Integrated Reservoir Management
Technical Section

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SPE Integrated Reservoir Management Technical Section (IRMTS)

Newsletter

OCTOBER 2025
ISSUE 03

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SPE IRMTS NEWSLETTER
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Integrated Reservoir Management Technical Section

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INSIDE THIS EDITION

The Chairman's Message

"What began as an aspiration is now a movement—where collaboration and integration are transforming ideas into real-world impact"

— Muhammad Navaid Khan, Chair, IRMTS

Dear Colleagues—As the **IRM Technical Section** celebrates its **first anniversary**, it's inspiring to reflect on how far we've come—from an emerging vision to a vibrant community of over **4,000 professionals** across platforms, united by a shared belief in **the power of integration.** What began as an aspiration has evolved into a movement—demonstrating that when collaboration drives purpose, progress follows naturally.

Last year, we pledged to challenge conventions and make collaboration our compass. In **twelve months**, we've hosted **17 events**, with **60% in partnership** with external societies and other SPE Technical Sections, engaging up to **265 participants** per event. Our platforms sparked **5,000+ reactions**, connecting members across **eight regions**. Most importantly, we've built a **volunteer team of 30**—spanning **fresh graduates** to **experts with over 30 years** of experience—driving progress in IRM to maximum recovery at minimal cost and carbon impact by **integrating every discipline toward a shared purpose.**

This milestone year also marks the **launch of the SPE IRMTS Youth Wing**, a first-of-its-kind initiative empowering students and young professionals while enabling senior members to benefit from next-gen skills and digital fluency. Among its initiatives, the **Reverse Mentoring Program** creates a unique, two-way exchange of learning and leadership across generations. Several exciting programs under the Youth Wing are on the way—stay tuned!

In this edition of our newsletter, we continue sharing curated case studies and technical insights and highlight our flagship events. This time our *IRM in Action* series features the **SPE Reservoir Technical Director**, offering perspectives on the philosophies, data strategies, and organizational enablers needed to scale IRM effectively—balancing today's performance with tomorrow's sustainability.

I sincerely thank our **industry leaders** for contributing their knowledge to the IRM community, as well as **our Newsletter Editors** for delivering this high-quality newsletter.

Coming soon at **ATCE 2025**, IRMTS will co-host a collaborative reception and lead a Special Session on sustainable reservoir management, advancing our core mission. Next month, at **ADIPEC 2025** in Abu Dhabi, we will support the **SPE Middle East University Program,** mentoring the next generation to champion integration and collaboration.

Thank you for being part of this journey. As we enter our second year, let's continue learning, innovating, and advancing integrated reservoir management—**together with purpose.**

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Introducing the SPE IRM TS Youth Wing

First of its kind. Powered by youth. Defined by impact.

The **SPE IRMTS Youth Wing** is a dynamic platform for early-career professionals and students carving their careers while shaping the future of reservoir management.

Through initiatives like **Reverse Mentoring**, where youth empower seniors with next-gen skills, **Youth-Led Technical Sessions** focused on early-career growth, **Recognizing Exceptional Talent, and SPE Student Connect**, the Youth Wing connects young professionals globally, fosters innovation, and builds the next generation of IRM leaders.

Here, young professionals don't just learn - they lead, innovate, and make an impact.

Meet the team driving the SPE IRMTS Youth Wing!

CHAIR, SPE IRMTS YOUTH WING
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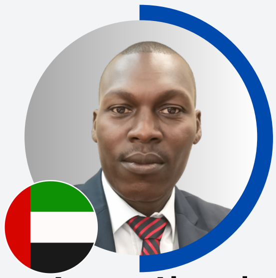

Ameen Ahmed
Reservoir Engineer
2B Operating Company

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Integrated Reservoir Management Technical Section

IRM in Action:

Insights from the SPE Reservoir Technical Director

Integrated reservoir management is no longer just a framework for optimizing recovery—it is shaping how companies prioritize assets, adapt to uncertainty, and prepare for the energy transition. From data-driven insights to resilient operating models, IRM is increasingly defining competitiveness and sustainability across the reservoir lifecycle.

In this edition, we speak with Rahim Masoudi, PhD, SPE Reservoir Technical Director, who shares his perspectives on the philosophies, data strategies, and organizational enablers required to scale IRM effectively—helping operators balance near-term performance with sustainability and future readiness.

Rahim Masoudi, PhD
SPE Board Member
Reservoir Technical Director

Chief Technical Lead
Enquest/Veri Energy

With more than **25 years** of experience spanning PETRONAS and EnQuest, Rahim has **driven innovative** approaches in **field development, integrated reservoir management, and carbon capture and storage,** while advancing energy transition projects across Asia, the Middle East, and the North Sea.

IRMTS: What is your core philosophy for Integrated Reservoir Management (IRM)?

Rahim: IRM is about joined-up value creation while navigating through the uncertainties and aligning subsurface science, operations, commercial strategy, and stakeholder engagement so that every technical decision clearly maps to portfolio value, risk, and the realities of the hydrocarbon asset.

It reveals the true life-cycle potential of assets, which is why IRM is not optional; it's essential. It must be data-driven, outcomes-focused, and adaptive, delivering measurable uplift today while progressively de-risking tomorrow.

IRM is not just a workflow or a set of guidelines; it's a mindset. One that ensures the health of the entire asset value chain from subsurface to wells and facilities while connecting reservoir and operational uncertainties to commercial clarity and sound decision-making.

IRMTS: How does IRM influence portfolio decisions across different reservoirs?

Rahim: IRM plays a pivotal role in shaping portfolio decisions by offering a comprehensive framework that aligns subsurface understanding with commercial strategy and operational realities. In producing and complex fields, IRM enables operators to unlock remaining value through objective-driven digital surveillance, targeted re-optimization, emissions reduction, enhanced recovery techniques, and cost-efficiency initiatives.

Globally, we see compelling examples of IRM in action—across mature fields (e.g., the Magnus Field in the North Sea operated by EnQuest and the Angsi Field operated by Petronas in Malaysia), marginal assets (e.g., the East Belumut oil rim and Seligi Field in Malaysia), and deepwater developments (e.g., the Kikeh Field and Gumusut-Kakap Field in Malaysia).

In each case, a disciplined IRM approach has delivered world-class recovery factors and significant incremental value, while extending facility life at minimal cost. In frontier reservoirs, the emphasis shifts toward de-risking through selective appraisal and flexible development concepts that preserve optionality.

Whether applied to mature or greenfield assets, IRM ensures that resources are directed toward the highest life-cycle value and lowest-risk opportunities across the portfolio.

IRMTS: How are data strategies improving decision-making?

Rahim: Reservoir and production data strategies have evolved from static reporting to dynamic, real-time decision-making ecosystems. The integration of AI, machine learning, automated workflows, and cloud-based platforms enables operators to contextualize vast volumes of data, supporting predictive diagnostics and proactive reservoir management.

In one mature offshore asset in Malaysia, I led a project where automated history matching and sensitivity analysis reduced a planned campaign of 12 production enhancement and well workover jobs to six high-value candidates—achieving comparable uplift with 40% less capital and faster execution.

Throughout my experience, I've initiated, developed, and collaborated on innovative tools and platforms such as Asset Value Framing (AVF), the Asset Management Integrated Review (AMIR) system, Reservoir-Well-Facility Management (RWFM) platforms, Locating the Remaining Oil (LTRO), saturation and pressure mapping, predictive maintenance, and value optimization across complex topside production networks—all of which are data-analytics-driven IRM tools that transform noisy data into actionable insights.

Modern IRM data strategies make uncertainty transparent and enable faster, smarter decision-making across the asset lifecycle.

IRMTS: How can reservoir management build resilience against unexpected challenges?

Rahim: Resilience in reservoir management is built on adaptability, optionality, foresight, and integration.

IRM strategies that incorporate scenario-based planning, predictive tools, digital twins, and cross-functional collaboration are most effective in navigating uncertainty.

In one offshore project in Malaysia, we saved a well that encountered low pressure and high water saturation by proactively redirecting it to a deeper secondary target—achieving even better production through real-time scenario planning supported with pre-designed uncertainty-based what-if scenarios.

Whether facing reservoir surprises, regulatory shifts, or market disruptions, the ability to simulate outcomes and adjust plans on the fly is invaluable.

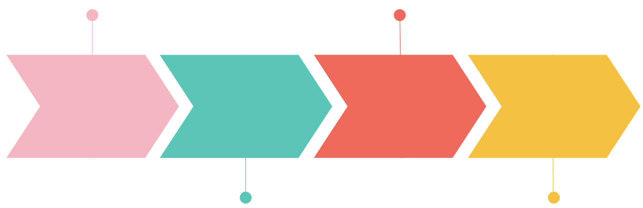
During the 2020 oil price collapse, assets with robust IRM frameworks responded swiftly—reallocating capital, shutting in non-viable wells, and accelerating low-carbon initiatives.

Resilience is no longer reactive; it is embedded in IRM through flexible workflows, development optionality, and a culture of continuous learning—ensuring alignment with both short-term performance and long-term sustainability.

IRMTS: How do IRM practices vary across organizations of different sizes?

Rahim: IRM is vital to unlocking the full potential of any hydrocarbon asset. While smaller operators tend to be nimble—focusing on low-cost development, lean surveillance, and targeted interventions—larger operators can invest in comprehensive evaluations, full digital twins, R&D hubs, and integrated global data lakes.

The principle of IRM remains the same: adapt the cadence and toolset to match the asset's budget, complexity, and risk profile.



IRMTS: How are operators preparing reservoirs for competitiveness and sustainability?

Rahim: Many are retooling assets to serve dual purposes. In my experience with both PETRONAS and EnQuest, we've seen mature hydrocarbon fields strategically evaluated for continued production as well as future CO_2 storage—effectively future-proofing the asset.

These projects also incorporate efficiency gains, decarbonization, electrification, and transparent emission & MMV reporting.

Such steps not only enhance current performance but also position assets for success in a low-carbon economy.

IRMTS: How could SPE enable stronger IRM adoption?

Rahim: SPE can play a pivotal role in convening and standardizing. We need IRM-enhanced platforms, open data schemas, domain-specific AI playbooks, and shared case study platforms.

A global sandbox for AI-enabled IRM, backed by SPE, would accelerate trust and collaboration among operators, service providers, and regulators. SPE's role should be to act as the "integrator of integrators" — enabling seamless knowledge exchange, promoting best practices, and continuously evolving industry guidelines and standards.

IRMTS: What skills and organizational shifts are needed for IRM at scale?

Rahim: Cross-discipline fluency, agile governance, and platform thinking. We need engineers who understand both data and business, decision cycles that are short and trigger-based, and automated workflows built on trusted data. Above all, leaders must reward those who connect the dots — translating technical insight into commercial value.

IRMTS: How can engineers leverage AI to enhance Integrated Reservoir Management (IRM) and stay future-ready?

Rahim: Engineers can leverage AI as a co-pilot in Integrated Reservoir Management, using it for real-time simulations, predictive modeling, and optimization while focusing on strategic decision-making, ethical oversight, and sustainability. Digital twins and integrated dashboards will enable proactive management and seamless operations across subsurface, surface, market, and sustainability data.

Future engineers will combine domain expertise with digital literacy, shifting from manual simulations to interpreting AI insights, designing value-driven strategies, and balancing recovery with goals of reducing carbon footprint and promoting energy transition.

Opportunities include ultra-fast scenario testing, optimized recovery, and cost-effective integration of CCUS, hydrogen, and geothermal energy, while risks involve data bias, AI transparency, and workforce resistance.

Collaboration with tech partners, academia, and other industries will accelerate adoption, and professional societies like SPE will play a key role in upskilling, setting ethical standards, and facilitating cross-disciplinary collaboration.

To stay future-ready, engineers must develop AI fluency, promote team collaboration, foster innovation, and embrace integrated, sustainable energy stewardship.

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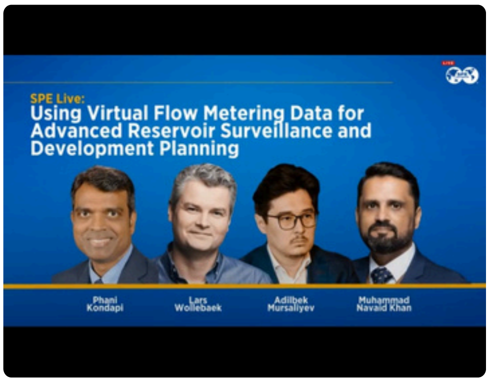
Integrated Reservoir Management Technical Section

SPE WEBINARS AND LIVE EVENTS: Q3 2025

The SPE IRM Technical Section’s third quarter featured an engaging lineup of webinars and live sessions, highlighted by the Performance Monitoring Series led by pioneers and experts in PTA, DCA, and RTA. These were complemented by collaborations with the SPE Flow Measurement Technical Section (FMTS) and professionals across flow measurement, AI, and data science, and more.

In this webinar, one of the pioneers of reservoir engineering, **Dr. Tom Blasingame** from **Texas A&M University**, led a session delving into the advanced techniques used in the evaluation of well performance using Pressure Transient Analysis, Decline Curve Analysis, and Rate Transient Analysis – highlighting their evolution from foundational theory to cutting-edge advancements while also showcasing their practical applications across conventional and unconventional reservoirs.

Florian Hollaender, PhD—Scientific Advisor, **SLB,** and **Vincent Artus, PhD—**Regional Manager (Americas), **KAPPA Engineering,** offered great expert-led insight in the webinar, uncovering the abilities and limitations of Pressure Transient Analysis and bridging the gap between reservoir and production engineering through fresh outlooks on descriptive PTA, deconvolution, numerical matching, and the often overlooked value of production-scale PTA.



In collaboration with the SPE Flow Measurement Technical Section (FMTS), the IRMTS held a live event where a panel discussion with **Lars Wollebæk** from **Turbulent Flux, Adilbek Mursaliyev** from **Dereknet,** and **Muhammad Navaid Khan** from **ADNOC** presented how Virtual Flow Metering (VFM) solutions are being deployed, validated, and refined to meet the industry's evolving operational and reservoir management needs through case examples and technical insights.

In this thirty-minute dialogue held on SPE LIVE, industry thought leaders **Rahim Masoudi, PhD,** from **EnQuest/Veri Energy,** and **Sushma Bhan** from **Accuria Data** led the conversation exploring the integration of human expertise with artificial intelligence in reshaping reservoir management in the decade ahead, the skills/roles that will define the next generation of reservoir professionals and the key risks/opportunities facing companies and individuals in the industry alike.

WEB EVENTS DIRECTORY

Missed Our Web Events? Catch Up Anytime!

- **24 Sep, 2025 |** Reservoir Management 2035—The Human + AI Alliance
- **10 Sep, 2025 |** Virtual Flow Metering Data for Advanced Reservoir Surveillance and Development Planning
- **27 Aug, 2025 |** PTA with Purpose: Objective-driven Interpretation and Scalable Modelling Workflows
- **23 July, 2025 |** Well Performance Masterclass: Integrating PTA, DCA, & RTA for Deeper Diagnostics
- **25 June, 2025 |** Field Proven Insights: 4D Seismic Application in Reservoir Management and CCS Monitoring
- **28 May, 2025 |** Enhancing Forecast Reliability through Computational Intelligence in Integrated Modelling using 4D Seismic data
- **6 May, 2025 |** Maximizing Waterflooding Value: Strategies, Technologies, and Future Outlook
- **28 Apr, 2025 |** Real-Time Production System Optimization and the Future Role of AI
- **9 Apr, 2025 |** Integrating Uncertainty with Data Analytics and Machine Learning for Subsurface Modeling
- **19 Mar, 2025 |** Geomechanics in Reservoir Management: Predicting and Optimizing Reservoir Behavior
- **19 Feb, 2025 |** Digital Twin for Production Optimization: Mere Hype or True Enabler?
- **21 Jan, 2025 |** Leveraging Tracers for Well Optimization and Reservoir Management: Strategies and Real-World Applications
- **11 Dec, 2024 |** Decode Your Reservoir: Machine Learning for Facies Prediction and Petrophysical Analysis
- **19 Nov, 2024 |** Steps in Intelligent Upstream Operations: Today's Innovations for Delivering Tomorrow's Goals
- **29 Oct, 2024 |** Cross-disciplinary collaboration in Integrated Reservoir Management: Integrating Geosciences, Engineering, and Economics
- **17 Sep, 2024 |** Launch Event – Introducing the SPE Integrated Reservoir Management Technical Section

Access the complete archive of past SPE IRMTS webinars by visiting the SPE Energy Stream platform.

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SPE IRMTS at ATCE 2025

Joint Technical Section Reception – "Power of Collaboration"
Monday, 20 Oct | 6:30–8:00 PM CDT | Room 362BE, GRBCC

Co-hosted with DSEA, R&D, and Asset Management Technical Sections. Network with industry peers, hear about successes in 2025, share ideas, and explore plans for 2026 collaboration.

Technical Section Booth Day – Meet the IRMTS Team
Tuesday, 21 Oct | 12:00-01:00 PM CDT | ATCE Exhibit Floor near the Pavilion & Member Lounge

Step by our booth to share your ideas, discover ways to get involved, and be part of the movement driving real impact in integrated reservoir management.

Special Session – Sustainable Reservoir Management: Leveraging Technology, AI, and Cross-Industry Innovation for Maximum Value
Wednesday, 22 Oct | 08:45–09:45 AM CDT | Special Session Room 1

Explore how technology, AI, and cross-industry collaboration are transforming sustainable reservoir management.

PERSPECTIVE: EXPERT INSIGHTS

Well Performance Masterclass with Prof. Blasingame

This article highlights valuable insights and perspectives from Dr. Thomas Blasingame during the SPE IRMTS webinar on July 23, 2025. Dr. Blasingame has authored 200+ papers and supervised 130+ students. His pioneering work in well analysis, deconvolution, fractured-well modeling, and PTA–RTA integration reflects his lifelong pursuit of advancing reservoir diagnostics and analytical methods.

(Speaker)
Dr. Thomas A. Blasingame
Distinguished Professor & Head of Petroleum Engineering
Texas A&M University

(Moderator)
Sule Gurses
Advisor, Reservoir Domain, SLB
Program Chair, SPE IRMTS

Reservoir engineering has long transformed basic measurements, rates, pressures, and potentially temperature into performance insights. Evolving from early decline curve models to modern analytics, the field blends intuition, observation, and analytical rigor rooted in early 20th-century foundations.

In his webinar, Dr. Thomas Blasingame shared decades of experience, offering historical context and practical guidance on well performance evaluation, tracing the evolution of DCA, PTA, and RTA from numerical models and log–log diagnostics into today's powerful analytical frameworks.

Blending history with modern practice, Dr. Blasingame emphasized that these evolving analytical methods—rooted in strong theory—remain essential for understanding and optimizing both conventional and unconventional reservoirs.

His session showcased the evolution and enduring relevance of these techniques in data-driven decision-making. This article summarizes his key insights and audience questions, offering practical guidance for engineers, geoscientists, and asset teams seeking smarter, adaptive reservoir management.

Insights from an Expert on Well Performance Evaluation

Dr. Blasingame revisited the origins of Decline Curve Analysis (DCA), tracing it to 1927, when Johnson and Bolin introduced the "loss ratio" that linked production rates to decline trends. By 1935, Rawlins and Schellhardt advanced the concept foundation of inflow performance relationships that shaped reservoir analysis for decades.

Dr. Blasingame traced how Muskat's 1935 equation, refined by Arps in the 1940s, established decline curve analysis (DCA) as a cornerstone of reservoir engineering. Arps and Smith simplified Muskat's work into practical plotting methods, while Arps' exponential, hyperbolic, and harmonic forms endured for their clarity and utility. Later, Jones (1942) introduced log–log plotting that foreshadowed the power-law exponential (PLE) concept, formally recognized decades later. In the 1960s, Fetkovich unified empirical and analytical approaches by linking transient flow theory with DCA, advancing the method's theoretical foundation.

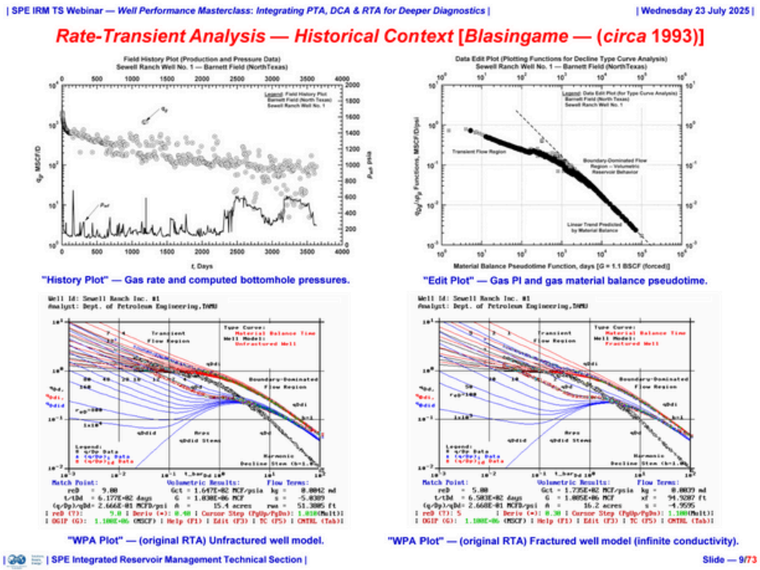
As Dr. Blasingame noted, this integration "revealed the consistent trends across plots and reinforced the power of combining observation with analytical reasoning," marking a pivotal step in linking theoretical understanding with practical reservoir evaluation.

Building on these foundations, Dr. Blasingame traced Rate Transient Analysis (RTA) to his 1985 numerical modeling work, observing patterns resembling well-test behavior.

Guided by his advisor, Dr. John Lee, he grounded these insights in Muskat's theory, producing seminal papers on oil-in-place estimation, flowing material balance, and extending the approach to gas systems and decline curve analysis.

What began as a numerical experiment evolved into the foundation of RTA, built on the now-familiar log–log diagnostic plot.

He went on further to expound on years of publications aimed at attempting various scenarios, like using integral formulations for production data, fractured wells, horizontal wells, and multi-well solutions.



Dr. Blasingame highlighted how operational constraints can impact reservoir performance as much as geology or completion design, showing that factors like fluctuations in a low-pressure gathering system significantly affect production.

Analyzing gas rate and pressure data, he found the best match using a simple fractured well model with infinite conductivity and uniform flux, emphasizing fracturing's role. His Barnett Shale study revealed high permeability, providing early insights into shale behavior well before horizontal fracturing became common.

Further discussing RTA example cases, Dr. Blasingame highlighted how good diagnostics could be made even from low-quality data. He said, *"Even though the data looks really noisy and maybe questionable. As long as it's high fidelity, that is, the pressures and rates are properly correlated and representative. You can still take a case that looks like that and get something out of it."*

Dr. Blasingame noted that when history matching is difficult despite proper diagnostics, software adjustments—such as modifying successive skin factors—can achieve a strong match.

He, however, cautioned against using such internal adjustments: *"I don't advocate that you do this,"* especially without transparency, stressing that *"if you use something that is an internal adjustment, be sure and mention that you did that."*

Dr. Blasingame highlighted the practical challenges of using field data from multiple operators, noting that quality often varies in public datasets. While completeness and consistency differed, many datasets still showed strong pressure buildup responses and credible history matches.

Dr. Blasingame emphasized that reliable results depend on maintaining data integrity and analytical transparency. His examples demonstrated that when data fidelity is preserved, accurate history matches and diagnostic evaluations are possible—even under less-than-ideal conditions.

Dr. Blasingame also described a long-producing well that was shut in and instrumented with bottomhole gauges. Despite relying on calculated pressures, both log–log and Blasingame plots offered strong interpretations, and the pressure buildup test produced an exceptionally good history match—even after manually splicing over 30 million data points from three gauges collected over six months.

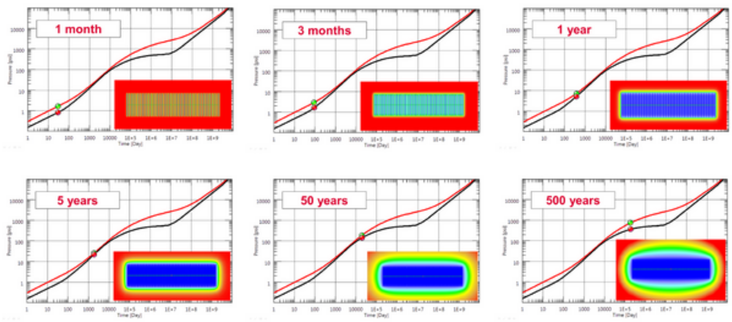
Comparing surface and bottomhole data, Dr. Blasingame found that only minor adjustments to permeability and skin factor were needed, with both cases yielding consistent results. This highlighted the value of high-quality, well-measured data and showed that careful, detailed analysis—even when complex—can produce highly reliable reservoir insights.

PTA Masterclass

Reflecting on his PTA work, Dr. Blasingame highlighted technical advances like the pressure integral and direct deconvolution method, applying material balance time to PTA. While he humorously admitted some ideas *"weren't as genius"* as first thought, he emphasized their impact on diagnostic interpretation and well performance evaluation.

He described his ongoing pursuit—his "Moby Dick story"—of solving the complex analytical problem of wellbore storage, noting that it remains a challenge for future researchers.

On unconventional reservoirs, Dr. Blasingame discussed the challenge of time interference in shale, describing how flow regimes evolve over months to years. Early interference appears at three months, intensifies by a year, and reaches a unit-slope trend by five years—humorously called "pseudo-pseudo steady state"—before eventually transitioning to native rock behavior over decades. He noted that full pressure transient tests would take centuries, while shorter tests capture only partial flow regimes, complicating diagnostics.



He discussed early shale PTA work that revealed puzzling derivative slopes—like one-third and two-fifths—that deviated from standard models. He suggested the one-third slope could indicate natural fracturing, while the two-fifths slope might reflect multiphase flow effects, emphasizing that such variations often relate to reservoir properties or well spacing rather than simple fractured well behavior.

Dr. Blasingame highlighted the growing use of multi-well PTA to assess interwell connectivity in unconventional reservoirs. By analyzing responses of nearby wells and using diagnostics like Chow group plots, engineers can gauge how interconnected wells are, showcasing the evolving sophistication of PTA. He presented a shale well case study where pressure buildup tests during operational shut-ins revealed that many wells lacked expected linear flow, due to short circuits between wells that obscure typical multi-fractured horizontal behavior.

Dr. Blasingame also discussed the process of model development itself—testing ideas, validating behavior against simulated and field data, and discarding formulations that fail to align with physical interpretation. He reflected on how these analytical pursuits often involve "a fair bit of trial, error, and humility," but that such exploration has led to more reliable diagnostic and forecasting tools.

DCA Masterclass

He underscored the importance of mechanistic awareness, reminding the audience that while DCA can yield excellent fits, "a good fit does not guarantee a good model."

Dr. Blasingame's work with students and collaborators, including novel decline functions and self-terminating exponential sums, showcased how creativity and rigor advance DCA. His key message: *despite endless plots and statistics, human judgment is essential for meaningful reservoir evaluation.*

Turning to field applications, he cautioned that extrapolating short-duration unconventional data requires discipline, letting physics guide forecasts. Through case studies, he highlighted how decline parameters, flow regimes, and geology influence model reliability. While DCA is never fully mechanistic, when applied with sound understanding and transparent data handling, it remains *"one of the most powerful, practical tools" for evaluating wells and forecasting recovery.*

Interactive Insights: Q&A with Dr. Blasingame

Following his lecture, Dr. Blasingame engaged with the audience in a comprehensive question-and-answer session, addressing key challenges and exploring deeper practical insights into well performance evaluation.

Q1. How do the fundamental principles of PTA, dating back to Muskat's 1935 work, hold up today, especially for unconventional reservoirs with complex flow regimes?

A. Hydrogeology was applying the same theories long before oil and gas, with methods like straight-line analysis used as early as the 1920s. In unconventionals, single wells without interference often show only simple signatures—wellbore storage, some linear flow, and little more—which limits interpretation.

In multi-well, highly fractured systems, classical signatures appear because the fractures create extensive connectivity. So, traditional theory still applies, but with caveats: fracture–matrix interaction must be understood, and pseudo-radial flow usually indicates massive fracture communication. In such cases, numerical simulation is essential. Approaches like monitoring offset wells, as done by Wei Chun Chu and colleagues, help reveal connectivity, though they don't fully explain its nature.

Q2 How applicable is RTA for high-permeability conventional reservoirs (200 mD+), where interference occurs quickly? Can mid- to late-time data still be used?

A. Very applicable. Multi-well RTA methods incorporate the full rate and pressure history across wells, similar to large-scale reservoir simulation. I've applied RTA even in reservoirs with 5 Darcy oil and 1 Darcy gas. The key is integrating reservoir geometry, well placement, and geology. Both major vendor tools support this, so high-perm cases can be analyzed effectively, provided interference is accounted for.

Q3. How should multiphase effects, such as water breakthrough, be handled in RTA? Is a single-phase calibration sufficient, or is a numerical multiphase simulation required?

A. Multiphase effects are harder and often require numerical models. I recommend calibrating with single-phase first, then moving to multiphase. One practical approach is to convert everything to total molar rates before analysis. If results remain unclear, use a multiphase simulation. Approximations exist, but modern numerical tools generally give more reliable results.

Q4. How reliable is RTA for wells producing under choke control, where natural decline shapes are not observed?

If bottom-hole pressure data are available, analysis is straightforward and can be done like any other case. Without pressure data, decline analysis isn't possible.

Q5. For gas wells with high WOR and rising FTHP/FBHP, violating constant FBHP assumptions, how can DCA or RTA be performed?

It depends on the severity of liquid loading. If the well is fully loaded and dead, interpretation isn't possible. But if the well still shows reservoir signals—even with intermittent flow—RTA can sometimes work. Severe loading, however, can distort or invalidate diagnostics.

Q6. How can the effects of natural versus hydraulic fractures be distinguished in linear-flow RTA, and what is the role of geologic input or microseismic data?

In most cases, hydraulic fractures dominate. Natural fracture effects are usually short-lived and rarely visible in production data unless they control the system, as seen in reservoirs like the Austin Chalk. Identifying them requires strong geological evidence or, in rare cases, microseismic data. Without that, I'd be cautious about attributing signatures to natural fractures.

PERSPECTIVE: EXPERT INSIGHTS

PTA with Purpose by Dr. Florian Hollaender and Dr. Vincent Artus

"Pressure transient analysis (PTA) is one of the most powerful reservoir diagnostic tools — but only when applied with intent and rigor." — Dr. Florian Hollaender

At a recent SPE IRMTS technical session, two of the field's leading experts, Dr. Florian Hollaender and Dr. Vincent Artus, tackled the deceptively complex topic of PTA.

The session delivered a rare combination of technical insight, practical wisdom, and methodological rigor.

Centered on the theme "PTA with Purpose," it emphasized that PTA's true value does not lie in the latest computational algorithm, but in the precision of the engineering question driving the analysis.

(Speaker)
Florian Hollaender, PhD
Scientific Advisor
SLB

(Speaker)
Vincent Artus, PhD
Regional Manager, Americas
KAPPA

(Moderator)
Khalid Javid
Senior Reservoir Engineer
ADNOC

Rediscovering the Physics of Interpretation by Dr. Florian Hollaender

Dr. Hollaender opened with a perspective—a historical arc stretching from the hydrogeological work of Theis (1935) to the modern derivative and deconvolution era. Early methods, he said, relied on *"straight lines and infinite assumptions,"* extracting permeability but blind to complexity. The derivative changed that.

"The derivative was the real revolution," he explained. *"It gave us a window into the reservoir's heterogeneities, not just its averages."*

But that progress came at a price. With more models and more parameters came a tendency to overfit. PTA, he reminded the audience, measures a single scalar response—pressure—integrated over the reservoir volume around the well.

"You detect a boundary," he said, *"but you don't know if it's above, below, left, or right. The signal doesn't carry that directional information."*

The Double-Edged Sword of Complexity

Hollaender illustrated how model non-uniqueness can turn good mathematics into bad physics.

A dual-porosity response can often be matched equally well by a composite system, a partial barrier, or even a processing artifact.

"Different geological realities can yield identical pressure transients," he said. *"That's not an interpretation flaw — it's physics."*

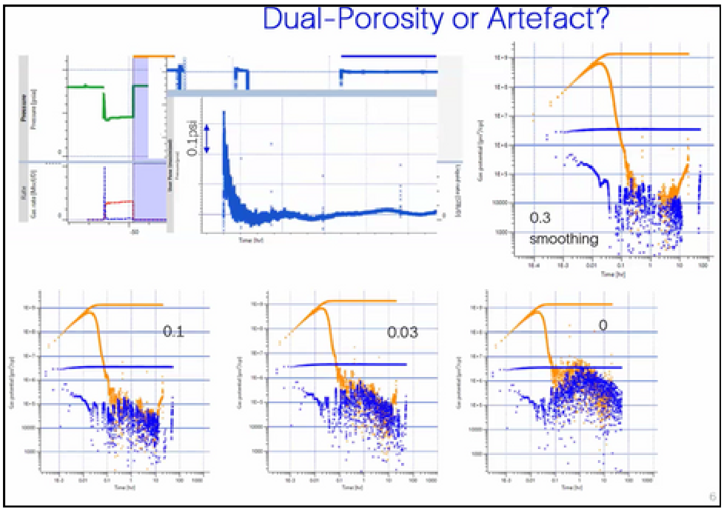
He urged engineers to recognize the resolution limits of PTA. Even in formations with centimeter-scale laminations, a 100-hour well test may show a perfectly flat derivative. The data simply cannot resolve features smaller than the diffusion length associated with the test time.

Noise, Derivatives, and False Dual Porosity

He demonstrated how data smoothing can create artificial structure in derivative plots.

Using real test data, he showed two nearly identical datasets processed with slightly different derivative windows. One displayed a textbook dual-porosity "dip and hump"; the other did not.

"Sometimes the dual-porosity you think you see is just your denoising algorithm," he warned. "The derivative doesn't lie—but it can be made to hallucinate."



The "Loch Ness" Radius of Investigation

Hollaender addressed one of the well testing's oldest questions: How far did we see?

He called the radius of investigation *"the Loch Ness Monster of reservoir engineering."* The classical definition—proportional to the square root of diffusivity times time—assumes homogeneity. In reality, signal propagation depends on anisotropy and heterogeneity.

Recent work by his colleague Lei Jiang replaces that notion with a detectability radius—the radial distance at which a boundary's signal falls below the measurement noise.

"It's not about how far the pressure travels," he said. "It's how far you can still distinguish its effect from noise. *That's what we actually see."*

Purpose as a Design Principle

Most well tests, Hollaender said, are executed without diagnostic intent. *"We collect data because we can,"* he observed, *"not because we've decided what we want to learn."*

To reclaim purpose, he proposed that every test should start with a question:

- Are we assessing vertical communication between layers?
- Are we quantifying fracture connectivity?
- Are we identifying sealing boundaries?
- Each objective implies different test durations, flow rates, and gauge placements.

He showed examples where multi-rate tests, coupled with Bayesian global sensitivity analysis, identified which parameters (permeability, skin, boundary distance) could be resolved and which remained non-unique.

"You should know before the job whether the test will be interpretable," he said. *"That's what PTA with purpose really means."*

Extending PTA into the Numerical Domain by Dr. Vincent Artus

"There's no such thing as numerical PTA," Dr. Vincent Artus began. *"PTA is PTA. Whether you solve it analytically or numerically, you're solving the same physics."*

Where analytical models rely on closed-form equations and superposition, numerical models discretize the reservoir into cells and solve the same diffusivity equation directly.

In simple cases—like a homogeneous, bounded reservoir—the two approaches give identical results. But for irregular geometries, multi-phase flow, or complex fracture systems, numerical methods open the door to physics analytical models cannot reach.

Why Numerical Modeling Matters

Numerical modeling, Artus explained, allows engineers to observe variables at any location and time: not just pressure at the wellbore, but saturation, temperature, or phase front evolution deep within the reservoir.

This capability becomes vital in systems involving:

- Nonlinear multiphase flow (gas exsolution, condensate banking)
- Composite zones with variable permeability
- Faults and anisotropy breaking radial symmetry
- Thermal effects during injection or stimulation

"Those are cases where analytical methods can't help," he said. "Numerical modeling extends the same PTA logic into those nonlinear domains."

Accuracy, Resolution, and Numerical Noise

PTA is extremely sensitive to derivative distortions, which magnify even tiny numerical instabilities.

"PTA looks at the derivative of pressure—meaning every small solver error gets amplified," Artus said.

That's why traditional production simulators—built for long-term forecasts—cannot be repurposed for transient interpretation. They operate at coarser time steps, introducing artificial smoothing.

Specialized numerical PTA solvers use adaptive time stepping, near-well refinement, and high-precision transmissibility handling to preserve signal fidelity over milliseconds to days.

He stressed that results must remain physically interpretable. Parameters like skin, permeability, and mobility have direct physical meaning; simulation-specific indices (e.g., Peaceman factors) obscure it.

"We want the engineer thinking in physical terms, not numerical artifacts," he said.

The Power of Small Models

Contrary to expectation, Artus showed that small, simple numerical models can often deliver the best balance of insight and efficiency. A 1D radial model, for example, can simulate gas liberation or temperature transients with full PVT and thermal coupling—something no analytical solution can match.

These compact grids run nearly as fast as analytical solvers but retain the flexibility to include nonlinear, time-dependent effects.

"Simple geometries," he said, *"can give you analytical speed with numerical power."*

Discipline Before Complexity

Artus cautioned that numerical freedom can easily lead to false certainty.

"If you're not careful," he said, "you can build a model with so many degrees of freedom that you'll always get a perfect match—and it will mean nothing."

He outlined a disciplined workflow:

1. Load and QA/QC the data—ensuring accuracy and gauge reliability.
2. Run diagnostics—use derivatives to identify flow regimes.
3. Apply analytical models first—to define physical expectations.
4. Then move to numerical models—only when justified by geometry or multiphase flow.

"Numerical modeling is not the first step," he said. *"It's the last step—when the simpler physics can't explain the data."*

From Interpretation to Test Design

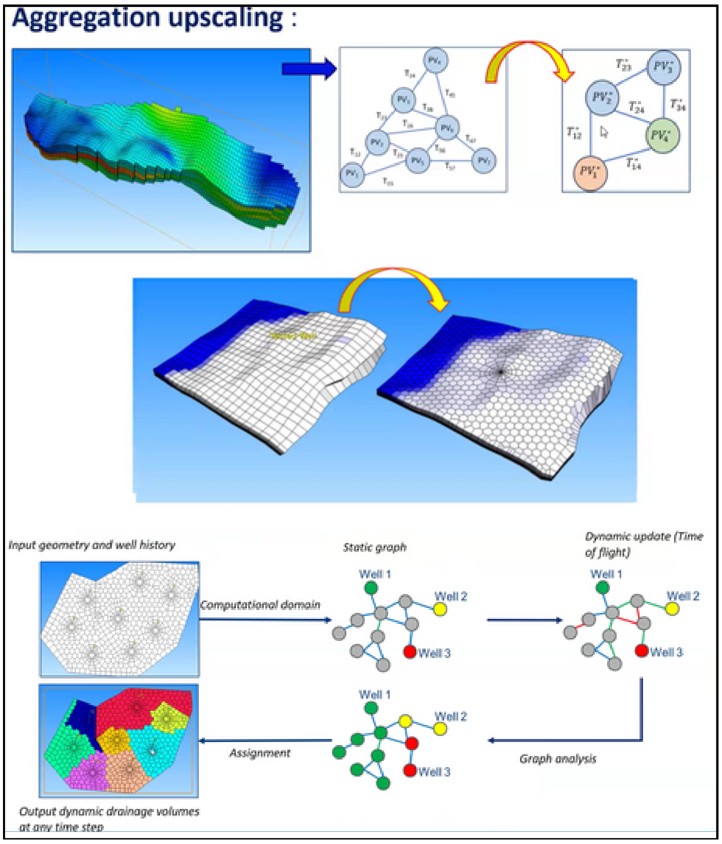
Artus showcased how analytical and numerical methods can complement each other.

In one case, a four-boundary analytical model matched data perfectly but bore little geological realism. When seismic and structural information were added to a numerical grid, certain boundaries proved misplaced.

Combining the two approaches yielded a geologically consistent and diagnostically correct interpretation.

He also demonstrated using fast numerical models to simulate tests before execution, predicting which reservoir parameters would be measurable under expected flow conditions.

That, he said, ties directly to Hollaender's call for purpose: "We can use numerical modeling not just to interpret, but to design smarter tests."



Toward Real-Time, Closed-Loop PTA

Looking ahead, Artus described how automation is closing the loop between testing and modeling. In future digital fields, continuous pressure and rate monitoring will allow systems to automatically detect shut-ins, isolate the event, run a transient analysis, and feed updated permeability or skin directly into the reservoir model—in near real time.
To make that possible, his team is developing solvers that embed physical knowledge directly into the numerical kernel, enabling 10–100× faster runs without sacrificing transient accuracy.

"That's how PTA becomes a living part of reservoir management, not just a one-off interpretation," he said.

Audience Q&A: Deepening the Dialogue on "PTA with Purpose"

Q: Can traditional PTA methods be applied to geothermal wells? How does that compare to gas-well analysis?

A. It depends on the type of geothermal system and the objectives of the test.

In conventional hydrothermal systems, well testing is central to data acquisition and system characterization.

The goal is not only to evaluate permeability and flow capacity but also enthalpy and fracture connectivity, since most geothermal systems are naturally fractured.

In such systems, PTA methods remain applicable. The interpretation workflow is broadly similar to that in oil and gas wells, even though the theoretical foundations may draw from hydrogeology.

Whether the working fluid is treated as a gas or a liquid depends on its pressure–temperature state in the reservoir.

Challenges arise in fractured and engineered geothermal systems (EGS), where fluid and heat transport are strongly coupled. In doublet configurations (producer–injector pairs), pressure interference interacts with thermal gradients, viscosity and density variations, and phase transitions. Under these conditions, numerical models become essential to capture the full thermo-hydraulic behavior.

Establishing a baseline under initial equilibrium conditions—before significant temperature perturbation—is critical for meaningful PTA in geothermal contexts.

Q. How significant is wellbore storage, and how can its impact be minimized?
A. Wellbore storage is inevitable whenever compressible fluids occupy the wellbore— even water contributes, albeit slightly. This "afterflow" effect arises as formation and wellbore pressures equilibrate.

While using low-compressibility fluids (e.g., for injection testing) can help, it often complicates interpretation by introducing multiphase conditions near the wellbore. A more practical strategy is to minimize wellbore volume through careful completion design—using downhole shut-ins or dual-packer assemblies that isolate the test interval.
Reducing wellbore volume not only limits afterflow but also minimizes fluid-level redistribution effects, which often dominate the distortion of early-time data.

From a modeling perspective, wellbore storage and skin effects appear as the dimensionless product $C_d e^{2s}$ in type-curve analysis—meaning that a lower skin value effectively shortens the apparent storage regime.

Q. How can the non-uniqueness of PTA interpretation be addressed?
A. Non-uniqueness is inherent to PTA. Multiple reservoir models can produce identical pressure responses. The goal is not to eliminate non-uniqueness, but to constrain it with geological and operational context.

A credible interpretation aligns with all available information—geological models, logs, seismic, production history—even if the match to pressure data is imperfect. It's better to accept a small mismatch that makes geological sense than to over-fit data with unrealistic parameters.

Reducing uncertainty requires targeted data acquisition:

- Anisotropy can be constrained by multi-probe formation testing.
- Fracture connectivity is better assessed through interference testing.
- Vertical layering benefits from production logging (PLT) data.

Each measurement type resolves a specific ambiguity. PTA should be viewed as one diagnostic among several, not a standalone truth.

Q. How can surface disturbances during buildup tests be corrected?
A. The impact depends on the nature of the disturbance.

- Short data gaps are generally harmless.
- Pressure pulses traveling downhole may cause transient noise but can often be corrected if they do not alter the long-term derivative trend.
- Fluid movement in the tubing can shift hydrostatic pressure but may be compensated through recalibration.

If the disturbance causes actual sandface flow—for example, from a valve reopening or fluid bleed-off—it effectively introduces a new flow period and must be modeled as such.

In short, assess whether the event changed reservoir behavior or only measurement conditions before proceeding with interpretation.

Q. For open-hole horizontal wells without production logging or DTS data, how can the contributing length be determined?
A. Pressure-transient data alone can sometimes reveal the effective producing length, provided three flow regimes are identifiable:

- Early radial,
- Transitional linear, and
- Late radial flow.

From these regimes, one can infer the product of contributing length and geometric mean permeability, $L \times \left(\frac{k_v}{k_h}\right)^{0.5}$ then separate vertical and horizontal permeabilities from their respective time markers.

However, real wells rarely exhibit all three regimes cleanly. Heterogeneity complicates the analysis, and disconnected flow units can distort transition timing. When uncertainty in connectivity is significant, a PLT or DTS survey remains the only reliable method to confirm effective drainage length

Q. Does using rate-convolved pressure improve model outcomes?
A. Rate-convolved analysis accounts for the full variable-rate history of flowing data rather than relying on rate-normalized approximations.

When high-frequency, synchronized rate and pressure data are available, this approach yields more accurate representations of transient behavior—especially with multiple short shut-ins or frequent rate changes.

Historically, adoption was limited by poor rate resolution and time-synchronization issues. With modern sensors and digital data historians, rate convolution is becoming practical, though it comes with a higher computational cost. As always, the trade-off is between data fidelity and runtime.

Q. Can numerical PTA models include aquifer support?
A. Yes. Boundary cells can be connected to lateral or bottom aquifers, modeled either analytically (e.g., using Carter–Tracy) or through full numerical coupling. The response depends on aquifer volume, permeability, and compressibility, and can reproduce both steady-state and transient influx behavior.

Q. When do numerical models fail to run or converge?
A. Two main causes:

- Meshing complexity—the automatic grid generator cannot discretize the geometry with the default parameters.
- Solver instability — convergence fails when solving highly nonlinear processes such as phase appearance or counter-flow.

Improved meshing algorithms now report problem locations, allowing users to adjust geometry manually. Solver issues can often be mitigated by refining time steps, damping iterations, or simplifying property correlations.

And a final caution: numerical modeling cannot resolve geological unknowns that are not defined in the first place. Adding hypothetical complexity where understanding is weak usually leads to confusion, not clarity.

Q. How valid is multiphase upscaling or grid coarsening in PTA simulations?
A. Aggressive coarsening introduces numerical dispersion, smearing out saturation fronts and masking key PTA signatures. Pseudo-relative permeability curves can compensate partially, but their calibration depends on test conditions.

A more robust approach is directional upscaling, where control volumes are aggregated preferentially along non-critical axes, preserving multiphase gradients near the well. This technique maintains accuracy in low-permeability systems while reducing computational load.

Q. How are thermal refinements handled in geothermal and CO_2 simulations?
A. The strategy mirrors that used for multiphase displacement: local grid refinement follows the advancing mobility or thermal front.

Thermal diffusion is slow, and temperature strongly affects PVT properties, making fine near-well discretization essential. Refinement ensures that viscosity, density, and phase-change effects are properly captured at the front as it moves outward.

Q: How does time-lapse interpretation using permanent downhole gauges (PDGs) work?
A. Modern workflows can continuously interrogate the data historian linked to PDGs, automatically detecting shut-ins, filtering pressure and rate data, and flagging events suitable for analysis.

Once a base model is defined, the system can re-run and history-match each new shut-in automatically. This allows time-lapse interpretation of near-well parameters such as permeability or skin, tracking their evolution and revealing trends like formation cleanup, damage, or fluid-front movement.

Q. How can flux and rock-typing effects be accounted for in development-well test design when the numerical model is not derived from a full-field simulation?
A. Neighboring wells and their full production history can be included to capture long-term interference and pressure depletion effects.

Maps of permeability or rock types may be imported directly, allowing the user to adjust each type's properties to study their influence on flow and transient response. This provides a practical compromise between sector modeling and full-field simulation.

Q. Can AI tools help accelerate PTA workflows?
A. Yes—AI can reduce workflow time in two ways:

- **Preprocessing automation:** automatically identifying shut-ins, synchronizing data, generating diagnostics, and initializing a first-pass model.

- **Iterative model updating:** once a model exists, AI can automatically re-run and re-match it as new data arrives.

Another application is *"model mining,"* where AI assists in exploring parameter space efficiently. A large ensemble of simulations is run, and AI algorithms use the results to generate probabilistic distributions of reservoir parameters—providing uncertainty quantification at a fraction of the computational cost of full brute-force ensembles.

The Common Thread: Purpose Before Complexity

Though their talks approached PTA from different angles, both experts converged on a single philosophy: clarity before complexity.

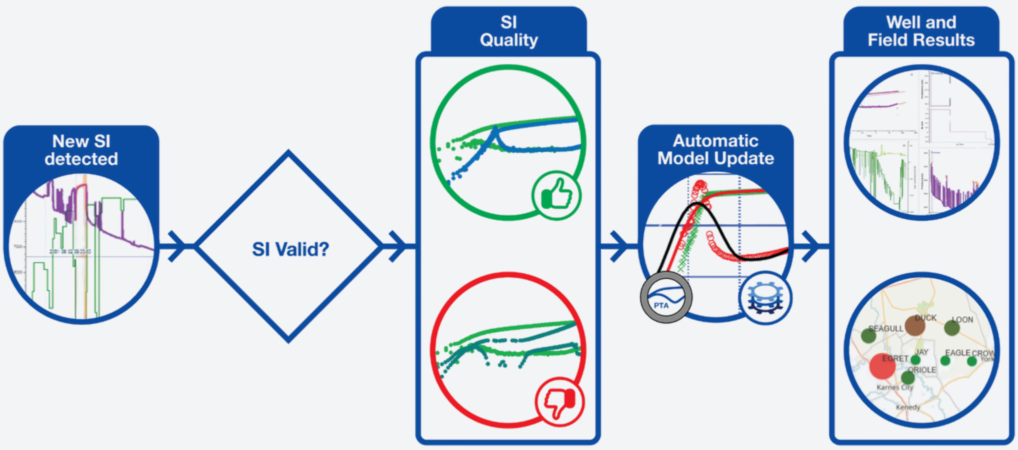
"PTA doesn't answer every question," Hollaender said. *"It answers the ones you ask it well."*

"Numerical modeling isn't a magic button," Artus added. *"It's a finer lens—useful only if you already know what you're looking for."*

Their message was not nostalgic but forward-looking: in an era of machine learning and automation, PTA with Purpose remains a cornerstone of technical judgment—a reminder that *true progress comes from understanding, not just computation.*

Faster Data-Driven Reservoir Management Decisions with Automated Workflows

Authors: Walid Choueiri, Regional Manager, KAPPA - Middle East
Umair Tariq, Product Manager, KAPPA



Production monitoring data and pressure/temperature from PDGs were integrated into a single platform. Elements of automation included smart filtration and data reduction, shut-in (SI) identification and quality assessment, rate-pressure synchronization, updating PTA models to match new data, and consolidating all time-lapse results.

The semi-autonomous workflow enables detection and analysis of all SIs (planned or unplanned). Results were available to the reservoir management team within minutes/hours of SI conclusion at the well site, a process that usually takes days to conclude. Different visualization dashboards were set up for different user roles.

This allows reservoir management decisions (well stimulation, pressure maintenance, etc.) to be taken within minutes/hours of an SI, instead of days/weeks.

THE RESERVOIR CHRONICLES: TRIVIA & TIDBIT

**Interested in testing your knowledge of Integrated Reservoir Management?
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DID YOU KNOW?

In 1926, near El Dorado, Arkansas, Edgar and Mordica Johnston faced a common reservoir challenge: thin, irregular formations that required frequent flow verification. At the time, testing required setting **casing, cementing, and bailing**—costly steps that offered little real-time insight. Determined to improve efficiency, the brothers engineered a solution.

Using discarded **belting, a poppet valve, and a heavy boxcar spring**, they built a tool that could be run on the drill stem to isolate and evaluate formations directly. It worked—and demand surged.

By 1929, their design earned a U.S. patent, and the later integration of a pressure recorder transformed it into a true diagnostic tool. When their company joined Schlumberger in 1956, the innovation became a global standard in formation evaluation.

That simple field-built tool became one of the industry's defining advances—the **Drillstem Test (DST).**

Source: History of Petroleum Engineering, API Division of Production, New York City, 1961, pages 561–566

SPECULATE: QUIZ ZONE

Born in 1886, I pioneered applied geophysics and reshaped petroleum exploration.

My legacy:

Recognized as the father of American geophysics
Oil company executive and exploration leader
Builder of a world-renowned rare book collection

I didn't just explore for oil—I expanded frontiers of science, industry, and knowledge.

Who Am I?

PETROPAGES: BIBLIOPHILE BULLETIN

Reservoir Surveillance
By Jitendra Kikani
Society of Petroleum Engineers
DOI: https://doi.org/10.2118/9781613993040
ISBN electronic: 978-1-61399-882-3
Publication date: 2013

Generating economic producing opportunities in a new or existing field is key to the success of an oil and gas company. These opportunities arise from a systematic assessment of key value drivers through relevant and appropriate measurements and by performing vigorous analysis that creates intelligence for the field.

Interwoven in this evident and simple construct is the understanding of reservoir surveillance technologies. This book will help the reader not only clearly understand the broad spectrum of issues to consider for surveillance but also provide tools, techniques, and templates to adapt to his or her specific needs. The theory behind some of the equipment, as well as data analytics, is illustrated with examples. It is essential reading for reservoir, production, operations engineers, and earth scientists. The theoretical background and concepts discussed will be valuable for the university student to gain fluency in this integrated subject.

Spotlight Publication

Smart Analytics Empowering Production

This article contains highlights of paper SPE-211820-MS "Digital Solution for Production Optimization and Production Losses Estimation Using Data Analytics in Real Time in a Brown Field," by Hugo Quevedo, Luis Marchán, Willem Sepúlveda, et al. The paper has not been peer reviewed. This paper was prepared for presentation at the ADIPEC held in Abu Dhabi, UAE, 2022.

Background & Technical Challenges

Traditional monitoring methods rely heavily on manual checks and reactive maintenance, which are inefficient in large-scale operations where a single engineer may oversee hundreds of wells. The main challenge is detecting and predicting ESP failures early. Conventional systems struggle to process large volumes of real-time data and miss subtle signs of malfunction. Additionally, the lack of integrated diagnostic tools makes it difficult to identify root causes, delaying corrective actions and increasing operational risks.

Electrical Submersible Pumps (ESPs) are one of the most commonly used artificial lift systems in the oil and gas sector, contributing to over 30% of global oil output. They play a vital role in sustaining production, especially in aging fields with declining reservoir pressure. However, ESPs often face operational issues due to extreme downhole environments, mechanical degradation, and electrical faults. These problems lead to unexpected shutdowns, higher maintenance expenses, and reduced equipment reliability.

Methodology & Solutions

The paper introduces a novel predictive analytics framework that leverages a variant of Principal Component Analysis (PCA) called Moving Mean PCA introduced in a field located in the Amazon region (Figure-1). This technique is designed to handle time-series data from ESP sensors, capturing dynamic changes in operational parameters (Figure-2). The workflow involves several stages:

Data Ingestion: Real-time sensor data from ESPs is collected and pre-processed

Feature Extraction: Key operational metrics such as motor current, discharge pressure, and temperature are extracted

Normalization: Data is standardized to ensure consistency across different wells and operating conditions

Model Training: The Moving Mean PCA model is trained to recognize patterns associated with normal and faulty operations

Evaluation: The model is validated using historical failure data to assess its predictive accuracy.

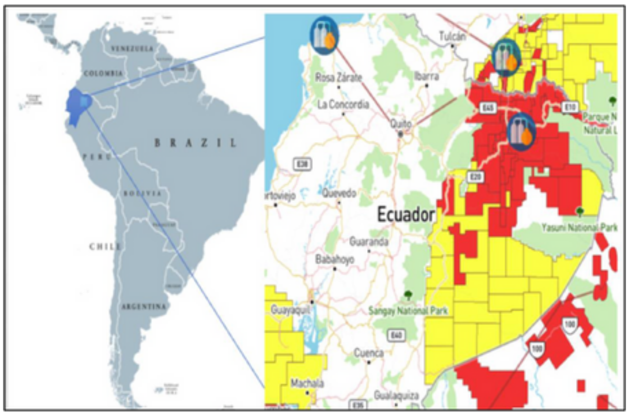

Figure 1: Brown Field location map – Amazon Region

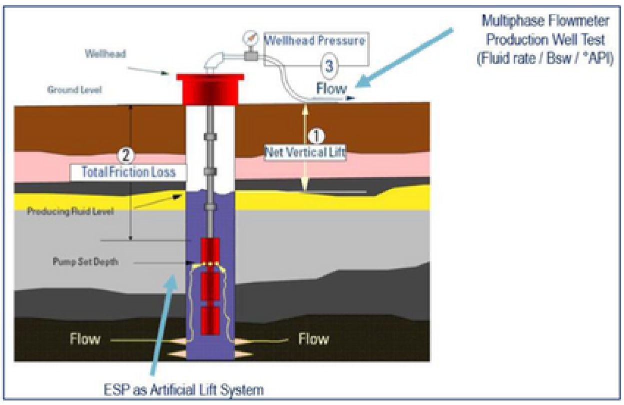

Figure 2: Data Acquiring from the ESP

Smart Analytics Empowering Production

Fault Tree Analysis Component

Complementing the ML model is a rule-based Fault Tree Analysis (FTA) system. FTA uses logical trees to diagnose specific fault conditions based on predefined rules (Figure-3). This includes detection of:

Deadheading: Identified through pressure anomalies and flow inconsistencies

Motor Current Anomalies: Detected via sudden spikes or drops in electrical current

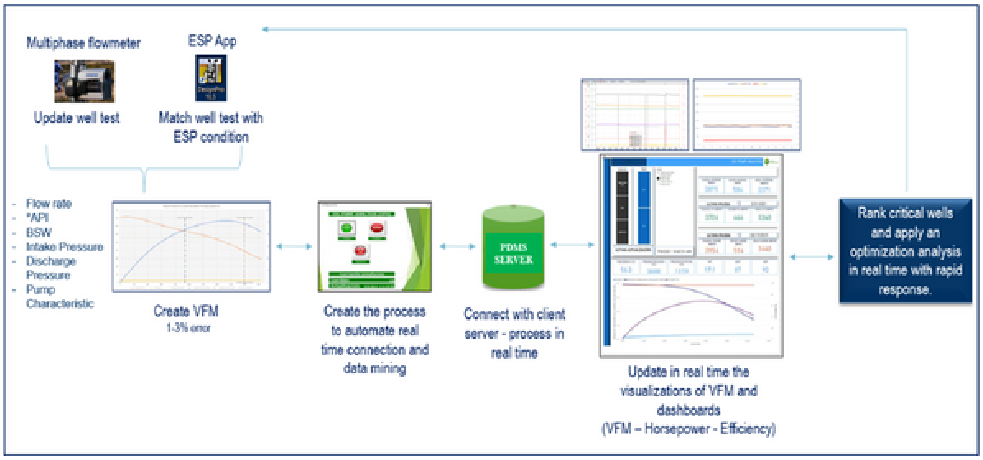

Figure-3: Solution Workflow

Temperature Spikes: Monitored to prevent overheating and thermal damage

The integration of FTA provides interpretability to the ML predictions, allowing engineers to understand the underlying causes of alerts and take appropriate action

Implementation Details

The unified application is designed to operate in real-time, continuously monitoring ESP performance across multiple wells. It features a user-friendly interface that displays alerts, diagnostic insights, and historical trends. The system is scalable, capable of handling data from thousands of sensors, and can be customized for different field configurations.

Results and Operational Impact

Field implementation of the predictive analytics system improved ESP reliability and efficiency:

- Boosting productivity by 25% due to reduced downtime and optimized performance
- Cutting breakdowns by 70% through early fault detection
- Reducing maintenance costs by 25%.

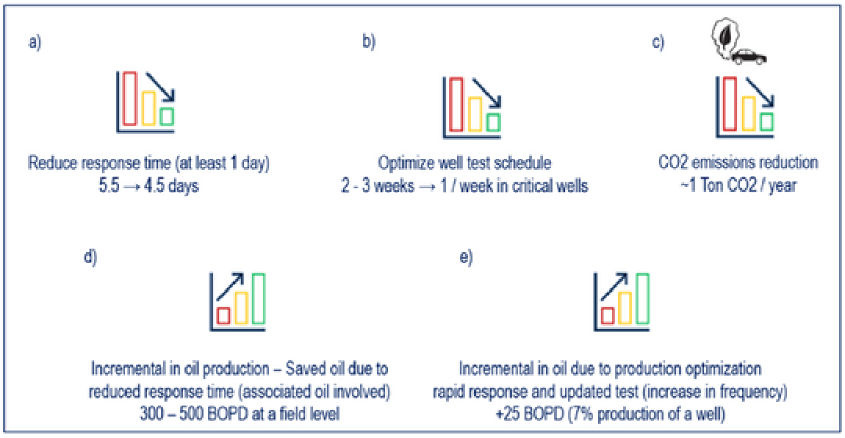

Figure 4: Results showed during the pilot project

These results demonstrate the effectiveness of combining ML and FTA in a single application, enabling data-driven decision-making and enhancing asset integrity (Figure-4).

Forward Outlook

Future enhancements will integrate diverse artificial lift systems, apply advanced machine learning such as deep learning and tailor solutions to specific reservoirs. Leveraging supercomputing and edge technologies will enable faster, scalable and more autonomous oilfield operations.

SPE IRMTS in Pictures

The last quarter was a dynamic period for SPE IRMTS members, marked by active participation across both regional and international platforms. Members demonstrated thought leadership and collaboration, strengthening the chapter's global footprint and contributing to its mission of knowledge sharing and professional growth. Their engagement at key industry events showcased the chapter's commitment to advancing technical excellence and fostering meaningful connections within the energy community.

SPE IRMTS members made impactful contributions at several prestigious conferences, including the SPE Integrated Intelligent Well Completion in Rio de Janeiro, Brazil, where they delivered technical sessions and exchanged insights with global peers. The chapter was also represented at the MEOS GEO Conference, the GWECCC2025 Technology Forum in Bahrain and GCC AI & Digitisation in Oil and Gas in the UAE , highlighting regional expertise and exploring emerging innovations like AI-driven energy solutions. Additionally, members participated in the Hydraulic Fracturing Technology Conference in Muscat, Oman, engaging with leading industry players, alongside continuing to inspire future professionals during an SPE ALP Talk at Pandit Deendayal Energy University (PDEU), encouraging students to join the SPE community and nurture the next generation of energy leaders.

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Sponsorship Opportunity

Would you be interested in supporting the SPE IRMTS? Reach out to our Sponsorship Champion, **Maryvi Martinez Santiago**, to explore opportunities to collaborate with us and amplify your organization's presence within the global energy community.

From the Editors' Desk

Here we are! The SPE IRMTS 3rd Edition. It has been a brief but enlightening journey so far. The SPE IRMTS Newsletter continues to evolve as more than just a periodic publication. It is becoming a living archive of technical knowledge, capturing the best thinking, innovations and practices, shaping Integrated Reservoir Management (IRM) today.

In this edition, we are pleased to introduce the SPE IRMTS Youth Chapter, marking a step forward in engaging young professionals. Insightful conversations with thought leaders like Dr. Rahim Masoudi and Dr. Blasingame, who brings depth to pressure transient analysis and scalable modeling workflows. We also feature insights on Smart Analytics Empowering Production, showcasing how digital intelligence continues to transform field management and operational resilience.

As the newsletter grows, our goal is to bring together the best minds in the industry, researchers, practitioners, and innovators to curate a technological repository that serves both today's challenges and tomorrow's opportunities. In future editions, we look forward to exploring more advanced technologies, integrated methodologies, and real-world applications that continue to define the evolving landscape of reservoir management.

We welcome our readers to share their thoughts and topic suggestions for future editions. If there's a subject or theme you would like us to explore, we would be delighted to hear from you at **irmtechnicalsection@gmail.com**

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October 28–30, 2025
Offshore Technology Conference OTC Brasil (25OTCB)
Rio de Janeiro, BRA

October 28–30, 2025
SPE Eastern Regional Meeting (25ERM)
Wheeling, West Virginia, USA

November 03–06, 2025
ADIPEC (25ADIP)
Abu Dhabi, Abu Dhabi Emirate, ARE

November 05 –07, 2025
SPE Montney/Duvernay Symposium (25MODU)
Banff, Alberta, CAN

November 18–20, 2025
SPE Permian Basin Energy Conference (25PBEC)
Midland, Texas, USA

November 25-27, 2025
SPE Annual Caspian Technical Conference and Exhibition(25CTC)
Baku, Baku City, AZE

Workshops

October 21 -22, 2025
Collaborative Geological-Engineering Integration for Unconventional Reservoir Development (25WA03)
Shanghai, CHN

October 28-29, 2025
Gas Field Development for a Changing Asia : Driving Sustainability and Efficiency (26WM04)
Kota, Kinabalu, Sabah, MYS

November 03 -05, 2025
Field Performance and Design of Water Injectors: Injectivity, Fluid conformance and containment (25ASA1)
San Antonio, Texas, USA

November 12 -13, 2025
Digital Transformation(25ARI2)
Rio de Janeiro, BRA

November 25 -26, 2025
SPE Workshop: Integrated Carbonate Reservoir Development and Management (25BWM6)
Kuching, Sarawak, MYS

Call for Papers

SPE Latin American and Caribbean Petroleum Engineering COnference (LACPEC) 2026
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SPE Conference at Oman Petroleum and Energy Show 2026
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