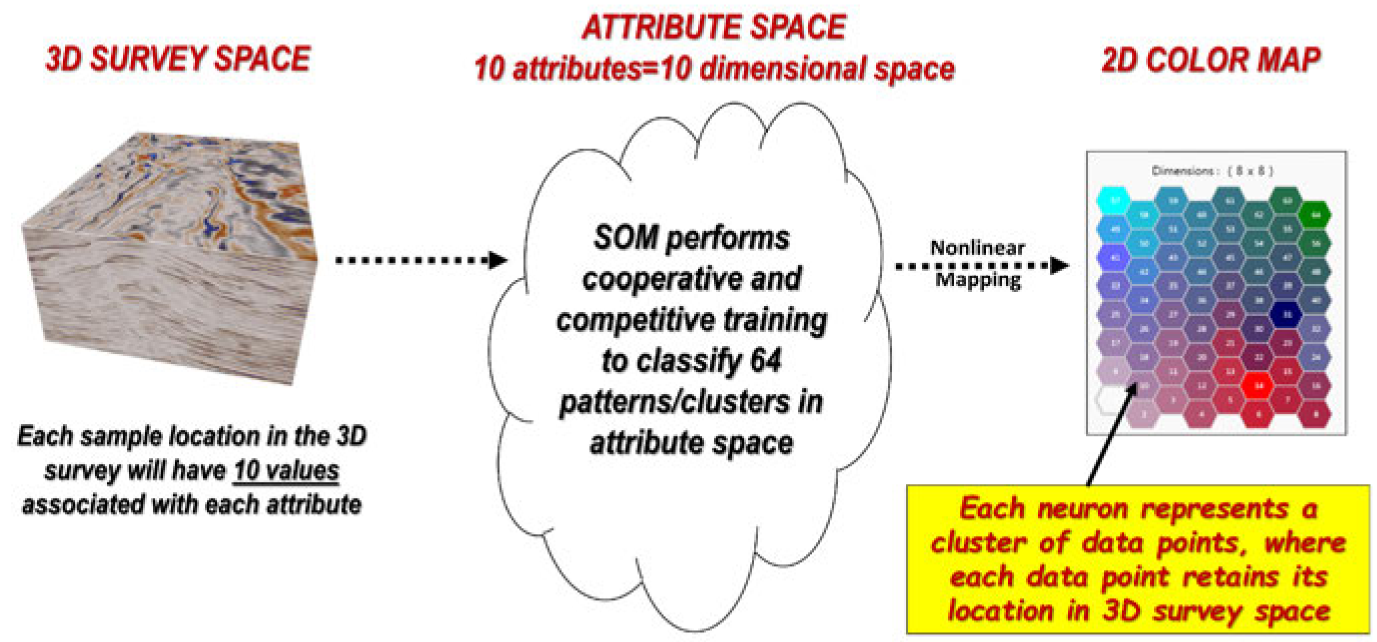


Figure 2. Display of SOM workflow where selected volume and data points from ten associated seismic attributes are input into Attribute Space. These data points are scaled and analyzed by the SOM process to identify 64 patterns by associated winning neurons. These neurons are nonlinearly mapped back to a 2D colormap where interpreters identify neurons and visually view the location of the patterns in the 3D survey

the natural groupings that are difficult to view any other way. The self-organizing property of SOM identifies and classifies natural clusters.

The SOM machine learning process is graphically presented in Figure 2. How large an area to select is dependent on the size of the geologic feature to be interpreted. For thin beds and DHIs, usually a relatively thin zone of 50-250 ms around the anomalies is selected over a reasonable areal extent to provide sufficient data points for the SOM analysis. The selection of the seismic attributes is usually based on principal component analysis (PCA) and an interpreter's knowledge of appropriate attributes for the area. Experience with SOM analysis has indicated that six to ten instantaneous seismic attributes are usually selected for thin beds and DHIs, depending on the geologic setting and data quality. In Figure 2 ten attributes are employed and all the data points from every sample from these attributes in the zone to be analyzed are placed in attribute space where they are normalized to put on the same scale. The SOM process employs cooperative and competitive learning techniques to identify the natural patterns or clusters in the data. Each pattern is identified by a neuron that sorts through the data in attribute space during the SOM training process of self-organization. In Figure 2 after training is completed, 64 winning neurons have identified 64 patterns or clusters in attribute space with an 8X8 neuron network. The SOM results are nonlinearly mapped back to a neuron topology map (2D colormap) where interpreters can select the winning neurons from the 2D colormap and identify in the 3D volume where the patterns and clusters occur for thin beds and DHIs.

In addition to the resultant classification volume, a probability volume is also generated which is a measure of the Euclidean distance from a data point to its associated winning neuron in attribute space (Roden et al., 2015). The winning neuron identifies a specific cluster or pattern. It has been discovered that a low classification probability corresponds to areas that are quite anomalous as opposed to high probability zones that relate to regional and common events in the data. Low probability anomalies identified by the SOM process are quite often associated with DHI characteristics.

Discriminating Thin Beds

The conventionally accepted definition of the tuning thickness (vertical resolution) is a bed that is ¼ wavelength in thickness, for which reflections from its upper and lower surfaces interfere and interference is constructive where the interface contrasts are of opposite polarity, often resulting in an exceptionally strong reflection (Sheriff, 2002). Several authors have described approaches to measure below tuning or thin beds usually employing various scaling techniques of amplitude or inversion data (Meckel and Nath, 1977; Neidell and Poggiagliolmi, 1977; Schramm et al., 1977; Brown et al., 1986; and Connolly, 2007). However, these various techniques to determine thin beds have limitations and require assumptions that may not be met consistently (Simm, 2009). The application of SOM machine learning utilizing a multi-attribute classification has enabled the identification of thin beds and stratigraphy below tuning in a systematic and consistent manner as represented in the following case study.

The Eagle Ford Shale is a well-known unconventional resource play in Texas. Operators in this play must account for changing stratigraphy and facies to properly locate horizontal wells for optimum perforation intervals. The Eagle Ford stratigraphy is often associated with thin beds and facies well below conventional seismic resolution that change both vertically and laterally. This Eagle Ford case study contains 216 mi² (560 km²) of enhanced 3D PSTM data processed at a 2 ms sample interval. Conventional vertical resolution (tuning thickness) is 100-150 feet (30-45 meters) depending on the location within the Eagle Ford unit. In this study, over 300 wells were available for correlation including 23 type logs, 249 horizontal borehole montages,

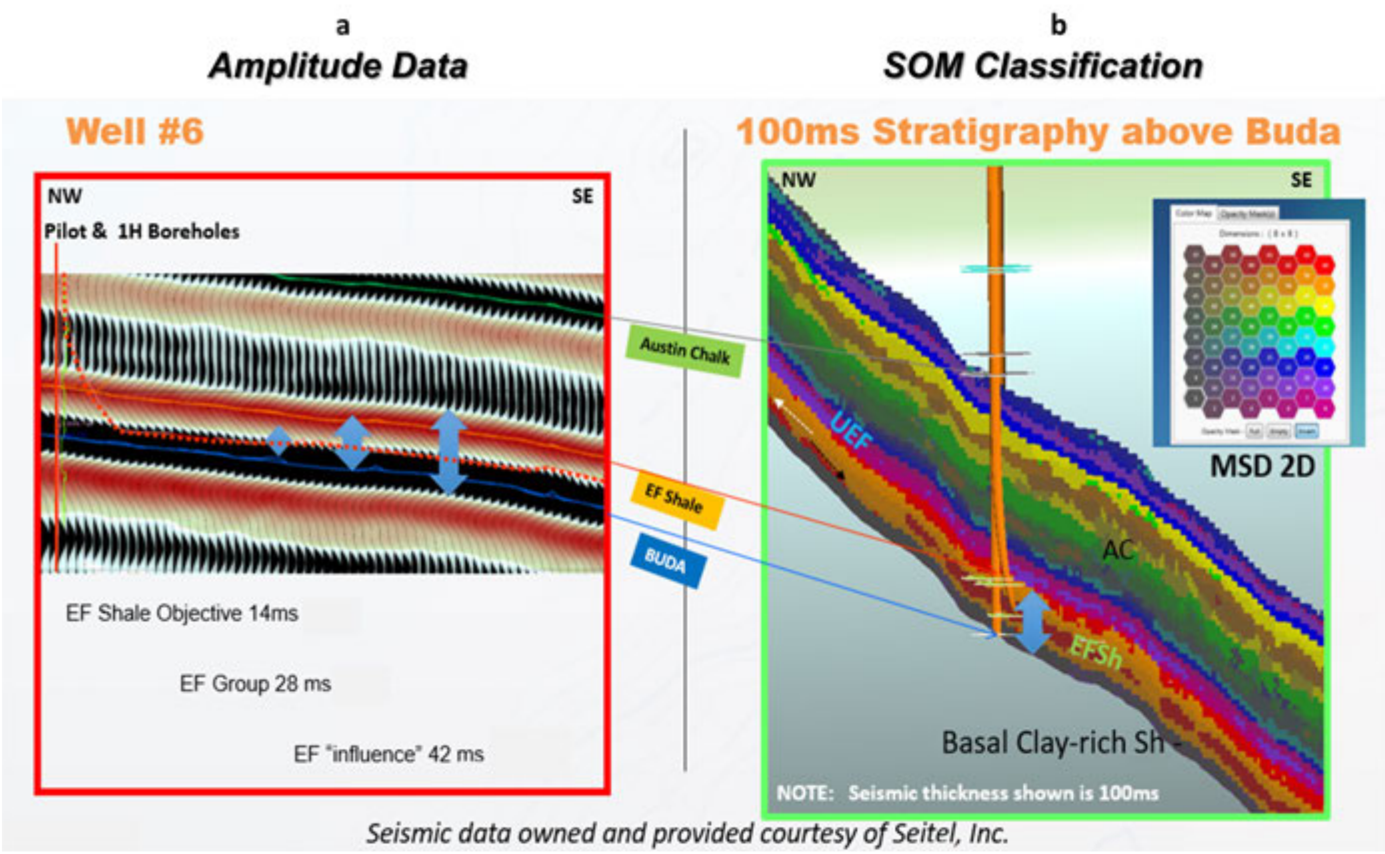


Figure 3. Resolution comparison between conventional seismic display and a Paradise® multi-attribute Self Organizing Map (SOM) classification: (a) Seismic amplitude profile through the 6 Well; and (b) the SOM results of the same profile identifying the Eagle Ford Group that comprises 26 sample based neuron clusters which are calibrated to facies and systems tracts. The 2D colormap displays the associated winning neuron cluster colors

9 vertical calibration wells with tops, logs, and time-depth corrections. Also available were five cores for which X-ray diffraction and saturation information was available. Well information was incorporated to corroborate the SOM results.

Ten instantaneous seismic attributes prominent in a Principal Component Analysis were selected for SOM. SOM training was conducted on a set of trial harvest lines and the successful line was then used to classify the entire survey. Figure 3a is a seismic amplitude line in color raster and wiggle-trace variable area formats across the location of Well 6 (V and 1H). The Figure shows the Austin Chalk-Eagle Ford Group-Buda stratigraphic interval represented by roughly 2.5 peak/trough cycles of a seismic trace. In the Eagle Ford the amplitude appears continuous, yet any details are obscured because of the resolution limitations of the amplitude data where conventional tuning is 100-150 feet (30-45 meters). Figure 3b displays the equivalent line showing results of the SOM analysis. Sixty four neurons were employed to identify 64 patterns in the data as seen on the associated 2D colormap. A seismic interval from 10 ms below the Buda to 100 ms above the Buda or near the top of the Austin Chalk was chosen for the SOM analysis. Shown clearly comparing Figures 3a and 3b is the resolution improvement provided by the SOM analysis over the seismic amplitude. The results reveal non-layer cake facies bands that include details in the Eagle Ford's basal clay-rich shale, high resistivity and low resistivity Eagle Ford Shale objectives, the Eagle Ford ash, and the Upper Eagle Ford marl, which are overlain disconformably by the Austin Chalk (disconformity is a break in a sedimentary sequence that does not involve a difference in bedding angles). This interval of roughly 28 ms (or 14 samples) amounts to some 26 of the 64 SOM winning neurons to illuminate the various systems tracts within the Eagle Ford Group for this survey.

Adjacent to the SOM results at Well 6 are similar results at a nearby well. Figure 4a displays a zoomed-in vertical line display of the SOM results through Well 8(V) with the winning neurons identified. Figure 4b denotes the associated well log curves from well 8 and the correlative neuron associations. Winning neurons 63 and 64 are associated with the low resistivity Eagle Ford shale unit and neurons 53, 54, and 60 denote the high resistivity and more desirable Eagle Ford unit. The expanded display of the SOM results in Figure 4a denotes a low resistivity gold thin bed that is identified by a single neuron (#55) and is only one sample thick (2 ms). Shown here is clear evidence of consistent results between Wells 6 and 8 that lends itself to stratigraphic facies interpretation.

Over this survey area, 16 different winning neurons represent the various facies present in the Eagle Ford Shale over a 14 ms window (70-84 feet/21-26 meters). The facies of the entire Eagle Ford Group which includes the Basal Clay shale, Eagle Ford Shale, and Eagle Ford Marl, are defined by 26 different winning neurons over 28 ms (210-252 feet/64-77 meters). Individual facies units are as thin as one sample interval of 2 ms (10-12 feet/3-4 meters). These results of a single SOM classification are corroborated at multiple wells across the survey area.

Revealing Direct Hydrocarbon Indicators (DHIs)

The accurate interpretation of seismic DHI characteristics has proven to significantly improve the drilling success rates in the appropriate geologic setting where there is also

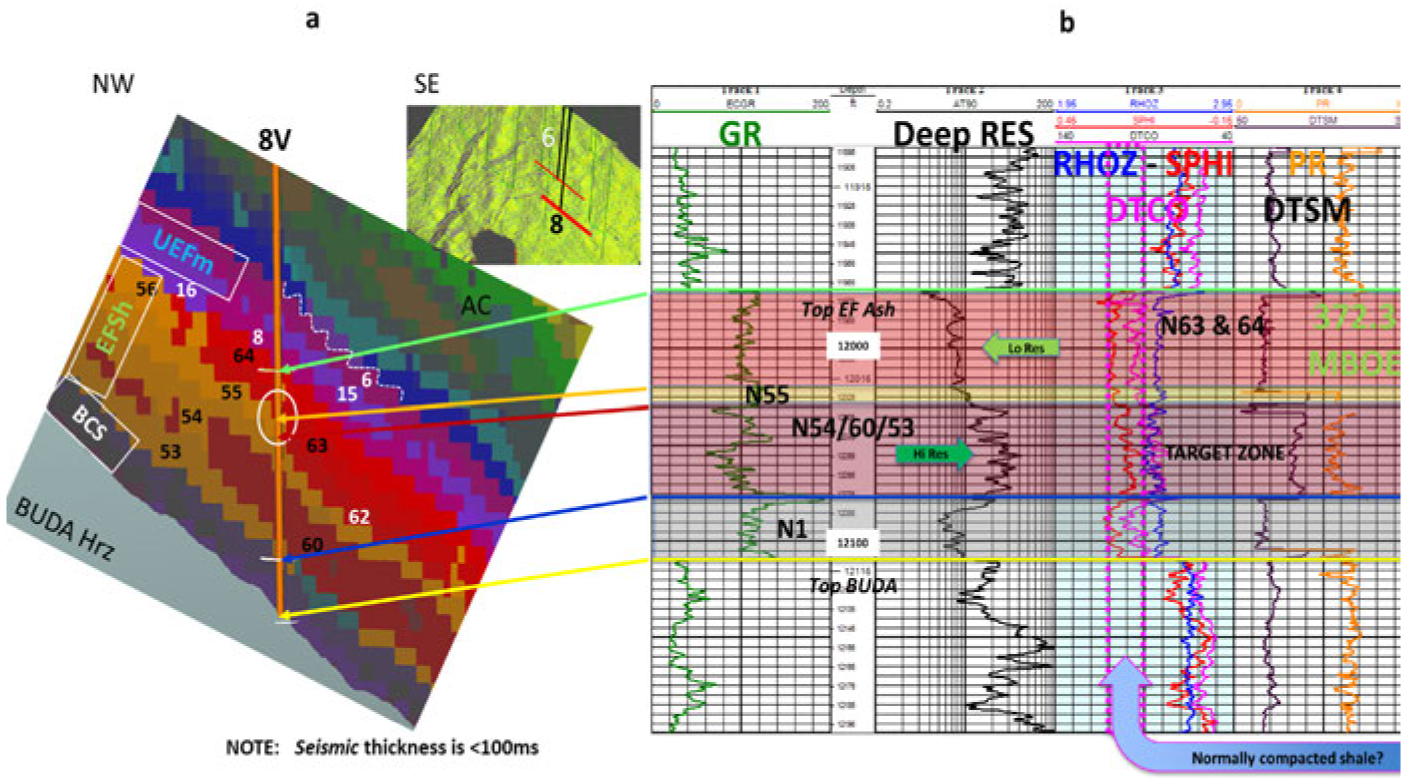


Figure 4. View of SOM results correlated with Well 8 logs: (a) Expanded view of SOM profile through Well 8; and (b) Well 8 logs with Eagle Ford units correlated with the SOM results of (a). Note that the resolution is down to the sample level of 10-12 feet and is illustrated by winning neuron 55 in (a). The dashed white line in (a) represents the top of the Eagle Ford and base of the Austin Chalk

adequate seismic data quality (Roden et al., 2012; Rudolph and Goulding, 2017). Specifically, DHIs are anomalies due to the presence of hydrocarbons induced by changes in rock physics properties (P and S wave velocities, and density). Typically, anomalies stand out as the difference in a hydrocarbon-filled reservoir in relation to the encasing rock or the brine portion of the reservoir. DHI characteristics are usually associated with anomalous seismic responses in a trapping configuration, such as structural traps, stratigraphic traps, or a combination of both. These include bright spots, flat spots, amplitude conformance to structure, etc. DHI anomalies are often compared to models, similar events, background trends, proven productive anomalies, and geologic features. DHI indicators can also be located below presumed trapped hydrocarbons where shadow zones or velocity pull-down effects may be present. These DHI effects can even be present and dispersed in the sediment column in the form of gas chimneys or clouds.

As described above there are numerous DHI characteristics and all of which should be evaluated in a consistent and systematic approach for any prospect or project. Forrest et al. (2010) and Roden et al. (2012) have identified the top four DHI characteristics, as related to commercially successful wells in a Class 3 AVO setting, based on an industry-wide database of almost 300 wells. These DHI characteristics include:

1. Anomaly conformance to structure
2. Phase or character change at the down-dip edge of the anomaly
3. Anomaly consistency in the mapped target area
4. Flat spots

These DHI characteristics will be identified in the following case study by a multi-attribute SOM analysis.

The case study is an offshore oil/gas field in 470 feet (145 meters) of water on the Louisiana continental shelf of the Gulf of Mexico. The field has two producing wells that were drilled on the upthrown side of a normal fault and into an amplitude anomaly. The normally-pressured reservoir is approximately 100 feet (30 meters) thick and contains oil and gas. The hydrocarbon filled sandstone reservoir has low impedance compared to the encasing shales, indicative of a Class 3 AVO environment. The SOM analyzed a 170 ms window surrounding the reservoir. Applying the (SOM) multi-attribute analysis, a group of eight seismic attributes were selected based on Principal Component Analysis that would best expose Direct Hydrocarbon Indicators (DHIs). A neuron network of 5X5 (25 neurons) was employed.

Figure 5a displays a time structure map as denoted by the contours with an amplitude overlay (color) from the mapped top of the reservoir in this field. The horizon at the top of the reservoir was picked on a trough (low impedance) on zero phase seismic data (SEG normal polarity). Figure 5a indicates there is a relatively good amplitude conformance to structure based on the amplitude as noted by the general agreement of the time contour and the red/green amplitude break (see colorbar insert). Figure 5b is a display of classification probability from the SOM analysis at the top of the reservoir at the same scale as Figure 5a. This indicates that the top of the reservoir exhibits an anomalous response from the SOM analysis. Ordinary classifications such as those of green and yellow-greens are shown around the reservoir (see colormap insert). However, within the reservoir and in several other areas, anomalous classification of low probability below 1% are colored white. In comparing Figure 5a and 5b it is apparent that

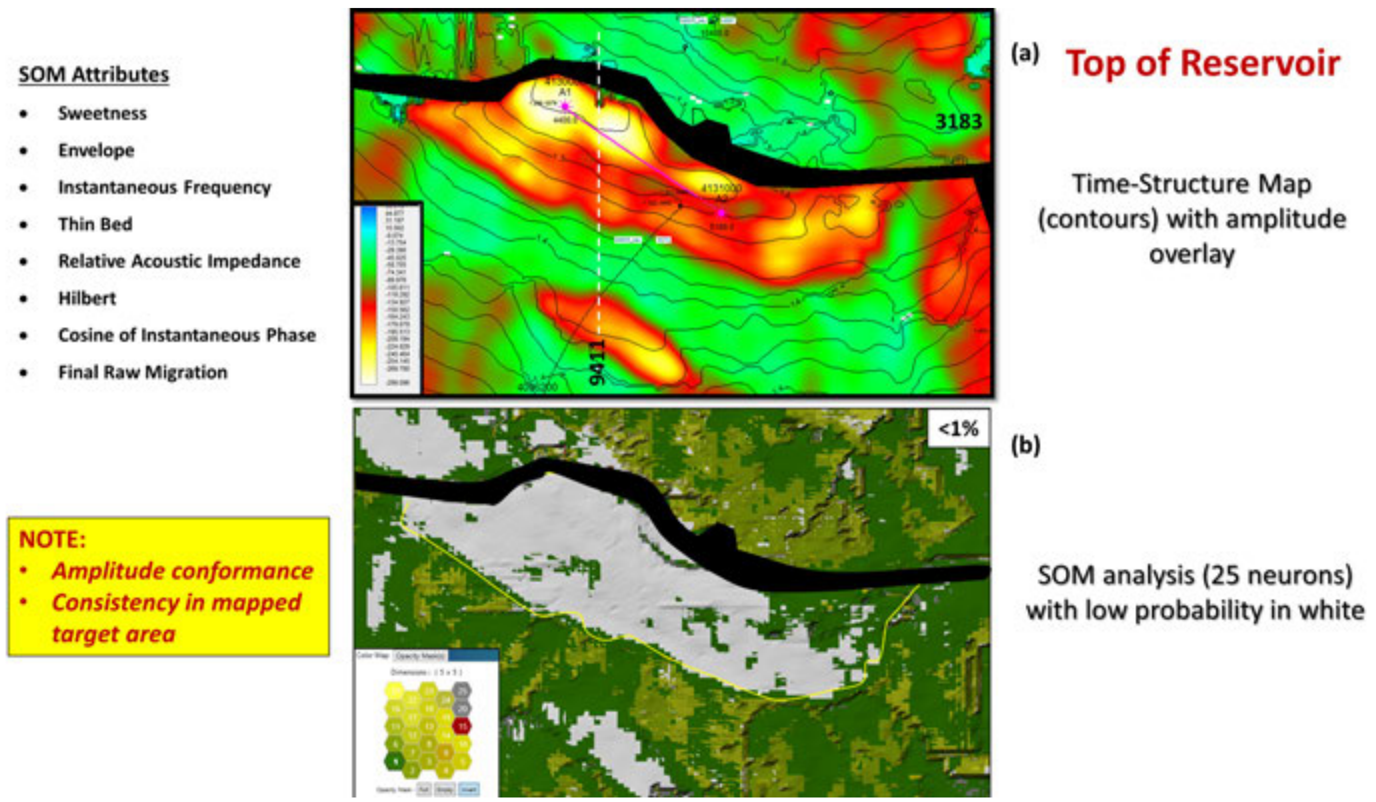


Figure 5. From the top of the producing reservoir: a) time structure map in contours with an amplitude overlay in color and b) SOM classification with low probability less than 1% denoted by white areas. The yellow line in b) represents the downdip edge of the high amplitude zone picked from a)

the low probability area corresponds closely to the amplitude conformance to structure as denoted by the yellow outline in Figure 5b. This confirms the identification of the productive area with low probability and proves the efficacy of this SOM approach. The consistency of the low probability SOM response in the field is another positive DHI indicator. In fact, the probabilities as low as .01% still produce a consistent response over the field indicating how significant evaluating low probability anomalies is critical in the interpretation of DHI characteristics.

This field contains an oil phase with a gas cap and before drilling there were hints of possible flat spots suggesting hydrocarbon contacts on the seismic data, but the evidence was inconsistent and not definitive. Figure 6 displays a north-south vertical inline seismic profile through the middle of the field with its location denoted in Figure 5. Figure 6a exhibits the initial stacked amplitude data with the location of the field marked. Figure 6b denotes the SOM analysis results of this same vertical inline which incorporates the eight instantaneous attributes listed with the 5X5 neuron matrix in Figure 5. The associated 2D colormap in Figure 6b denotes the 25 natural patterns or clusters identified from the SOM process (see colormap insert).

It is apparent in Figure 6b that the reservoir and portions of both the gas/oil contact and the oil/water contact are easily identified as opposed to the conventional seismic data shown in Figure 6a. This is more easily seen in Figure 6c where the 2D colormap indicates that the neurons highlighted in gray (winning neurons 20 and 25) are defining the hydrocarbon bearing portions of the reservoir above the hydrocarbon contacts and the flat spots interpreted as hydrocarbon contacts are designated by the rust colored winning neuron 15. The location of the reservoir and hydrocarbon contacts are corroborated by well control (not shown). Note that the southern edge of the reservoir is revealed in the enlargements in the column on the right (from dashed black box on left). A character change at the downdip edge of the anomaly where the oil contact thins out is easily identified compared to the line of amplitude change. Downdip of the field is another undrilled anomaly defined by the SOM analysis that exhibits similar DHI characteristics identified by the same neurons.

Conclusions

A seismic multi-attribute analysis utilizing Self-Organizing-Maps is a machine learning approach that distills information from numerous attributes on a sample-by-sample basis to provide a more accurate assessment of thin beds and DHI characteristics than conventional methods. We have shown in these cases that the results readily correlate to conventional well log data. The SOM classification process takes advantage of natural patterns in multiple seismic attributes space that is not restricted to the resolution limits of conventional amplitude data. This process enables interpreters to produce higher resolution interpretations of reservoirs and stratigraphy. Another advantage of a SOM analysis is the generation of classification probability where low probability anomalies are often associated with DHIs. SOM analyses in appropriate geologic settings can improve confidence in interpreting DHI characteristics and more clearly define reservoir edges and thin bed components.

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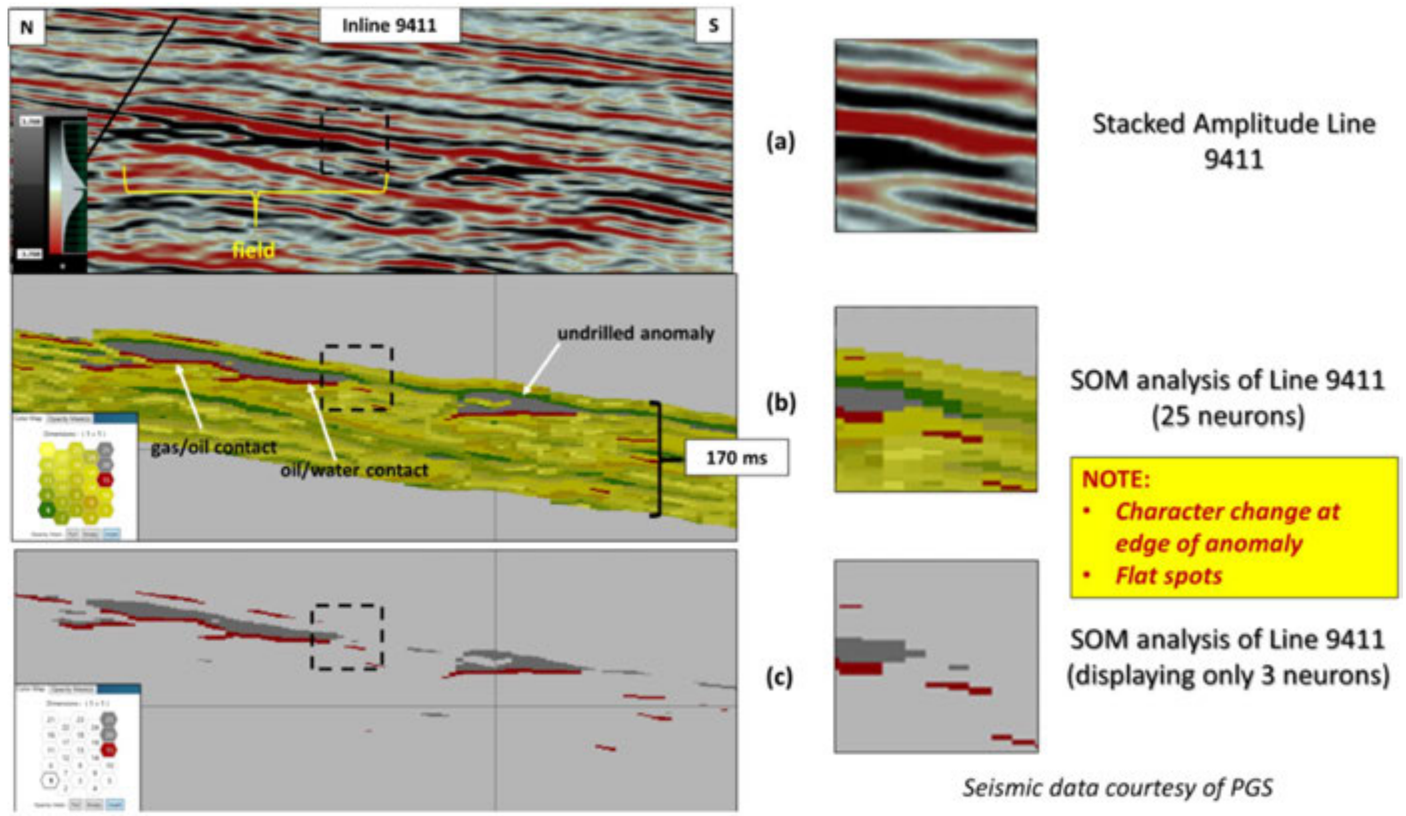

Figure 6. North-south vertical profile 9411 through the middle of the field: a) stacked seismic amplitude display with the field location marked, b) SOM classification with 25 neurons (5X5) indicated by the 2D colormap over a 170 ms window, and c) three neurons highlighting the reservoir above the oil/water and gas/oil contacts and the hydrocarbon contacts (flat spots) as marked by winning neurons 15, 20, and 25. The expanded insets in the right column denote the details from the SOM results at the downdip edge of the field (see dashed black boxes on left)

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OPTISIM – Innovative Solution to Obtain Formation Flow Profile From Fiber Optics – DTS and DAS

by Sergey Aristov and Rita-Michel Greiss, TGT Oilfield Services

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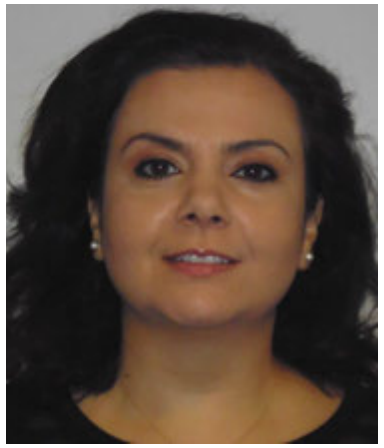

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Over the last decade, Fiber Optics (FO) installations have been gaining significant popularity with Operators as a means to acquiring reservoir measurements. The FO systems were originally patented in the 1960s, with first Distributed Temperature Sensing DTS applications dating back to the 1980s. Significant improvements to the technology as well as application scenarios have been achieved in the last decades, making DTS more and more attractive for a wider range of applications, such as Hydraulic Fracture Monitoring, Vertical Seismic Profiling, Gas Lift Surveillance, Integrity Monitoring, Injection and Production Conformance Monitoring, as well as others.

Recent advancements in Thermohydrodynamic Simulation [1] has allowed Operators to acquire formation flow profiles in their wells with the use of High Precision Temperature (HPT) logging and TERMOSIM™ simulation technique. In a typical HPT survey, a high sensitivity, fast-response temperature sensor, located at the bottom of the tool-string, is run at a stable speed of 2 m/min (or slower), taking readings during a downward pass when the sensor is in touch with the borehole fluid ahead of the tool body, thus avoiding fluid displacement and heat exchange between the fluid and the tool before temperature sensing. The logging procedures have to be designed in a certain way, usually including multiple flowing and shut-in passes to create temperature perturbations, allowing deciphering and quantifying of the flow profile.

TERMOSIM™ software application is designed for temperature and hydrodynamic simulations. It quantitatively analyses temperature logs and can be utilised in the following applications:

For injectors

- Injection profiling across flowing reservoir units
- Quantification of injection loss outside survey intervals
- Identification and quantification of behind casing channeling and wellbore crossflows including those in unperforated zones
- Quantitative characterisation of historical injection zones

For producers

- Production profiling across flowing reservoir units
- Identification and quantification of behind casing channeling and wellbore crossflows including those from unperforated zones
- Location of zones of water breakthrough from nearby injectors

TERMOSIM™ software numerically solves the problems of flow hydrodynamics and heat exchange between the wellbore fluid, completion components, surrounding anisotropic rocks and reservoirs. TERMOSIM™ can flexibly tune a multi-parameter thermohydrodynamic model to match simulated and measured temperatures. It operates in two modes: injection mode for injection temperature modeling and production mode for production temperature modeling. The simulation is based on the assumption that fluid and gas flow in the reservoir radially from and to the well. It also takes into consideration thermodynamic effects caused by fluid and gas flows through a reservoir, behind casing and along the wellbore as well as wellbore and behind-casing cross-flows.

TERMOSIM™ technology is described in more detail on TGT website www.tgtoil.com and in [2]. OPTISIM is an advanced thermal simulator, that builds on decades of Research & Development on the above described industry-proven technology, adding the ability to process and simulate Fiber Optics data. OPTISIM determines and quantifies flow profiles recorded in accordance with a well-specific data acquisition program. It has the ability to identify behind-casing flow and out-of-zone injection or production.

The advantages of Fiber Optic Based Surveillance are:

- Applicability in the wide range of wells, from water injectors and oil producers to polymer/ Enhanced Oil Recovery (EOR) wells, deep wells, observation wells etc.
- Low cost of installation compared to dual wellhead completion for pumped wells
- Their non-intrusive nature reduces operational load in the field, logistics and HSSE exposure
- Automated on-demand time-lapse surveillance potential, which further reduces lifetime costs compared to conventional logging
- Fiber Optic based production/injection profiling can support the asset teams in assessing production and injection conformance, allow faster turnaround from the planning of the survey to obtaining the results, taking timely decisions

Case Study

OPTISIM data interpretation was performed for a vertical water injector in the Middle East. The well was drilled in May 2016, completed as cased/ cemented with permanent DTS installed outside the casing, and put on stream in June 2016 with a target injection rate of 200 m3/d. The field is char-

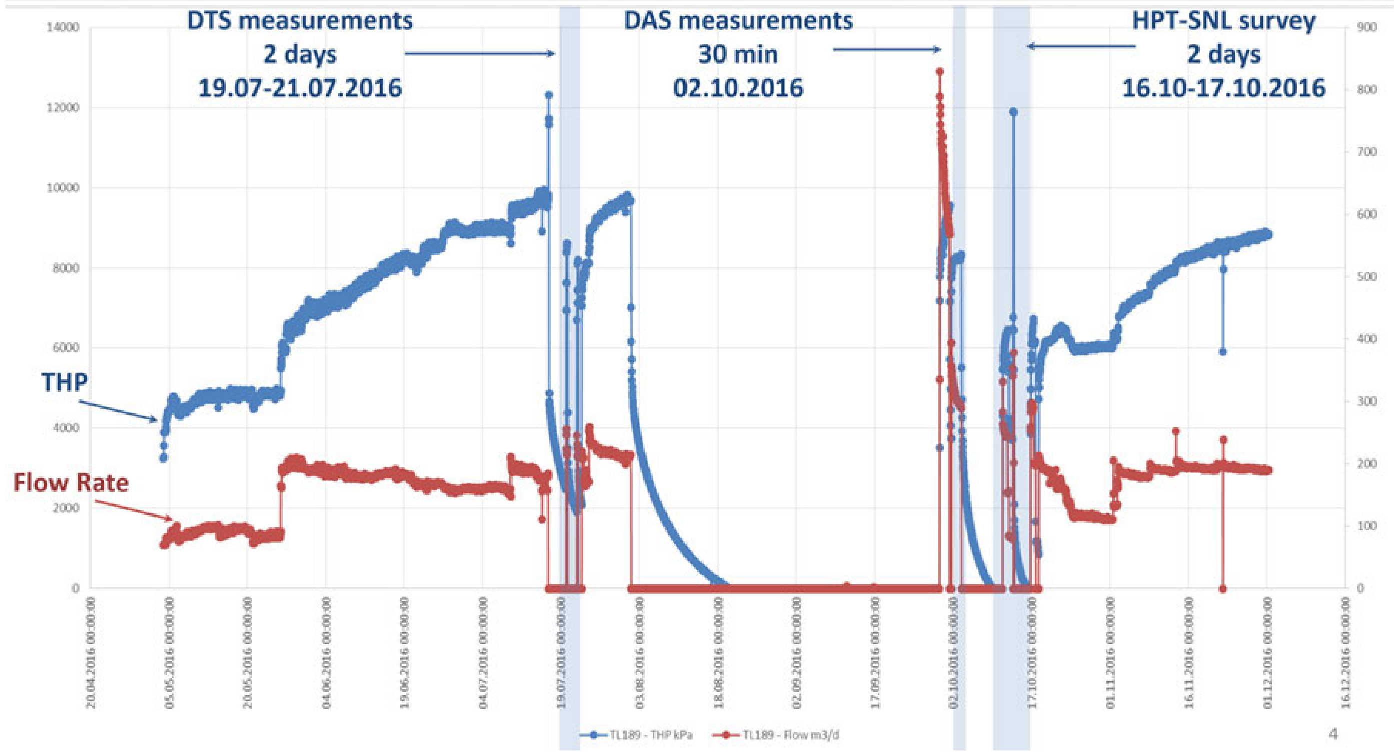

Figure1. Well injection history and timing of surveys

acterized by thinly laminated sandstone with highly variable permeability, interbedded with shales. This makes achieving injection conformance a very difficult task.

DTS data had been acquired over the period of 2 days (Fig.1) with static data recorded at the end of 3.5 days shut-in period, followed by an injection period, during which the flowing data were collected. Then, the well was shut-in again, allowing the gathering of the transient data.

This well's fiber optic installation is Distributed Acoustic Sensing (DAS)-enabled. The DAS data were collected on October 2 (Fig.1). Later in October, an HPT-SNL survey was performed.

The results of all the data processing and interpretation of all the three surveys are summarized in Fig.2.

Looking at the acoustic data first, one can see that out of the three active zones captured by the HPT-SNL logging, only two zones were detected by DAS. The DAS data were very noisy, so heavy amount of processing and filtering were required in order to 'clean up' the picture. It was also found that all the informative noise in the DAS was in the very low frequency range (below 50 Hz).

In the temperature panel, blue lines represent injection logs for HPT and DTS (illustrated in Fig.2). The discrepancy in absolute tempera-

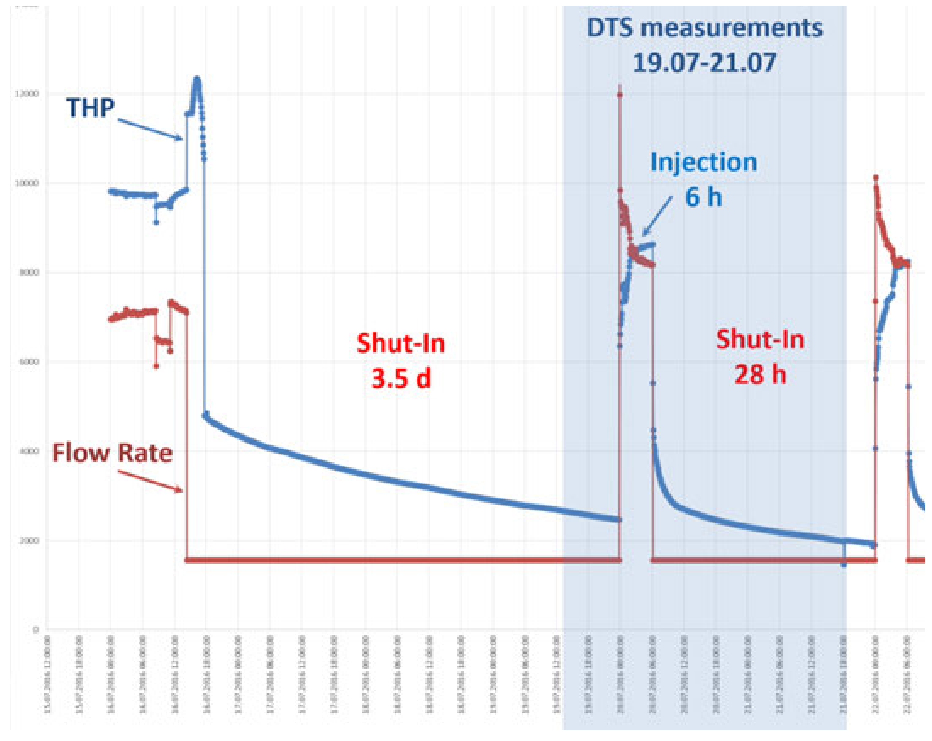

Figure 1a. DTS procedure

ture is most likely due to the different timing of the two surveys. One can see high level of noise in the DTS logs (STD ±0.2 °C, while HPT STD ±0.005 °C). This masked the minute details in the flowing log, making it possible to match only the average injection temperature (dashed lines represent the simulated temperature response).

The lines from green to brown represent the transient logs of 1, 2, 4, 10 and 28 hours of shut-in times accordingly. It is the transient logs that allowed to simulate the temperature response in this well, as opposed to the HPT survey, where all the matching was done by the flowing and the static passes. It can also be observed that the later transient logs give

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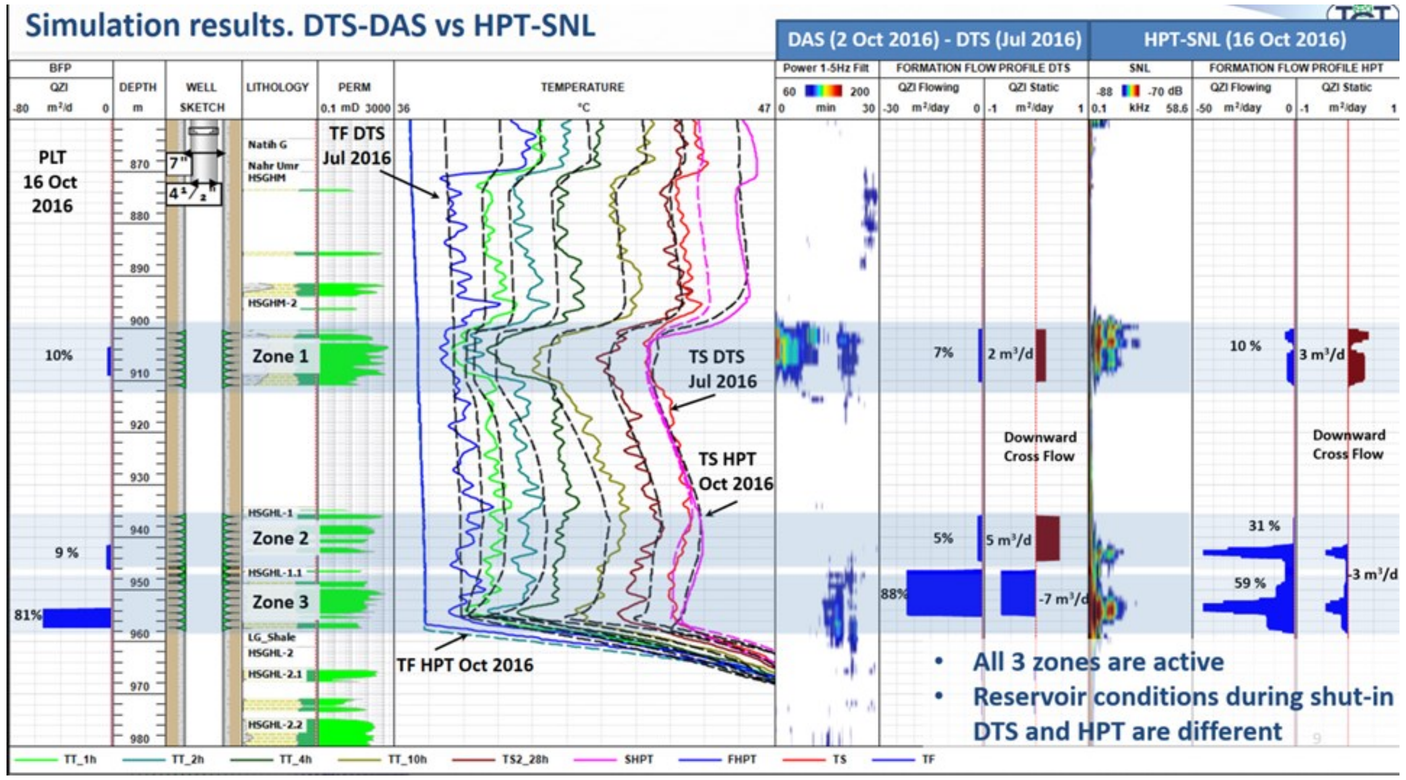

Figure 2. Results of DTS-DAS and HPT-SNL surveys

better matching than the early ones (dashed lines). The two rightmost curves are the static passes from DTS and HPT (marked on Fig.2). Both methods give adequate identification and quantification of the formation flow profile (see respective panels). Note that in static conditions, both surveys identified crossflow between the zones. Difference in the crossflow distribution is caused by the changed well and reservoir conditions. DTS, taken soon after the well had been put on stream, shows two upper zones producing and only the lower zone accepting water. Whereas in October, we can see only the upper zone producing and the two lower zones accepting.

During injection, all three zones have been identified as active in both surveys. Variance in the profile distribution in again caused by the changed well and reservoir conditions between the two time periods.

Summary

On DAS:

- Informative noises across Zone 1 and Zone 3 were detected. Noise across Zone 2 was not detected
- Overall, good correlation with SNL
- Informative noise is lower than 50 Hz
- Data are very noisy, additional processing required

On DTS:

- DTS data are noisy (STD (DTS) ±0.2 °C, while STD (HPT) ± 0.005 °C)
- Injection profile was identified by OPTISIM. Most useful information was derived from transient logs
- Good correlation between DTS and HPT results were found
- Discrepancy between HPT and DTS injection profiles is explained by different survey dates, well and reservoir conditions

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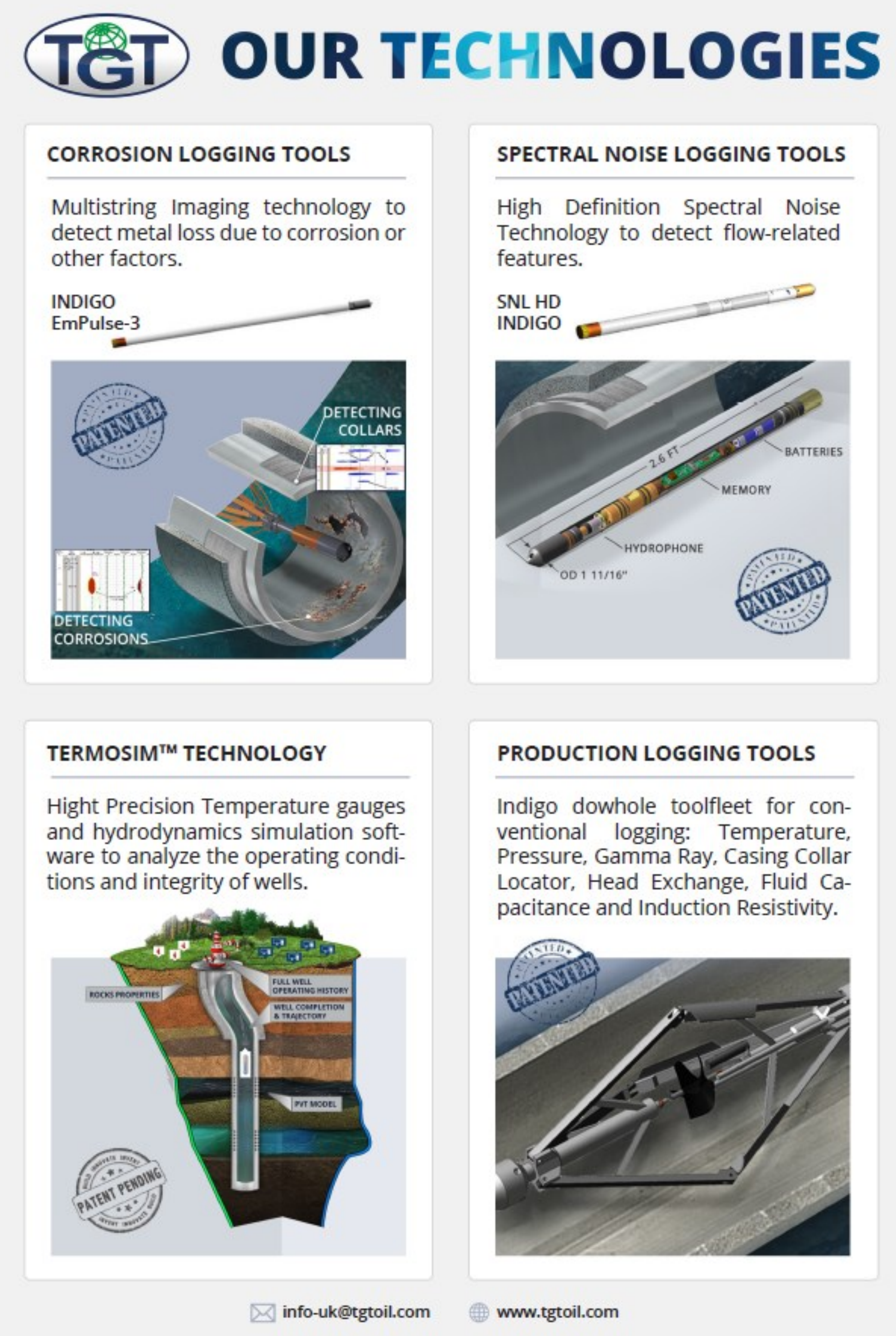

Improving Intervention Efficiency with Downhole X-ray Diagnostics

by Melissa Spannuth, PhD, Senior Physicist, Visuray

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Visuray

Poor well performance and downhole failures have a significant impact on the profitability of a well. To combat this, operators spend billions of USD each year on time-consuming and costly well interventions to improve production and repair hardware. These interventions cover a broad range of activities from straightforward maintenance to complicated workovers, but in all cases, operators strive for efficient and low-risk operations. A major factor contributing to inefficiency in interventions is the lack of reliable information about the current condition of the downhole equipment. When initially planning an intervention, operators frequently infer downhole conditions either from surface measurements or from downhole measurements that are ancillary to the issue they are investigating [1]. Such limited information often fails to accurately diagnose the issue or misses an underlying problem, which in turn leads to ineffectual intervention activities that do not achieve the objectives. The operator must then investigate further using the same insufficient tools and try another intervention. This trial-and-error cycle repeats with costs and non-productive time mounting until eventually the issue is resolved or the operator abandons the original intervention objectives. To break this inefficient cycle, a number of downhole imaging techniques have been developed.

The purpose of downhole imaging is to improve the initial investigation step of the intervention cycle, as well as any subsequent investigations, by providing a clear visual representation of what is happening in the well. Typical techniques include the lead impression block and optical camera, with ultrasonic imaging having been recently introduced. The first technique uses a block of lead lowered inside the well to take an impression of the object [2]. While fast and inexpensive, the impression can often be difficult to interpret. As a second option, optical cameras can provide images in well fluids transparent to visible light or in gas filled wells, but even small traces of oil or particulates will distort the images [3]. As a result, wells must be cleaned and well fluids replaced with clear fluid or gas before attempting optical imaging. A more recent technology involves using ultrasonic imaging to produce an image of an object inside a fluid-filled well [4]. Ultrasonic imaging works even when the well is filled with opaque fluids, but fails when the fluid is too heterogeneous, for example when the fluid contains suspended particles or bubbles, or when the speed of sound is inaccurately estimated.

As an alternative, Visuray has recently introduced the VR90 downhole X-ray diagnostic service [5]. While X-ray imaging has been applied advantageously in the health and security industries for decades, Visuray is the first company to have successfully adapted this powerful technique to the challenging downhole environment. The primary advantage of using X-rays for imaging in an oil well is that the radiation can penetrate materials that are opaque and highly heterogeneous. Such materials include oil, brine, oil/water mixtures, and fluids with a large amount of suspended particulates, as well as some solid materials such as cement and sediments [6]. The ability of X-rays to "see" in almost any fluid means that the VR90 tool reliably produces accurate diagnoses without extensive well preparation, saving time and money during interventions.

The VR90 tool's imaging capabilities rest on a patent-pending technique for reconstructing the surface topography of objects in a well based on the X-rays backscattered from the well fluids [6]. The amount of X-ray radiation recorded by the VR90 tool's detectors depends upon the amount of X-ray-illuminated well fluid between the VR90 tool and the target object in the well. This radiation recorded by each pixel of the detectors is converted into a distance to the surface of the object viewed by that pixel using a semi-empirical formula based on the physics of X-ray scattering. In this way, we reconstruct the surface of the target object in three dimensions.

An example of one such reconstruction is shown in Figure 1 where it is displayed both as a two-dimensional depth map image and a three-dimensional rendering. In the depth map representation, white and light grey pixels represent areas that are closer to the VR90 tool, while black and dark grey pixels represent areas that are farther from the tool (i.e. the depth of the surface of the object is mapped to a grey scale color scheme). The imaging data were obtained during laboratory tests in water made completely opaque by particles of rust suspended in it. The results reveal an easily-recognizable adjustable spanner. Fine details on the spanner are visible, such as a small hole in the neck and the threads on the adjustment screw, demonstrating the millimeter-scale resolution of the VR90 tool's reconstructions. Furthermore, these reconstructions are dimensionally-accurate, so the resulting images and renderings can be used to measure features on the target object with millimeter-scale accuracy. While these results were obtained in the lab, the VR90 service reliably produces the same caliber results in the field – all in real-time without any well preparation necessary.

To demonstrate these capabilities, consider a recent case from offshore Norway [7]. The operator was considering converting the North Sea injector well back into a producer, but the decision on how to proceed was held up by uncertainty about the downhole safety valve (DHSV). The DHSV had failed during testing and attempts to install an insert DHSV had been unsuccessful. The operator had also attempted to lock the valve open, so they suspected that the flapper on the DHSV was stuck in a partially open position. They wanted to determine whether it would be possible to repair or replace the safety valve as part of the conversion to a producer without having to recomplete the well. Our objectives for the VR90 service's X-ray diagnosis were thus to investigate the valve and define the clearance through the valve.

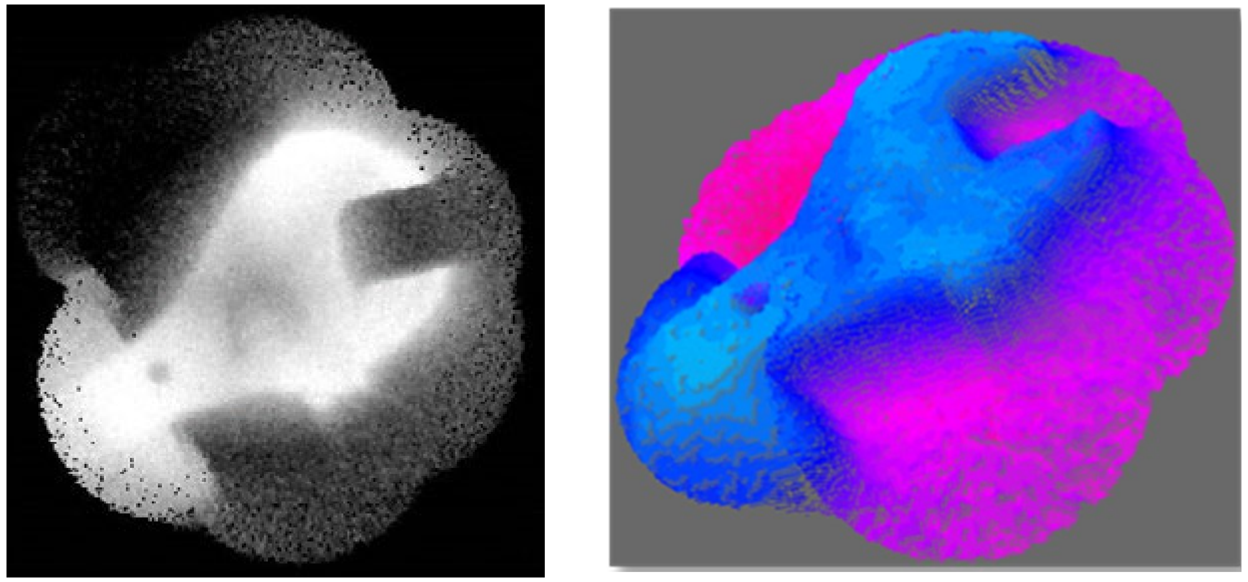

Figure 1. Examples of 2d depth map (left) and 3d rendering (right) from laboratory imaging of an adjustable spanner

We achieved these objectives by acquiring multiple X-ray images with the VR90 tool positioned at various locations within the DHSV. Three of the X-ray images acquired by the VR90 tool are shown in Figure 2. Side view drawings of the corresponding tool and flapper positions, and renderings of what the tool sees are also shown. From top to bottom, the X-ray images show the flapper nearly closed, half-way closed, and almost fully open. As indicated by the drawings, the VR90 tool was resting on the flapper and pushed it open as the tool was moved through the valve. The X-ray images show that the maximum measured opening angle of the flapper was 73°.

In particular, the VR90 diagnostic service provided two key pieces of information: the flapper was not locked open and the flapper could open wide enough to install the insert safety valve. By performing this diagnostic imaging before beginning the intervention on the DHSV, the operator was able to eliminate other time-consuming and risky options, such as recompleting the well or attempting to mill the flapper. Instead, they were able to success-

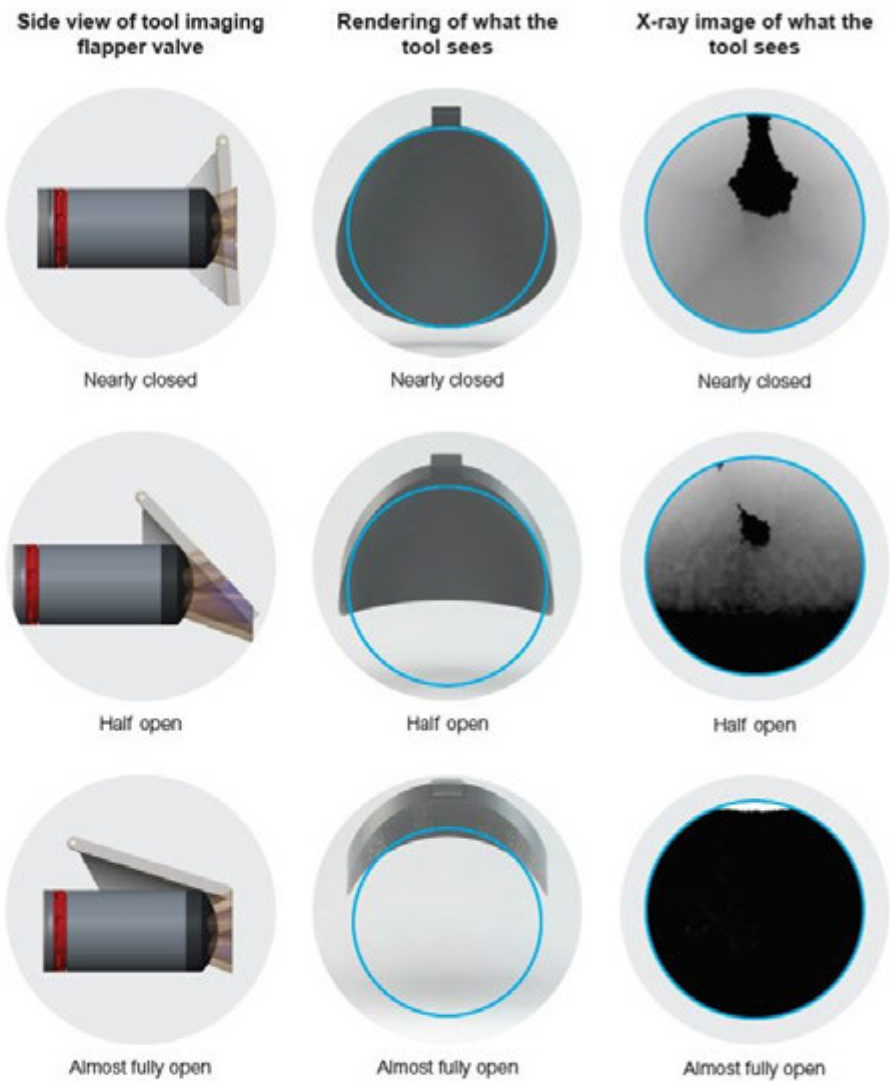

Figure 2. Results of VR90 service's X-ray investigation of DHSV in a North Sea well

fully install an insert DHSV, an efficient and cost-effective solution.

In a second example, we provided our service to an operator in the Permian Basin in West Texas. In this case, the tubing was being pulled from the well during an intervention when it became stuck and eventually parted. The remaining tubing needed to be fished, but the fishing company was unsure of the exact location and shape of the top of the fish. The situation was further complicated by the state of the tubing that had been pulled from the well. The bottom of that tubing showed severe damage due to milling, which suggested that the top of the tubing left in hole could be mangled. Our objectives for the VR90 service's X-ray diagnosis were thus to locate the top of the tubing to be fished and provide a visualization of the tubing with accurate dimensions so that the fishing company could design an appropriate fishing tool.

We achieved these objectives by tagging the top of the tubing and then acquiring multiple images above and below the top. One of the resulting images is shown in Figure 3 along with a photograph of the stuck tubing after it was fished from the well. The image reveals that the tubing had been slightly crushed against the casing producing an oval-shape at the top. Additionally, a sharp edge became folded over the top of the tubing blocking the inside of the tubing. The images also revealed damage along the tubing as no clear outer diameter was visible.

Based upon these images, obtained in real-time at the well site, Visuray recommended against further milling attempts and suggested a specific type of fishing tool. The client chose to follow these recommendations and successfully fished the tubing on the first attempt. When the tubing was pulled from the well, the VR90 service's diagnosis was confirmed as the folded-over top and shredded outer diameter were clearly evident on the fished tubing top. This outstanding outcome was possible due to the dimensional-accuracy of the reconstructions and the quick, reliable results produced by the VR90 service.

Overall, these case studies demonstrate how the VR90 downhole X-ray diagnostic service can be used to improve efficiency in well intervention activities. The VR90 service provides quick, reliable and accurate visualizations of downhole hardware without the need for any well preparation, which makes it ideal as a diagnostic tool. The cases further demonstrate how performing X-ray diagnostics during the early stages of an intervention can turn the typical trial-and-error intervention cycle into an efficient intervention process. Performing intelligent interventions with diagnostic imaging at the outset has the potential to increase intervention efficiency, saving time and money, and reducing the risk associated with well interventions.

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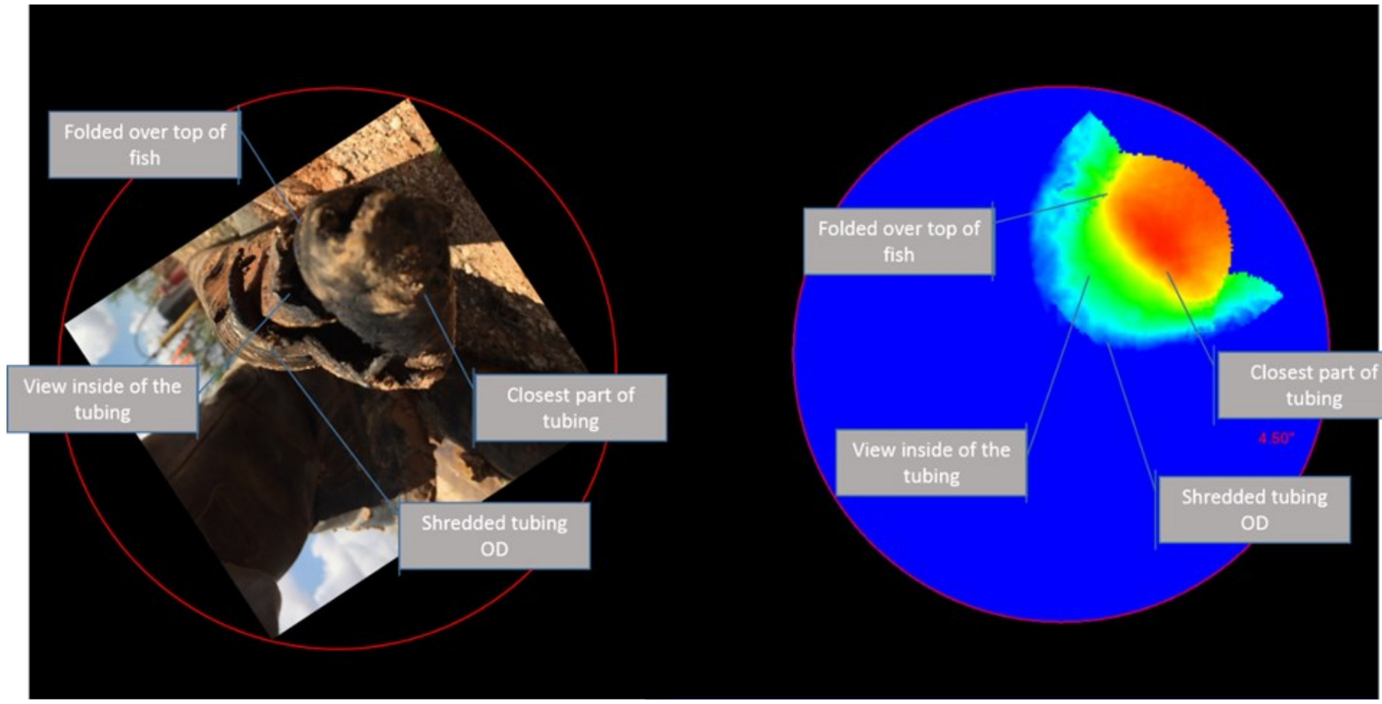

Figure 3. Results of VR90 service's X-ray investigation of parted tubing in Permian Basin (right) and photo of actual tubing pulled from well (left)

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