SPE-230157-MS

A Case Study: Integrated Surface Based Tracer and Acoustic Gas Lift Surveillance vs. Traditional Slickline Flowing Gradient Survey for Enhanced Diagnostic and Bottomhole Flowing Pressure (Pwf) Estimation

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This paper was prepared for presentation at the ADIPEC held in Abu Dhabi, UAE, 3 – 6 November 2025.

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Abstract

Effective surveillance and optimization of gas lifted wells are the paramount for maximizing the hydrocarbon recovery and overall operational efficiency. The keystone of this surveillance is the precise & accurate determination of flowing bottom-hole pressure (Pwf), which traditionally relies on intrusive methods such as slickline-deployed flowing gradient surveys (FGS). While this method provides direct and accurate measurements, it also involves well intervention, convey inherent operational risks, sustain significant costs, and alter the well's production dynamics which lead to masking the instabilities we aim to diagnose.

This paper presents a comprehensive comparative evaluation of a non-intrusive Acoustic Gas Surveillance (AGS) technology against the traditional FGS for gas lift well surveillance. The AGS methodology employs a suite of surface-based measurement which includes tracer gas injection for flow rate determination via the dilution principle, acoustic monitoring for anomaly detection, and continuous surface data logging. These data are integrated into a calibrated, dynamic, hybrid well model, combining mechanistic principles with empirical correlations to calculate Pwf and other critical downhole parameters without well intervention.

The study focuses on an extensive field campaign conducted on more than 180 gas-lifted wells in the Middle East. We present a detailed analysis comparing the calculated Pwf profiles by the AGS system with those directly measured by FGS across several wells. The results demonstrate a strong statistical correlation (R^2=0.84) between two methods, with the majority of Pwf estimation falling within a 10% variance, particularly when surveys are conducted in close proximity. In addition, the Field data also shows the AGS production rate measurements are within 10% agreement with results from a Portable Test Separator (PTS).

The findings confirm that while the FGS remains the definitive benchmark for calibration and diagnostics of complex well issues, the AGS technology offers a non-intrusive, safer, and highly cost-effective alternative for routine performance monitoring. A key advantage highlighted is the ability of AGS to survey the well under its true, undisturbed operating conditions. The paper concludes that an integrated surveillance strategy, leveraging FGS for periodic benchmarking and AGS for frequent, routine monitoring,

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provides an optimum framework for maximizing production, improving operational safety, and achieving comprehensive reservoir management. This work offers a practical workflow for operators to enhance the gas lift optimization programs.

Introduction

Gas lift is one of the most widely applied artificial lift techniques in the global oil and gas industry, used to unload wells with insufficient reservoir pressure to produce naturally or to enhance production from flowing wells. The method's effectiveness is critically dependent on the precise control of gas injection rates to optimize production while minimizing operational cost associated with gas compression. Under performed injection will fail to achieve the maximum production potential, while over performed injection can lead to production losses due to increased frictional pressure drop and inefficient use of lift gas, a phenomenon well-documented by authors like (Brown, 1984) and (Decker, 2013).

The optimization of gas lift system pivots a thorough understanding of well's performance, which requires accurate and timely surveillance data. Among the most critical parameters is the flowing bottom hole pressure (Pwf). This data is essential for Inflow Performance Relationship (IPR) analysis, diagnosing production problems, assessing formation damage, and calibrating reservoir simulation models (Guo et al., 2007). For decades, the industry standard for acquiring downhole flowing pressure and temperature data has been the through the Flowing Gradient Survey (FGS), typically performed by running memory gauges into the well by Slickline or Wireline. This method provides a direct, high-reliability measurement of the pressure profile along the wellbore. However, despite its accuracy, FGS has significant limitations. The operation is intrusive, requiring the shut-in of the well for rig-up and rig-down, leading to deferred production. It carries inherent operational risks, including the potential for tool string getting stuck or loss downhole, and incurs substantial costs related to personnel equipment and logistics.

A more subtle yet significant drawback of intrusive methods is the *"observer effect"* – the act of measurement can alter the state of the system being measured. The introduction of slickline tool string and the associated operational procedures can disturb the well's thermal and hydraulic equilibrium. This can be particularly problematic in wells experiencing subtle instabilities or slugging flow, where the survey itself might temporarily stabilize the flow regime, thus failing to capture the well's true dynamic behavior (Brito et al., 2018).

In response to these challenges, industry has pursued the development of non-intrusive surveillance technologies. These methods aim to provide critical-well performance data from surface-based measurement, eliminating the need for well intervention. Early development focused on acoustic well sounding to determine liquid levels in the annulus. More recent advancements, as explored in this paper, integrate multiple surface measurements including tracer flow metering and advanced acoustic analysis with sophisticated wellbore flow models to provide a more comprehensive diagnostic toolkit. Technologies leveraging tracer dilution have been discussed for multiphase flow metering application (MPFM) with their principles and accuracy being a subject of various studies (Kragset et al., 2007; Torkildsen., 2010).

This paper investigates one such modern approach, a non-intrusive Acoustic Gas Surveillance (AGS) system. This technology does not seek to replace the high-accuracy benchmark provided by FGS. Instead, it proposes a paradigm shift in surveillance strategy: using FGS as a powerful, periodic tool for calibration and in-depth diagnostics, while employing the non-intrusive AGS for frequent, routine, and cost-effective monitoring. This integrated approach allows operators to maintain a continuous pulse on well performance, identify optimization opportunities more rapidly, and allocate intervention resources more effectively. The primary objective of this study is to provide a detailed technical evaluation of AGS technology based on a large-scale field application. We will:

1. Describe the methodologies of both the conventional FGS and the non-intrusive AGS.

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2. Present a comparative analysis of Pwf data obtained from both methods across numerous wells from a major onshore field.
3. Discuss the operational, safety, and economic benefits of an integrated surveillance strategy.
4. Provide a clear message on the complementary roles of these two technologies in the context of modern production optimization and reservoir management.

Methodology

The core of this study is the comparison of two methodologies for determining Pwf and well performance. This section details the principles and procedures for both the conventional, intrusive FGS and the non-intrusive AGS.

Conventional Flowing Gradient Survey (FGS)

The FGS is a direct measure technique that has been the backbone of production surveillance for many years. The primary objective is to record the pressure and temperature distribution along the tubing string during flowing well condition. Typical FGS operation involves the following step:

1. **Preparation**: A slickline unit is mobilized to the wellsite. Upon securing the well, a lubricator is rigged up on the wellhead.
2. **Tool Run**: A tool string consists of tandem memory gauges carrier with high precision pressure and temperature sensors is run into the well through the production tubing.
3. **Gradient Stops**: The tools string is lowered to a depth below the deepest gas lift valve or the point of interest. The well is then monitored to reach stabilization for a predetermined period. The tool is subsequently pulled out of the hole, stopping at pre-defined depths (gradient stops) for a short duration to record stable pressure and temperature readings.
4. **Data Retrieval**: Once the tool string is back on the surface, the data will be downloaded from the memory gauges. The outcome resulting pressure and temperature vs. depth plot which constitutes the flowing gradient survey.

Advantages:

- **High Accuracy**: As a direct measurement, FGS is considered the industry benchmark or *"ground truth"* for Pwf. The result is used to calibrate well models and other surveillance systems.
- **Detailed Profile**: Provides a detailed profile of pressure and temperature across the entire wellbore along with fluid gradient that will support identifying liquid loading, locate leaks, and analyze flow regimes.

Disadvantages:

- **Intrusive**: Requires well intervention, leading to deferred production during the rig-up, the survey, and rig-down.
- **Cost**: High operational cost associated with equipment, personnel, and logistics.
- **Safety Risks**: Carries inherent risks of well control incidents and downhole tool fishing jobs.
- **Wellbore Disturbance**: The presence and movement of slickline tool can alter the in-situ flow conditions. This disturbance can be significant, in particularly for wells with multiphase flow, potentially leading to the measurements that are not representing the normal, undisturbed flowing condition of the well.
- **Infrequent**: Considering its high cost and operational integrity, FGS is typically performed infrequently (e.g., annually or biannually), resulting in unmonitored insight of well performance between surveys.

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Non-Intrusive Acoustic Gas Surveillance (AGS)

The AGS technology represents a fundamentally different approach. It avoids well intervention by combining a suite of surface measurements with a sophisticated mathematical model of the wellbore to infer downhole conditions. A schematic of the data acquisition component is shown in Figure 1. A tracer injection skid (e.g., N2 cylinders and a mass flow controller) is connected to the gas lift injection line.

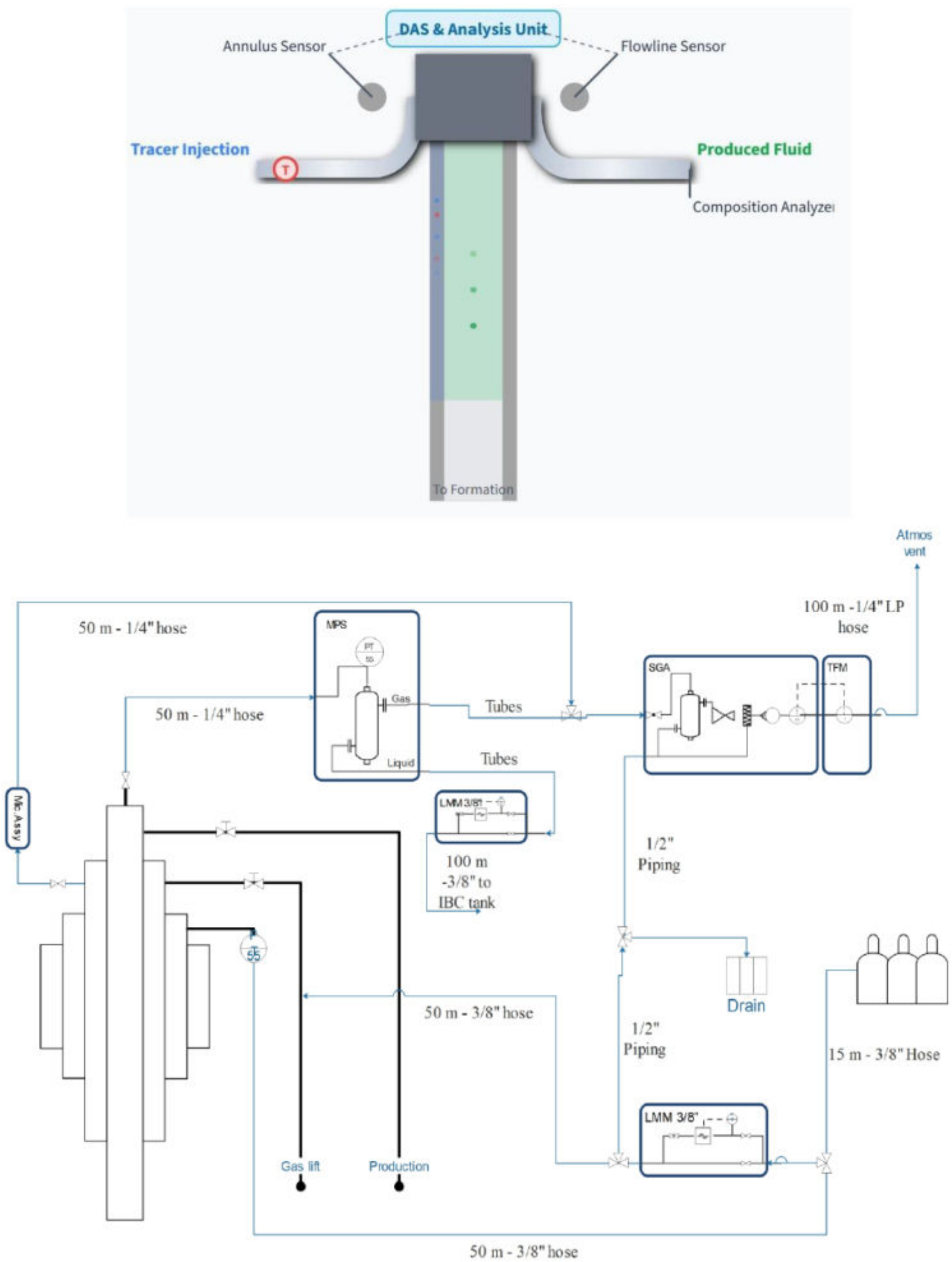

Figure 1—Schematic of the Acoustic Gas Surveillance (AGS) System Components, including tracer injection skid, acoustic sensors on the flowline and annulus and a data acquisition unit. This diagram illustrates the surface equipment layout for the non-intrusive survey.

Clamp on acoustic sensors are placed on the exterior of the annulus line and the main production flowline. These sensors along with standard pressure and temperature transmitters on the wellhead, feed data into a central data acquisition system (DAS) and laptop for processing and analysis.

Operating Principle and Components. The AGS system is a multi-measurement platform that acquires data from several sources simultaneously:

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- **Tracer-Based Flow Rate Measurement**: Core of the flow rate measurement which is the tracer dilution technique. This involves injecting a known quantity of a tracer substance into the flow stream and measuring its concentration at a point downstream after it has thoroughly mixed.
- **Acoustic Monitoring**: High fidelity acoustic sensors are clamped onto the exterior of the production flowline and annulus lines. These sensors record on the characteristic acoustic signatures associated with gas lift valve operation, flow through restrictions, and potential integrity issues like downhole leaks.
- **Surface Pressure and Temperature**: Sensors that continuously record pressure and temperature at the wellhead and at the gas lift injection line.
- **Gas Compositional Analysis**: Gas chromatograph (GC) and real-time sensors composition of the produced-injected gas.

Flow Rate Determination by Tracer Dilution. The tracer dilution method is a well-established technique as described in the international standards such as ASTM E2029-99.

- **Gas Flow Rate**: Measure the gas lift injection rate or the produced gas rate, a non-reactive tracer gas (e.g., Nitrogen as in this scenario is not the primary lift gas) is injected at a precisely known and constant rate ($M_{tr,\,i}$) into the gas line. At the downstream, a gas analyzer measures the concentration of the tracer ($C_{tr,\,d}$). In mass conservation principle. The total flow rate of the stream (Q_d) can be calculated. The increase in tracer concentration is inversely proportional to the stream's volumetric flow rate. The governing equation is, where:

$$Qd = \frac{Mtr,i}{\rho s\int_{td1}^{td2}[Ctr,d(t) - Ctr2,d]dt} \qquad \text{(Equation 1)}$$

where:
Qd = calculated volumetric flow rate of the main fluid stream
Mtr,i = total mass of injected tracer
ρs = density of the fluid stream at standard conditions
td1 = time detection at the start of recording the concentration
td2 = time detection when it stops recording, after the tracer has passed
Ctr,d = measured concentration of the tracer measured at the detection point
Ctr2,d = baseline concentration of the tracer measured before the injection started.
dt = increments of time over which the summing of concentration

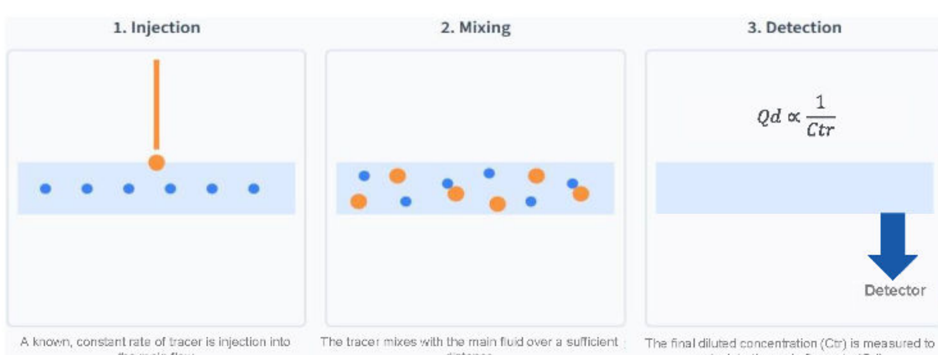

Figure 2—Principle of Flow Metering by Tracer Dilution.1: Tracer is injected and metered at a known and constant rate into the flow stream. 2: After a sufficient mixing length, a concentration detector measures the fluid and determines the diluted tracer concentration. 3: The flow rate of the mainstream is inversely proportional to this measured concentration.

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- **Liquid Flow Rate**: Similar principle is applied to measure the liquid (oil and water) rates. A conductive and/or fluorescent water-based tracer is injected into the multiphase flow stream. An online analyzer at the downstream detects changes in fluid's conductivity and fluorescence further determining the tracer concentration, subsequently, the liquid rates.

Mathematical Well Model. A mere surface data is insufficient to determine the Pwf. The critical link is a robust mathematical model that simulates the fluid dynamics within the wellbore. The model used in this technology is a hybrid approach, combining a mechanistic model with empirical correlations and field data for tuning.

The model builds upon the fundamental framework and successful pilot study (Cornwall et al., 2021), which first validated this non-intrusive surveillance technique. This model is founded on the fundamental principles of conservation of mass and momentum for each phase, derived under the following key assumptions:

- All variables depend only on one spatial dimension, i.e. the flow along the flow line.
- Flow is assumed as isothermal
- Exchange of mass takes place between formation gas and formation fluid only
- The different gases do not mix
- No slip between the gases.

From these concepts, a system of governing conservation equations is established and solved numerically to simulate the well's behavior:

- Conservation of formation liquid (Oil and Water)

$$\frac{\partial\left(A\alpha_l\rho_l\right)}{\partial t}+\frac{\partial\left(A\alpha_l v_l\rho_l\right)}{\partial s}=Amg+Q_l \quad \text{(Equation 2)}$$

- Conservation of free formation gas

$$\frac{\partial\left(A\alpha_{gf}\rho gf\right)}{\partial t}+\frac{\partial\left(A\alpha_{gf}v_{gf}\rho_{gf}\right)}{\partial s}=-\mathrm{A}mg+Q_g \quad \text{(Equation 3)}$$

- Conservation of dissolved formation gas

$$\frac{\partial\left(A\alpha_{gf}x_{dg}\rho_{gf}\right)}{\partial t}+\frac{\partial\left(A\alpha_{gf}x_{dg}vl\rho_{gf}\right)}{\partial s}=\mathrm{A}mg+Q_{dg} \quad \text{(Equation 4)}$$

- Conservation of lift gas

$$\frac{\partial\left(A\rho_{gl}\right)}{\partial t}+\frac{\partial\left(Av_g\rho_{gl}\right)}{\partial s}=0 \quad \text{(Equation 5)}$$

- Conservation of tracer gas

$$\frac{\partial\rho_{gt}}{\partial t}+\frac{\partial\left(Av_g\rho_{gt}\right)}{\partial s}=0 \quad \text{(Equation 6)}$$

- Conservation of mixture momentum

$$\frac{\partial(Ap)}{\partial s}+\frac{\partial\left(Ap_{\mathrm{fric}}\right)}{\partial s}+A\,p_{\mathrm{mix}}\,g\cos(\theta)=0 \quad \text{(Equation 7)}$$

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Fluid Property and Closure Models. To ensure the system of equations provides accurate results, the model integrates a suite of industry-standard correlations for complex characterization of multiphase fluids under varying pressures and temperatures.

- **Formation Fluid Density**: The model computes the density of the formation fluids by treating it as a composite water and dead oil, weighted by their respective mass fractions (x_w, x_o, x_{dg}):

$$\rho_l\left(\rho, t, x_0, x_{dg}\right) = \frac{1}{\frac{x_w}{\rho_w(P,T)} + \frac{x_0 + x_{dg}}{\rho_o\left(P,T,x_{dg}\right)}} \quad \text{(Equation 8)}$$

The model can utilize either for a direct PVT table data or implement correlations for fluid properties. Specifically, *the Vasquez-Beggs (1977)* correlation is employed for oil density and gas oil ratio (GOR) calculations, while the *Hall and Yarborough* method defines the formation gas density.

- **Lift and Tracer Gas Density**: *The Peng-Robinson* equation of state is applied to accurately determine the densities of both injected lift gas and the tracer gas.
- **Frictional Pressure Loss**: Calculating energy losses due to friction using the standard formulation of pressure drop *Colebrook and White* friction factor model (f_f), a methodology reviewed in detail by Genić et al., 2011.

$$\frac{\partial f_{fric}}{\partial_s} = \frac{f_f \rho_{mix} v_{mix}^2}{2d} \quad \text{(Equation 9)}$$

- **Gas Slip Relation**: Accurately capturing the velocity between the gas and liquid phases is the paramount in multiphase flow. The model incorporates the robust gas slip relationship developed by Hassan and Kabir (2002) to handle this critical parameter.

Reservoir and Boundary Conditions. The model seamlessly integrates the wellbore with the reservoir through two distinct inflow performance relationships (IPR) models, chosen based on the reservoir's saturation state.

1. **Productivity Index (PI)**: For wells which are produced at undersaturated reservoirs, a straightforward linier PI model is utilized:

$$Q_o = PI\left(P_r - P_{wf}\right) \quad \text{(Equation 10)}$$

2. **Vogel's Inflow Performance Relationship (IPR)**: Condition where the reservoir is saturated and flowing below the bubble point pressure (Pb), the industry standard Vogel's IPR is applied to describe the inflow.

$$Q_o = Q_{o,max}\left[1 - 0.2\left(\frac{P_{wf}}{P_r}\right) - 0.8\left(\frac{P_{wf}}{P_r}\right)^2\right] \quad \text{(Equation 11)}$$

The model is constrained by the following boundary conditions (captured directly at the surface):

- Real-time volumetric rate of the injected lift gas and tracer gas.
- Continuous monitored wellhead pressure.

Model Calibration and Pwf Calculation. The uniqueness of this approach lies in its ability to tune the model using the measured field data (dynamic calibration process). The measured surface rates (gas and liquid), gas compositions, and downhole gas distribution (inferred from acoustic data indicating which valves are active), used as inputs. The model then calculates the Pwf that honors these surface constraints.

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This process provides a holistic and internally consistent picture of well performance without physically entering the well (illustrated in Figure 3).

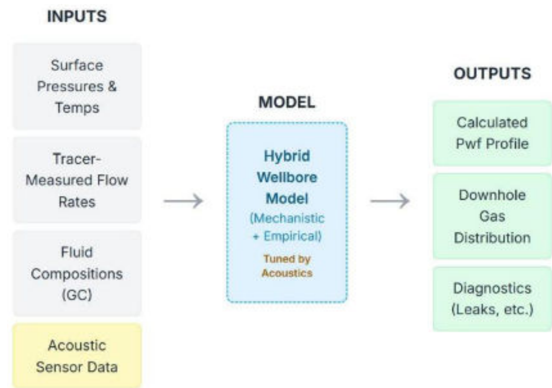

Figure 3—A workflow diagram showing inputs (Surface Pressures, Rates, Compositions) feeding into the "Hybrid Well Model", which is tuned by "Acoustic Data," and produces outputs like "Calculated Pwf" and "Pressure/Temp Profile"

Field Case Study and Results

Following the successful validation of this technology in a pilot study, a large-scale surveillance campaign was initiated to confirm the technology's robustness, scalability, and value across a major onshore oil field in the Middle East. This extensive campaign serves as the case study for this paper, demonstrating the transition from a successful pilot to full field implementation.

Scope of the Campaign

Throughout 2024 and early 2025, an intensive surveillance program was executed, encompassing more than 180 individual wells and generating 370 individual survey reports across five distinct field areas. The scope of work included determining gas lift injection rates (GLIR), produced gas rates, downhole gas lift distribution, calculation of flowing bottom hole pressure (Pwf), among other diagnostic outputs.

Comparative Analysis: AGS vs. FGS

The primary objective of this study is to evaluate the accuracy of the Pwf calculated by the non-intrusive AGS method against the direct measurement from conventional Flowing Gradient Survey (FGS). FGS were conducted in several wells with close in time to the Acoustic Gas Surveillance (AGS), allowing for direct comparisons of the Pwf results. The Pwf calculated by the AGS model was plotted against the Pwf profile measured directly by the FGS memory gauges.

Statistical Summary of AGS vs. FGS for Pwf Comparison. Total of eight (8) wells have been analyzed from XZ field presenting the statistical summary. It is critical to acknowledge that the FGS and AGS surveys were not performed simultaneously. The time lapse between these two surveys, ranging from 1 to 9 months, introduces inherent variability due to changes in well conditions, choke sizes, or injection rates.

The statistical summary showed a very strong correlation between these methods. The coefficient of determination (R^2) value of 0.84 is a key finding, indicating that 84% of the variance in the FGS-measured Pwf is predictable from the AGS-calculated Pwf. This demonstrates a strong linear relationship and high degree of confidence in the AGS model, especially considering the operational variables introduced by the time delay.

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Table 1—Pwf comparative results and statistical analysis. A comparison of Flowing Bottomhole Pressure (Pwf) values from FGS (measured) and AGS (calculated) in XZ field including the time lapse between surveys and a statistical summary of the correlation

Well ID	Pwf (FGS)	Pwf (AGS)	Difference (psi)	% Difference	Survey Dates (FGS / AGS)	Time Lapse (Months)
XZ-155	1,324	1,372	-48	+3.6%	Nov-23 / Feb-24	3
XZ-219	1,702	1,577	125	-7.3%	Aug-24 / May-24	9
XZ-067	1,460	1,379	81	-5.5%	Sep-23 / May-24	8
XZ-117	1,320	1,194	126	-9.5%	Mar-25 / Apr-25	1
XZ-178	1,415	1,300	115	-8.1%	Apr-25 / May-25	1
XZ-251	1,996	1,808	188	-9.4%	Mar-25 / May-25	2
XZ-087	1,048	817	231	-22.0%	Sep-24 / May-24	8
XZ-122	1,550	1,200	350	-22.6%	Dec-24 / Apr-25	4
Statistical Summary: • Mean Absolute Error (MAE) = 158 psi • Standard Deviation of Error = 116 psi • Coefficient of Determination (R^2) = 0.84						

The Mean Absolute Error (MAE) across the data set is 158 psi, with a Standard Deviation of Error 116 psi. This quantifies the average magnitude of the difference between the two methods. As expected, the wells with a shorter time lapse between surveys (1-3 months), such as XZ-117, XZ-178, and XZ-251, show a percentage difference that remains within the desired ±10% threshold. The larger deviations seen in wells like XZ-087 and XZ-122 are likely attributed to the significant time lapse (8 and 4 months, respectively) and known operational changes between the surveys, rather than an inaccuracy in the AGS method itself. The following sections provide a qualitative analysis of three representative well cases to further explore these results.

Well XZ-155 Analysis. Figure 4 shows the pressure-depth plot for well XZ-155. The green line represents the Pwf profile calculated by the AGS system, and the blue line represents the profile measured by the FGS. The plot shows excellent agreement along the entire wellbore, with the calculated Pwf at the formation depth being very close to the measured value. The horizontal lines indicate the depths of the side-pocket mandrels (SPMs) where gas lift valves are located.

Numerically, the FGS measured a Pwf of 1,324 psi, while the AGS, conducted three months later, calculated a Pwf of 1,372 psi. This represents a difference of only +3.6%, well within the acceptable tolerance and showcasing the model's high accuracy when well conditions remain stable.

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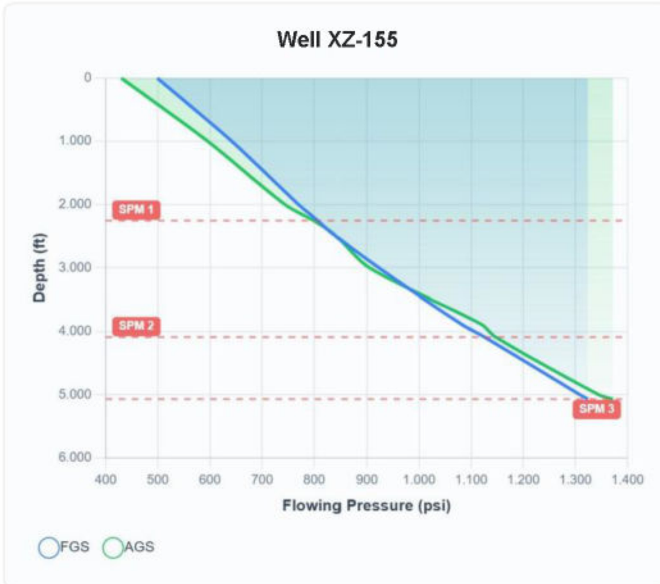

Figure 4—A graph of Flowing Pressure vs. True Vertical Depth for well XZ-155, plotting the AGS calculated profile against the FGS measured profile.

Well XZ-219 Analysis. The comparison for well XZ-219 is shown in Figure 5. In this well case, there is a noticeable deviation between the AGS calculated pressure (green line) and the FGS measured pressure (orange line). The AGS model initially predicted a lighter fluid column. However, post fine tuning the model with additional data (represented by the blue line), the calculated profile aligns closely with the FGS benchmark. This highlights the critical aspect of the AGS methodology: its accuracy is highly dependent on the quality of the data input and reliability of the well model. The model proved its capability to refine and improve throughout the processes.

Figure 5—A graph of Flowing Pressure vs. True Vertical Depth for well XZ-219, plotting the AGS calculated profile against the FGS measured profile.

This well case highlights the impact of significant time lapses, the FGS measured a Pwf of 1,702 psi, while the final tuned AGS survey, conducted nine months later, calculated a Pwf of 1,577 psi, a difference of -7.3%. This deviation is likely attributable to changes in reservoir performance or operational parameters over the extended period.

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Well XZ-067 Analysis. Figure 6 represents another example of a close match between the AGS and FGS surveys for well XZ-067. The consistent alignment across multiple wells builds confidence in the AGS system's ability to reliably estimate Pwf under various well conditions.

Figure 6—A graph for well XZ-067, showing a close match between the AGS and FGS pressure profile

This result, showing a -5.5% difference between the FGS value of 1,460 psi and the AGS value of 1,379 psi measured eight months apart, further strengthens the case for the AGS model's reliability for routine surveillance, even with considerable time gaps between benchmark surveys.

Validation Against Test Separator

In addition to FGS comparison, the flow rate measurement component of the AGS system was validated against a conventional Portable Test Separator (PTS). The evaluation covered multiple wells under varying flow regimes including slugging, natural flow, and stable conditions.

Instead of presenting absolute gas rates, the comparison is expressed in terms of percentage deviation relative to the PTS baseline. Across all tested wells, the AGS measurements showed deviation ranging from -8.4% to +7.3%, with the majority falling within a ±10% envelope. This confirms the reliability of the tracer-based flow metering approach under diverse operating conditions. It is worth noting that the PTS data has additional uncertainty due to orifice meter corrections based on manual measurement of CO_2 content and assumed specific gravity whereas the AGS system measures these parameters directly and continuously.

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Table 2—A table presents the AGS gas rate measurements as percentage deviations from PTS values, with most wells showing deviation within ±10%, confirming the reliability of the tracer-based method

Well	Test	Well Condition (Flow Regime)	% Difference
XZ-067	#1	Slugging	-4.1%
	#2	Slugging	2.6%
XZ-081	#1	Natural Flow	-7.8%
	#2	Natural Flow	+1.1%
XZ-097	#1	Stable	-8.4%
XZ-098	#1	Stable	-0.4%
XZ-099	#1	Slugging	+5.6%
XZ-100	#1	Slugging	-0.8%
XZ-016	#1	Slugging	+7.3%

Added Value Diagnostics from AGS

Beyond the primary objective of Pwf calculation, the AGS technology provides a suite of powerful diagnostic measurements that are not available through conventional FGS. These added values deliver a much deeper understanding of the well's operational health and integrity.

One of the key outputs is the ability to perform periodic, non-intrusive validation of critical field instrumentation. For the case study well, the baseline Gas Lift injection Rate (GLIR) from the inline flowmeter was used as the initial input. The AGS survey then employed two independent methods to verify this rate. The tracer dilution method measured a GLIR that was approximately 18% lower than the baseline value, as illustrated in Figure 7.

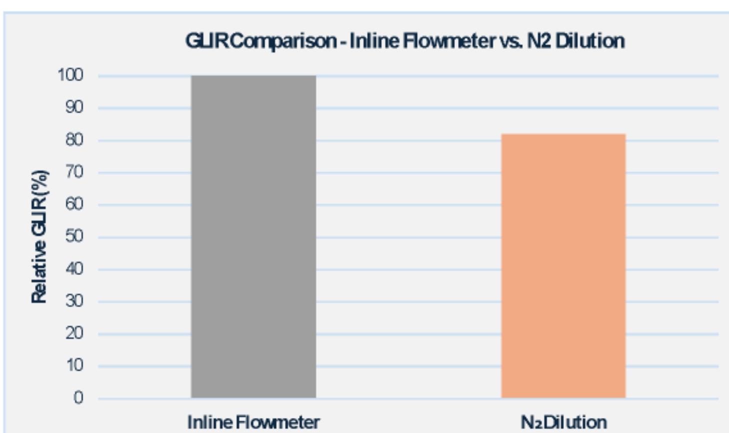

Figure 7—Illustrates the N2 dilution method revealed a GLIR approximately 18% lower than the inline flowmeter reading, highlighting potential inaccuracies in field instrumentation

This finding was corroborated by a second, independent method using a clamp-on ultrasonic meter. As shown in Figure 8, the clamp-on meter measured a GLIR that was approximately 13.5% lower than the inline flowmeter reading. The consistent results from both non-intrusive methods provide a high-confidence data point, highlighting an opportunity to recalibrate the well model for improved accuracy. This underscores the

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importance of periodic validation to account for potential drift in field instrumentation over time, ensuring that optimization decisions are based on the most current and accurate data available.

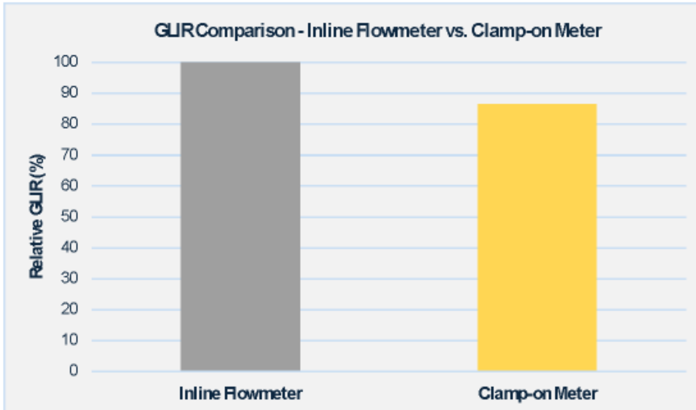

Figure 8—Visualization the under-injection trend, with the clamp-on meter showing a GLIR approximately 13.5% below the inline flowmeter, reinforcing the need for non-intrusive validation

Additionally, the AGS tracer fingerprint analysis confirmed 100% gas return grom the designated injection depth, specifically from SPM #3. To determine the true injection depth and verify well integrity, a pulse of N2 tracer was injected into the gas lift supply. The resulting tracer fingerprint is shown in Figure 9, which plots the measured N2 return at the surface against the simulated return times for each side pocket mandrel (SPM).

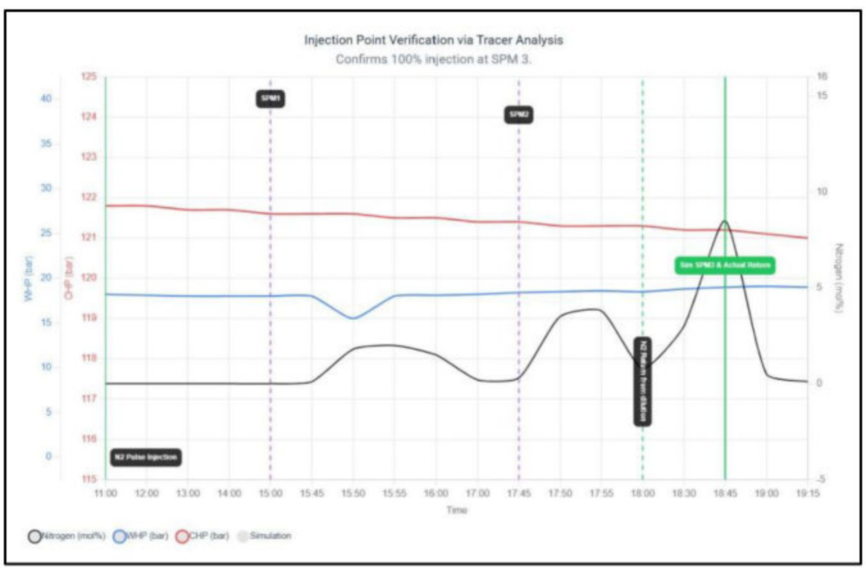

Figure 9—Injection Point Verification via Tracer Analysis. A multi-axis plot showing the measured N2 tracer return peak (black line) at the surface, along with the Casing Head Pressure (red line) and Wellhead Pressure (blue line). The alignment of the primary measured return peak with the simulated return time for SPM #3 (green annotation) provides definitive, non-intrusive proof that 100% of the lift gas is reaching the designated injection depth, confirming the integrity of the upper gas lift mandrels and tubing string.

The analysis provides a clear and unambiguous result: the primary measured tracer peak, representing the bulk of the injected gas, aligns perfectly with the simulation for SPM #3. This provides definitive, non-intrusive proof that vast majority of the lift gas is entering the tubing at the correct, designated depth. While minor, earlier return of low amplitude are observed, the dominant signal confirms the primary injection point and the integrity of the upper completion, a critical insight unattainable with conventional FGS.

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In addition, continuous gas composition analysis was performed, providing valuable data on both produced and lift gas stream (Table 3). The analysis shows a distinct compositional difference between the two streams. The lift gas is significantly "lighter", with a higher concentration of C1 and C2 hydrocarbon (85.3%) compared to the produced gas (77.6%). Conversely, the produced gas contains a higher percentage of heavier C3 to C5 hydrocarbons (20.5% vs. 12.6%) which is expected as it includes vaporized crude components.

Table 3—A table presents gas compositional analysis for the case study well, detailing the mole fraction of components in both the produced gas and the lift gas streams as measured by the AGS system

Produced Gas	Mole Fraction
Nitrogen (N2)	0.0000
Carbon dioxide (CO2)	0.0189
Methane (CH4)	0.6290
Ethane (C2H6)	0.1470
Propane (C3H8)	0.1086
Iso-Butane i-C4H10	0.0246
n-Butane n-C4H10	0.0569
Iso-Pentane i-C5H12	0.0074
n-Pentane n-C5H12	0.0070
Hexane C6	0.0015
Hydrogen sulfide (H2S)	312 ppm
Total	1.0000

Lift Gas	Mole Fraction
Nitrogen (N2)	0.0000
Carbon dioxide (CO2)	0.0203
Methane (CH4)	0.7085
Ethane (C2H6)	0.1441
Propane (C3H8)	0.0850
Iso-Butane i-C4H10	0.0135
n-Butane n-C4H10	0.0215
Iso-Pentane i-C5H12	0.0030
n-Pentane n-C5H12	0.0027
Hexane C6	0.0010
Hydrogen sulfide (H2S)	407 ppm
Total	1.0000

Discussion of Results

The results from this extensive field campaign led to several important observations:

1. **Viability of AGS for Pwf Estimation**: The consistent, close agreement between the AGS-calculated Pwf and the FGS-measured Pwf across a large and diverse set of wells validates the AGS technology as a reliable tool for routine surveillance. The variance is typically within the acceptable range for operation optimization decisions.
2. **Importance of Model Fidelity**: The of well XZ-219 underscores that the AGS is not a *"black box"*. The accuracy of its output is directly tied to the quality of its inputs (surface rates, pressure, fluid compositions) and the robustness of the underlying multiphase flow model. Accurate PVT characterization is particularly essential. This reinforces the need for periodic calibration and validation against benchmark data, such as an FGS.
3. **Undisturbed Well Condition**: A key qualitative advantage of the AGS is that it surveys the wells in its natural, undisturbed flowing state. The FGS, by its intrusive nature, introduces a foreign object (the tool string) into the tubing, which can alter the dynamic flow, in particularly in slugging or unstable wells. The AGS provides a snapshot of how the well truly operates day-to-day which is invaluable for diagnosing intermittent issues and optimizing performance based on actual conditions, not survey-induced conditions.
4. **Operational Efficiency and Safety**: The operational benefits realized during the campaign were significant. The AGS surveys were conducted with minimal personnel and equipment, without any

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well-shut-ins, and with zero well-intervention risk. This allowed for a much higher frequency of surveillance with FGS alone, enabling the engineers to react more promptly to changes in well performance.

5. **Added Values**: The study highlights the significance of added values as outputs by the AGS diagnostic toolkit. The ability to accurately measure the true GLIR as demonstrated in the case study (Figure 7 and Figure 8) is a critical finding. Inaccurate field meters can lead to the flawed well models and non-optimal gas allocation. The AGS provides a method to promptly identify and quantify these discrepancies without intervening the well. Similarly, the Injection point verification via tracer analysis (Figure 9) offers definitive confirmation of well integrity and injection depth, a crucial piece of information that FGS cannot provide. These added values transition on the AGS from being merely a Pwf calculator to a comprehensive well health and performance monitoring system.

An Integrated Surveillance Strategy

The findings of this study do not advocate for the complete replacement of FGS with AGS. Rather, they strongly support an integrated and synergetic surveillance strategy that leverages the strengths of both technologies. The traditional view of well surveillance as a periodic, intervention-heavy event is evolving towards a model of continuous and data driven performance management.

Roles of Each Technology

- **Flowing Gradient Survey (FGS)**
  - **Benchmark**: Remain the definitive *"ground truth"* for downhole pressure.
  - **Model Calibration**: Essential for periodically calibrating and validating the mathematical models used by the AGS and other simulation software. This method should be done for the new wells, after workover, or if the AGS indicates a significant deviation in well performance that cannot be accounted for or unexplained.
  - **Complex Diagnostic**: The preferred tool for in-depth investigation of complex problems like suspected tubing leaks or identifying the unknown restrictions, where a detailed, direct measurement profile is required.
- **Acoustic Gas Surveillance (AGS)**
  - **Routine Monitoring**: The ideal tool for frequent e.g., quarterly or semi-annual well-health checks and performance tracking.
  - **Optimization**: Provides the necessary data (Pwf, GLIR) to perform routine gas lift optimization, ensuring each well is operating at its optimal injection rate.
  - **Early Anomaly Detection**: Continuous or frequent monitoring allows for early detection of developing issues such as liquid loading or valve degradation before they become severe.
  - **Pre- and Post-Intervention Analysis**: It can be used to promptly assess the well performance before and after a workover/well intervention to quantify the impact.
  - **GLIR, Integrity Confirmation, Gas Compositional**: These are the added values which regularly audit the accuracy of inline field meter to ensure the correct gas rate allocation, confirm the injection is occurring at the correct depth, verifying any tubing/valve leaks, in addition to providing the real-time gas compositional analysis without manual sampling.

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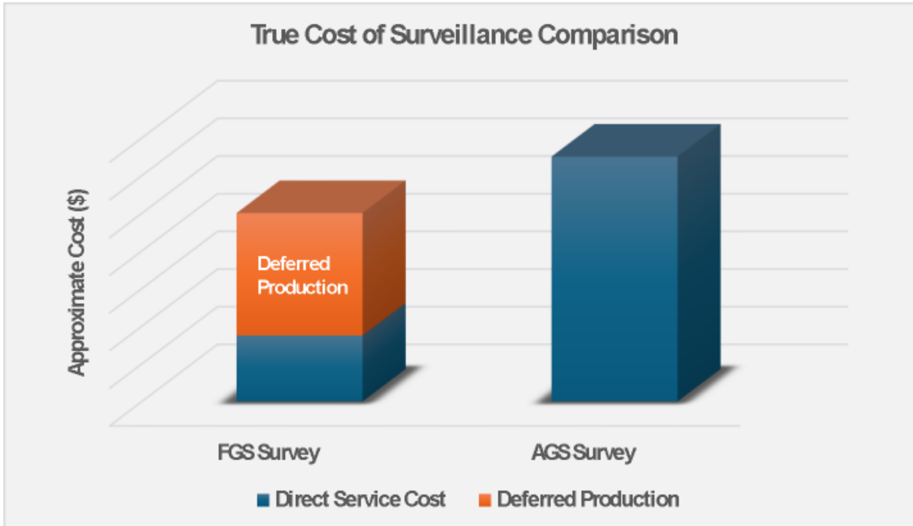

Figure 10—Illustrate the "true cost" comparison, highlighting that the FGS's hidden costs make the AGS approach is highly competitive, especially when frequent data acquisition is required for proactive optimization.

Comparative Cost Analysis

A complete economic evaluation must consider not only the direct service fees, but also the significant, often overlooked, indirect costs associated with intrusive operations. The primary economic differentiator between FGS and AGS is the cost of deferred production.

An FGS survey requires the well to be shut-in for several hours (rig-up, tool deployment, and rig-down). Based on conservative assumption of a well producing an average of 500 BOPD and a market price of $75/bbl, a typical 4-hrs shut-in period results in approximately $6,250 lost revenue. This deferred production cost is a direct operational expenditure that must be added to the direct service cost for every single FGS survey performed, revealing a much higher *"true cost"*.

In contrast, the AGS method is entirely non-intrusive, meaning the cost of deferred production is zero. This fundamental advantage shifts the economic discussion from a simple cost per survey comparison to a broader evaluation of operational efficiency and value creation. The AGS service model, typically structured as a continuous monitoring fee, enables a strategic shift from infrequent, costly data points to a steady stream of performance data. The high-frequency data allows for proactive optimization and early problem detection, generating value that can far exceed the service cost itself.

Conclusion and Future Outlook: Integration with Digital Twins

This paper presented a comprehensive evaluation of a non-intrusive Acoustic Gas Surveillance (AGS) system against the conventional slickline based Flowing Gradient Survey (FGS) for gas lift well surveillance. Based on a large-scale field campaign and a detailed well-case study, the following conclusion are drawn:

1. The non-intrusive AGS technology has demonstrated its reliability and robustness to provide the estimated Pwf and production rates, with results showing strong correlation and acceptable variance to the benchmark-direct measurements of FGS and test separator. The AGS method shows a strong statistical correlation (R^2=0.84) with benchmark FGS measurement, validating its use.
2. The accuracy of the AGS system is fundamentally dependent on the quality of the surface measurement data and the fidelity of the calibrated, dynamic well model. Periodic validation against a standard FGS is crucial for maintaining model accuracy.

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3. AGS system offers significant operational advantages over FGS, including enhanced safety by eliminating well intervention, reduced operational costs, and the elimination of deferred production, allowing for a much higher frequency of surveillance.
4. A key benefit of the non-intrusive approach is its ability to survey the well under its true, undisturbed operating conditions, providing a more representative assessment of well performance than is possible with intrusive methods which can alter the flow regime.
5. The optimal approach for modern gas lift surveillance is not a choice between FGS and AGS, but rather their strategic integration. An integrated strategy that uses FGS for benchmarking and complex diagnostics, AGS for frequent, routine monitoring, offers the most comprehensive, cost-effective, and safest framework for maximizing production and recovery from gas-lifted fields.
6. The *"added value"* diagnostic, such as accurate GLIR measurement and injection point verification, provide critical operational insight unattainable with FGS alone, transforming the AGS from a simple Pwf tool into a comprehensive well health system.
7. The economic benefits of AGS are significant, primarily through the elimination of deferred production costs associated with intrusive FGS operations, enabling more frequent surveillance for a greater return on investment.

Looking forward, the high-frequency data stream generated by the AGS technology is a perfect enabler for the next generation of reservoir management, Digital Twins. A digital twin is a living, virtual model of a physical asset that is continuously updated with real-time data. The frequent Pwf calculations, GLIR measurements, and integrity checks from AGS can serve as the live data feed to automatically and continuously calibrate the Digital Twin's well models. This would allow for:

- **Real-time Optimization**: The digital twin could constantly run *"what-if"* scenarios to recommend optimal gas injection rates based on the latest well performance data.
- **Predictive Maintenance**: By analyzing trends in the AGS data, the Digital Twin could predict potential issues like liquid loading or valve failure before it occurs.
- **Automated Well Health Alerts**: The system could automatically flag wells that are deviating from their expected performance envelope, allowing engineers to focus their attention where it is needed most.

The integration of AGS within a Digital Twin framework marks a significant advancement in intelligent well surveillance, transitioning from intermittent data collection to continuous, predictive, and automated optimization. To realize this future state, operators are encouraged to broadly adopt integrated surveillance strategies to enhance gas lift optimization, invest in the ongoing refinement of dynamic wellbore models, potentially leveraging machine learning algorithms to improve tuning processes and predictive accuracy based on historical data, and expand the application of AGS technology to address diagnostic challenges such as real-time slug detection and control, as well as other artificial lift systems. Additionally, developing standardized operational workflows that clearly define the triggers and frequency for both AGS and FGS surveys within the integrated surveillance program is recommended.

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