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INTERVIEW
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AT IADC

INTERVIEW
ENG. ABDEL MAKSOUD DESOUKY
GOS DISTRICT ENGINEERING GENERAL MANAGER
AT DRAGON OIL-EGYPT

INTERVIEW
MR. ANDREW MABIAN
PETROLEUM ENGINEERING / PRODUCTION OPERATIONS
MANAGEMENT

MULTISENSE DYNAMICS MAPPING SYSTEM TECHNOLOGY

FROM SERVICE LOOP TO E-LOOP TECHNOLOGY

LATEST OIL & GAS INDUSTRY NEWS

IADC
SUEZ UNIVERSITY
STUDENT CHAPTER

IADC SUEZ TECHNICAL MAGAZINE
ISSUE 1 | FEB 2025

OIL PRODUCTION BY COUNTRY

	COUNTRY	YEARLY OIL PRODUCTION (BARRELS PER DAY)
1	United States	14,837,639,510
2	Saudi Arabia	12,402,761,040
3	Russia	11,262,746,200
4	China	4,905,070,874
5	Canada	4,596,724,820
6	Iraq	4,443,457,393
7	Iran	4,376,194,355
8	United Arab Emirates	3,772,788,273
9	Brazil	3,242,957,836
10	Kuwait	2,990,544,137

OIL RESERVES BY COUNTRY

	COUNTRY	OIL RESERVES (BARRELS) IN 2016	WORLD SHARE
1	Venezuela	299,953,000,000	18.2%
2	Saudi Arabia	266,578,000,000	16.2%
3	Canada	170,863,000,000	10.4%
4	Iran	157,530,000,000	9.5%
5	Iraq	143,069,000,000	8.7%
6	Kuwait	101,500,000,000	6.1%
7	United Arab Emirates	97,800,000,000	5.9%
8	Russia	80,000,000,000	4.8%
9	Libya	48,363,000,000	2.9%
10	Nigeria	37,070,000,000	2.2%

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IADC is dedicated to enhancing the interests of the oil-and-gas and geothermal drilling and completion industry worldwide. Membership is open to any company involved in oil and gas exploration, drilling or production, well servicing, oilfield manufacturing, or other rig-site services. Founded in 1940, IADC mission is to improve industry health, safety, and environmental practices; advance drilling and completion technology; and champion responsible standards, practices, legislation, and regulations that provide for safe, efficient, and environmentally sound drilling operations worldwide. Through conferences, training seminars, print and electronic publications, and a comprehensive network of technical publications, IADC continually fosters education and communication within the upstream petroleum industry.

HISTORY

SINCE 1940

FOR 80 YEARS, IADC HAS CHAMPIONED THE DRILLING INDUSTRY THROUGH TRAINING PROGRAMS, GUIDELINES, PUBLICATIONS, COMMITTEES, CONFERENCES, AND ADVOCACY FOR THE GLOBAL DRILLING INDUSTRY.

QUOTE

IADC is focused on core industry issues, like health and safety, training and accreditation, attracting the next generation to work alongside us, and serving as a strong advocate for oil and gas activities.

– Jason McFarland, IADC President

IADC
SUEZ UNIVERSITY
STUDENT CHAPTER

Founded in January 2024 and affiliated with the International Association of Drilling Contractors (IADC), our chapter is your gateway to a world of opportunities in the drilling industry. We aim to build a community of passionate students, bridge the gap between academia and industry through expert insights, practical experiences, and career opportunities, and advocate for sustainable and innovative drilling practices.

VISION

Urging the value of volunteerism and creating harmony among teams; enabling them to explore their potential technically and non-technically.

MISSION

We aim to build a community of passionate students, bridge the gap between academia and industry through expert insights, practical experiences, and career opportunities, and advocate for sustainable and innovative drilling practices.

FOREWORD

ENG. MAGED AHMADY

IADC Suez Chairman & Founder

STUDENT ACTIVITIES AND ITS EFFECT ON THE STUDENTS

INTRODUCTION

Welcome to the IADC Suez University Student Chapter's magazine! As the chairman and founder of this chapter, I am proud to share our journey of creating an engaging platform for students passionate about petroleum engineering. Our chapter was established with the vision of providing students with opportunities to enhance their technical knowledge, develop professional skills, and build meaningful industry connections. Through technical workshops, competitions, and networking events, we strive to empower our members and prepare them for leadership roles in the petroleum sector. Our mission is to instill a spirit of continuous learning, innovation, and excellence, ensuring our members are equipped to tackle future challenges and opportunities.

STUDENT CHAPTER MEANING

Student chapters, like ours at Suez University, play a crucial role in academic institutions. They offer students a unique space to learn, grow, and thrive in their chosen fields by balancing theoretical and applied knowledge. By participating in various activities, students gain valuable insights and hands-on experience that bridge the gap between academic learning and industry applications. Through our chapter, members have the opportunity to network with industry experts, contribute to their field's development, and stay informed about the latest trends and challenges. Student chapters foster a spirit of collaboration, innovation, and continuous learning, creating a rewarding and enjoyable environment for all participants. I am immensely proud of our members' dedication and enthusiasm and look forward to witnessing their continued growth and success. Together, we are shaping a brighter future for our industry.

HOW TO GET THE MOST OUT OF STUDENT CHAPTERS?

As the Chairman of the IADC Suez Chapter, I encourage students to actively engage with our chapter to make the most of their experience. Academic life is not just about acquiring theoretical knowledge but also about applying it to real-world scenarios. To truly benefit, students should actively participate in chapter activities, projects, and events. These experiences help reinforce classroom learning and develop essential skills. Taking on leadership roles within the chapter can also help students enhance their organizational, communication, and problem-solving abilities while making a tangible impact. Seeking feedback is another crucial aspect of growth. Reflecting on experiences, learning from mentors, and striving for improvement will help students develop both personally and professionally. By being proactive, open to learning, and committed to self-improvement, students can make the most of their Student Chapter journey and prepare for a successful future.

CONCLUSION

The magazine project is a prime example of how student activities can bridge the gap between theoretical knowledge and practical skills. A dedicated team of students collaborated on various roles, from writing to project management, gaining hands-on experience in publishing. They learned teamwork, deadline management, and effective communication. Continuous feedback helped them improve and produce a high-quality magazine. This experience not only enhanced their technical skills but also boosted their confidence and prepared them for future challenges. Engaging in such activities fosters personal and professional growth, setting students up for success.

MESSAGE

ASSOC. PROF. NEVEN ALY

Petroleum Engineering Department Head & IADC Suez Faculty Advisor

Dear IADC Family,

I hope all of you in high spirit as usual. As We embark another season together, I want to highlight some thoughts about my journey with IADC Suez which is the only IADC student chapter in the Egyptian Universities. The establishing of the chapter was not an easy task but the rewards are great. The unique combination of technical and soft Skills that have been delivered though the different activities of our chapter was phenomenal and helped the overall development of the Suez University students . the growing of the chapter reputation is built on our recognized quality, commitment, accountability and integrity.

Hand by hand, focusing on our main target which is preparing Suez university students into confident, enterprising and wholesome personalities in a way they can face the stark realities of life and equipping them with employability.

I have to thank all the chapter members, for their contained participation and enthusiasm in ou professional community .

Finally, I have to give a special shout out of appreciation to the Vice President- Eastern Hemisphere – IADC (Mr.Hisham N. Zebian) and Senior Vice President, International Development- IADC (Mr. Mike Dubose) for the great support and guidance they provide to us step by step.

Assoc. Prof. Nevin Aly
IADC Suez Advisor

1 ARTICLE

ENG. HANY METWALLY

A DRILLING AND WELL CONTROL SPECIALIST AT ARAMCO WELL CONTROL SCHOOL IN SAUDI ARABIA.

AN ANALYTICAL STUDY ON EARLY KICK DETECTION AND WELL CONTROL CONSIDERATIONS FOR CASING WHILE DRILLING TECHNOLOGY

ABSTRACT

Casing while drilling (CwD) technology helps reduce drilling time and costs by enhancing wellbore stability, fracture gradient, and minimizing formation damage. However, it alters the wellbore geometry and volumes compared to conventional drilling, requiring a different well control approach. This study presents a simplified method for evaluating kick tolerance and allowable well shut-in time for both CwD and conventional drilling techniques using a mathematical model. Preliminary findings show that CwD results in three times higher annulus pressure loss, a 50% reduction in kick tolerance, and a 65% decrease in the maximum allowable well shut-in time, highlighting the need for an early kick detection system.

INTRODUCTION

As deeper, more complex, and costly reservoirs are developed, there is a growing demand for solutions that improve drilling efficiency while minimizing risks and costs. Casing while drilling (CwD) technology addresses this by allowing the casing to reach total depth (TD) and optimize the well structure, especially in soft formations with borehole issues in the top section. CwD's bottom hole assembly (BHA) typically includes a pilot bit, reamer, stabilizer, and drill lock assembly (DLA), with the DLA acting as the hydraulic sealing connection between the drilling assembly and casing string (Fig. 1 and Fig. 2). This study focuses on the maximum allowable well shut-in time as a measure of kick tolerance and inflow rate, comparing well control in a simulated vertical well drilled conventionally and with CwD, using a single-phase kick tolerance model with water-based mud and a gas kick (Fig. 3)..

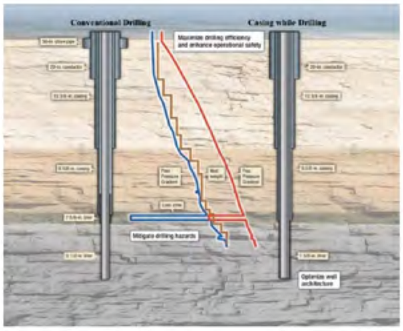


Fig. 1. Conventional drilling vs. casing while drilling technology.

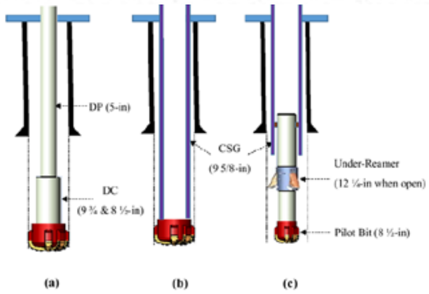


Fig. 2. Conventional drilling BHA vs. casing while drilling BHA.

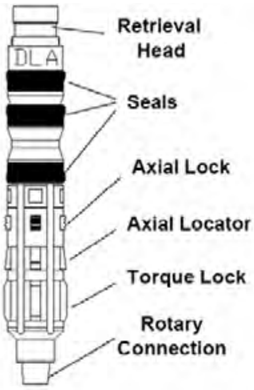


Fig. 3. Drill lock assembly.

CASING WHILE DRILLING (CWD) SYSTEMS ARE CLASSIFIED INTO TWO MAIN TYPES:

1. Retrievable System: In this system, once the target depth is reached, the bottom hole assembly (BHA) can be retrieved using a wireline unit or drill pipe. This system allows for the recovery of the BHA connected to the first joint of the casing string with a drill lock assembly (DLA).
2. Non-Retrievable System: This system does not allow for the recovery of the BHA. Once the required depth is achieved, the well is immediately cemented. If further drilling is needed, a drillable bit, such as a polycrystalline diamond composite (PDC) drill bit, is used to drill out the existing bit.

These two systems cater to different operational needs and strategies in CwD technology.

FEATURES AND BENEFITS OF CWD TECHNOLOGY

Casing while drilling (CwD) technology, while similar to conventional drilling methods, represents a significant advancement in the industry. It offers substantial cost savings by eliminating expenses related to the acquisition, handling, inspection, transportation, and tripping of drill strings, potentially reducing costs by 10% and saving 30% of drilling time. Additionally, CwD significantly decreases the loss of circulation issues. Research has highlighted successful implementations of CwD and suggested improvements for managing fracture gradients, all contributing to a reduction in overall well costs.

- Reducing drilling time & increasing efficiency
- Controlling casing strings cost
- Reducing cementing costs
- Improving borehole cleaning efficiency
- Improving wellbore stability
- Reducing loss of circulation
- Plastering/smearing effect
- Rig operating costs

LIMITATION OF CWD

CwD is becoming more widely regarded as a feasible means of lowering drilling expenses and resolving drilling challenges but still there are some practical limitations in CwD as follows:
1. Formation evaluation: Casing while drilling necessitates casing the well as soon as drilling begins. Once the hole section is complete, traditional wireline logging tools cannot be used to log the open hole unless the casing is raised above the zone and logged below the bottom.

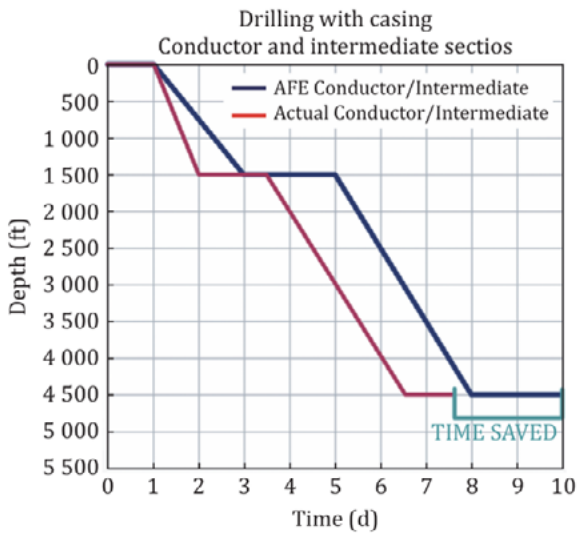


Fig. 5. Tesco's CwD practice.

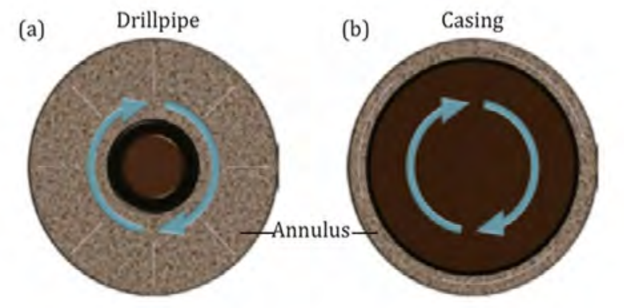


Fig. 6. Annular space of the conventional drilling (a) versus CwD (b).

2. Casing connections: Casing connections are commonly guaranteed to operate stationary in the hole as in conventional drilling and may not be able to withstand high torque and compressive loads in a buckling environment, so the Casing while drilling operation is restricted to drill with low torque, low weight on bit, and maintain buckling to a lower limit with smaller hole sizes.

3. Cementing: The BHA is wireline recovered in the casing while drilling once the casing has been drilled to the planned casing setting depth. The cement plug will be landed without the need for a float collar, The displacement plug should drop and latch onto the casing, acting as a float, to solve this problem. To drill out the plug and cement in the shoe joint, an under reamer and pilot bit assembly linked to the next smaller size of casing must then be used.

Fig. 7. Plastering effect in the casing while drilling operation.

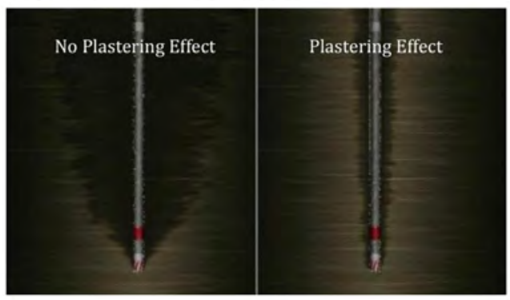


Fig. 8. Illustration of plastering effect.

WELL CONTROL FOR CWD AND PROBLEM STATEMENT

More than 70% of well control incidents occur during drill string tripping, but with the CwD (controlled drilling) technique, the bottom of the string remains at the bottom of the hole, reducing the likelihood of kick events. However, it is still important to study the allowable response time for handling kicks in CwD operations, as early kick detection remains a key part of well control safety. The CwD technique alters borehole geometry, which significantly impacts well control methods and monitoring systems. Understanding the differences between CwD and conventional drilling is essential to preventing blowouts, with effective kick detection and termination being critical. Kick tolerance (KT) is defined as the largest influx that can be tolerated without fracturing the casing shoe, and design limits must be carefully managed to ensure well integrity and safety. Effective early kick detection (EKD) and blowout prevention are essential to avoid costly losses and environmental damage. Key performance indicators (KPIs) such as Kick Detection Volume (KDV) and Kick Response Time (KRT) help assess kick safety. Designers must account for crew response time, equipment reliability, and well control procedures, ensuring thorough training and preparation. Proper risk analysis and emergency response plans during the design phase are crucial for minimizing errors and ensuring an effective response in the event of a well control incident.

Fig. 9. (a) Conventional drilling, and (b) CwD wellbore geometry

FIELD CASE STUDY

Well X-2 was planned as a replacement for well X-1, which faced significant drilling challenges in the intermediate hole section due to borehole instability from reactive shale formation, leading to plugging and abandonment. Non-productive time (NPT) was caused by stuck drill strings and continuous reaming, impacting drilling efficiency and increasing costs. In response, well engineering teams sought a solution to reduce drilling costs and improve performance, leading to the decision to use Casing while Drilling (CwD) technology in well X-2. CwD would allow the casing to be drilled through the problematic formation and cemented once the total depth is reached, reducing exposure to aqueous fluids and minimizing wellbore collapse risks. However, before implementation, the team must assess control conditions and borehole instability to ensure CwD effectively addresses these challenges and maximizes drilling performance

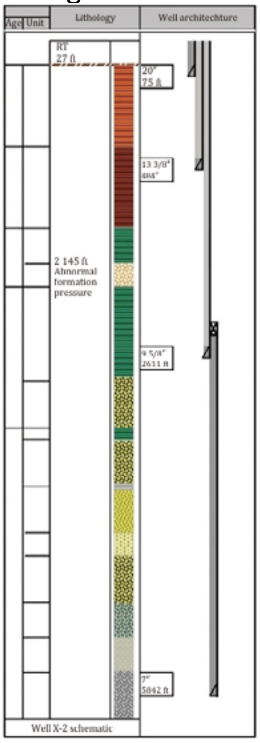


Fig. 10. Schematic diagram of wellbore.

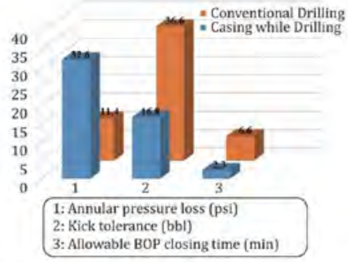


Fig. 12. Column chart of resulted APL, kick tolerance and allowable BOP closing time of conventional and CwD technique.

Due to the high APL in CwD, pumps should be adjusted to maintain constant bottom-hole pressure during well control. Another important conclusion is that the length of overpressure formation drilled before a kick is detected must be considered in careful planning (see Table). Because the annulus of a CwD well is so narrow compared to a conventional well, even a small change in influx volume can result in a large difference in allowable blowout preventer (BOP) closure time and well control procedure.

Table Drilled length into the overpressure formation vs. allowable well shut-in time.

Length drilled (ft)	Kick inflow rate Q_{influx} (bbl/min)	Maximum allowable well shut-in time (min)	
		Conventional method	CwD method
1.00	0.23	132.8	46.9
2.00	0.46	66.4	23.4
3.00	0.69	44.3	15.6
4.00	0.92	33.2	11.7
5.00	1.15	26.6	9.4
6.00	1.38	22.1	7.8
7.00	1.61	19.0	6.7
8.00	1.84	16.6	5.9
9.00	2.07	14.8	5.2
10.00	2.30	13.3	4.7
11.00	2.54	12.1	4.3
12.00	2.77	11.1	3.9
13.00	3.00	10.2	3.6
14.00	3.23	9.5	3.3
15.00	3.46	8.9	3.1
16.00	3.69	8.3	2.9
17.00	3.92	7.8	2.8
18.00	4.15	7.4	2.6
19.00	4.38	7.0	2.5
20.00	4.61	6.6	2.3

RESULTS AND COMPARISON

This section outlines the study results and comparison of the results obtained from the proposed methodology of kick tolerance and allowable well shut-in time. To evaluate the proposed methodology, data from the simulated vertical well was used. After data collection, the two sets for conventional and the CwD method were used to implement the proposed methodology as shown in Table below.

Table Results of the study.

Output data	Unit	Conventional drilling method	CwD method
Hydrostatic pressure (HP)	psi	1015	1015
Annular pressure loss (APL)	psi	11.4	32.6
Bottom hole pressure (BHP)	psi	1026.4	1047.6
Formation pressure (FP)	psi	928.8	928.8
Fracture gradient (FG)	ppg	15.6	15.6
Kick height (H_{kick})	ft	673	673
Kick tolerance (KT)	bbl	36.6	16.8
Maximum allowable surface pressure (MAASP)	psi	163.6	163.6
Kick inflow rate (Q_{influx})	bbl/min	4.6	4.6
Allowable well shut-in time with 20 ft drilled into overpressured formation	min	6.6	2.3

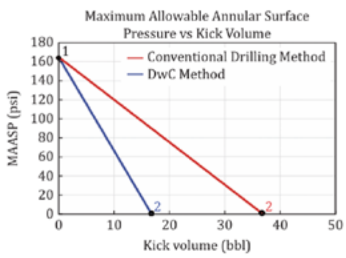


Fig. 11. Comparison between conventional and CwD methods.

CONCLUSION

(CwD) technology has proven to lower well costs, reduce non-productive time, and mitigate wellbore challenges. It is particularly effective in softer formations and with larger casing sizes, though it may not always be cost-effective. As the technology evolves, especially with advancements in retrievable liner drilling, its applications are expanding. CwD aims to drive casing as deep as possible to address problematic zones, but this requires careful operational and technical planning. A study on CwD highlighted it results in three times higher annulus pressure loss compared to conventional drilling. Additionally, kick tolerance is reduced by 50%, and the maximum allowable well shut-in time is reduced by 65%, emphasizing the necessity for an early kick detection system to ensure well control and safety.

2 ARTICLE

ENG. LEOPOLDO SIERRA

DIRECTOR OF ENGINEERING APPLICATIONS AT LINQX

HYDRAULIC FRACTURING DESIGN CONSIDERATIONS FOR CARBON CAPTURE, UTILIZATION, AND STORAGE (CCUS)

ABSTRACT

Hydraulic fracturing, commonly used in oil and gas, is being explored to enhance the efficiency of Carbon Capture, Utilization, and Storage (CCUS). This paper reviews the feasibility of using hydraulic fracturing in CCUS, focusing on factors like wellbore and fracture orientation, fluid selection (especially supercritical CO2), and proppant usage. It evaluates the impact of rock properties, reservoir conditions, and CO2 injection on storage capacity and injectivity. Simulations show how these factors can improve the success of CCUS projects, increasing storage efficiency and CO2 disposal. The paper provides insights into overcoming technical challenges and optimizing the combination of hydraulic fracturing with CCUS.

INTRODUCTION

As companies strive to reduce carbon emissions, CCUS has become a key focus, attracting interest from oil and gas operators and carbon-intensive industries. The 45Q tax credit incentivizes CO2 injection, but economic feasibility depends on factors like proximity to emitters, rock quality, and the risk of groundwater contamination. High-permeability rock is ideal for CCUS, reducing the number of wells needed and making projects more cost-effective. The Gulf Coast's Miocene and Frio sandstones are prime locations, but as competition increases, hydraulic fracturing offers a solution by enabling CO2 injection in lower-permeability rocks. This technology can expand CCUS potential, reducing transportation costs and increasing storage capacity by making more marginal sites viable for injection. This paper explores how hydraulic fracturing can enhance CCUS efforts and increase project feasibility.

INJECTIVITY PROBLEMS IN CCUS PROJECTS. POTENTIAL SOLUTIONS TO ADDRESS IT

An ideal environment for disposing of captured $scCO_2$ is a large, vertically contained saline aquifer with high permeability and porosity, along with a cap rock to prevent CO_2 migration and contamination of freshwater sources. However, during drilling and completion, injectivity damage can occur, reducing $scCO_2$ injection rates. In such cases, a small hydraulic fracture may be needed to bypass the damaged zone, restore injectivity, and ensure compliance with regulations. If the reservoir permeability is lower than expected, or if the saline aquifer is located far from CO_2 sources, a more aggressive hydraulic fracture may be required. In these cases, horizontal wellbore completions with multiple fractures can help increase the injection area and ensure adequate injectivity. Hydraulic fracturing is essential for meeting the injection requirements and maintaining the commercial-scale viability of geologic CO_2 sequestration projects

WELLS ARCHITECTURE AND WELLBORE ORIENTATION CONSIDERATIONS FOR CCUS

Wellbore and fracture orientation are critical for optimizing CO_2 injection, similar to hydrocarbon production. In low-permeability formations, wells should be aligned with maximum stress to generate longitudinal fractures, while horizontal wells in unconventional reservoirs are aligned with minimum stress to create transverse fractures. For high-permeability CO_2 injectors, a vertical well may suffice for higher injection rates if the reservoir is uniform. However, variations in reservoir properties often necessitate hydraulic fracturing in high-permeability aquifers (e.g., k = 1000 md) to achieve the desired CO_2 injection rates, as shown in Fig. 1

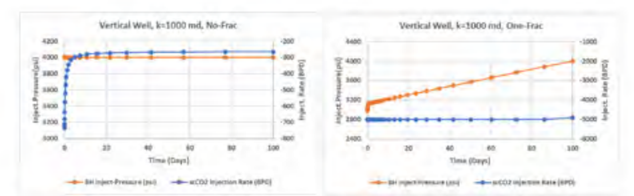


Figure 1—$scCO_2$ Injection estimation for High Permeability (1000 md) Vertical Well, No Frac & Non-Damaged and Fractured

COMPLETION CONSIDERATIONS FOR FRACTURING IN CCUS PROJECTS

Considering the listed considerations, this is in addition to the requirement to implement a hydraulic fracture stimulation. As mentioned before and shown in Table 1 the architecture of the wellbore for CCUS is going to be conditioned by the permeability level of the saline aquifer. For high permeability wells a vertical or deviated wellbore could assure the expected injection targets for this kind of project, but in the case of low permeability reservoirs the drill and completion of horizontal wells will be required to place multiple fractures to ensure the expected $scCO_2$ injection levels

Table 1—Completion options for $scCO_2$ injection

Reservoir Permability Level	Wellbore Architecture		
	Vertical Wellbore	Deviated (Slant) Wellbore	Horizontal Wellbore
Low Permeability Saline Aquifer (eg. 15 md)			√
Medium Permeability Saline Aquifer		√	√
High Permeability Saline Aquifer (eg. > 1000 md)	√	√	

To minimize the potential CO_2 leakage risk at the level of the wellbore, as shown in Fig. 2, the entire wellbore needs to be cemented using an appropriate cement slurry and placing an acid resistive cement slurry in the lower section of the wellbore where the saline aquifer is located.

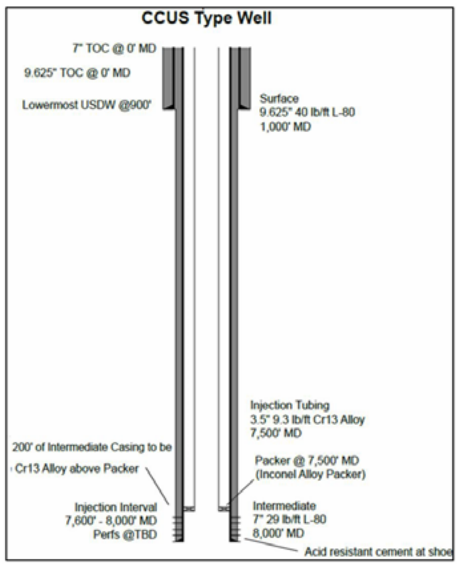


Figure 2—Example completion schematic for $scCO_2$ injection

Hydraulic fracturing in CCUS projects can increase CO_2 disposal volumes in saline aquifers. The choice of fracturing fluid and proppant is critical for effective proppant transport and fracture conductivity. Foam-based fracturing fluids, especially those using CO_2 or N_2, are optimal for reducing fracture face damage and improving proppant transport. A foam quality of 60% to 80% creates a stable, viscous fluid, as shown in Figure 3. Depending on the disposal environment, saline water from the aquifer can be used as the liquid phase, combined with gelling agents or viscoelastic systems as needed

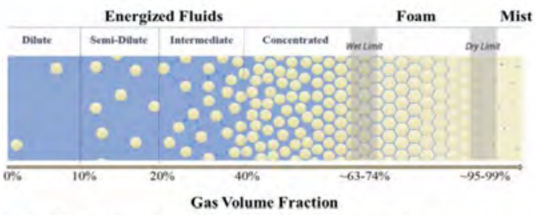


Figure 3—2D illustration of common classification of gas-liquid mixture according to gas volume fraction. Dispersed phase is assumed to be monomodal (Faroughi et al., 2018)

To effectively pump proppant concentrations without affecting equipment, CO2 foam quality should be limited to 80%. For instance, with a foam quality of 75%, proppant concentration must be four times higher to achieve the desired placement. Foam creates a stable, viscous structure that enhances proppant transport and reduces fluid loss, especially in high permeability environments. A base case simulation using properties from Fu et al. (2017) for a 15 mD permeability reservoir (Table 2) and alternate designs for a higher permeability case (1000 md, Table 3) were also evaluated, with all other parameters kept constant.

Table 2—Formation tops and rock properties, Low permeability Saline Aquifer

Formation Type	Sandstone	Formation tops (ft)	6400-6500
Thickness (ft)	100	Stress (psi)	4400
Permeability (md)	15	YM (psi)	1.5 e $^{+6}$
Porosity (%)	15	PR	0.25
Pressure (psi)	4900	Frac. Toughness (psi-in $^{1/2}$)	1000

Table 3—Formation tops and rock properties, High Permeability Saline Aquifer

Formation Type	Sandstone	Formation tops (ft)	6400-6500
Thickness (ft)	100	Stress (psi)	4400
Permeability (md)	1000	YM (psi)	1.5 e $^{+6}$
Porosity (%)	15	PR	0.25
Pressure (psi)	4900	Frac. Toughness (psi-in $^{1/2}$)	1000

The simulations show that CO2 foam can effectively generate fractures and place conductive fractures in both low and high permeability CO2 disposal reservoirs. The rate and pressure history, proppant concentration, and fracture conductivity are illustrated in Figs. 4, 5, and 6 for the first design. The results suggest that under the given reservoir and stress conditions, the vertical growth of the fracture does not compromise the integrity of the cap rock

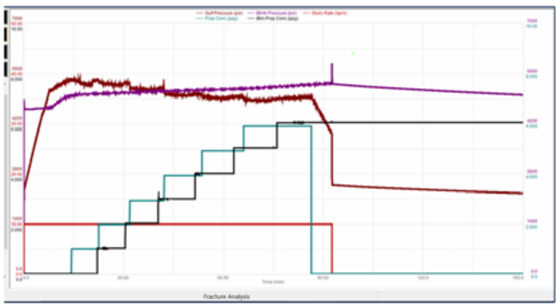


Figure 4—Design-1, Rate and Treatment Pressure History

This paper doesn›t analyze long-term thermal effects on cap rock stress, but evaluating the cooldown effect is key for predicting thermal fracturing and its impact on cap rock integrity. For $scCO_2$ injection in a low-permeability aquifer with seven fractures, Fig. 8 shows temperature variations around the fractures. After 100 days of injection, the temperature drop in the cap rock is minimal, with the primary cooling effect confined to the fractured area

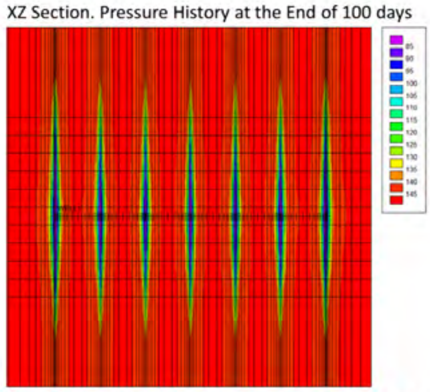


Figure 8—Design-1, Fracture Geometry and Fluid Temperature Inside Fracture

Another visualization of temperature drops around the fracture in the Y-Z plane is shown in Fig. 9, where the temperature drop around the cap rock area connected by the hydraulic fracture is nearly 20°F after 100 days of $scCO_2$ injection. This temperature drop results in a cap rock stress reduction of only 114 psi. This thermal effect is still too low to impact the integrity of the cap rock.

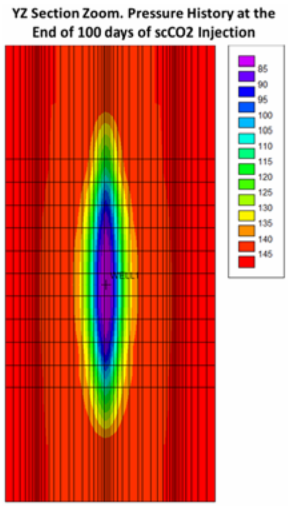


Figure 9—Design-1, Fracture Geometry and Fluid Temperature Inside Fracture

EVALUATION OF THE HYDRAULIC FRACTURING FOR CCUS

The benefits of hydraulic fracturing for injectivity and storage in low- and high-permeability saline aquifers were evaluated based on fracture geometry and conductivity. To prevent $scCO_2$ migration to upper horizons, such as freshwater layers or the surface, the maximum injection pressure in the simulations was set at 4000 psi, or 80% of the minimum stress of the upper and lower cap rocks. Fig. 12 shows the $scCO_2$ injection rate and Injectivity Index (I-Ix) for an unfractured well in a 15 md permeability reservoir with a skin value of 10. As expected, the injection rate and I-Ix for a vertical well are low (0.55 BPD/psi). To avoid cap rock failure and maintain the maximum injection pressure of 4000 psi, the injection rate must be reduced, resulting in limited $scCO_2$ storage capability.

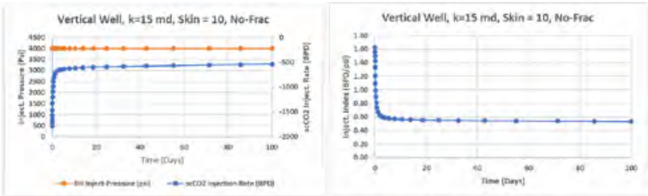


Figure 12—Simulated Injection Rate, Injection Pressure, and Injectivity Index. K = 15 md, Skin = 10, Not fractured

The same simulation was conducted for a vertical well completed in an undamaged 1000 md reservoir. As shown in Fig. 13, despite the higher permeability, the injection rate must still be reduced due to the fixed injection pressure limitations. However, compared to the low-permeability case, the Injectivity Index (I-Ix) in this case increases to 1.4 BPD/psi, which is 2.5 times higher than the 15 md case.

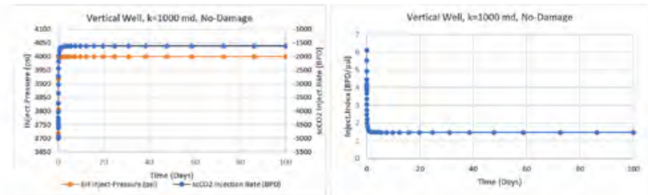


Figure 13—Simulated Injection Rate, Injection Pressure, and Injectivity Index. K = 1000 md, Skin = 0, Not fractured

The simulated cases show that reservoir permeability and the type of completion limit the long-term injection and storage of $scCO_2$. To improve injectivity and storability, hydraulic fracturing stimulation is required. Fig. 14 illustrates the comparative injectivity benefits of a hydraulically fractured vertical well with a permeability of 1000 md

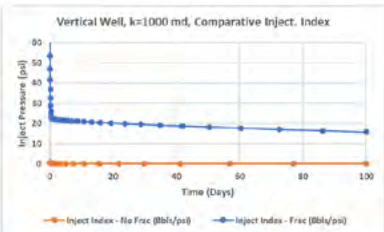


Figure 14—Simulated Injection Rate, Injection Pressure, and Injectivity Index. K = 1000 md, Vertical Well

For the case of lower permeability reservoir (15 md), it was considered a horizontal completion architecture where the scCO2 injectivity was evaluated placing 1, 4 and 7 transverse fractures. As shown in Figs. 15 and 16, the injection rate, and I-Ix increase substantially due to the hydraulic fracture stimulation. For the case of a reservoir of 15 md, the placement of more than 7 transverse fractures will improve the injection rate or I-Ix in short or long term

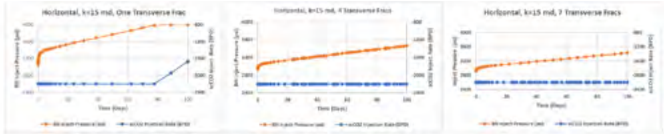


Figure 15—Simulated Injection Rate, Injection Pressure. K = 15 md, with one, 4 and 7 fractures

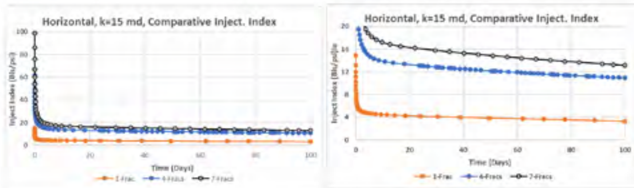


Figure 16—Complete and Expanded Comparative Injectivity for a K = 15 md reservoir and one, 4 and 7 Fractures

An alternative to improve $scCO_2$ injectivity in both low and high permeability cases is to drill a horizontal well aligned with the maximum stress, creating longitudinal fractures. Fig. 17 shows that for a 15 md permeability reservoir, placing three longitudinal fractures enhances the injection rate, and Fig. 18 shows an increase in the Injectivity Index (I-Ix). While fewer longitudinal fractures may be more cost-effective, placing transverse fractures results in higher injection rates and I-Ix for this permeability level.

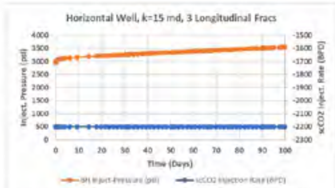


Figure 17—Complete and Expanded Comparative Injectivity for a K = 15 md reservoir and one, 4 and 7 Fractures

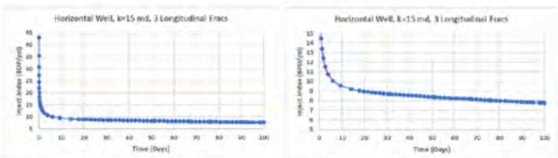


Figure 18—Complete and Expanded Comparative Injectivity for a K = 15 md reservoir and one, 4 and 7 Fractures

Fig. 19 shows the reservoir pressure distribution after 100 days of $scCO_2$ injection in a low-permeability formation with seven transverse fractures. As previously mentioned, the reservoir pressure, initially at 2900 psi, will increase over time. The time required to reach the maximum injection pressure of 4000 psi, set to avoid cap rock failure, will depend on the size of the saline aquifer chosen for CO_2 disposal.

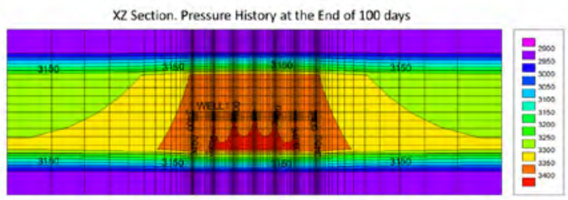
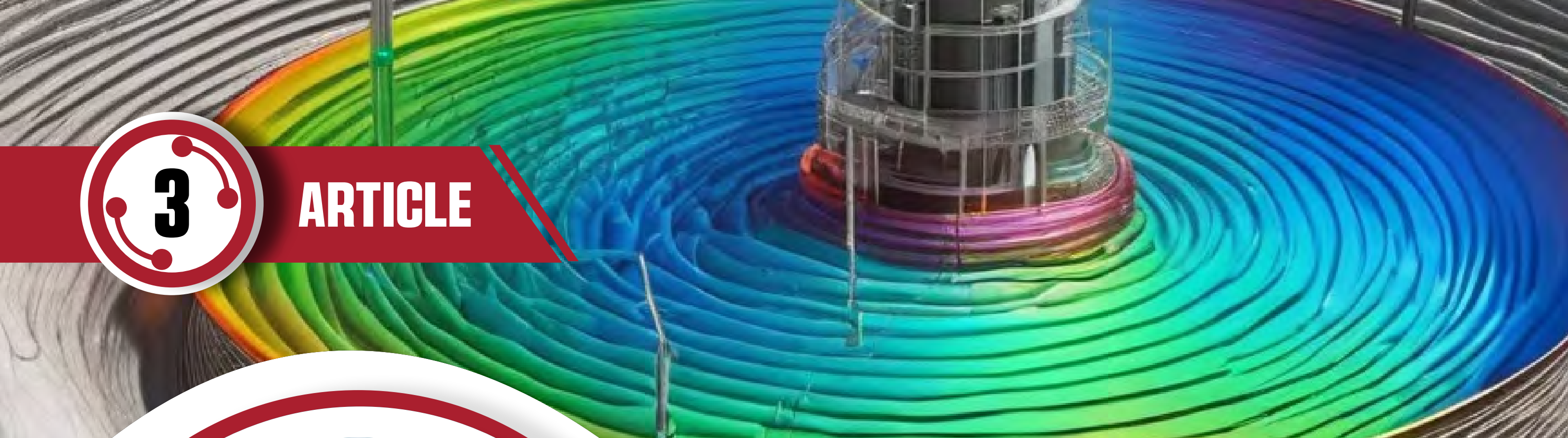


Figure 19—Complete and Expanded Comparative Injectivity for a K = 15 md Fractured Formation



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DOWNHOLE TEMPERATURE ESTIMATION IN GEOTHERMAL WELLS USING A DEEP LEARNING MODEL BASED ON LSTM NEURAL NETWORKS

ABSTRACT

A new Deep Long Short-Term Memory (DLSTM) machine learning model has been developed to predict downhole temperature (DHT) in real time for geothermal wells. This model, trained on data from simulated FORGE wells, offers faster computations with high accuracy, achieving a Mean Absolute Error (MAE) below 1°C in most scenarios. It considers factors like prior temperature readings, mud type, and wellbore length, effectively predicting DHT during both circulation and pump-off phases. The model aligns with temperature management practices, offering insights into cooling strategies and bottomhole temperature behavior

INTRODUCTION

Geothermal energy harnesses heat from deep subsurface rock formations but drilling in high-temperature (HT) environments poses challenges. Temperatures exceeding 150°C can alter drilling fluid properties, compromise downhole tools, and increase costs. Most tools operate within 150°C–175°C, with only a few rated for 300°C, necessitating precise temperature management to maintain tool and fluid integrity. A novel Deep Long Short-Term Memory Networks (DLSTM) model accurately predicts downhole temperature (DHT) during both circulation and non-circulation phases, addressing a critical gap in managing transient DHT behavior. This innovation ensures better cooling strategies, tool protection, and operational efficiency in geothermal drilling. In this paper, we present a Deep Long Short-Term Memory Networks (DLSTM) model capable of accurately capturing transient DHT behavior during both circulation and non-circulation (pumps-off) scenarios in high-temperature geothermal wells.

LONG-SHORT TERM MEMORY NETWORKS (LSTM) ALGORITHM

Long-short term memory networks (LSTM) are a specific type of recurrent neural network (RNN) designed to suppress the influence of outdated data while effectively tracking long-term dependencies in time-series information. LSTMs achieve this by using gates and memory cells to manage the flow of information. Key elements of the LSTM structure include:

•**Cell State:** A central component that preserves information across time steps, represented by the top horizontal line in the architecture (Fig. 1).

•**Hidden State:** Contains information learned at the current time step **t**.

LSTMs employ three primary gates:

1.**Forget Gate (f):** Regulates which parts of the cell state are discarded (Eq. 1).

2.**Update Gate:** Includes the input gate (i) and memory cell (mmm), responsible for adding new relevant information to the cell state (Eqs. 2 and 3).

3.**Output Gate (o):** Determines the parts of the cell state to use for calculating the output (Eq. 4).

The hidden state (ht) and the cell state (Ct) at time step t are computed using Eqs. 5–6. These mechanisms allow LSTM models to excel in learning long-term dependencies and accurately modeling time-series data. The equations are as follows:

$$f_t = \sigma\left(X_t U^f + h_{t-1} W^f + b_f\right) \tag{1}$$

where X_t is the input parameters at time step t, h_{t-1} represents the hidden state of the previous time step, U is the input weight, W is the recurrent weight, and b is the bias.

$$i_t = \sigma\left(X_t U^i + h_{t-1} W^i + b_i\right) \tag{2}$$

$$m_t = tanh\left(X_t U^m + h_{t-1} W^m + b_m\right) \tag{3}$$

$$o_t = \sigma\left(X_t U^o + h_{t-1} W^o + b_o\right) \tag{4}$$

$$C_t = f_t \odot c_{t-1} + i_t \odot m_t \tag{5}$$

$$h_t = o_t \odot \tanh C_t \tag{6}$$

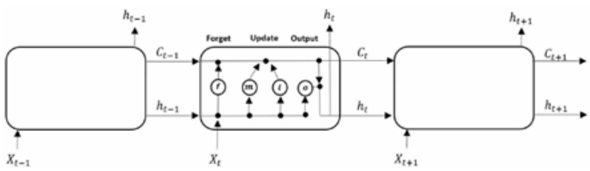

Figure 1—LSTM blocks, including the forget, update, and output gates.

AN OVERVIEW OF THE THERMO-HYDRAULIC MODELING AND DLSTM ML MODEL DEVELOPMENT

In geothermal and oil/gas drilling, operations alternate between circulation and pump-off phases, except in continuous circulation like managed pressure drilling (MPD). During circulation, cool drilling fluid reduces bottom-hole circulating temperature (BHCT), which stabilizes over time. When circulation stops, DHT increases logarithmically due to heat transfer from the formation, matching the reservoir's temperature. Mud coolers can lower DHT, especially in high-temperature geothermal drilling, but their effectiveness decreases with longer well lengths. The proposed machine learning (ML) model predicts DHT during both circulation and pump-off phases using ten key input parameters: drilling flow rate, mud inlet temperature, well vertical depth (TVD), wellbore lateral length, wellbore hydraulic diameter, drill pipe (DP) inside diameter (ID), pipe conductivity, drilling fluid type, mud weight, and viscosity. The hydraulic diameter is calculated by subtracting the DP outside diameter (OD) from the hole diameter. The study evaluates three types of drilling fluids: water-based mud (WBM) and two synthetic/oil-based muds (SBM) with oil/water ratios of 80:20 and 90:10. The dataset used in this study includes wellbore total vertical depths (TVD) for drilling geothermal reservoirs at the FORGE field, with in-situ temperatures ranging from 150°C to 350°C. It also incorporates horizontal wells with lateral lengths up to 7 kilometers, addressing future geothermal energy extraction needs. The dataset covers various wellbore sizes, with hole diameters ranging from 5.75 inches to 12.25 inches, and examines the impact of different drill pipe (DP) sizes on downhole temperature (DHT).

DLSTM ML MODEL DESCRIPTION

The dataset was split 80:20 into training and testing sets, with feature normalization applied to enhance model performance. Initially, Grid and Random search algorithms were used for hyperparameter optimization, but inefficiencies and residual errors compared to numerical models led to the adoption of Bayesian optimization. This approach reduced optimization time by considering previous trials. The network configuration for predicting DHT was found, and a three-minute lag time was added to capture time dependencies. However, the model tended to overestimate DHT with more than three lag time steps.

Table 4—Hyperparameters tuning process of LSTM model.

	Hyperparameter search ranges	Best hyperparameters
Lag observations (backward time steps), min	1 - 5	3
LSTM layers	1 - 4	2
LSTM no. of units	11 - 512	506, 506
Neural network no. of units	11 - 512	506
Optimizer	'Adam' & 'SGD'	Adam
Learning rate	0.01 - 0.0001	0.0001

The optimal model architecture consisted of two stacked LSTM layers, each with 506 units, The second LSTM layer was then combined with conventional neural networks. The model used the Adam optimizer for weight updates during training, as shown in Fig. 2.

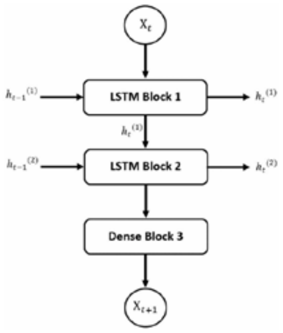

Figure 2—Schematic of the DLSTM model - stacking two LSTM layers with an additional artificial neural network.

In the DLSTM model, the first LSTM layer calculates the hidden state using input features and the previous hidden state. This hidden state is passed to the second LSTM layer, where it is combined with the second layer's previous hidden state to compute the next hidden state. The output is processed through a linear activation layer and used as an input for the artificial neural network along with other drilling parameters. The original dataset had a high sampling frequency of 0.2 Hz, which caused overfitting and inaccurate predictions due to the model needing more historical data. Lower sampling rates resulted in the loss of crucial information. A sensitivity analysis determined that the best results were achieved when the DLSTM model was trained with a dataset sampled at 0.017 Hz.

RESULTS AND DISCUSSIONS

The DLSTM model was trained and tested on over 150,000 dataset points. As shown in Fig. 3, the model predicted DHT with high accuracy, with most predicted data points falling within a ±15% tolerance envelope, as detailed in Table 5.

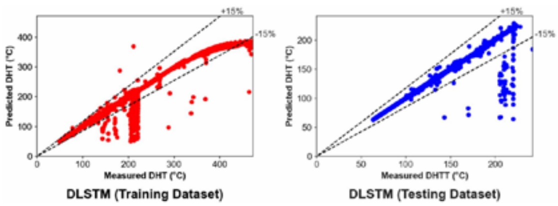

Figure 3—Cross graphs of measured versus predicated DHT by the DLSTM model for the training and testing dataset, as indicated.

Table 5—Metric values of the DHT predictions for the training and testing datasets.

Metric	Training Dataset	Testing Dataset
R^2	0.98	0.99
Mean absolute error (MAE)	2.4	1.17
Root mean square error (RMSE)	8.4	4.08
Mean absolute percentage error (MAPE)	0.01	0.007

The DLSTM model shows slight overfitting in the first three time steps, particularly when DHT is around 210°C, due to a lack of historical data. Despite this, the model maintains an average mean absolute error below 2.5°C for both training and testing datasets, showcasing its strong predictive capability. Lunberg and Lee (2017) introduced the SHapley Additive Explanations (SHAP) method, which uses game theory to quantify the importance of features in complex machine learning models. The SHAP plot ranks features on the y-axis based on importance, while the x-axis shows the magnitude of SHAP values for each instance.

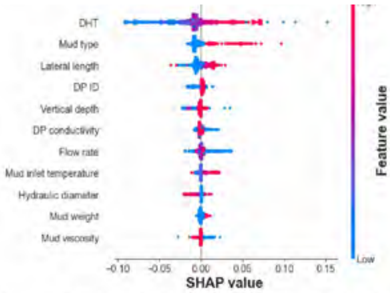

Figure 4—Summary plot showing the input parameters feature importance combined with the feature effects (SHAP value).

The analysis identifies key factors influencing DHT predictions, such as previous DHT values, mud type, and wellbore lateral length, all positively correlated with DHT. Other factors like DP ID, hole vertical depth, and mud weight also increase DHT. The effect of mud type is due to a reduced fluid heat capacity when switching from WBM to SBM. Wellbore hydraulic diameter and fluid viscosity negatively impact DHT. Interestingly, increasing flow rate or reducing pipe conductivity typically lowers DHT but may increase it in extended horizontal lateral sections due to friction.

DLSTM MODEL VALIDATION AGAINST NEVER-BEFORE-SEEN DATA

Four new case scenarios, generated from a thermo-hydraulic model with unseen data, were used to validate the DLSTM model's predictive ability. These scenarios simulate different conditions encountered while drilling geothermal wells in the FORGE field. In the first scenario, an 8.75-inch vertical well is drilled with 9.5 ppg SBM in an 80:20 ratio, targeting a reservoir with a DHT of 250°C. The circulation maintains a flow rate of 800 gpm and an inlet temperature of 30°C. The DLSTM model accurately captures the transient DHT behavior, with a low MAE of less than 0.5°C, as validated against the thermo-hydraulic model

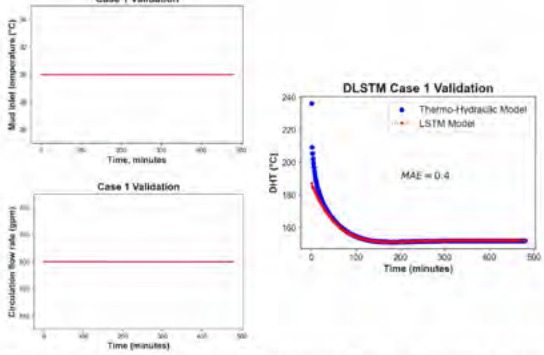

Figure 5—TM model first validation against the thermo-hydraulic model under continuous circulation.

In the second case validation, the DLSTM model simulates a vertical well operation targeting a geothermal reservoir with an initial DHT of 220°. The scenario includes changes in mud inlet temperature due to factors like cooler failure or the addition of a cooler, and variations in flow rate caused by issues like hole cleaning, pump failures, or adjustments to the equivalent circulating density (ECD).

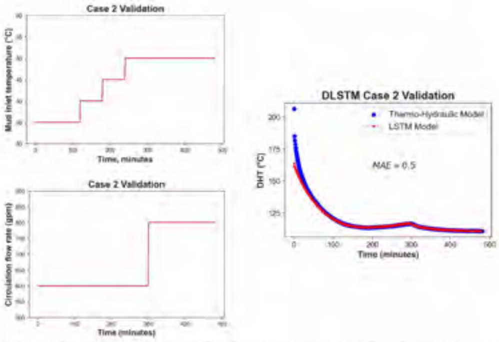

Figure 6—DLSTM model second validation against the thermo-hydraulic model under dynamic conditions.

The third case scenario simulates a horizontal well with a 3 km lateral section, drilled using 9 ppg WBM and an IDP. DHT changes occur during circulation halts, such as during drill pipe connection or pump failure. After a 20-minute stoppage, circulation resumes at 500 gpm with a mud inlet temperature of 40°C. The DLSTM model accurately predicts DHT during both circulation and pump stoppage, with a low MAE of 0.7°C compared to the thermo-hydraulic model

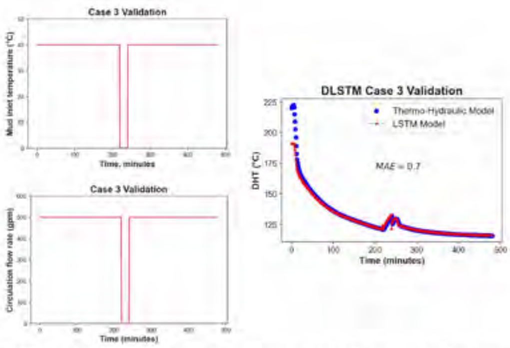

Figure 7—DLSTM model third validation against the thermo-hydraulic model during circulation and pump stops scenario.

In the fourth scenario, a 1 km horizontal well is drilled with a 10.625-inch wellbore, targeting a geothermal reservoir with a 200°C formation temperature. Using an insulated drillpipe (IDP) and 9 ppg mud with a plastic viscosity of 7 cP, the well undergoes 1.5 hours of continuous circulation, followed by a 2-hour halt, and resumes at 700 gpm. The DLSTM model accurately predicts DHT, aligning with the thermo-hydraulic model and achieving a low MAE of 0.5°C.

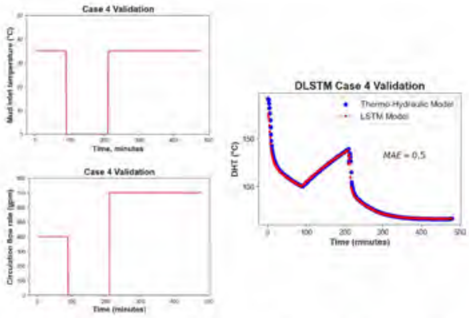

Figure 8—DLSTM model fourth validation against the thermo-hydraulic model during circulation and pump stops scenario.

The four cases validations confirm the robustness of the developed model, proving it as an effective alternative to time-consuming numerical models. It accurately predicts DHT and captures the full transient behavior during both circulation and pump stoppage scenarios in geothermal drilling operations.

SENSITIVITY ANALYSIS (PROOF OF CONCEPT)

A parametric analysis using the DLSTM model evaluated factors like drilling flow rate, reservoir DHT, wellbore hydraulic diameter, and fluid type. The results showed that a high drilling flow rate effectively cools the well during drilling and pump stoppage by reducing heat interaction with the high-temperature formation, minimizing temperature build-up when circulation stops. Fig. 9c shows that drilling a wellbore with a larger hydraulic diameter helps manage temperature by allowing more fluid in the annulus, which increases fluid convection resistance and reduces heat transfer during both circulation and pump stoppage. Fig. 9d underscores the efficacy of water-based mud›s high specific heat capacity in comparison to SBM in reducing heat interactions between the annular drilling mud and the formation, ultimately mitigating DHT.

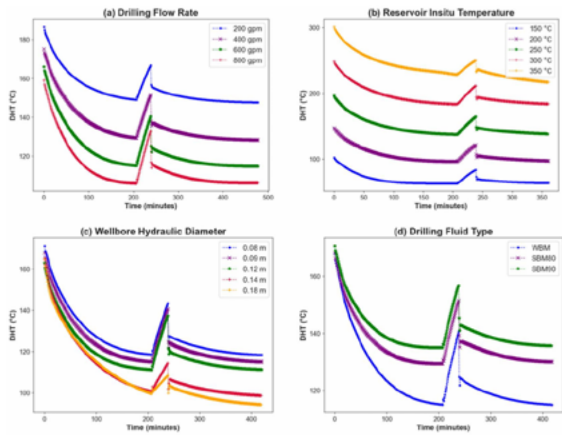

Figure 9—DLSTM model predictions for multiple case scenarios at the FORGE field (sensitivity analysis) under different conditions. (a) Impact of drilling flow rate on the DHT, (b) effect of reservoir insitu temperature on the DHT, (c) impact of wellbore hydraulic diameter on the DHT, (d) impact of the fluid type on the DHT of FORGE geothermal wells.

It is worth mentioning that the DLSTM model provides instant results, unlike numerical models that can take hours or even days to produce similar outcomes.

4 ARTICLE

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APPLICATIONS OF ARTIFICIAL INTELLIGENCE IN GEOTHERMAL RESOURCE EXPLORATION

ABSTRACT

Artificial intelligence (AI) plays a vital role in geothermal exploration, enhancing the efficiency of resource identification. This review highlights the progress and challenges in using AI techniques such as neural networks, support vector machines, and decision trees to estimate subsurface temperatures, predict properties, and identify drilling locations. The widespread adoption of AI faces challenges, including data quality and accessibility, and the need for specialized training. Addressing these issues can unlock cost-effective, sustainable geothermal energy development.

THE AI REVOLUTION IN GEOTHERMAL EXPLORATION—UNEARTHING EARTH'S HIDDEN ENERGY

How machine learning is transforming the search for sustainable, reliable power. Geothermal energy, harnessed from the Earth's subsurface heat, is a cornerstone of the renewable energy transition. Unlike solar or wind, it provides uninterrupted baseload power, making it indispensable for grid stability. However, traditional exploration methods—reliant on costly drilling, subjective geological interpretations, and fragmented datasets—are inefficient and risky. Artificial intelligence (AI) is revolutionizing this field by synthesizing vast datasets, predicting subsurface conditions with unprecedented accuracy, and slashing exploration costs by up to 40%.

Why Geothermal Energy?

1.Reliability: Geothermal plants operate 24/7, unaffected by weather or daylight, providing a stable energy supply.

2. Scalability: The U.S. Department of Energy estimates geothermal could supply 8.5% of national electricity

by 2050. Globally, untapped resources exceed 200 gigawatts (GW), enough to power 200 million homes.
3. Sustainability: Geothermal systems emit 97% less CO_2 than coal plants and use 1% of the land required for equivalent solar farms.

AI'S ROLE IN MODERN GEOTHERMAL EXPLORATION

Machine learning (ML) algorithms excel at identifying patterns in complex, noisy datasets. Key techniques include: Neural Networks (ANNs): Analyze seismic waves, electromagnetic surveys, and thermal gradients to predict subsurface temperatures with <10% error. For example, ANNs trained on Iceland's electromagnetic data achieved <5% error at depths twice that of boreholes. Decision Trees: Integrate geological fault maps, geochemical anomalies, and thermal data to rank drilling sites by potential. In Nevada's Great Basin, this approach reduced dry well risks by 30%. Support Vector Machines (SVMs): Classify geochemical samples (e.g., silica concentrations, isotope ratios) to distinguish low-temperature (80°C) from high-temperature (>160°C) reservoirs.

CASE STUDY: NEVADA'S PLAY FAIRWAY ANALYSIS (PFA)

Play Fairway Analysis (PFA) traditionally weights geological, geophysical, and geochemical parameters to assess geothermal potential. AI supercharges this by uncovering non-linear relationships:
- Smith et al. (2021) combined Bayesian Neural Networks with unsupervised clustering to analyze fault lines and chloride anomalies in Nevada's Great Basin. Their model identified 12 overlooked geothermal sites with 85% accuracy, avoiding $20 million in unnecessary drilling costs.
- Vesselinov et al. (2020) applied non-negative matrix factorization (NMF-k) to sparse datasets in Southwest New Mexico, revealing silica concentrations and temperature gradients as critical indicators of hidden systems.

CHALLENGES AND OPPORTUNITIES

While AI democratizes access to geothermal exploration—enabling startups in Kenya and Indonesia to use tools like *GeoThermalCloud*—key hurdles remain:
- Data Scarcity: Many regions lack high-resolution geophysical or geochemical datasets.
- Model Interpretability: Complex ML models like deep neural networks (DNNs) often act

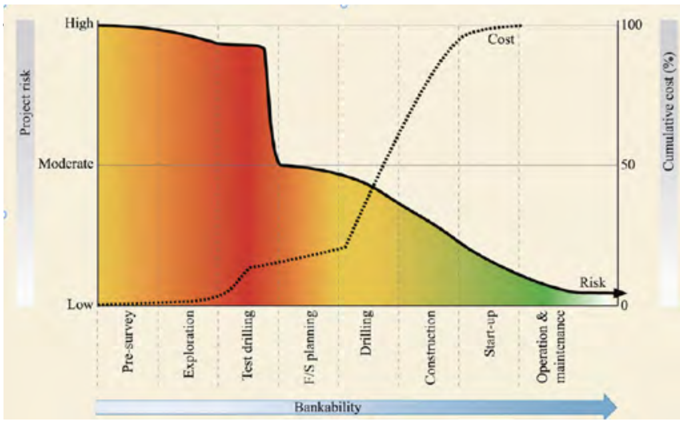


FIGURE1 Geothermal development project cost and risk profile throughout various project stages (Gehringer & Loksha, 2012; The World Bank et al., 2012)

DECODING EARTH'S CHEMISTRY—AI-DRIVEN GEOTHERMAL PREDICTIONS

From geochemical fingerprints to reservoir mapping, machine learning unlocks hidden systems.

1. Play Fairway Analysis (PFA) Enhanced by Machine Learning

PFA integrates geological, geophysical, and geochemical data to rank geothermal potential. ML enhances this by identifying subtle, non-linear relationships:
-Nevada's Hidden Reservoirs: Smith et al. (2021) combined Bayesian Neural Networks with k-means clustering to analyze fault density and chloride anomalies. Their model revealed geothermal systems masked by volcanic rock layers, which traditional surveys missed.

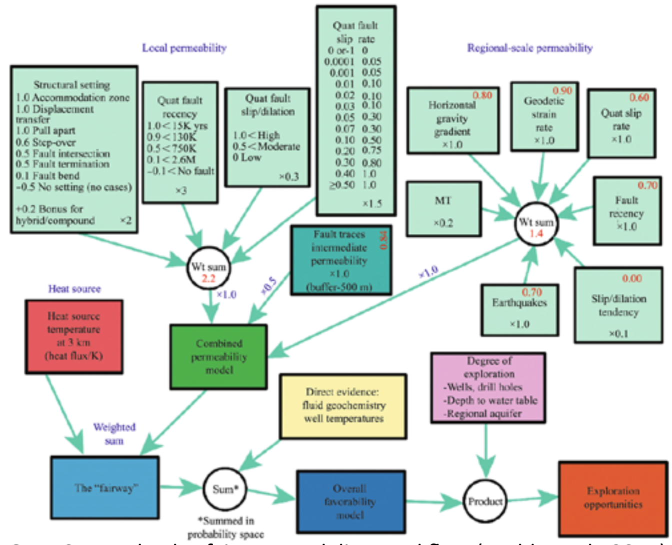


FIGURE2 Nevada play fairway modeling workflow (Faulds et al., 2017).

- Southwest New Mexico's Breakthrough: Vesselinov et al. (2020) applied NMF-k to datasets with missing values, identifying silica concentrations (>300 ppm) and calcium anomalies as proxies for high-temperature reservoirs.

2. AI-Powered Geothermometers

Traditional geothermometers rely on assumptions of chemical equilibrium between fluids and rocks, often leading to errors. AI bypasses these limitations:

Na/K Geothermometers

- Ferhat Bayram (2001): Developed an ANN with two hidden layers trained on 600 synthetic Na/K data points. While innovative, the model overestimated temperatures in Turkish fields by 15–20% due to limited real-world data.
- Can (2002): Trained a simpler ANN on 39 global wells (94–345°C), achieving <10% error within calibration ranges. However, predictions faltered outside this range, highlighting the need for diverse training data.
- Serpen et al. (2009): Optimized ANNs using genetic algorithms, reducing errors to ~10% even in low-temperature systems (<160°C).

Gas Geothermometers

- Pérez-Zárate et al. (2019): Designed a three-layer ANN using CO_2, H_2S, and CH_4 data from 591 global wells. The model achieved 2–11% error rates, outperforming 25 conventional gas geothermometers.
- Acevedo-Anicasio et al. (2021): Expanded this work, creating eight gas geothermometers tailored for steam- and fluid-dominated reservoirs.

3. Integrated Subsurface Data Platforms

- GeoThermalCloud (GTC): Developed by Los Alamos National Lab (LANL), GTC merges geological, thermal, and geochemical data to generate prospectivity maps. At Utah's FORGE site, GTC validated blind predictions of hidden reservoirs, reducing exploration time by 50%.
- Iran's Success: Sadeghi and Khalajmasoumi (2022) combined fuzzy logic with GIS to prioritize drill sites in Northwestern Iran. Their model integrated volcanic activity, fault density, and geochemical data, identifying high-potential zones with 90% accuracy.

BEYOND THE SURFACE—AI'S MASTERY OF GEOPHYSICS & THERMAL DATA

How neural networks decode seismic waves, resistivity anomalies, and heat flow patterns.

1. Electromagnetic (EM) & Seismic Surveys

Electromagnetic Surveys

- ANN vs. Traditional Methods: Spichak and Zakharova (2009a) trained ANNs on EM data from Iceland's Hengill volcanic zone. The model estimated subsurface temperatures with <5% error at twice borehole depth, outperforming linear regression.
- Neural Kriging (NK): Ishitsuka et al. (2018) combined Kriging (a spatial interpolation technique) with ANNs in Japan's Hokkaido region. NK improved temperature prediction accuracy by 25% by incorporating spatial correlations.

Seismic Fault Mapping

- Gao et al. (2021): Developed a Multiscale Connection-Fusion U-shaped CNN (MCFU) to analyze 3D seismic data from Nevada's Soda Lake. The model mapped faults within 5 meters of accuracy—critical for targeting permeable zones in fractured reservoirs.
- Perozzi et al. (2021): Applied unsupervised k-means clustering to seismic lines in Switzerland, automating lithofacies classification and reducing manual interpretation time by 70%.

2. Thermal Data's Predictive Power

Extreme Gradient Boosting (XGB)

- Shahdi et al. (2021): Analyzed bottom-hole temperature (BHT) data from 20,750 U.S. wells using XGBoost. The model generated continuous 2D temperature maps (see Figure 5), achieving $R^2 = 0.94$ and identifying high-potential zones in the Appalachian Basin.

Static Formation Temperature (SFT) Prediction

- Bassam et al. (2010): Trained ANNs on BHT and shut-in time data to estimate SFT with <5% error, eliminating the need for costly well stabilization periods.

3. Remote Sensing & Surface Manifestations

- GoogLeNet's Precision: Xiong et al. (2022) compiled 8,000 images of geothermal surface features (e.g., hot springs, fumaroles) and trained GoogLeNet via transfer learning. The model classified features with 95% accuracy, reducing field survey costs by 70%.
- Satellite Data Integration: Moraga et al. (2022) combined AI with remote sensing to detect surface deformation and gas emissions in Chile's Andes Mountains, identifying three new geothermal anomalies.

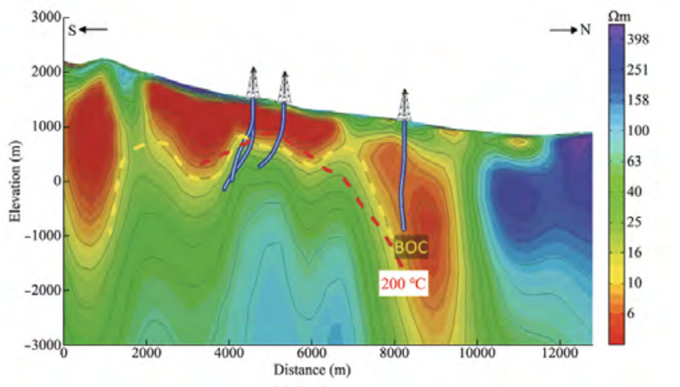


FIGURE4 Isothermal at 200°C and Best of Conductor (BOC) lines (Sutarmin & Daud, 2021).

Challenges

Data Scarcity: Regions like East Africa's Rift Valley lack high-resolution geophysical datasets, limiting AI's applicability.

- Computational Costs: Training deep learning models requires expensive GPUs, creating barriers for small firms.

OVERCOMING BARRIERS—COLLABORATION, POLICY, AND THE FUTURE OF GEOTHERMAL ENERGY

How partnerships and innovation can propel geothermal into the mainstream energy mix.

Persistent Challenges

1. Data Gaps: Only 15% of geothermal-rich regions have publicly available subsurface datasets. For example, Indonesia's vast resources remain understudied due to proprietary data restrictions.

2. Expertise Shortage: Less than 10% of geoscientists are trained in ML, creating bottlenecks in model validation and deployment.

3. High Initial Costs: Exploratory drilling accounts for 40% of project expenses, though AI reduces dry well risks by 35%.

Emerging Opportunities

Open-Source Platforms

- Open Energy Information (OpenEI): Hosts 50+ terabytes of geothermal data, including well logs, geochemical analyses, and seismic surveys. Startups in Kenya's Rift Valley used OpenEI to identify 15+ drill-ready sites.
- Global Geothermal Machine Learning (GOOML): A collaborative project optimizing geothermal operations using historical data from 1,200+ global wells.

Transfer Learning

- Oil & Gas Adaptations: AI tools developed for oil/gas seismic interpretation (e.g., convolutional neural networks) are being retrained for geothermal fault mapping, cutting model development time by 50%.

Policy Levers

- Tax Incentives: Chile's government offers 20% tax rebates for AI-geothermal pilot projects.
- Data-Sharing Mandates: Iceland requires energy firms to share non-proprietary subsurface data, fostering innovation.

The Road Ahead

- Enhanced Drilling Accuracy: At Utah's FORGE site, ML models reduced drilling risks by 35%, saving $10 million per project.
- Global Scalability: In Kenya, AI identified geothermal reservoirs capable of generating 1 GW by 2030—enough to power 3 million homes.

A Call to Action

As Holmes and Fournier (2022) concluded, "AI doesn't replace geologists—it empowers them to explore smarter." Cross-industry collaboration and policy support are critical to unlocking geothermal's full potential.

Final Takeaway: With AI, geothermal energy could supply 10% of global electricity by 2050, offering a sustainable, resilient alternative to fossil fuels

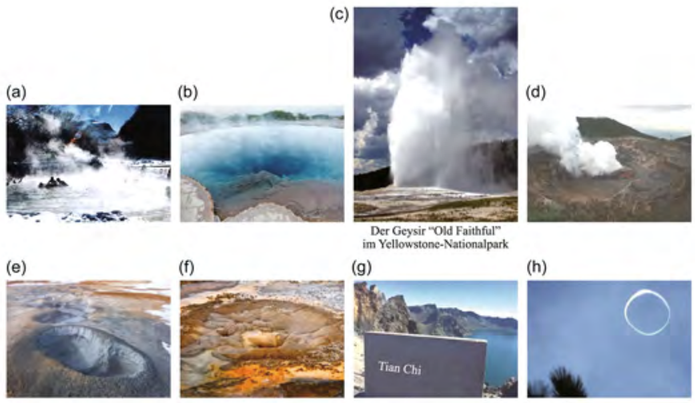


FIGURE6 Example images of the types of geothermal surface manifestations (a) warm spring, (b) hot spring, (c) geyser, (d) fumarole, (e) mud pot, (f) hydrothermal alteration, (g) crater lake, and (h) a non-GSM type (Xiong et al., 2022)

CONCLUSION

Artificial intelligence is revolutionizing geothermal exploration by significantly improving the accuracy, efficiency, and cost-effectiveness of resource identification. By leveraging machine learning techniques such as neural networks, decision trees, and support vector machines, AI enhances subsurface predictions, reduces exploration risks, and unlocks new geothermal potential worldwide. However, challenges such as data scarcity, model interpretability, and high computational costs must be addressed to fully harness AI's potential. Through collaboration, open-source initiatives, and supportive policies, AI-driven geothermal exploration can contribute significantly to global renewable energy goals, providing a sustainable and reliable power source for the future.

INTERVIEW

MR. HISHAM ZEBIAN

Vice President - Eastern Hemisphere at IADC

With more than 16 years of experience today, Hisham graduated with a bachelor's degree in Mechanical Engineering in 2008 from the American University of Beirut, were he directly joined the Oil & Gas industry

Hisham joined the upstream side of the business as part of the Sales & Business Development team for National Oilwell Varco (NOV), Rig Systems division in Dubai in 2014. He then joined the IADC as a Regional Representative in 2017, looking after the Middle East & Africa. In January 2020, he was promoted to Vice President

Q1 MR. HISHAM ZEBIAN, FIRST WOULD YOU TELL US ABOUT YOURSELF, AND YOUR JOURNEY TO REACH SUCH A MARVELOUS POSITION IN IADC?

I am a Mechanical Engineer by education, studied at the American University of Beirut, Lebanon, and then joined the oil & gas industry in 2008. I studied mechanical engineering since it is closest to Aviation. My father is a pilot and the university I attended didn't have aeronautical engineering. My plan was to join the aviation industry, but coincidently I have joined an industry which has a lot of similarities to Aviation, in terms of working in a big industry, in big teams, focused on people, safety and an industry which is very essential in our daily lives. In 2008, I joined an EPC company called Petrofac part of their Fresh Graduate Program, where I was promoted to a Project Engineer, then in 2014 I joined National Oilwell Varco where the upstream side of the oil & gas industry was very new to me, until 2016. In 2017, I stumbled upon a job opportunity with IADC, which I applied to and was selected to be their regional representative for Middle East & Africa. In 2020, I was promoted to VP Eastern Hemisphere.

Q2 WHAT DO YOU CONSIDER THE MOST SIGNIFICANT MILESTONES IN YOUR CAREER?

Starting my career at a big company, with a very good reputation.

Q3 CAN YOU SHARE A SIGNIFICANT CHALLENGE YOU FACED WHILE WORKING ON OFFSHORE CAPITAL PROJECTS AT PETROFAC, AND HOW YOU RESOLVED IT?

The Offshore Capital Projects business unit at Petrofac was a relatively new unit back then when I joined it, as Petrofac wanted to venture into building facilities and servicing the offshore side of the EPC business. One of the significant challenges I faced was when I served around 3 months at one of the fabrication yards in Abu Dhabi, to fabricate and assemble offshore jackets, where we had to construct, inspect and complete big structures of steel in a very short timeline. Luckly we had a great team of people working together which led to us delivering the project on time

Q4 WHAT INSPIRED YOU TO JOIN THE IADC, AND HOW HAS YOUR JOURNEY SHAPED YOUR LEADERSHIP VISION?

What inspired me to join the IADC, is the idea that through the IADC I will be able to give back to the industry. For so many years I was getting a lot from the industry while now I feel like I am giving back through the conferences, the lobbying effort, sharing information, the engagements, the discussions and supporting the young generation.

Q5 AS VICE PRESIDENT FOR THE EASTERN HEMISPHERE AT IADC, WHAT DOES YOUR ROLE ENTAIL, AND WHAT ARE YOUR MAIN RESPONSIBILITIES?

As IADC's VP Eastern Hemisphere, I support all related projects and initiatives in the Middle East, Africa, Caspian, East Asia and Australia. We do that through a number of venues, by attracting more member companies to join our efforts in achieving this mission and goals. IADC mainly operates under the umbrella of regional chapters, and the chapters are like branches of IADC who work independently of each other, but all towards one goal which is to give back to the industry, share information and collaborate. A few years ago, we also started the Student Chapter program, where we started in 2018 with 1 student chapter in the US, reaching now 21 student chapters globally.

Q6 WHAT IS YOUR VISION FOR THE FUTURE OF IADC AND ITS ROLE IN SHAPING THE GLOBAL DRILLING INDUSTRY?

We hope to remain a reliable source of information, for all HSE, sustainability and statistical information for our member companies working in the energy sector. Even during the COVID-19 pandemic, IADC was able to play a role in guiding a informing our members of the latest information and guidelines on travel measures and guidelines, and we hope that we can work further on keeping our members informed and stay relevant to the energy industry

Q7 HOW DOES THE IADC FOSTERS COLLABORATION BETWEEN ACADEMIA, INDUSTRY PROFESSIONALS, AND STUDENTS TO BRIDGE THE GAP BETWEEN EDUCATION AND THE LABOR MARKET?

IADC is trying to achieve that through three main initiatives:

a. Conferences: IADC is inviting a number of students globally to attend IADC conferences in a number of different countries, sometimes flying those students from far away places just to show them that the nature of this industry that it is a global industry, and not that you can only join the industry if there are hydrocarbon resources in your country or the region you live in / come from.

b. Chapters: As mentioned previously, the IADC has been working on establishing student chapters in the world, where we have reached 21 student chapters.

c. YP Committee: This is also one of the ways to try to close the gap between the young generation and the labor market, as this committee only accepts members who are under 35 years of age, who try to see ways on how to attract, inform and educate the younger generation to join our industry.

Q8 WHAT TRENDS OR ADVANCEMENTS DO YOU SEE SHAPING THE FUTURE OF THE OIL AND GAS INDUSTRY, PARTICULARLY IN THE EASTERN HEMISPHERE?

Artificial Intelligence (AI), but the industry still doesn't know how exactly AI will be affecting our industry. Our industry and due to its nature is still a very traditional industry, since you still need tools and heavy equipment to be able to extract hydrocarbons from below the ground, and you cannot replace a rig and people on the rig with AI, while in other industries we are seeing that the nature of work is changing where people's skills now do require that you are more informed about coding and AI.

Q9 WHAT ARE THE BIGGEST CHALLENGES THE OIL AND GAS INDUSTRY IS FACING IN THE EASTERN HEMISPHERE, AND HOW IS IADC ADDRESSING THEM?

Biggest challenges the industry is facing globally is regulation, although what has happened in the past few years, and how the conversation changed to energy security. As you know regulation is trying to push the industry and the world towards goals that seem challenging, and that heavily depend on technology. IADC tries to constantly play an influential role in keeping a good balance between fair laws and the safety of our industry.

Q10 BALANCING BETWEEN ECO FRIENDLY AND DRILLING OPERATIONS. HOW COULD WE ACHIEVE THIS?

IADC sets global guidelines related to safety and operations on how to manage waste and protect the environment during drilling operations. IADC is not an enforcing body, it is always up to the NOCs and IOCs to make sure that eco friendly drilling is enforced and budgeted for.

Q11 FINALLY, WHAT IS THE MOST VALUABLE LESSON YOU'VE LEARNED DURING YOUR CAREER IN THE ENERGY SECTOR?

My most valuable lesson working in the energy sector, is that the world is all connected to each other, and the glue that is connecting the world together is the energy industry. Without the energy industry we will lose all the advancements that the human race has achieved. I learned that we all play a role in making this world a better place, and it is our responsibility to maintain our world in a healthy and safe state for the future of our children and humanity.

INTERVIEW

ENG. ABDEL MAKSOUD DESOUKY

GOS District Engineering General Manager at Dragon Oil-Egypt

Has an Oil & Gas industry veteran with over 39 years extensive experience through Five different Organizations in the oil and gas sector. Proven ability to devise and implement strategy changes within established businesses; complemented by 15 years experiences working within executive teams and boards in Dubai and Egypt.

Q1 CAN YOU TELL US ABOUT YOUR JOURNEY INTO THE OIL AND GAS INDUSTRY? WHAT INITIALLY DREW YOU TO THIS FIELD?

My dream since childhood was to become a petroleum engineer and to delve into oil & gas industry. I graduated from high school with a score of 92% at a time when this score would have allowed me to study medicine and the highest engineering universities. But I defied my entire family and joined the Suez Canal University "Petroleum and Mining College" despite all the difficulties of life in Suez before construction

Q2 WHAT DO YOU CONSIDER THE MOST SIGNIFICANT MILESTONES IN YOUR CAREER?

One of the most important steps in my life was traveling and moving to the UAE and joined ZADCO – ADNOC as a Lead Petroleum Engineer in 1998. Then I moved to ConocoPhillips in Dubai in 2003. This was the biggest challenge station as it was the first time I worked with an all-American organization. Despite the working hours extending to more than 11 hours a day, I was happy and very interactive with working with them and their drilling and production projects. I became a production manager and am responsible for all well intervention, well maintenance and production follow-up work.

Q3 WITH OVER 39 YEARS OF EXPERIENCE, HOW HAS THE INDUSTRY EVOLVED OVER THE YEARS, ESPECIALLY IN THE REGIONS YOU'VE WORKED IN?

One of the most significant advancements in the oil and gas industry is the digitization and automation of various processes. Digitalization enables real-time monitoring and analysis of drilling, production data, allowing for proactive maintenance and optimization of operations.

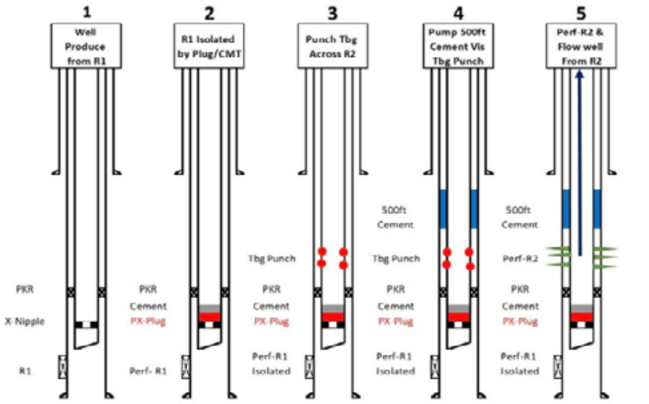
Over the 39 years, the industry has advanced rapidly in all areas. For example, in drilling operations, horizontal drilling and reaching more than 18,000 feet, drill multi-lateral "more than 5 laterals from a single well and each branch reached a depth of 5,000 feet, Intelligent completion that help to control zonal production and control water cut remotely from surface. In addition to the technology of logging while drilling "LWD" which reduces drilling constraints and target the location of the well with saving time and saves costs.

For rig-less operations, there are many new logging techniques for well integrity diagnostic and investigation, new technology for production logging. In the field of well intervention, descaling and dissolving asphalt and scale removing in the well. It has already developed step by step all over the world.

Established many new Technologies that enabled oil and gas businesses all over the world to uncover new deposits, optimize operations, and reduce costs. This technology includes enhanced seismic imaging techniques as well as robotic drilling platforms which are being used in some areas.

Q4 WHAT ARE SOME OF THE MOST CHALLENGING YET REWARDING PROJECTS YOU'VE LED THROUGHOUT YOUR CAREER?

The most challenging rewarding projects I have met at ConocoPhillips in Dubai are perforating and producing oil zones above the packer of the existing well without rig intervention. We have achieved that by using new Techniques named Cement packer that completed by pumping vessel and e-line with very attractive cost saving Cement packer Technique Work Scope



Q5 YOU'VE WORKED ON BOTH ONSHORE AND OFFSHORE PROJECTS. WHAT ARE SOME OF THE KEY DIFFERENCES IN MANAGING OPERATIONS IN THESE TWO ENVIRONMENTS?

Operation concepts, there is no major difference between offshore and onshore in oil & gas industry but there are major differences in all the following:

- **Infrastructure**: offshore requires complex infrastructure but onshore requires simply infrastructure.
- **Operations Cost**: offshore is significantly more expensive due to the high cost of equipment, logistics, transportation. But cheaper with lower operational and logistical costs.
- **Risk and Safety:** offshore, is higher risks compared to onshore to harsh marine conditions.
- **Environmental Impact**: offshore is leading to major environmental disasters, such as oil spills, the Deepwater Horizon spill is a prime example of the potential for catastrophic environmental damage. but onshore raises concerns about land degradation.
- **Accessibility and transportation**: Offshore access to drilling sites is challenging, requiring helicopters or boats to transport personnel and equipment. But onshore it is very simple and easier.
- **Economic Impact**: offshore contributes significantly to a country's economy through high-value oil and gas production. But onshore provides good economic benefits

Q6 YOU HAVE EXTENSIVE EXPERTISE IN WELL INTERVENTION AND WELL INTEGRITY. CAN YOU EXPLAIN THE MOST CRITICAL ASPECTS OF THESE OPERATIONS, AND WHY THEY ARE SO VITAL FOR MAINTAINING OIL AND GAS ASSETS?

A well intervention, or 'well work', is essential operations for production enhancement and susceptibility. It is any operation carried out on an oil or gas well during, or at the end of, its productive life, that alters the state of the well and or well geometry, provides well diagnostics or manages the production of the well. The most important of Well Intervention is plugging and abandoning the wells safely and successfully. So, well intervention is the most important for well life cycle. In conclusion, well intervention and maintaining well integrity are the most important and essential operations for ensuring the safety, reliability, and efficiency of upstream operations in the oil and gas industry. Well integrity is a safeguard against any potential hazards such as fluid leaks, blowouts, and environmental contamination.

Q7 FINALLY, WHAT IS THE MOST VALUABLE LESSON YOU'VE LEARNED DURING YOUR CAREER IN THE ENERGY SECTOR?

The most valuable lesson I've learned is to stay adaptable with any organization change, able to manage change. During my work with DPE at Dubai, Dubai Government decided to fire some people for cost reduction due to low oil prices. The company decided to fire Well Intervention & Well Integrity Mangers as they salaries were very high and requested me to take over their roles and responsibility. Initially I hesitated but I had accepted that challenge. Being successful at work comes from working and developing as a team. You may have responsibilities of your own, but group success is what drives businesses forward. Again, you must have a clear plan for your future, and you should appraise your plan from time to time and ask yourself about what you planned and what you achieved. You should learn lessons from any events or incident that happened in your life for further mitigation and avoids

INTERVIEW

MR. ANDREW MABIAN

Petroleum Engineering / Production Operations Management - Oil and Gas

Professional Petroleum Engineering leader with international experience across the whole E&P value chain in various multidiscipline and managerial positions including Wells, Reservoirs and Facilities Management , Production Operations, Operations Readiness/ Commissioning and Startup (OR/CSU), Projects management (Digital Fields), Hydrocarbon maturation & economics, Field Development Planning,, Data Management, Surface and Subsurface performance Optimisation.

Q1

CAN YOU TELL US ABOUT YOUR JOURNEY INTO THE OIL AND GAS INDUSTRY?

After completing in 1996 my Masters Degree with Hons at the Technical University of Moscow, Russia, I joined Shell as a drilling/Production engineer in Cameroon Operations, moved internationally in Russia and Egypt while working on various leadership positions including Wells, Reservoirs and Facilities management, Production Operations, Operations Readiness/Commissioning and Startup Projects management (Digital Fields), Hydrocarbon maturation & economics, Forecasting and Reporting, Integrated Activity planning, Data Management, Surface and Subsurface performance Optimisation, Continuous improvements (Lean) deployments.

Q2

WHAT DO YOU CONSIDER THE MOST SIGNIFICANT MILESTONES IN YOUR CAREER?

I believe everything you do is a milestone – at work and on personal life. Celebrate what you are doing everyday – these form part of your milestones and achievements.

Q3

YOU'VE HELD MANAGERIAL POSITIONS IN OPERATIONS, PRODUCTION OPTIMIZATION, AND DIGITAL FIELD PROJECTS. WHAT ARE THE KEY SKILLS NEEDED TO EXCEL IN SUCH MULTIDISCIPLINARY ROLES?

These are critical roles and to perform at excellence, you should be able equipped with core skills which can be listed as - Agility and adaptability, Decision making/critical thinking, Interpersonal Communications, Innovation and creativity, Multitasking, Teamworking and Coaching, Problem Solving Asset management/Business planning and execution, Customers focus/Excellence in delivery.

Q4

YOU ARE CURRENTLY WORKING AS A FREELANCE CONSULTANT IN PRODUCTION OPERATIONS MANAGEMENT. WHAT INSPIRED YOU TO TAKE ON THIS ROLE AFTER YEARS IN MANAGERIAL POSITIONS?

I continuous learn – consultancy is a great space to apply your skills and professional knowledge to deliver above customers goals, while participating to their and self-growth. While this is a temporary role, I do enjoy the time.

Q5

HOW DOES YOUR CURRENT ROLE DIFFER FROM YOUR PREVIOUS CORPORATE ROLES IN TERMS OF RESPONSIBILITIES AND CHALLENGES?

I do not really see any majors differences – you have a customer, goals/targets and you deliver to excellence - everyday.

Q6

CAN YOU DESCRIBE THE TYPES OF PROJECTS YOU'RE CURRENTLY WORKING ON AS A FREELANCE CONSULTANT?

These can be summarized as follows : delivery of assigned projects (Field Development plan 5 years review and update); Continuous improvements concepts strategies and execution planning; Process auditing expertise via Value Stream Mapping/SIPOC process scope resulting in waste execution time elimination enabling a production plan stability; Review of engineering staff capabilities, assessment and coaching to support upskilling capabilities.

Q7 CAN YOU SHARE AN EXAMPLE OF A SITUATION WHERE TEAMWORK PLAYED A CRITICAL ROLE IN OVERCOMING A SIGNIFICANT CHALLENGE?

There are mainly of such examples and I am a strong believer of excellent Teamwork delivers success. One brief example is our optimisation and restoration plan stability which was below 40%. By ensuring team integration, visibility, communication and challenging each other, we were able to improve our plan stability to above 90%, exceed on our mandate and promises – on safety, cost and volumes.

Q8 CAN YOU WALK US THROUGH YOUR EXPERIENCE LEADING THE WRFM (WELLS, RESERVOIRS, AND FACILITIES MANAGEMENT) TEAM?WHAT WERE THE BIGGEST CHALLENGES AND ACHIEVEMENTS?

Wells, Reservoirs and Facilities Management is a robust process to enable safe, integrated and cost efficient move of hydrocarbons from reservoirs pore throat to sales points at lowest possible cost and minimum emissions. The process requires an integrated approach to data gathering, analysis, modelling, review, and decision-making to generate opportunities to optimize asset value. Challenges to excel in WRFM can be summarized in 5 main blocks: 1: Understanding your asset (data gathering – measurement, monitoring. transmission; data management/processing); 2) modelling (analysis, interpretation, model management); 3) Generate, evaluate options, decision and plans (uncertainty analysis, prioritization, ranking and decision management); 4) Execution (activities management, lookback, continuous improvement); 5) People knowledge, skills and development.

Some examples such as increasing production by implementing excellent waterflood management has resulted in increasing production by 4 times with 3 years; others example such as executing additional perforation has increased gas production of selected wells by 40%; other examples are related to an increase in ESP run life by 25% and unscheduled production deferment by applying proper monitoring, modelling and fir for purpose pro-active trouble shooting techniques.

Q9 AS SOMEONE WITH EXTENSIVE EXPERIENCE IN INTRODUCING NEW TECHNOLOGIES, CAN YOU DISCUSS HOW DIGITAL TRANSFORMATION IS RESHAPING THE OIL AND GAS INDUSTRY?

Digital technology is key to ensuring the reliability and sustainability of today's energy systems and creating and scaling the energy systems of tomorrow. Today, the adoption of digital technologies is making a material impact on the oil and gas industry. It is improving efficiency, reducing cycle times from exploration to production, and increasing productivity while lowering costs, reducing risks, minimizing the footprint of operations, and lowering greenhouse gas emissions. In both oil and gas and new energy systems, the impact of digital transformation will increasingly intensify. Automation and autonomous operations have only scratched the surface (and subsurface). As with other sectors, the energy industry is just now beginning to tap the transformational potential of Artificial Intelligence (AI) and generative AI. From digitally connected solutions that reduce personnel footprint in the field or make operations more efficient to measuring, reporting and taking prescriptive actions that reduce or eliminate emissions, digital and AI will play a massive role in ensuring the sustainability of today's and tomorrow's energy systems.

Q10 HOW IS THE INDUSTRY ADAPTING TO THE GLOBAL PUSH TOWARD SUSTAINABILITY AND RENEWABLE ENERGY SOURCES?

Countries around the world are exploring ways to transition away from fossil fuels. The transition, prompted by carbon emissions that exacerbate climate change, is vast and includes renewables such as solar, wind, and hydro. But transitioning is not as simple as choosing renewables for energy, so although we are still a long way from getting to these goals, work is being done to tackle the following factors which are crucial for the transition to renewable energy: Investment in renewable energy infrastructures, Technology innovation and research and development, Energy efficiency measures, Policy support and regulatory frameworks, Global cooperation and collective action

Q11 FINALLY, WHAT IS THE MOST VALUABLE LESSON YOU'VE LEARNED DURING YOUR CAREER IN THE ENERGY SECTOR?

Deliver – everyday to excellence on all actions and at all levels.

CASE STUDY 1

SWITCH FROM INDUCTION TO MAGNEFFICIENT PMM REDUCED POWER CONSUMPTION BY 25 PERCENT, INCREASED PRODUCTION BY 10 PERCENT IN DEEP WELL

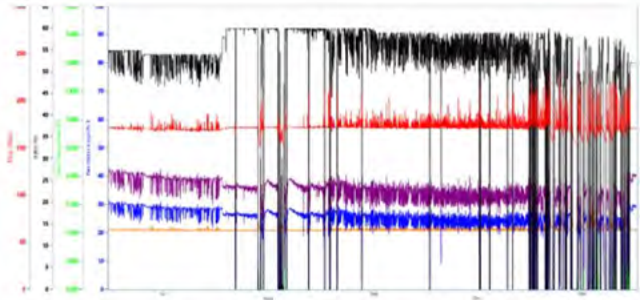
MIDLAND, TEXAS, UNITED STATES

CHALLENGES

- 9,000 ft deep well with high gas-to-liquids ratio (GLR)
- Lost production due to excessive shutdowns and high downtime
- Amp fluctuations due to high gas in the pump
- Short run life due to instability and a high number of shutdowns

SOLUTION

- The Magnefficientmotor (PMM) permanent magnet was recommended for its ability to:
–Lower heat generation with higher efficiency
–Reduce downtime, power consumption, and flow rates
–Maintain a more constant power factor and efficiency rating over a larger load range compared to induction motor technology
– Reduce cable power losses, or when applicable, allows you to use a smaller cable to save additional costs.



Induction motor performance trends show multiple high motor temperature shutdowns (black) caused by gas interference.

RESULTS

25%
Reduction in power consumption

10%
Reduction in downtime and increase in production through lower flow rates

$1M USD
Increase in annual production revenue

Baker Hughes

CASE STUDY 2

HPUMP SURFACE PUMPING SYSTEM SUPPLEMENTS COMPRESSORS TO RELIABLY BOOST CO2 INJECTION AT LOWER POWER DEMAND

CO2 INJECTION

CHALLENGES

Conventional 700-HP compressors for CO_2 injection suffered from:

- Reduced performance with slight increases in CO_2 temperatures
- High CAPEX and large power requirements during operation
- Complicated and time-consuming installation on site
- Labor-intensive maintenance and repair, which increases nonproductive time and decreases CO_2 injection volumes

SOLUTION

Supplements compressor with the HPump™ surface pumping system to improve pumping efficiency and lower costs with features including:

- Proven performance based on electrical submersible pump technology
- Scalable, modular design and off-the-shelf components for faster install and repairs
- Optimized pump stage count for efficient CO_2 pumping at reduced densities
- Greater pumping flexibility and flow assurance at half the operating cost of a single compressor

RESULTS

26.7 MMcf/d
transported at 450 HP load

36% less power
required to run the pumps

Increased pumping
output at continuous injection rates

Lower costs
to install, operate, and maintain

Baker Hughes

CASE STUDY 3

NEW EMULSION BREAKER REDUCES TREATMENT AND TRANSPORTATION COSTS

SPECIALIZED TECHNOLOGY SAVES OPERATOR APPROXIMATELY 28$ MILLION ANNUALLY

CHALLENGES

Heavy crude oil is often treated with naphtha to facilitate dehydration during transportation. However, naphtha drives up treatment and transportation costs due to viscosity-related challenges. Treatment and transportation costs amounted to almost $28 million a year for an operator in Colombia and negatively affected their profitability. After unsuccessful results with other options, the operator turned to Halliburton for our emulsion breaker expertise and technology.

SOLUTION

Halliburton proposed a tailored technology to the operator that replaces traditional demulsifiers.

The proposed emulsion breaker consists of new molecules created through innovative synthesis and alkylation processes to help efficient dehydration under high-viscosity conditions.

RESULTS

After the application of the emulsion breaker, the naphtha injection volume decreased by 15% to20%. The overflow of the gun barrel maintained the required 0.5% basic sediment and water(BS&W).

During an 11-week period, the operator reducednaphtha dilution from 9.4% to 7.4% and saved 21% of the naphtha needed for oil dehydration. The operator pumped 400-500 fewer barrels of water per day (BWPD). This saved them $2.8 million per year.

The reduced naphtha use translated to a gross savings of more than $75,000 per day or nearly $28 million a year.

In addition, crude oil volume stored in treatment stations decreased by 15%

HALLIBURTON

CASE STUDY 4

CORROSION-RESISTANT CEMENT SYSTEMS ACHIEVE ZONAL ISOLATION IN CO2 STORAGE WELL

CORROSALOCK™ AND CORROSACEM™ CEMENT SYSTEMS SUCCESSFULLY PLACED ON PRODUCTION LINER IN CCUS WELL

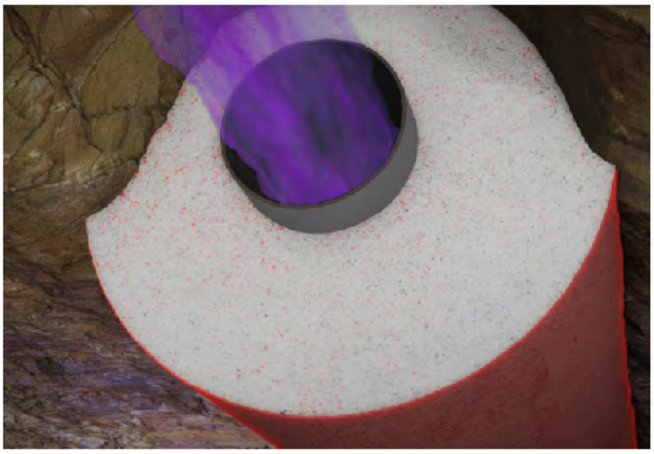
CHALLENGES

An operator in North America required a CO2 corrosion-resistant cement system to obtain a CCUS well permit.

The primary purpose of this well is to store the CO2 captured from a nearby treating facility. The CO2 is a natural byproduct from natural gas production of nearby wells Injection of excess CO2 back to the subsurface formation was planned. Because of a relatively low fracture gradient in the injection section, lost circulation also posed a challenge.

SOLUTION

To address the corrosive nature of the injected stream, along with slim equivalent circulating density (ECD) margins, a relatively low-density low-rheology 13.5-lbm/gal CorrosaLock™ cement system lead and 14-lbm/gal CorrosaCem™ cement system tail were deployed. The CorrosaLock corrosion-resistant system is a composite mixture of Portland-based cement and Welllock® resin additive. The resin component helps enhance the system's mechanical properties by increasing elasticity, which helps mitigate the effect of cyclic loading on the cement sheath. Inclusion of resin also reduces the permeability and porosity of the composite system, which enhances corrosion resistance.



CorrosaLock™ cement system provides a significant permeability reduction and enhanced mechanical properties to enable superior corrosion resistance in CO_2 environments.

RESULTS

Full circulation was maintained throughout pumping and displacement operations. A total of 64 bbl of CorrosaLock cement lead and 60 bbl of CorrosaCem cement tail slurries were effectively placed over the entire length of the liner. Low-pressure and high-pressure liner top tests were successfully performed. Additionally, a successful negative test was performed. A cement bond log (CBL) verified the quality of the cement sheath behind the liner and confirmed excellent cement coverage throughout the wellbore.

HALLIBURTON

NEW TECHNOLOGY 1

MULTISENSE DYNAMICS MAPPING SYSTEM

Deliver more efficient and consistent drilling performance

APPLICATIONS

• Single and multiple wells with hole sizes of 5 in. (127 mm) and greater
• Wells with a risk of drilling vibrations
• Identifying performance limiters
• Root cause and failure analysis
• Benchmarking and building parameter roadmap

BENEFITS

• Provides dynamic, at-the-bit measurements
• Maintains consistent BHA length above the bit
• Reduces non-productive time
• Delivers high drilling efficiency
• Helps ensure consistent predictable drilling performance

INTRODUCTION

Understanding the dynamics of bit-rock interactions is crucial to maximizing the efficiency and safety of drilling operations. The MultiSense™ dynamics mapping system is an advanced in-bit sensing technology that provides a deeper understanding of drilling dynamics at the rock face. As an add-on service for any bit, the MultiSense system delivers continuous, high-frequency measurements of parameters at the bit for smarter insights that guide design decisions and improve formation characterization. The system helps maximize drilling performance at a lower cost-per-foot in several ways.

RELIABLE AND CONSISTENT

Operators need assurances that their downhole tools will provide consistent, reliable, and high-quality data. The MultiSense system's module meets the highest internal reliability standards for operability and data quality. The module's in-bit sensors measure a range of parameters—including vibrations, stick/slip, shock, and revolutions per minute—and identify any inaccuracies faster and more precisely than a human. The drilling team can then make more informed assessments and quicker adjustments to maintain drilling efficiency and minimize nonproductive time.

FAST, AGILE RESPONSE

Rapid access to downhole data is essential to forming actionable insights that improve the speed and certainty of drilling. The self-contained, self activated MultiSense module connects easily to the BHA and deploys quickly, with the support of field crews trained in time-saving workflows that ensure operational readiness once the system reaches its measuring depth. Whether an operator needs data back before the next bit touches bottom or wants to conduct a thorough post-well analysis, data is always available from a robust digital infrastructure. Streamlined analysis helps minimize review time and decision-making—without waiting for input from data specialists.

DRIVING CONTINUOUS IMPROVEMENTS

As operators keep looking to boost drilling efficiency, lower costs, and maximize production from every well, the MultiSense system accelerates continuous improvement in the drilling process. Application engineers review and analyze the high-density data through simple yet meaningful visualizations, and deliver clear, detailed insights to operators. Such insights can help fine-tune bit designs and operational parameters to deliver more efficient and consistent drilling performance.

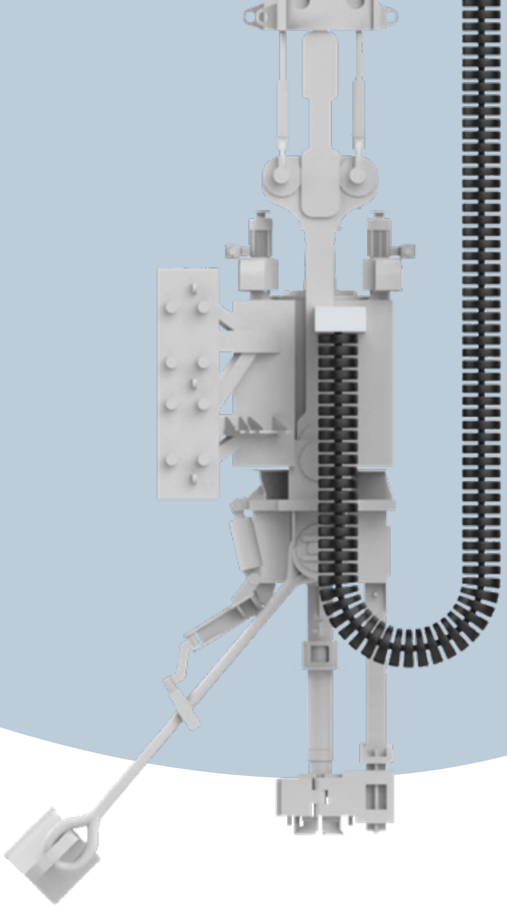
The MultiSense data seamlessly integrates into the Drilling Insights platform, which uses our cloud based digital ecosystem to develop actionable insights that help plan and execute a single well, multiple wells, or an entire field campaign. Contact your Baker Hughes representative to learn how the MultiSense dynamics mapping system can help deliver more efficient and consistent drilling performance in your wells.

Baker Hughes

NEW TECHNOLOGY 2

CABLE GUIDING IN VERTICAL DRILLING RIGS: FROM SERVICE LOOP TO E-LOOP

A newly developed alternative to service loops on vertical drilling rigs, offering significantly longer service life under extreme environmental conditions



INTRODUCTION

Mobile and semi-mobile deep drilling rigs in the oil and gas industry are engineered for extreme conditions, drilling holes several kilometers deep with drill pipes weighing up to 1,000 tones. These rigs face significant challenges, including vibrations, irregular mechanical stresses, and heavy contamination. The energy supply systems, which transmit electrical current, signals, and hydraulic media to the top drive (the component that propels the drill pipe), must operate effectively under these harsh conditions (Figure 1)..

Figure 1: Top drive with service loops and flushing hose on an oil drilling platform (Source: Adobe Stock, Alexandr, 211146059)

THE DESIGN

In the design of mobile and semi-mobile deep drilling rigs, ensuring high availability and reliability of energy and signal supply systems to the top drive is critical, as these rigs operate continuously and downtime can lead to significant productivity losses. To minimize "set-up times" during rig relocations, these rigs are engineered for quick disassembly and reassembly.

Key Points:

- Service Loops: Traditionally, service loops made of coiled cable packages housed in rubber hoses are used for energy supply.

- Design Challenges: These loops are suspended from a fixed point on the rig, which can lead to uncontrolled movement and wear due to the lack of guidance and defined bend radii.

- Operational Risks: Loosely hanging service loops are prone to entanglement with other rig components and may fail under adverse weather conditions, leading to cable breakage.

- Impact on Availability: Such failures necessitate complete replacement of cable assemblies, affecting the overall availability and efficiency of the rig.

DEVELOPED FOR THE APPLICATION: THE E-LOOP

Developed for a niche application, the igus® designers created the e-loop system after studying the demanding requirements. They focused on mechanical properties, 3D mobility, compactness, ease of service, and a small bend radius. This system is designed to operate under adverse conditions and withstand rough handling. Figure 3: The e-loop system.

●New development specifically for top drivesystems

●Design features are: compact, robust design, three-dimensional mobility.

●The interchangeability of all modular components saves costs in service and time in procurement.

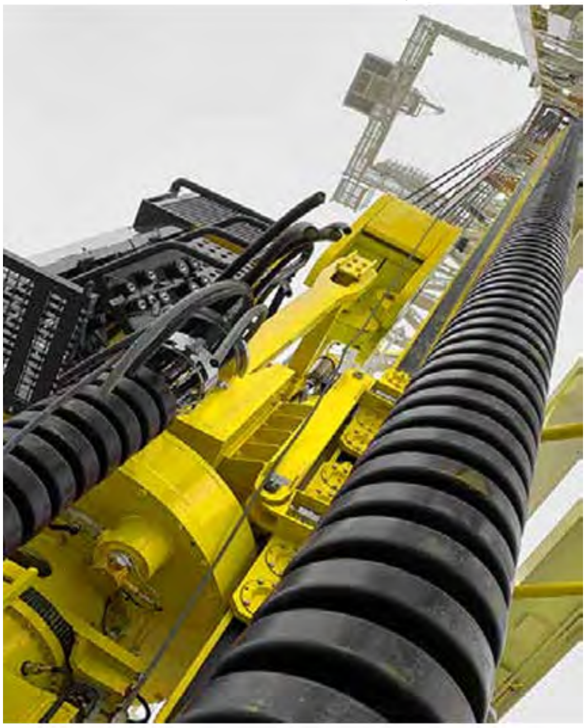


Figure 3: The e-loop system combines all cables into a compact and modular system (Source: igus® GmbH)

ONE SYSTEM FOR ALL CABLES

The e-loop system can accommodate all cables routed to the top drive, including motor cables, signal cables, and hydraulic medium. Unlike service loops, it prevents cables from becoming entangled, even in strong winds. The division into two chambers ensures wear-free movement of the various cables..

● A protected cable system is less susceptible to wear than two or three moulded cables that can move against each other.

● The separation of the e-loop into two chambers protects the individual cables.

EASY MAINTENANCE, ASSEMBLY AND DISASSEMBLY

Several secured screw connections are used between the elements of the energy supply, which prevent components from falling down and increasing operational reliability. The screwed mounting brackets also facilitate the assembly and disassembly of the e-loop.

●The e-loop is easy to install.

●If necessary, individual cables can be replaced with little time and effort.

RELIABLE CABLE PROTECTION

The e-loop consists of individual chain links with a shock-resistant PU foam outer protector and igumid high-performance polymer inner parts, which are corrosion-free and chemical-resistant. The chain link connections are designed for long service life under extreme conditions.

A synthetic plastic fiber rope at the center of the e-loop is shatterproof, weather-resistant, flexible, and corrosion-free. The links are clamped onto this pre-tensioned pull rope. This protection ensures the e-loop and cables have a long service life.

APPLICATION. NOT ONLY IN DEEP DRILLING RIGS

The e-loop is an energy supply system designed for deep drilling rigs, offered in 220mm and 300mm outer diameters. It has a travel length of 34m, a maximum speed of 2.2m/s, and supports a fill weight of 19kg/m. The e-loop is effective in various applications beyond vertical drilling, including offshore industry, construction machinery, shore power, and wind turbines. Custom modifications, such as rollers and handles, enhance its usability for demanding environments.

● The system has successfully completed the initial practical tests.

● In addition to vertical drilling technology, there are also other possible applications, e.g. in the offshore industry, construction machinery and shore power and wind turbines.

EGYPT NEWS

EGYPT AND SAUDI ARABIA FORGE STRATEGIC PARTNERSHIP TO BOOST ENERGY EFFICIENCY

Engineer Karim Badawy, Egypt's Minister of Petroleum and Mineral Resources, met with Prince Abdulaziz bin Salman, Saudi Arabia's Minister of Energy, to explore opportunities for advancing energy sector collaboration between the two nations.

During their meeting at the Saudi Ministry of Energy headquarters in Riyadh, the discussion centered on a joint initiative to enhance energy efficiency in Egypt and leverage Saudi Arabia's extensive expertise in this field. The initiative, currently in the final stages of development by joint working teams, is expected to be officially launched soon. This follows last month's comprehensive discussions in Cairo, hosted by Egypt's Ministry of Petroleum, which brought together experts from the Ministries of Petroleum and Electricity and Renewable Energy in Egypt, alongside specialists from Saudi Arabia's Ministry of Energy, the Saudi Energy Efficiency Center, and the Tarshid Company.

Minister Karim Badawy emphasized the growing strategic partnership between Egypt and Saudi Arabia, noting that the recent period has witnessed significant progress in energy collaboration. He highlighted the critical importance of improving energy efficiency in Egypt, which not only conserves valuable resources and reduces fuel import costs but also delivers substantial environmental benefits through reduced carbon emissions.

BADAWY HIGHLIGHTS UNIQUE GREEN AMMONIA PROJECT IN DAMIETTA IN PARTNERSHIPWITHGLOBALLEADERS

Eng. Karim Badawi, Minister of Petroleum and Mineral Resources, visited the MOPCO Fertilizers Complex in Damietta to oversee operations, emphasizing safety, sustainability, and green production. He affirmed full support for MOPCO's investment and expansion plans, highlighting its collaboration with Scatec and Yara on Egypt's first green ammonia project, a milestone for the energy transition. The minister noted that integrating renewable energy and maximizing natural gas efficiency will boost Egypt's position as a regional green energy hub while driving export growth. MOPCO Chairman Eng. Ahmed Mahmoud detailed the company's achievements, including meeting %30 of Egypt's urea demand, exporting to Europe, and reducing carbon emissions by 25,000 tons annually. MOPCO also introduced a new ADBlue unit to meet global demand for eco-friendly diesel additives and plans to expand solar capacity to 4 MW.

ETHYDCO SEEKS 40$ MILLION LOAN FROM MASHREQ BANK TO SETTLE GAS DUES

Ethydco, a leading producer of ethylene and polyethylene in Egypt, is seeking a 40$ million loan from the UAE-based Mashreq Bank to settle gas payments owed to the Egyptian Natural Gas Company (GASCO). According to a government official speaking to "Asharq Business with Bloomberg," the loan is still pending Cabinet approval, as the UAE bank has required the inclusion of an international arbitration clause in case of disputes over the loan. It is worth noting that Ethydco previously secured a 250$ million loan from Mashreq Bank in 2023 to repay dollar-denominated loans used for construction and establishment activities.

BP COMPLETES RAVEN FIELD DRILLING CAMPAIGN AND LAUNCHES EXPLORATION AT ELKING OFFSHORE EGYPT

41 NEW WELLS AND 3,300 ADDITIONAL BARRELS PER DAY: THE GENERAL PETROLEUM COMPANY'S PLAN TO BOOST PRODUCTION

CHEVRON TO DRILL SECOND WELL IN NARGIS FIELD, IN FEBRUARY WITH 150$ MILLION INVESTMENT

Chevron, the U.S.-based energy company, plans to begin drilling a second exploratory well in the Nargis gas field, located in deep waters of the Mediterranean Sea in Egypt, during February. The project involves an estimated investment of approximately 150$ million, according to a government official who spoke to Al-Sharq on condition of anonymity. The Nargis concession is jointly owned by Chevron and IEOC Production (a subsidiary of Italy's Eni), with each holding a %45 stake. The remaining %10 is owned by Egypt's Tharwa Petroleum Company.

EGYPT BOOSTS OIL AND GAS OUTPUT WITH 105 NEW WELLS

Egypt's petroleum sector has achieved a remarkable production increase of 1.4 million barrels of oil equivalent per day (BOE/D) in the second half of 2024 (July–December). This was made possible through the drilling of 105 new wells—95 oil wells and 10 gas wells—adding a daily output of 63,700 barrels of oil and condensates, along with 271 million cubic feet of natural gas.

These achievements are expected to save the country 1.5$ billion in additional import costs every six months, starting January 2025.

MIDDLE EAST NEWS

VIRIDIEN SECURES THREE-YEAR SEISMIC CONTRACT WITH PETROLEUM DEVELOPMENT OMAN

Viridien (formerly CGG) has been awarded a three-year contract by Petroleum Development Oman (PDO) to provide advanced land seismic imaging services at its dedicated processing center (DPC) in Muscat, Oman. This new contract continues a longstanding collaborative partnership between Viridien and PDO

PERMA-PIPE AWARDED 43$ MILLION CONTRACT FOR MIDDLE EAST DEVELOPMENT PROJECT

Perma-Pipe International Holdings, Inc. announced it has received a formal letter of award for a development project located in the GCC region. Perma-Pipe will provide thermal insulation, anti-corrosion coatings, and other services from its Abu Dhabi facility. Project commencement is expected to begin in the third quarter of 2025. The value of this project is estimated to exceed 43$ million.

SANDBOXAQ, ARAMCO TO DEPLOY NEW AI PLATFORM FOR OIL AND GAS FACILITIES

SandboxAQ announced it has signed an agreement with Aramco, one of the world›s leading integrated energy and chemicals companies, to collaborate on developing a multi-GPU enabled differentiable computational fluid dynamics solver for application in oil and gas processing facilities.

TOTALENERGIES KICKS OFF 250$ MILLION PROJECT TO CAPTURE GAS FROM IRAQI OIL FIELD

(Bloomberg)–TotalEnergies SE, Basra Oil Company and QatarEnergy broke ground on a 250$ million project to capture gas from the Ratawi oil field in Southern Iraq.

BAKER HUGHES AWARDED CONTRACT FOR PHASE 3 EXPANSION OF ARAMCO'S JAFURAH GAS FIELD

Baker Hughes has been awarded an order by Tecnicas Reunidas for six gas compression trains and six propane compressors, for the third expansion phase of Aramco's Jafurah gas field, located in the Kingdom of Saudi Arabia

ADNOC GAS, BAKER HUGHES LAUNCH LEVIDIAN TECHNOLOGY TO TURN METHANE INTO HYDROGEN, GRAPHENE

ADNOC Gas in partnership with Baker Hughes has successfullyinstalledBritish climate technology firm Levidian's patented LOOP technology at the Habshan Gas Processing Plant.

SANDBOXAQ, ARAMCO TO DEPLOY NEW AI PLATFORM FOR OIL AND GAS FACILITIES

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CB&I WINS EPC CONTRACT FOR RUWAIS LNG PROJECT IN UAE

CB&I has been awarded a substantial* lump sum contract by TJN Ruwais JV for engineering, procurement, and construction (EPC) of two cryogenic tanks and associated civil, structural, mechanical and piping works for its liquefied natural gas (LNG) project, located in Ruwais, Abu Dhabi, UAE. Once complete, the Ruwais LNG project will be the first net zero LNG facility in the Middle East. TJN Ruwais JV is a joint venture between Technip Energies France-Abu Dhabi, JGC Corporation and NMDC Energy.

OPEC PRODUCTION DIPS IN DECEMBER AS UAE IMPLEMENTS SUPPLY CUTBACKS

(Bloomberg) – OPEC's crude production dipped last month as the United Arab Emirates stepped up implementation of supply cutbacks aimed at buoying global oil markets.

OPENING PARTY & RECRUITMENT

The opening party and recruitment drive aimed at introducing students to the organization, showcasing its various committees and activities, and recruiting new members.
The event fostered engagement between students through a technical exhibition, interactive displays, and competitions.

ONLINE TECHNICAL CAMP

From October to December 2024, the IADC Suez Student Chapter hosted an online Technical Camp focused on drilling, reservoir, and production engineering in the oil and gas industry. The camp, taught by professional engineers, was divided into three tracks, each concluding with a quiz and prizes.

ARTOPIA EVENT

Artopia, held on November 12, 2024, at Montazah Badr, Suez, was a celebration of creativity and culture. The event featured art exhibitions displaying drawings and handmade creations, interactive workshops in drawing, crafts, and calligraphy, and competitions

TECHNICAL EXHIBITION

On May 12, 2024, IADC Suez held its first Technical Exhibition at Suez University. IT was graced by Suez University President Prof. Dr. Ashraf Heniegal, Dean Prof. Dr. Essam Ahmed, Dr. Nevin Aly (IADC Suez Faculty Advisor), Ms. Yasmine Ali and Ms. Rana Mostafa (UEE representatives). It showcased innovative projects and research, and featured competitions designed to test participants› knowledge, skills .

IADC
PROJ

SUEZ

JECTS

THE SECOND STUDENT CONFERENCE OF FACULTY OF PETROLEUM ENGINEERING

Hosted by Faculty of Petroleum and Mining Engineering, IADC Suez University Student Chapter and other student chapters, this event sought to foster networking and collaboration, offering valuable insights from industry professionals and professors to inspire and inform the next generation of petroleum engineers

CHARITY PROGRAM

On October 13, 2024, the IADC SU SC organized a charity event at the Al Safa Organization in Suez, which serves individuals with disabilities and special needs. The student group visited the organizatio spent time playing games and doing activities with the people there, and to support their daily lives and programs. The visit aimed to bring joy and support them

SCHOLARSHIP PROGRAM

In addition to providing opportunities to supplement academic education, this program has been offered by IADC to its student chapter members all over the world. It aims to encourage and empower the next generation of professionals. we are proud to have secured 2 of 20 Opportunities

THE IADC DRILLING MIDDLE EAST 2024 CONFERENCE & EXHIBITION

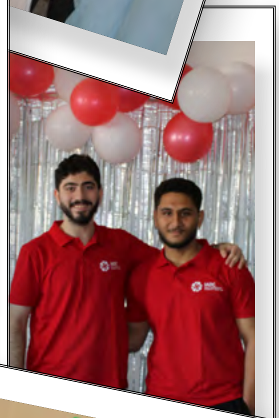
The IADC Drilling Middle East 2024 Conference & Exhibition, held in Muscat, Oman, from December 10-11, was attended by representatives from the IADC Suez University Student Chapter, including their advisor Dr. Nevin Aly, alongside other student chapters of IADC and industry leaders. The conference focused on key topics such as workforce development, drilling efficiency, safety, equipment maintenance, drilling automation, and HSE performance.


IADC
HUMANITY
Conference & Exhibition
PATTERSON-UTI









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IADC Suez
Chairman & Founder

PETRO GATE CHAIRMAN

SAAD WASEEM

IADC Suez
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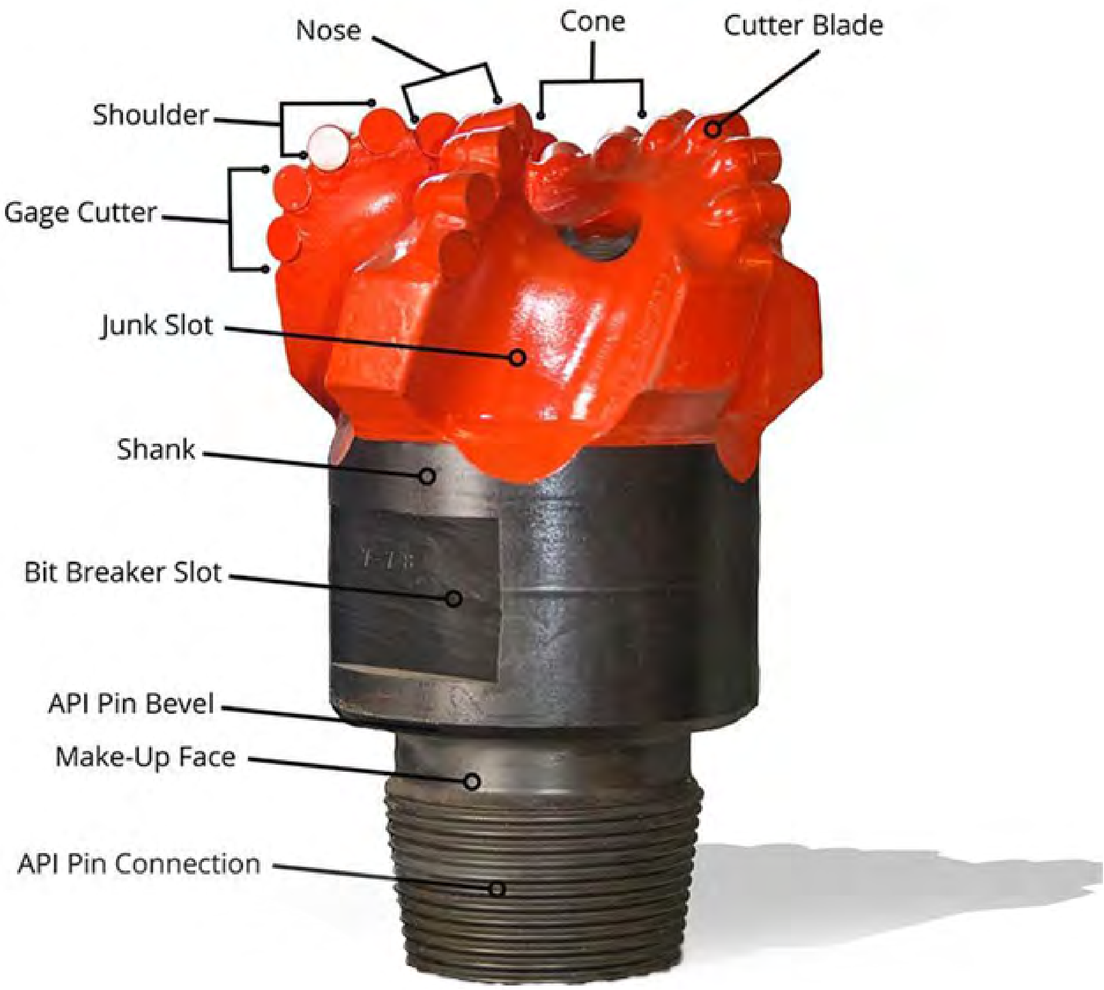
IADC CLASSIFICATION SYSTEM FOR PDC DRILL BITS



PDC drill bits nomenclature comprises a single letter and three numbers, each bearing critical significance. The letter designates the body type: M for matrix, S for steel, and D for diamond. Subsequent numbers delineate:

1. **Geological Formation Type To Be Drilled**
2. **Cutting Structure**
3. **Bit Profile**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