SPE/IADC-233133-MS

Achieving Zero Stuck Pipe Incidents in Horizontal Wells Through AI-Based Real-Time Risk Mitigation and ROP Optimization: A Story From BHA Graveyard in Offshore East Java Indonesia

Y. F. Yusicha, M. I. Akbar, J. Tobing, F. Ardhiansyah, and T. Setiawan, Petronas Carigali Ketapang II Ltd, Jakarta, Indonesia; H. P. Setiono, SKK MIGAS; N. Hanafiah and M. Regan, Exebenus Sdn Bhd, Kuala Lumpur, Malaysia

This paper was prepared for presentation at the SPE/IADC Asia Pacific Drilling Technology Conference and Exhibition held in Bali, Indonesia, 5 – 6 August 2026.

Abstract

PETRONAS has previously drilled 16 high-inclination and horizontal extended-reach development (ERD) wells in the JT field, offshore East Java, between 2015 and 2023. Historically, 8 of these wells representing a 50% risk probability, experienced significant stuck pipe incidents, which were driven by a combination of complex heterogeneous formations, variable formation pressure regimes inducing differential sticking tendencies, partial to severe fluid losses, and wellbore instability associated with planes of weakness when drilling at inclinations exceeding 60 degrees.

In 2025, a two-well horizontal infill drilling campaign was completed in the same field. The first well-built inclination from 40° to 61° through a 12¼″×14¾″ under-reamed section and built from 61° to 74° through 10-5/8″ × 12¼″ under-reamed section before landing a 3,200 ft RSS-geosteered 8½″ horizontal lateral. The second well extended a 4,800 ft tangent at 68° inclination before landing a 1,500 ft 8½″ RSS-geosteered horizontal lateral. Both well profiles presented significant drilling challenges amplified by the demanding geological environment, where conventional real-time monitoring, inherently reactive and reliant on manual surface parameter interpretation, was insufficient to pre-empt emerging risks in a timely manner.

This paper describes the successful field application of an integrated, real-time AI-driven advisory solution for predicting and identifying stuck pipe risk and supporting ROP optimization along with vibration monitoring, deployed without any requirement for additional model training from offset well data or prior well-specific calibration. The collective solution, comprising multiple interoperating real-time machine learning agents, facilitated flawless execution of both challenging infill wells, achieving zero stuck pipe incidents and completing operations 13 days ahead of the planned combined duration. Optimal drilling efficiency was sustained over key intervals, with overall average ROP improvement of 34% and 11% recorded for the first and second wells respectively over constrained sections. The substantial material savings realized in time, logistics, consumables, HSE exposure, emissions, and cost demonstrate the significant value of real-time, predictive AI advisory in complex horizontal well campaigns.

Introduction

Stuck pipe remains one of the most costly and operationally disruptive hazards in well construction globally. Industry analyses have consistently identified stuck pipe incidents as a primary contributor to non-productive time (NPT), accounting for an estimated 15% of total NPT across drilling operations worldwide (Alshaikh et al. 2019). The associated costs are substantial: stuck pipe is estimated to cost the industry many hundreds of millions of dollars annually in direct operational costs (Bradley et al. 1991, Muqeem et al. 2012), and the operational consequences extend beyond direct financial impact to include increased HSE exposure, emissions, and equipment risk.

The challenge is particularly acute in high-inclination and horizontal extended-reach drilling (ERD) environments, where the combination of complex formation pressures, and the mechanical demands of delivering geosteered laterals creates a convergence of risk factors for differential sticking, hole cleaning dysfunction, and mechanical instability. In such environments, even transient deviations from the drilling envelope, if undetected or detected too late, can rapidly escalate into costly stuck pipe events requiring significant remediation, potentially including sidetrack operations.

The JT field in the offshore East Java, Indonesia, exemplifies these challenges. The operator has been active in the field since the start of development drilling in 2015. Between 2015 and 2023, 16 high-inclination and horizontal ERD wells were drilled, half of which encountered significant stuck pipe events. These events resulted in substantial non-productive time (NPT), logistical disruption, and deferred production. The primary contributing factors include geomechanical wellbore instability, differential sticking across formations with variable pressure regimes, and partial to severe fluid losses, all exacerbated by the high-inclination well profiles required to deliver the well on target in order to maximise reservoir contact.

Conventional approaches to real-time stuck pipe risk management, reliant on the manual interpretation of surface drilling parameters by wellsite personnel, are inherently reactive in nature. By the time an emerging risk becomes apparent through observation of surface indicators, such as changes in hookload, torque, standpipe pressure, or ROP, the subsurface condition driving the risk may already be significantly advanced. The ability to identify, characterize, and pre-empt emerging stuck pipe risk with meaningful advance notice, enabling fit-for-purpose preventive action before conditions deteriorate, requires a more sophisticated, and data-driven, and predictive monitoring capability (Payrazyan et al. 2023, Gomes et al. 2024).

In 2025, the Operator decided to implement a more sophisticated data-driven approach through deployment of a real-time AI-driven advisory solution for a two-well horizontal infill drilling campaign in the JT field. The objective was to ensure zero stuck pipe incidents while maximizing consistent ROP performance across both wells. This paper presents the operational context, the solution methodology, and the results achieved, providing a field-validated case study of how targeted machine learning, applied without local retraining or well-specific calibration, can enhance real-time drilling risk management in a high-consequence offshore horizontal well construction environment.

Field and Well Description

Field Overview

The JT field is located in the offshore East Java, Indonesia, in water depths of approximately 184 ft. Development drilling in the field commenced in 2015 and has since progressed through multiple phases of infill and extended reach drilling to optimize reservoir contact and production.

The reservoir target is characterized by massive limestone, within a depth range of approximately 4600 ft-TVDSS to 6300 ft-TVDSS. The geological environment exhibits significant formation heterogeneity, including interbedded lithologies (shale / sand / limestone) in one formation layer as well as variable pore pressure regimes across the drilled sections. These conditions introduce complexity in maintaining wellbore stability and managing equivalent circulating density (ECD) within a narrow operating window. In addition, lithological variability and pressure contrasts contribute to increased susceptibility to differential sticking, fluid losses, and hole cleaning challenges, particularly in high-inclination and horizontal sections.

Historical Drilling Performance — 2015 to 2023

Between 2015 and 2023, there was a total of 16 high-inclination and horizontal ERD development wells in the JT field by PETRONAS. These wells were designed with inclinations reaching up to maximum 90 degree (horizontal well) and maximum MD up to 17,000 ft. The well profiles required extended tangent sections and, in several cases, horizontal laterals for optimal reservoir contact.

Half of the 16 wells drilled over this period experienced significant stuck pipe incidents. These incidents resulted in NPT and required remedial operations including jarring, fishing, and sidetracking the well. The root causes were distributed across three primary stuck pipe mechanisms: differential sticking driven by variable formation pressures, hole-cleaning dysfunction in high-inclination sections, and wellbore instability-induced mechanical sticking related to planes of weakness in the formations encountered above 60° inclination. Table 1 summarises the 16-well historical campaign, highlighting those wells that experienced stuck pipe incidents and the primary mechanism attributed to each event.

Table 1—Summary of JT Field historical drilling campaign (2015–2023): well profiles and stuck pipe incident history

Well	TD (ft MD)	Max Incl. (°)	Horizontal Length (ft)	Stuck Pipe	Primary Mechanism
Well 1	13,761 ft-MD	90°	904 ft	Yes	Mechanical Stuck
Well 2	12,755 ft-MD	91°	2,932 ft	Yes	Mechanical Stuck
Well 3	14,067 ft-MD	90°	3,116 ft	No	No Stuck Pipe
Well 4	13,983 ft-MD	90°	2,244 ft	No	No Stuck Pipe
Well 5	11,750 ft-MD	90°	2,552 ft	Yes	Mechanical Stuck
Well 6	13,383 ft-MD	90°	2,143 ft	No	No Stuck Pipe
Well 7	11,470 ft-MD	90°	2,032 ft	Yes	Differential Stuck
Well 8	14,785 ft-MD	82°	N/A	No	No Stuck Pipe
Well 9	11,245 ft-MD	90°	1,010 ft	No	No Stuck Pipe
Well 10	13,531 ft-MD	90°	1,049 ft	No	No Stuck Pipe
Well 11	16,446 ft-MD	80°	N/A	Yes	Mechanical Stuck
Well 12	14,305 ft-MD	90°	2,702 ft	Yes	Differential Stuck
Well 13	11,369 ft-MD	90°	2,343 ft	No	No Stuck Pipe
Well 14	15,217 ft-MD	90°	1,603 ft	Yes	Mechanical Stuck
Well 15	17,120 ft-MD	90°	2,431 ft	Yes	Mechanical Stuck
Well 16	15,685 ft-MD	90°	5,472 ft	No	No Stuck Pipe

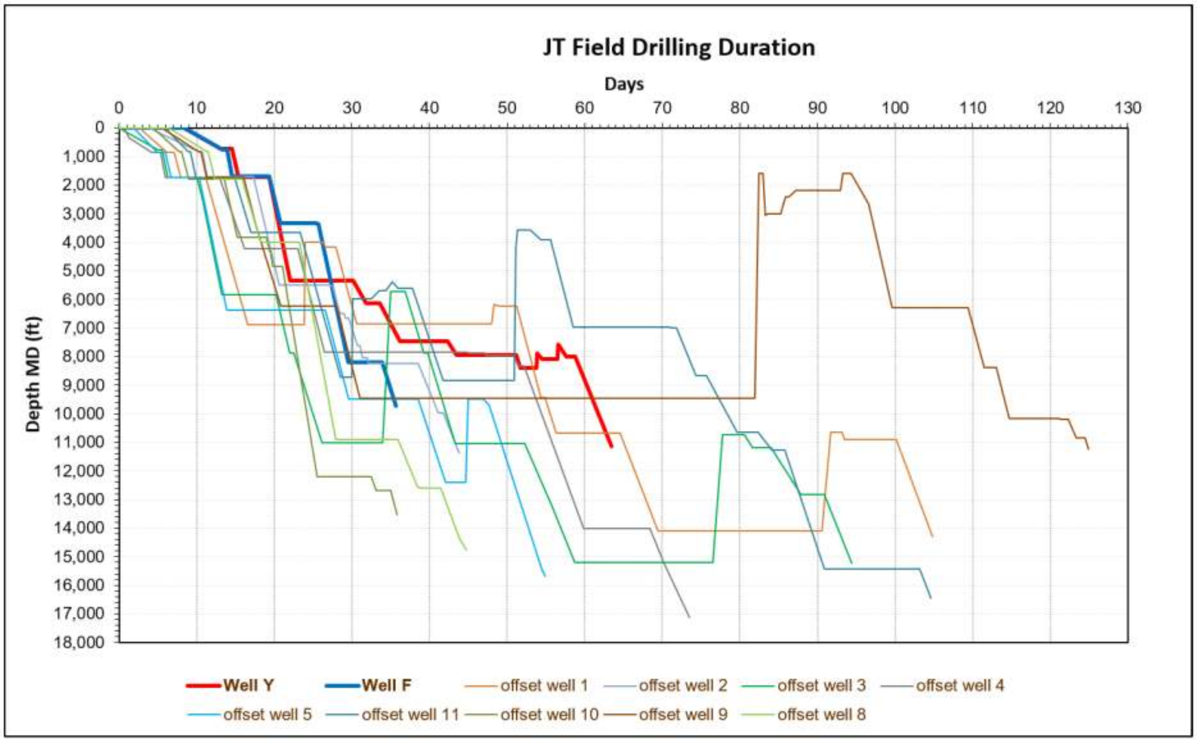

Figure 1—Use of an application predicting stuck pipe risk and optimising ROP resulted in Bit-on-Bottom (BoB) time in the drilled sections being consistently better than offset wells, with no sidetracks or redrilling, relative to the extensive sidetracking seen on most offsets.

2025 Infill Wells — Well Design and Profiles

In 2025, a two-well horizontal infill drilling campaign was executed in the JT field. Both wells were drilled as part of a back-to-back campaign using a jack-up rig. The wells were designed with challenging directional profiles to achieve optimal reservoir placement, building on geological and geomechanical insights derived from the historical campaign.

Well Y

Well Y with a total depth of 11155ft MD was designed as a multi-section well building inclination progressively from vertical to a horizontal 8½″ reservoir lateral. The well architecture comprised:

- Top section: Drive 30″ conductor, start drilling 22″ hole section with 18⅝″ surface casing and continue building inclination from 11° to 40° using 17½″ section then set 13⅜″ casing.
- Upper build section: inclination built from 40° to 61° using a 12¼″×14¾″ under-reamer assembly, drilling a 2,100 ft section with an intermediate 11¾″ casing set at 61°.
- Intermediate build section: a short 10⅝″×12¼″ drilled/under-reamed section-built inclination to 74°.
- Horizontal lateral: 3,200 ft 8½″ RSS-geosteered horizontal lateral drilled within the reservoir target.

Well F

Well F with a total depth of 9725 ft MD was designed with an extended tangent configuration:

- Top section: Drive 30″ conductor, start drilling 22″ hole section with 18⅝″ surface casing and continue building inclination from 15° to 55° using 17½″ section then set 13⅜″ casing.
- Extended tangent section: 4,800 ft 12¼″ tangent drilled at 68° inclination and building to 84° at TD section.

- Horizontal lateral: 1,500 ft 8½″ RSS-geosteered horizontal lateral to land and drill the reservoir target.

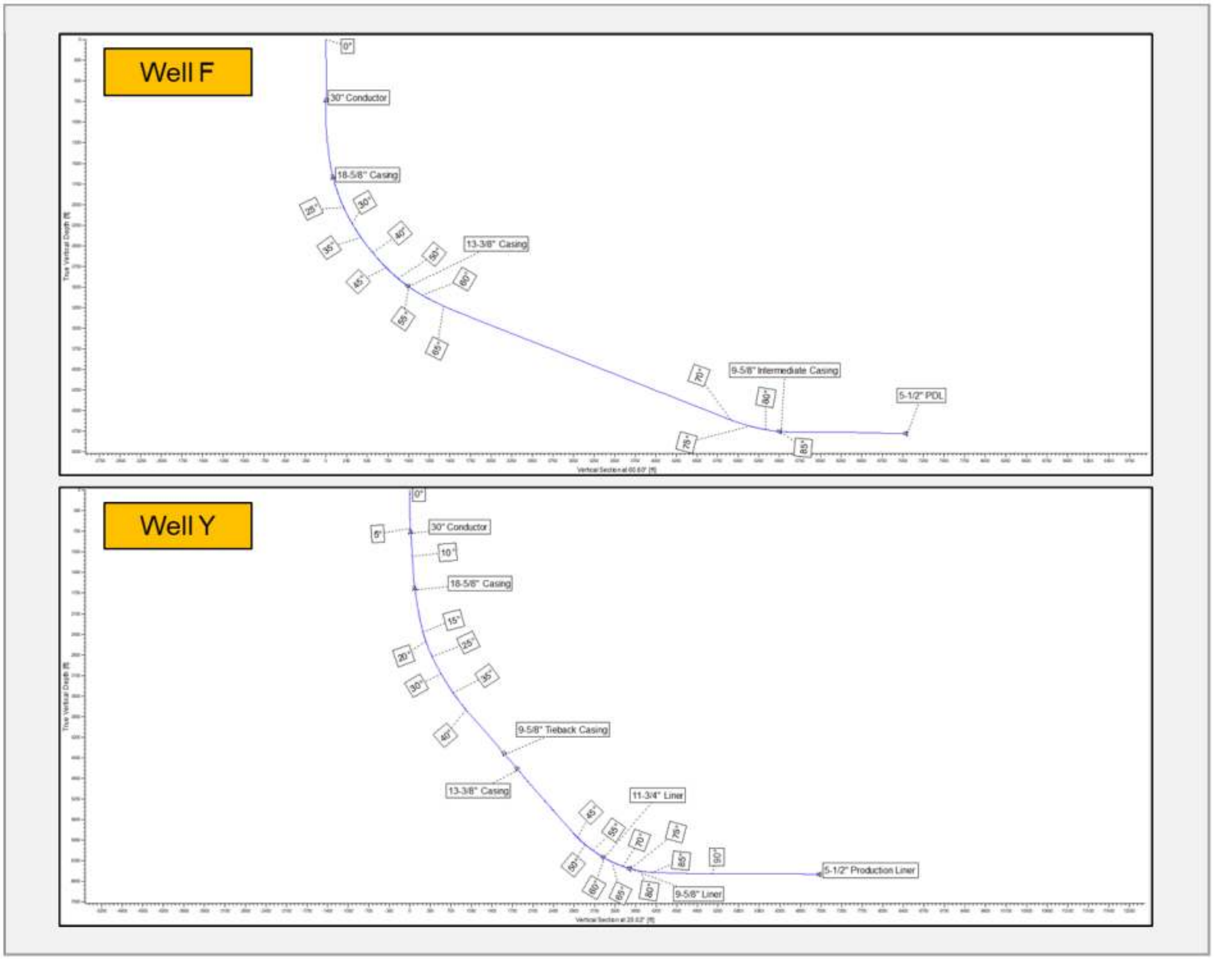

Figure 2—Planned well profile schematics for Well Y and Well F, showing inclination build sections, casing points, and horizontal lateral configurations.

Drilling Challenges

Geological and Geomechanics Issue

The formations encountered in the JT field present a highly demanding drilling environment arising from a combination of geological complexity and geomechanics sensitivity. The reservoir and overburden succession is characterized by interbedded sandstones and shales, carbonate stringers. Lateral and vertical heterogeneity in formation properties is pronounced.

Detailed geomechanical studies conducted prior to the 2025 campaign confirmed a high probability of wellbore instability due to planes of weakness when drilling with inclinations exceeding 60°. In this inclination range, the wellbore trajectory intersects the plane of weakness at angles particularly conducive to shear failure and block breakout, generating mechanical cavings that have a tendency to accumulate in the high-inclination annulus, elevating hole-cleaning risk.

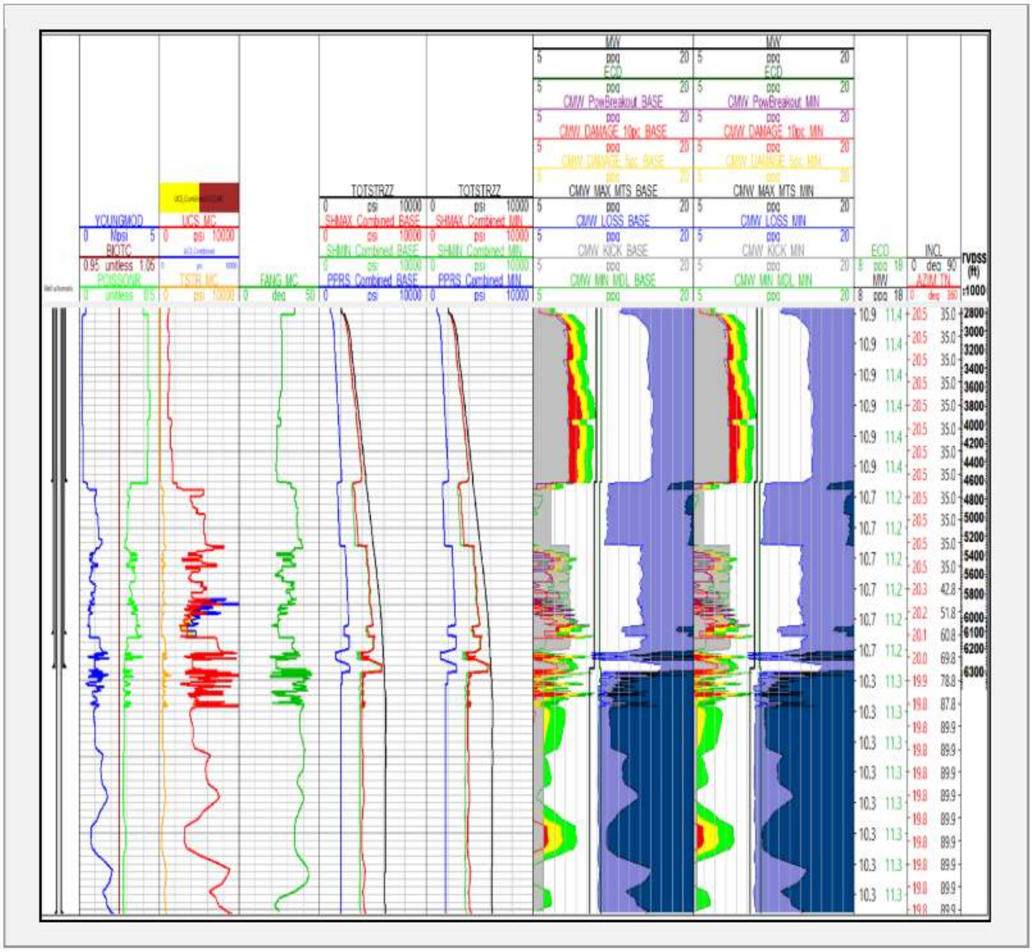

Figure 3—Wellbore stability window showing predicted stable mud weight range versus depth and inclination. The shaded zone above 60° inclination highlights the region of elevated instability risk due to planes of weakness.

Formation Pressure Variability and Differential Sticking

A key risk driver in the JT field environment is the variability in formation pressure across the open-hole interval. The heterogeneous nature of the formation succession means that a single mud weight selection, required to maintain wellbore integrity across a multi-formation open-hole section, inevitably results in significant overbalance in lower-pressure intervals. This differential between wellbore fluid pressure and formation pore pressure is the primary driver of differential sticking, where the drillstring becomes embedded in the mudcake against a permeable formation under the net radial force induced by the pressure differential.

In the historical JT field drilling campaign, the differential pressure range was between 700 to 1,500 psi. The combination of high inclination, which increases contact between the drillstring and the low side of the wellbore, and elevated differential pressure creates conditions in which differential sticking can develop rapidly, often with limited precursory surface indication under conventional monitoring approaches.

Fluid Loss

Partial to severe drilling fluid losses were encountered across multiple wells in the historical campaign and remained a risk for the 2025 infill wells. Severe to total losses were encountered during drilling through karstified and vuggy limestone with interconnected characterization which created additional complexity: managing equivalent circulating density (ECD) within a narrow margin between loss and instability and creating intermittent periods of reduced annular velocity that are detrimental to hole-cleaning efficiency in high-inclination and horizontal sections.

Limitations of Conventional Real-Time Monitoring

Under the demanding operational conditions described above, the limitations of conventional real-time monitoring become operationally critical. Standard wellsite monitoring, in which personnel track surface parameters including hookload, rotary torque, standpipe pressure, ROP, and weight on bit, requires manual interpretation and relies on the recognition of emerging trends by experienced individuals operating continuously across extended shift periods.

This approach has two fundamental shortcomings in the JT Field. First, it is inherently reactive; by the time a trend becomes sufficiently clear to prompt action at surface, the subsurface condition driving that trend, whether increasing differential pressure embedment, progressive solids accumulation, or early wellbore collapse, may already be substantially developed. Second, it is limited in its ability to simultaneously integrate and interpret multiple interacting parameters that characterize complex stuck pipe risk scenarios, particularly in distinguishing between different mechanisms, including differential sticking, mechanical instability, and hole-cleaning dysfunction, which can present with overlapping surface signatures.

Gomes et al. (2024) and Payrazyan et al. (2023) have demonstrated that machine learning-based advisory systems applied in real time can provide meaningful advance warning of stuck pipe risk, often several hours ahead of an incident, enabling pre-emptive corrective action that conventional monitoring cannot deliver. The deployment of such a system used extensively by the Operator in a variety of operating and geological conditions elsewhere worldwide, in the 2025, JT Field campaign was therefore motivated by both the demonstrated historical risk and the established capability of real-time AI advisory to improve outcomes in analogous environments.

AI Real-Time Advisory Solution — Methodology and Deployment

Solution Overview

The AI advisory solution deployed for the 2025 JT Field campaign was a real-time drilling optimization platform, comprising a physics-informed machine learning system with a documented field application history across approximately 1,000 well per Guenaga et al. 2025. The solution is purpose-built for real-time well construction risk management and has been applied previously across a range of operational environments including Southeast Asia (Meor Hashim et al. 2021a, 2021b, 2021c), Gulf of Mexico (Gomes et al. 2024), and the Caspian Sea (Guenaga et al. 2025).

A defining characteristic of the solution is its architecture, in which, rather than applying a single, holistic machine learning model to the full complexity of well construction activities, the system employs a suite of discrete, interoperating machine learning agents. Each agent is trained to monitor one specific facet of the well construction process and identify risk symptoms characteristic of one defined hazard category (Payrazyan et al. 2023, Guenaga et al. 2025). This decomposed, ‘one problem, one agent’ architecture confers two critical operational advantages: (i) the number of determinant input parameters per agent is substantially reduced, enabling robust pre-training on a globally diverse dataset; and (ii) the resulting agents are agnostic to the idiosyncrasies of local formation properties, rig configuration, or BHA design, and can therefore be deployed in any operating environment without requiring local retraining or well-specific calibration.

Machine Learning Agents and Monitored Parameters

The solution deployed for the JT Field drilling campaign comprised three primary stuck pipe risk detection agents, each targeting a distinct mechanism:

- **Differential Sticking (DS) Agent:** monitors for progressive trends in static friction (breakover torque at connections) and hookload evolution indicative of increasing embedment under differential pressure. The agent employs regression models to forecast the near-term trajectory of static friction indicators, providing advance warnings of developing differential sticking conditions (Meor Hashim et al. 2021a).

- **Hole Cleaning (HC) Agent** monitors equivalent circulating density (ECD) evolution and fluid friction indicators, utilizing a deep neural network for real-time downhole ECD estimation from surface parameters (Robinson et al. 2022) and forecasting its progression to provide early warning of solids accumulation and pack-off risk.
- **Mechanical Sticking (MS) Agent:** monitors for dynamic friction trends, overpulls, and rotational friction indicators associated with mechanical contact, borehole geometry restrictions, or wellbore collapse-induced fill accumulation. Modules targeting both slow-developing drag trends and short-timescale torque/standpipe pressure spikes are incorporated (Gomes et al. 2024).

In addition to stuck pipe risk monitoring, the solution incorporates modules for ROP optimization and vibration risk monitoring. The ROP optimization module continuously evaluates the three primary driller-controllable parameters, weight on bit (WOB), rotary speed (RPM), and mud flow rate, over a moving time window, identifying parameter adjustments within operational constraints that can deliver consistent and practical improvements in ROP (Robinson et al. 2022b; Al-Riyami et al. 2023). In parallel, the vibration monitoring module assesses downhole dynamic dysfunction, including stick-slip, providing early indication of conditions that may compromise drilling efficiency, tool reliability, and overall wellbore integrity.

The only input data required by the solution is standard surface drilling data, including time, bit depth, hole depth, hookload, flow rate, rpm, block position, trajectory, mud density in, ROP, and standpipe pressure. No downhole measurements, formation-specific data, or offset well datasets are required for either pre-training, forensic review, or realtime analysis. This source data is universally available via WITSML from modern rig PLC/SCADA systems or mudloggers, enabling rapid integration without additional instrumentation or data infrastructure investment.

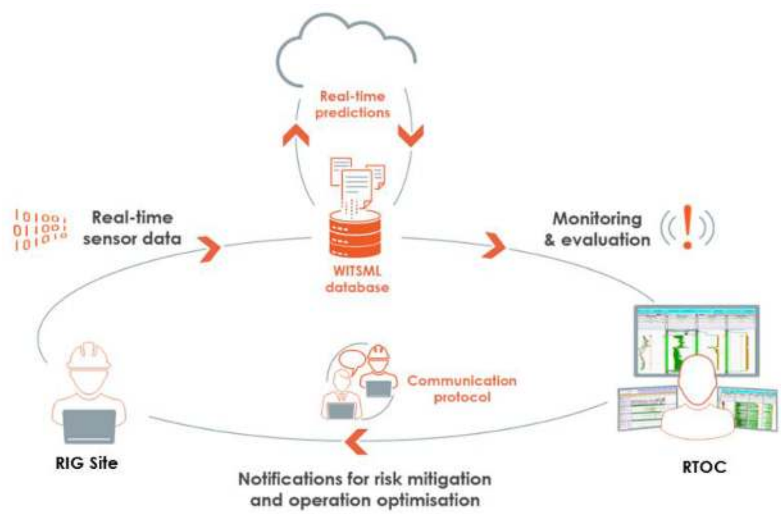

Figure 4—Architecture of the real-time AI advisory solution implemented during this project: surface drilling data ingested via WITSML feeds three Stuck pipe risk detection agents and an ROP optimization module, with advisory outputs delivered to the drilling team by the monitoring specialist in the Real-Time Operation Centre (RTOC).

Deployment and Integration

The solution was deployed on cloud infrastructure and connected to the operator's WITSML server via API prior to the commencement of drilling operations. Real-time surface drilling data was acquired at 0.2Hz, approximately every 5 seconds, and processed continuously throughout active operations on both wells from spud to landing liner. The solution was applied in the 12¼″ in and 8½″ in hole sections of both wells, covering the primary intervals of drilling risk exposure. Advisory outputs, including risk status indicators (yellow warnings and red alerts), descriptive warning/alert messages characterizing the identified risk type, and ROP optimization parameter recommendations, transmitted to the operator's existing real-time data viewer via WITSML, ensuring seamless integration with established rigsite and RTOC workflows.

Prior to the deployment, a familiarization and training session was conducted to ensure that both offshore and onshore personnel could correctly interpret the advisory outputs and respond in accordance with a defined communication protocol. During live operations, outputs were monitored by specialists based in the operator 24/7 RTOC office, with direct communication to the rig (DSV) and operations team to highlight developing stuck pipe risks and convey drilling parameter recommendations from the AI Advisory solution.

It is important to highlight that the solution is deployed ‘factory-pretrained’, thus, require neither pre-well calibration nor further retraining of the underlying machine learning models using JT Field offset well data. The system relied solely on measured surface drilling data and MWD trajectory survey data for processing, with contextual reference to the drilling program and standard instruction drilling (SID) to support operational interpretation.

Results and Discussion

Overall Campaign Outcome

The 2025 JT Field drilling campaign was completed with zero stuck pipe incidents across both wells, representing a step-change improvement compared with the historical 50% stuck pipe incidence rate in the field. Both wells reached their planned total depths, and reservoir objectives were successfully achieved. The combined campaign was completed 13 days ahead of the planned duration, resulting in significant savings in rig time, logistics, consumables, personnel exposure, and associated emissions.

The elimination of stuck pipe incidents reflects the system's ability to identify early risk precursors, enabling the rig team to implement timely mitigation actions before conditions escalated into more severe events. This proactive risk management approach contrasts with conventional monitoring practices, where responses are typically initiated only after surface indications become apparent. Table 2 provides a summary of stuck pipe and ROP agent deployment in well Y and F.

Table 2—Summary of stuck pipe and ROP agent deployment in Well Y and Well F.

Parameter	Well Y			Well F	
Total depth (ft MD)	11155			9725	
Hole Sections (in)	12¼" x 14¾"	12¼" x 10⅝"	8½"	12¼"	8½"
Total Drilling Duration (days)	Plan: 4.20 Actual: 4.21	Plan: 2.01 Actual: 1.24	Plan: 6.19 Actual: 6	Plan: 6.48 Actual: 3.83	Plan: 2.73 Actual: 1.77
Stuck Pipe and ROP Agent Deployment Duration (days)	42			15	
Section Avg. ROP without ROP Agent (ft/hr)	44.40	22.41	34.64	77.48	35.01
Section Avg. ROP with ROP Agent (ft/hr)	63.31	41.50	47.80	80.54	59.55
Average overall ROP improvement	+34%			+11%	

Well Y — AI Advisory Performance and ROP Results

Well Y presented the more complex of the two well profiles, with multiple inclination build sections and a long 12¼″×14¾″ under-reamed section drilling through the geomechanically sensitive zone above 60°. Both the stuck pipe and ROP agents were deployed for 42 days and active throughout operations covering the 12¼″ and 8½″ hole sections from spud to landing liner, delivering continuous real-time stuck pipe risk assessments and ROP optimization recommendations.

Stuck Pipe Agent — Well Y

The following examples illustrate the stuck pipe agent performance across three key intervals in Well Y.

Example 1- 12 ¼ × 14 ¾ in section

While drilling from 6,665 to 6,875 ft MD through interbedded limestone and claystone with 9.5 to 9.6 ppg SBM, the agent flagged elevated Differential Sticking (DS) risk through persistent static friction and Breakover Torque (BOT) warnings across two consecutive stands, approximately two hours before losses occurred at 6,875 ft MD. The warnings indicated deteriorating hole conditions and enabled the team to act proactively by pumping Hi-Vis sweeps and circulating hole clean while working the stand before conditions escalated into NPT. The agent continued to show elevated warnings throughout mitigation, prompting the team to sustain corrective action until conditions stabilize.

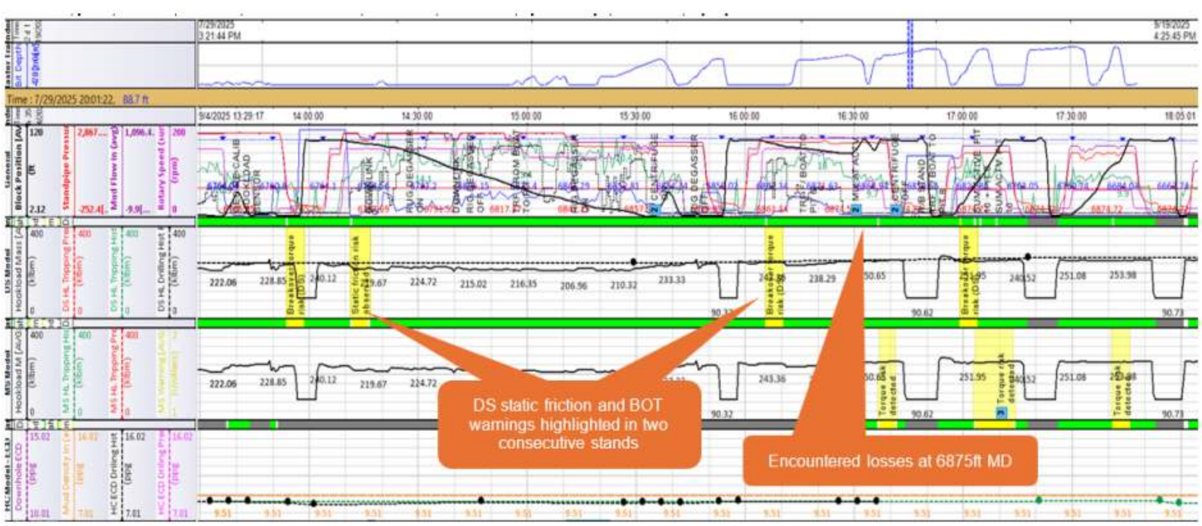

Figure 5—DS static friction and BOT warnings highlighted across two consecutive stands approximately two hours prior to losses at 6,875 ft MD.

Example 2- 12 ¼ × 10 ⅝ in section

This section was drilled through similar lithology to the preceding section but with 9.1 ppg WBM. All three agents — DS, MS, and HC issued concurrent warnings indicating worsening hole conditions three stands before the rig observed a 20 klbs increase in hookload. Multiple torque fluctuations, BOT warnings, and ECD increase alerts collectively characterized the developing risk ahead of any observable surface indication. The simultaneous activation of all three agents provided clear and confident risk characterization that no single indicator alone could deliver.

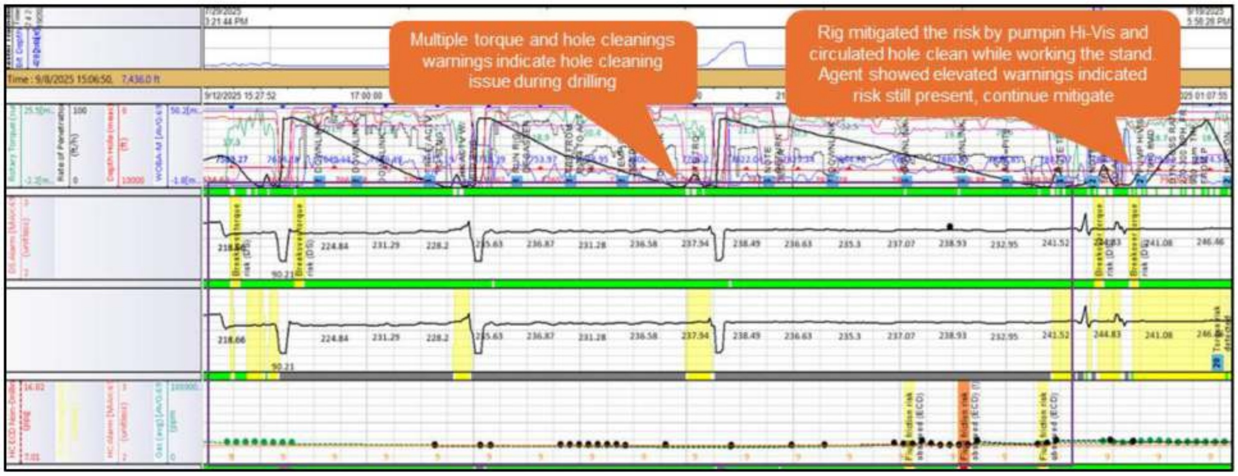

Figure 6—Torque fluctuations, breakover torque, and ECD increase warnings signaled deteriorating hole conditions three stands before the 20 klbs hookload increase was observed at surface.

Example 3- 8 ½ in section

The agent identified a sustained high-risk interval between 9,903 and 10,574 ft MD, characterized by persistent DS BOT and static friction warnings accompanied by concurrent hole-cleaning indicators across multiple stands. This interval was confirmed during subsequent operations when a temporary stuck event occurred at 9,310 ft MD during the lower completion run. MS warnings during drilling had also indicated increased drag corresponding to high DLS within this interval, consistent with the mechanical risk observed during completion.

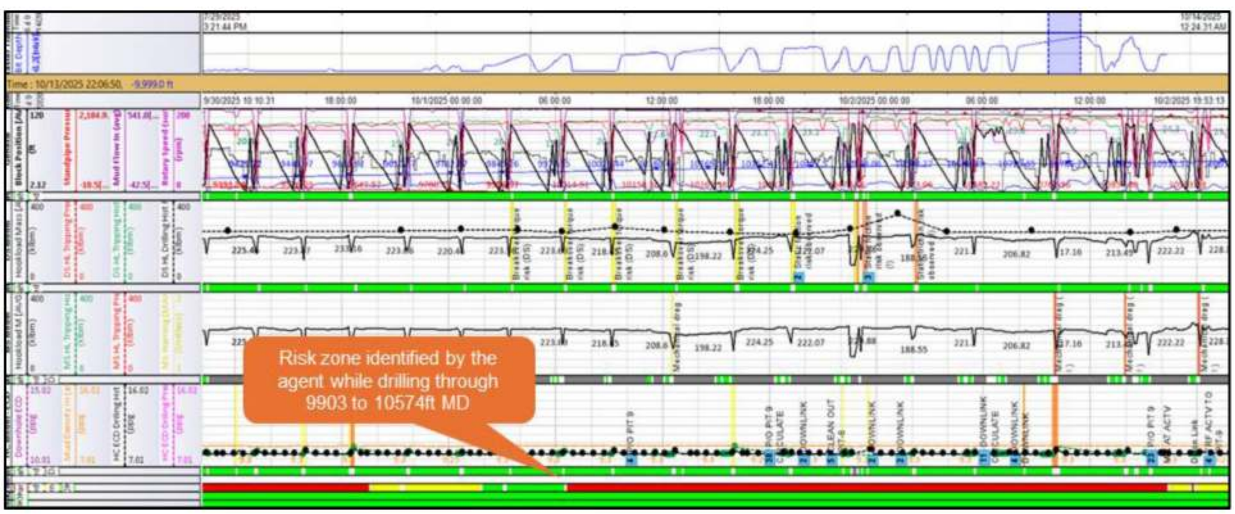

Figure 7—Persistent DS BOT, static friction, and hole-cleaning warnings issued by the agent while drilling through 9,903 to 10,574 ft MD.

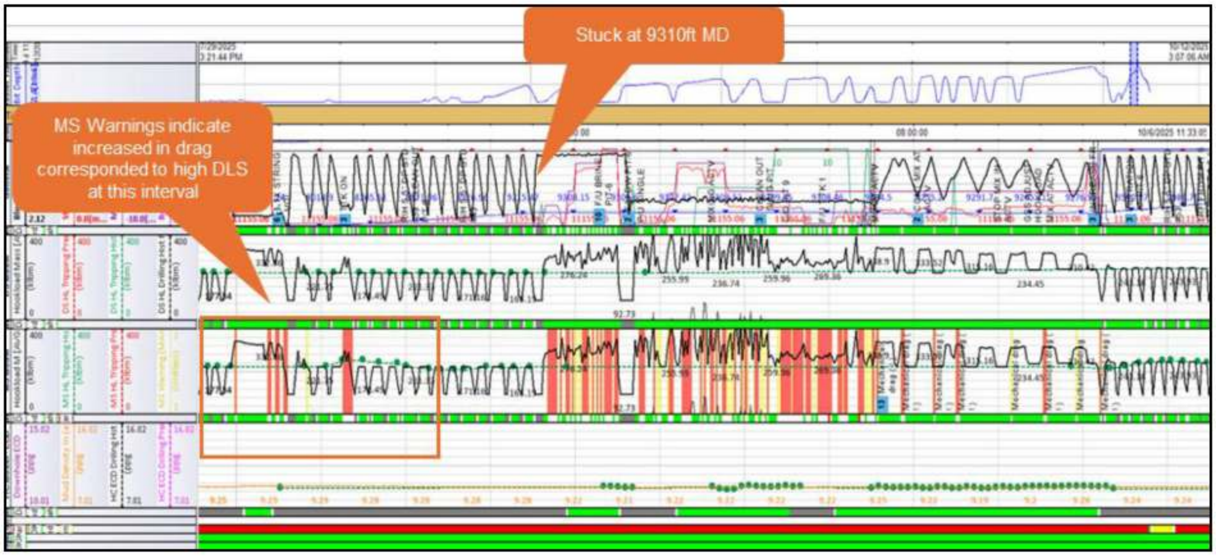

Figure 8—Temporary stuck event at 9,310 ft MD during the lower completion run at the same elevated risk interval identified during drilling

Across all three examples, the stuck pipe agent provided advance warning ahead of observable surface deterioration, enabling the drilling team to respond proactively across different hole sections, mud systems, and formation environments within Well Y.

ROP Optimization — Well Y

Over the key constrained drilling intervals of Well Y in all sections, the 12¼″ × 14¾″, 10⅝″×12¼″, and 8½″ the ROP optimization agent delivered continuous parameter recommendations targeting WOB, RPM, and flow rate adjustments within the applicable drilling program constraints. Sustained adoption of these recommendations resulted in a 34% increase in average ROP for the entire well when the ROP agent was being utilized.

It is important to highlight that the ROP agent was actively utilized over 29.3% of the applicable drilled distance. This reflects the intervals where formation conditions, drilling constraints, and concurrent risk levels permitted parameter optimization. For the remaining distance, the agent recommendations were either suppressed due to elevated stuck pipe risk, or the well was being drilled under conditions outside the scope of rotary drilling optimization, such as connections, reaming, or loss circulation management. This selective application is by design: ROP recommendations are only issued when wellbore conditions support them, ensuring drilling efficiency is never pursued at the expense of wellbore integrity.

Over the utilized intervals, average ROP with agent advisory was 54.30 ft/hr compared to 40.53 ft/hr without, representing the 34.0% improvement noted above. Realized time saving from ROP agent utilization was 0.25 days, with a total achievable time saving of 0.84 days had all drilling constraints permitted continuous utilization throughout the well.

The figures below show examples of ROP agent utilization in the 12¼″ × 14¾″ section (Fig. 9) and 8½″ section (Fig. 10).

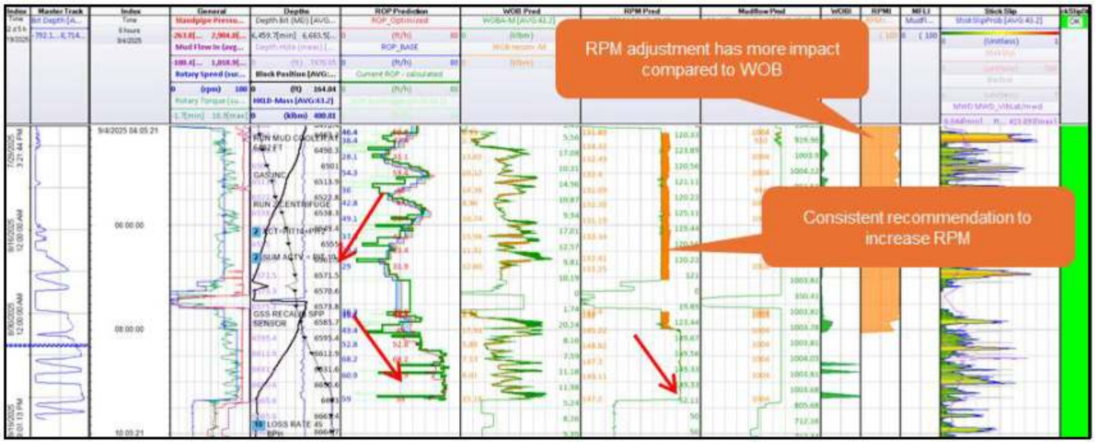

Figure 9—Increasing RPM from 123 to 150 as per agent recommendation resulted in ROP increased from 24.3 ft/hr to 38.1 ft/hr.

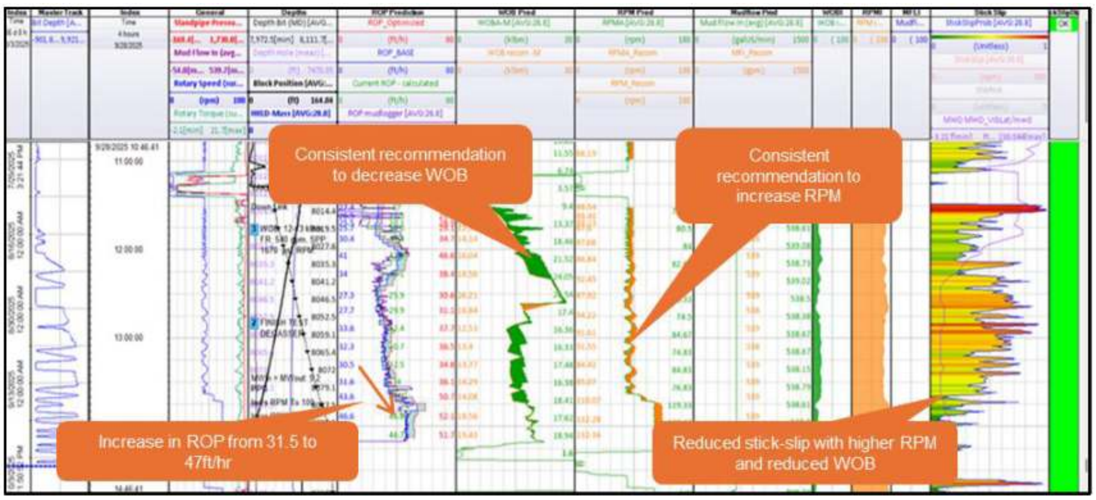

Figure 10—Reducing WOB from 24 to 16 klbm and increasing RPM from 82 to 120 resulted in efficient drilling reached at the end of the stand

Example 1 — 12¼″ × 14¾″ Section

Fig. 9 shows an interval where the agent identified RPM as the primary lever for ROP improvement, consistently recommending an increase from 123 to 150 rpm. WOB adjustment was assessed as having comparatively less impact in this interval. Following adoption of the recommendation, ROP increased from 24.3 ft/hr to 38.1 ft/hr. This highlights the solution's ability to differentiate between the relative influence of individual drilling parameters in a given interval, allowing the drilling team to focus on the most effective control lever.

Example 2 — 8½″ Section

Fig. 10 shows the application of the ROP optimization agent in tandem with the vibration monitoring agent during a high stick-slip interval in the 8½″ horizontal lateral. During this event, the agent consistently recommended decreasing WOB from 24 to 16 klbs and increasing RPM from 82 to 120 rpm. This parameter combination targeted reduction of torsional stick-slip whilst recovering ROP. Adoption of these recommendations resulted in ROP increasing from 31.5 to 47 ft/hr by the end of the stand, with stick-slip severity visibly reduced in the real-time log. This example demonstrates the value of the solution running both agents in tandem where ROP optimization and vibration monitoring, working together so that performance gains are not achieved at the cost of BHA damage risk.

Well F — AI Advisory Performance and ROP Results

Well F presented a different risk profile from Well Y, with an extended 4,800 ft tangent at 68° inclination followed by a 1,500 ft 8½″ horizontal lateral. The extended tangent at constant high inclination concentrated differential sticking and hole-cleaning risk across a prolonged interval, requiring sustained monitoring over an extended drilling period. Both agents were deployed for 15 days, covering the 12¼″ and 8½″ hole sections from spud to landing liner.

Stuck Pipe Agent — Well F

The following examples illustrate the stuck pipe agent performance across two key intervals in Well F.

Example 1 — 12¼″ Section

During drilling from 7,074 to 7,641ft MD, the agent identified a differential sticking risk zone, with multiple BOT and mechanical drag warnings indicating increased drillstring friction consistent with rising Torque and Drag (T&D) and ECD trends along this interval. In response, the team performed additional circulation and reaming while drilling to mitigate the risk. The agent's identification of this risk zone was subsequently confirmed when the rig encountered tight spots at 7,137 ft MD and 7,008 ft MD during pumping out of hole, within the same interval flagged during drilling. The tight spots were successfully worked through with further reaming and circulation, and a smooth 9⅝″ casing run was achieved, confirming effective mitigation through each phase of operations.

Figure 11—Agent output during drilling from 7,074 to 7,641 ft MD, with multiple BOT and mechanical drag warnings identifying the DS risk zone and the corresponding increase in Pick-up Weight (PUW) at 7,641 ft MD.

Figure 12—Tight spots encountered at 7,137 ft MD and 7,008 ft MD during pumping out of hole, within the same risk interval identified during drilling (fig.10).

Example 2 — 8½″ Section

The 8½″ horizontal lateral was drilled with smooth operations and no developing stuck pipe or hole-cleaning risks observed throughout. Proactive mitigation was maintained throughout each phase of the operation, including backreaming and wiping 20 ft before connections and circulating bottoms up with rotation. The agent consistently showed no-issue status across all three risk categories, DS, HC, and MS, with zero false warnings issued throughout the section. The absence of warnings in zones where no risk was developing confirms the solution's specificity and reduces the risk of alert fatigue, a known limitation of conventional monitoring approaches.

The clean agent output also provided a practical ILT saving opportunity. In intervals where the agent confirmed no developing risk, the frequency of precautionary reaming passes could be reduced without compromising wellbore integrity, allowing the drilling team to avoid unnecessary flat time. The lower completion was run smoothly to TD, confirming the effectiveness of the risk-informed operational approach throughout the 8½″ section.

Figure 13—The agent output during drilling of the 8½″ section, with all three agents showing no-issue status alongside smooth hookload and torque trends.

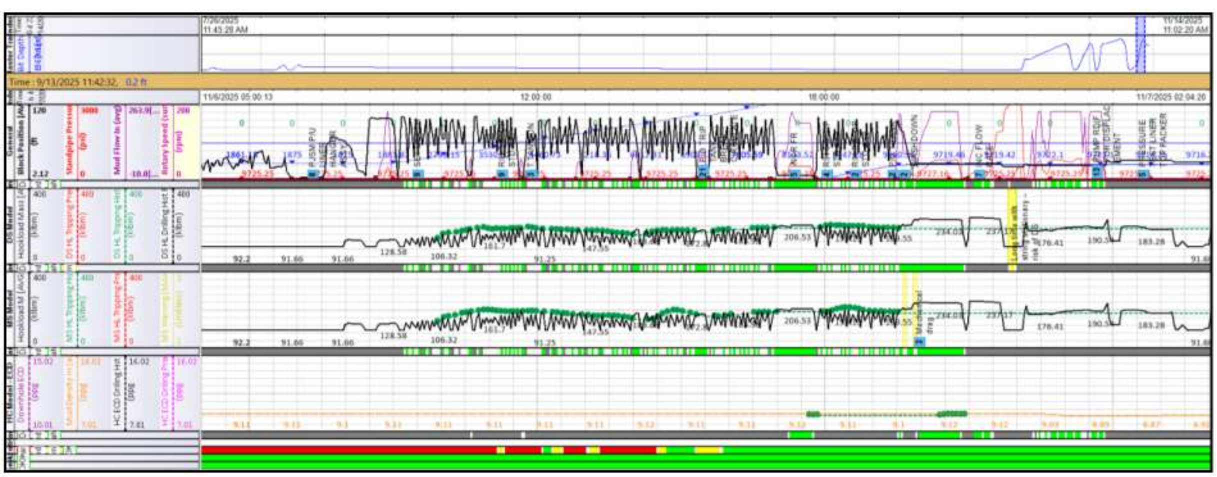

Figure 14—Smooth lower completion run with no developing risks observed.

ROP Optimization — Well F

Across both the 12¼″ and 8½″ sections of Well F, the ROP optimization agent delivered continuous parameter recommendations within the constraints defined by the approved drilling program. All recommendations were safeguarded against operating limits and ECD tolerance, with the vibration agent actively monitoring stick-slip probability throughout both sections.

The ROP agent utilized over 79.3% of the applicable drilled distance, reflecting the intervals where formation conditions, drilling constraints, and concurrent risk levels permitted parameter optimization. Over the utilized intervals, average ROP with agent advisory was 75.40 ft/hr compared to 67.74 ft/hr without, representing an 11.3% improvement. Realized time saving from ROP agent utilization was 0.29 days, with a total achievable time saving of 0.37 days had all drilling constraints permitted continuous utilization throughout the well.

The figures below show examples of ROP agent utilization in the 12¼″ section (Fig. 15) and 8½″ section (Fig. 16).

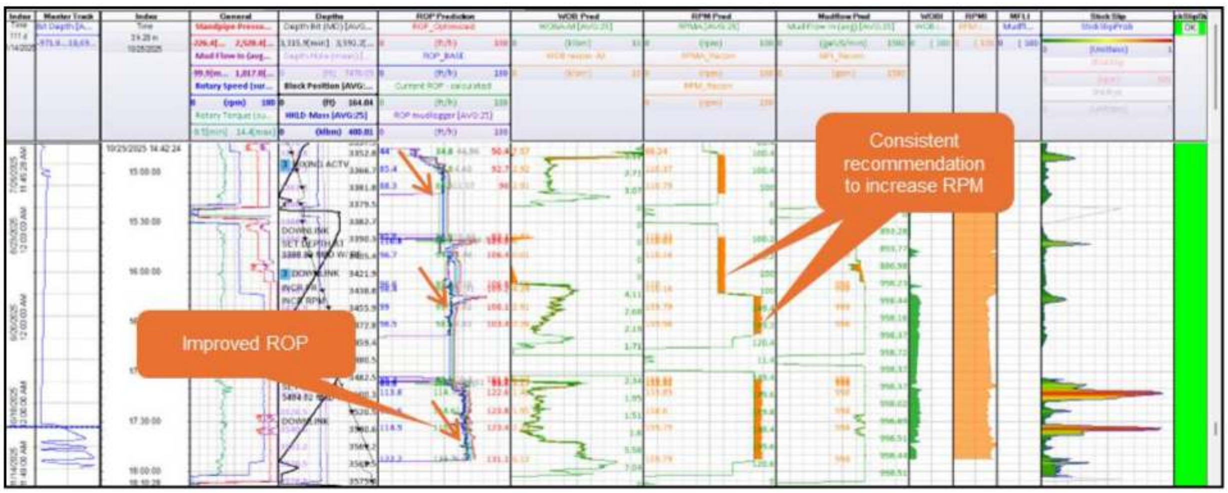

Figure 15—Increasing RPM from 100 to 110 to 150 as per agent recommendation resulted in ROP increased from 24.3 ft/hr to 38.1 ft/hr.

Figure 16—Increasing RPM from 100 to 110 to 150 as per agent recommendation resulted in ROP increased from 24.3 ft/hr to 38.1 ft/hr.

Example 1 — 12¼″ Section

Fig. 15 shows an interval from 3,440 to 3,579 ft MD where the agent identified RPM as the primary lever for ROP improvement, consistently recommending a stepwise increase from 100 to 110 to 150 rpm rather than a direct jump to the maximum operating limit, reflecting the solution's built-in safeguard approach to parameter changes. Following adoption of the recommendation, ROP increased from 74 ft/hr to 108 ft/hr, a 46% improvement over the stand.

Example 2 — 8½″ Section

Fig. 16 shows an interval from 8,357 to 8,447 ft MD where the agent identified WOB as the primary optimization lever, in contrast to the RPM-led recommendations in the 12¼″ section. The agent consistently recommended decreasing WOB from 6 to 3 klbs. Following adoption of the recommendation, ROP increased from 37 ft/hr to 51.8 ft/hr while stick-slip was visibly reduced in the real-time log. This example demonstrates the agent's ability to adapt its recommendations across different hole sections rather than applying a fixed parameter strategy throughout the well.

Overall Value Delivered

The combined outcome of zero stuck pipe incidents and ahead-of-schedule delivery across both wells represents a clearly quantifiable departure from the field's historical drilling performance. ROP improvements of 34% and 11% were recorded for Well Y and Well F respectively over the key constrained drilling intervals where the agent was utilized. The 13 days saved against the planned combined campaign duration translates to substantial savings across multiple cost categories. Additional savings were realised in reduced logistics requirements including fewer supply vessel trips and reduced consumables consumption, lower HSE exposure through fewer personnel rig-days, and reduced emissions, all of which are factors of increasing operational and regulatory significance for offshore operations in the region.

Conclusions

The following conclusions are drawn from the field application of real-time AI advisory in the 2025 JT field drilling campaign:

- 50% historical stuck pipe incidence rate, corresponding to 8 incidents across 16 wells drilled between 2015 and 2023, was reduced to zero across both 2025 infill wells following the deployment of a real-time, physics-informed machine learning advisory solution. This demonstrates the potential of targeted AI advisory to deliver a step-change improvement in drilling safety and operational performance in high-consequence horizontal well environments.
- The solution was deployed without the need for local retraining or offset well calibration and provided effective risk prediction in a geologically complex environment characterized by variable formation pressures, wellbore instability above 60° inclination, and partial to severe fluid losses. This confirms the general applicability of the pre-trained model architecture across diverse geological and operational conditions.
- The solution demonstrated reliable specificity across both wells, issuing warnings only when genuine hole deterioration was developing while maintaining a no-issue status during stable operations. No false warnings were observed in the 8½″ section of Well F, where drilling remained smooth throughout. The agent's ability to stay silent under benign conditions and respond only when necessary is operationally significant. This reduces alert fatigue and builds confidence in the advisory output. It also enables a reduction in precautionary actions such as wiper trips and circulation cycles in low-risk intervals, directly lowering invisible lost time (ILT).
- Real-time ROP optimization advisory delivered average ROP improvements of 34% and 11% in Well Y and Well F respectively across key constrained drilling intervals where the agent was utilized. These results demonstrate that the solution can simultaneously reduce stuck pipe risk and improve drilling efficiency without requiring operational trade-offs between the two objectives
- The combined campaign was completed 13 days ahead of the planned duration, resulting in measurable savings in rig time, logistics, consumables, HSE exposure, and emissions. This quantifies the direct operational value of real-time AI advisory beyond its safety benefits.
- Integration of the advisory outputs into the existing WITSML-based data infrastructure and communication workflows enabled seamless adoption without disruption to wellsite operations.

The delivery of actionable, mechanism-specific risk information rather than raw data was a key factor in enabling consistent and timely mitigation response by the drilling team.

Acknowledgements

The authors wish to express their sincere appreciation to PETRONAS Carigali Ketapang II Ltd management for their strategic support and authorization to publish this work, and to the drilling and operations teams whose execution of the 2025 JT Field drilling campaign made the results described herein possible.

The authors also extend their gratitude to the PETRONAS Wells Real Time Centre (WRTC) team, whose sustained collaboration with Exebenus and accumulated experience in real-time AI advisory laid the foundation for the successful first deployment of this solution during this project.

Nomenclature

AFE	Authorisation for Expenditure
AI	Artificial Intelligence
BHA	Bottom Hole Assembly
DDR	Daily Drilling Report
DLS	Dog-Leg Severity
DS	Differential Sticking
ECD	Equivalent Circulating Density
ERD	Extended Reach Drilling
HC	Hole Cleaning
HKL	Hookload
HSE	Health, Safety and Environment
ILT	Invisible Lost Time
LWD	Logging While Drilling
MD	Measured Depth
ML	Machine Learning
MS	Mechanical Sticking
MWD	Measurement While Drilling
NPT	Non-Productive Time
POOH	Pull / Pulling Out of Hole
RIH	Run / Running In Hole
ROP	Rate of Penetration
RPM	Rotations Per Minute
RSS	Rotary Steerable System
RTOC	Real Time Operations Centre
SPP	Standpipe Pressure
TD	Total Depth
TVD	True Vertical Depth
WOB	Weight on Bit
WITSML	Wellsite Information Transfer Standard Markup Language

References

1. Al-Riyami, N., Revheim, O., Robinson, T.S. et al 2023. "Drilling in the Digital Age: Case Studies of Field Testing a Real-Time ROP Optimization System Using Machine Learning". SPE/IADC

Middle East Drilling Technology Conference, Abu Dhabi, UAE, May 2023. SPE/IADC-214521-MS. DOI: https://doi.org/10.2118/214521-MS
2. Alshaikh, A., Magana-Mora, A., Gharbi, S.A. et al 2019. "Machine Learning for Detecting Stuck Pipe Incidents: Data Analytics and Models Evaluation". International Petroleum Technology Conference, Beijing, China, March 2019. IPTC-19394-MS. DOI: https://doi.org/10.2523/IPTC-19394-MS
3. Bradley, W.B., Jarman, D., Plot, R.S. et al 1991. "A Task Force Approach to Reducing Stuck Pipe Costs". SPE/IADC Drilling Conference, Amsterdam, Netherlands, March 1991. SPE-21999-MS. DOI: https://doi.org/10.2118/21999-MS
4. Gomes, D., Jaritz, T., Robinson, T.S. et al 2024. "Enhancing Stuck Pipe Risk Detection in Exploration Wells Using Machine Learning Based Tools: A Gulf of Mexico Case Study". IADC/SPE International Drilling Conference and Exhibition, Galveston, Texas, USA, March 2024. SPE-217963-MS. DOI: https://doi.org/10.2118/217963-MS
5. Guenaga, I., Singhal, R., Al-Farisi, O. et al 2025. "Application of Predictive Machine-Learning Optimisation Enables Successful Delivery of Highly Challenging Wells". Gas and Oil Technology Showcase and Conference (GOTECH), 2025. SPE-224618-MS.
6. Meor Hashim, M.M.H. 2020. "Wells Augmented Stuck Pipe (WASP) Indicator — Value Creation and Scalability of Artificial Neural Network for Real Time Drilling Operations to Identify Stuck Pipe Symptoms". Universiti Teknologi PETRONAS, Perak.
7. Meor Hashim, M.M.H., Yusoff, M.H., Arrifin, F. et al 2021a. "Utilizing Artificial Neural Network for Real-Time Prediction of Differential Sticking Symptoms". IPTC International Petroleum Technology Conference, Kuala Lumpur, Malaysia, 2021. IPTC-21221-MS. DOI: https://doi.org/10.2523/IPTC-21221-MS
8. Meor Hashim, M.M.H., Yusoff, M.H., Arrifin, F. et al 2021b. "Case Studies for the Successful Deployment of Wells Augmented Stuck Pipe Indicator in Wells Real Time Centre". IPTC International Petroleum Technology Conference, Kuala Lumpur, Malaysia, 2021. IPTC-21199-MS. DOI: https://doi.org/10.2523/IPTC-21199-MS
9. Meor Hashim, M.M.H., Yusoff, M.H., Arrifin, F. et al 2021c. "Performance Improvement of Wells Augmented Stuck Pipe Indicator via Model Evaluations". IPTC International Petroleum Technology Conference, Kuala Lumpur, Malaysia, 2021. IPTC-21455-MS. DOI: https://doi.org/10.2523/IPTC-21455-MS
10. Muqeem, M.A., Weekse, A.E., and Al-Hajji, A. 2012. "Stuck Pipe Best Practices — A Challenging Approach to Reducing Stuck Pipe Costs". SPE Saudi Arabia Section Technical Symposium, Saudi Arabia, April 2012. SPE-160845-MS. DOI: https://doi.org/10.2118/160845-MS
11. Payrazyan, V.K., Robinson, T.S. 2023. "Leveraging Targeted Machine Learning for Early Warning and Prevention of Stuck Pipe, Tight Holes, Pack Offs, Hole Cleaning Issues and Other Potential Drilling Hazards". Offshore Technology Conference, Houston, Texas, USA, May 2023. OTC-32169-MS. DOI: https://doi.org/10.4043/32169-MS
12. Robinson, T.S., Gomes, D., Meor Hashim, M.M.H. et al 2022a. "Real-Time Estimation of Downhole Equivalent Circulating Density ECD Using Machine Learning and Applications". IADC/SPE International Drilling Conference and Exhibition, Galveston, Texas, USA, March 2022. SPE-208675-MS. DOI: https://doi.org/10.2118/208675-MS
13. Robinson, T.S., Batruny, P. et al 2022b. "Successful Development and Deployment of a Global ROP Optimization Machine Learning Model". Offshore Technology Conference Asia, Kuala Lumpur, Malaysia, March 2022. OTC-31680-MS. DOI: https://doi.org/10.4043/31680-MS
14. Robinson, T.S., Revheim, O. 2023. "Automated Detection of Rig Events From Real-Time Surface Data Using Spectral Analysis and Machine Learning". SPE/IADC International Drilling

Conference and Exhibition, Stavanger, Norway, March 2023. SPE-212481-MS. DOI: https://doi.org/10.2118/212481-MS

15. Schaefer, S., Revheim, O. 2024. "Building Trust in AI/ML Solutions: Key Factors for Successful Adoption in Drilling Optimization and Hazard Prevention". SPE Norway Subsurface Conference, Bergen, Norway, April 2024. SPE-218455-MS. DOI: https://doi.org/10.2118/218455-MS