Evaluation of a Fractured Tight Reservoir in Real-Time: The Importance of Detecting Open Fractures while Drilling with Accurate Mud Flow Measurement*

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Abstract

An advanced system for mud flow measurement while drilling enables detection of fractures and intervals of high permeability within a tight, fractured reservoir via the identification and interpretation of mud micro-losses. The system is based on an electromagnetic flow meter installed on the flow line. This flow meter has a very high accuracy compared to the standard flow measurement system typically used in the field. Standard mud flow detection while drilling only enables a qualitative indication of the flow and it is not sensitive enough to identify subtle flow changes linked to the initial stages of an influx or to the minor fluid loss occurring when a formation fracture is encountered. However, the more direct instantaneous indication of the presence of an open fracture in a well comes from the mud flow variations. The authors have utilized such data in conjunction with offset data from previous wells and existing literature, which indicate the presence of two different sets of fractures with different apertures and densities. An interpretation model was then generated and applied to the well being drilled.

The fracture detection capability was enhanced by the analysis of drilling and hydraulic parameters variations recorded also in real-time; their changes were related to changes of the mechanical properties or the rock. Another decisive parameter monitored was the mud gas, since gas variations were often associated with the presence of open fractures in which hydrocarbons were circulating.

Two types of fractures were clearly identified using this technique. The system and procedure have been recognized as a valid solution for fractured reservoir characterization; data have been used in a composite log along with other datasets from e-logs, collected after the well was drilled. Furthermore, the system enabled detection of mechanical fractures induced by drilling, which masked the natural open fractures pattern in the e-logs of the offset wells previously drilled in the same basin.

Introduction

The Margarita Field is a gas condensate producer discovered in 1998 with well X1. The Margarita structure is located at the southern Bolivian Sub-Andean, on the structural trend of the Suaruro Range, 35 km to the west of the town of Villamontes. The Margarita Field lies in the Caipipendi Block. It is located in the north part of an elongated anticline oriented NNE-SSW, and has 30 km long and 9 km wide (Figure 1).

The Margarita closure presents several culminations separated by reverse faults. Log analysis, cores, sidewall core samples and well testing data indicate that the Huamampampa Formation is a low porosity quartzitic sandstone, with multi-scale natural fractures well connected, that allow fluid production. The high variation of fractures permeability in Margarita Field is the main driver in the high variation of production in the field reservoirs.

The fractures analysis from offset wells, shows multiple sets of fractures with different scales (Figure 2), the most frequent are discontinuous micro-fractures; their occurrence is strongly controlled by the sedimentary texture, tight sandstones show the highest fracture density compared to the laminated interval. In addition to the micro-fractures set, the reservoir is characterized by an additional set of largest fractures, more continuous with larger aperture; these main fractures are less frequent than the micro-fractures.

Hence, an accurate prediction of reservoir quality in low-porosity rocks requires a good understanding of the anisotropy and heterogeneity introduced by faults and fractures in the subsurface. In this regard, the critical questions are, how faults and fractures are distributed in folded sedimentary rocks, and what are the factors controlling their distribution. The significant answers to these questions continue to represent one of the main tasks in modeling and characterization of fractured reservoirs.

Conventional solutions of fractures detection with geophysical methods do not have the required resolution; with reference to the Margarita Field, due to the poor quality of the 3D seismic survey, and complexity of subsurface geometries, structural interpretation and reservoir characterization was largely model-driven.

On the other side, petrophysics present strong limitations in core analysis and log interpretation due to the very low porosity and naturally fractured reservoir environment. The reservoir rocks being around 3% porosity and formation water salinity of 20,000 ppm TDS (total dissolved solids), have normally prevented resistivity logs to have good contrast between gas-oil and water bearing formations. In this sense, it seems that Margarita is not an exception for such log limitations provided the resistivity contrast between water flowing and gas flowing intervals is almost negligible in many cases. Resistivities of tested pay zones in the Margarita wells are within 80 to 300 Ωm range. Over tested water zones, the range drops to 50-80 Ωm. E-log-derived water saturation has been constrained to a threshold (mean) value of 30%, based on irreducible water saturation values determined from mercury injection capillary pressure tests (MICP). In the pay zones, mean values of e-log Sw are rarely below 40%. The Indonesia model has been used to calculate e-log water saturation based on a variable cementation exponent derived from the Borai model. Shale volume has been derived from GR logs, applying non-linear models.

Neither e-logs nor core analysis are able to provide the actual formation permeability values. In addition, core analysis can clearly identify the fractures but is unable to discriminate between minor fractures and interconnected fractures with high permeability.

It is widely accepted that core plug analysis can provide an approach to the matrix permeability and that the fracture-matrix composite system permeability can be obtained by means of well testing techniques. However, uncertainties in net-to-gross determination can cause some erroneous estimations of permeability values derived from well testing; the matrix permeability observed in Margarita cores are between .001 and .1 mD; nevertheless, core permeability (Kair) has reached 8.13 mD in some intervals of the Huamampampa Formation in well x-3.

With reference to the offset wells drilled in the Margarita Field, the massive presence of induced fractures generated by the mechanical action of the bit over the rock, intensely masks the natural fracture pattern, leading to reservoir characterization problems. Furthermore, conventional testing techniques such as MDT are more problematic in fractured reservoirs.

Application

The proposed method enables us to identify natural open fractures through the detection of the micro-losses while drilling; whenever the bit intercepts an open fracture the mud invasion leads to a mud micro-loss. Such losses are identified at the surface, in real-time, throughout accurate and continuous monitoring of the mud flow out.

The standard techniques to detect mud losses are:

1) Mud level monitoring in active mud pits with acoustic, floating sensors.
2) Measuring the flow out using a Flow Paddle sensor installed on the flow line.

Both techniques are not suitable for fracture detection purpose because they lack the required accuracy to identify the associated micro-losses; in the best scenario a 0.5 bbls mud loss can be identified by measuring the mud level in the total active mud system, when usually the micro-losses associated with the fracture is on the order of 10-30 lt/min. With reference to the flow paddle, it provides only a qualitative indication of mud flow variation without quantitative measurement of the flow out.

A better accuracy and a quicker response to measure the flow out and to detect micro-losses have been achieved using a high resolution electromagnetic flow meter. The measuring principle is based on Faraday’s law of induction: conductive mud represents the electrical conductor moving through a magnetic field; the conductor induces a voltage that is perpendicular to the magnetic field and to the direction of the flow, the voltage is proportional to the flow velocity, thus to the flow rate. The performance of the meter is not affected by mud conditioning and it is capable of measuring the flow rate with an accuracy up to 10 lt/min.

Electromagnetic Flow Meter Installation

The advanced monitoring of the mud flow out using an electromagnetic flow meter tool has been implemented while drilling the MGR-6 well; the water-based drilling mud enabled the use of the electromagnetic principle to accurately measure the flow.

The sizing of the sensor and the installation design is of paramount importance to optimize the accuracy of the meter readings and to achieve the goal to identify the micro-losses. A feasibility study has been carried out to define meter size and the proper installation, according with the flow rate expected and mud properties (density, viscosity). The meter has been installed in an 8” bypass parallel to the flow line (Figure 3); a system of butterfly valves enables diversion of the flow from the flow line to the bypass at the occurrence.

Interpretation Model and Analysis Procedures (Time Based)

The proposed methodology consists of an integrated approach using delta flow time data (difference between Flow OUT and Flow IN) along with drilling data and gas data from mud logging. The aim is to identify the natural open fractures, their typology, and to gather information about the hydraulic aperture using the micro-losses dynamic trend analysis versus time.

The real-time analysis has been carried out at the rig site by a specialist whenever a real-time data transmission is available. The same analysis can be performed even at the office, however the rig site is preferable for a better quality control. The Delta Flow trend versus time is characteristic of the type of losses and consequently of the downhole fractures (Figure 4).

1) In a Natural Open Fracture the mud invades the fracture and a sudden decrease of Delta Flow is recorded in the surface by the Electromagnetic Flow Out Sensor; the solid particles of the mud gradually plug the fracture and Delta Flow returns to the base line.

2) On the contrary, a mechanical fracture induced by the action of the bit shows a Delta Flow decreasing when the fracture is generated, with an immediate recovery when the fluid invaded is given back.

3) The response of the Delta Flow in the case of Micro-Fractures pattern or Matrix Permeability shows a gradual decrease due to the invasion of the mud into the pores or micro-fractures, and at the end of the permeable zone the Delta Flow gradually increases.

4) In cavernous zones the mud losses occur suddenly at a high rate, with no return at the surface.

The data acquired with the flow analysis are integrated with mud logging time data such as WOB, Torque, Stand Pipe Pressure and Pump Strokes; the integration analysis can confirm that the flow rate variations are related to downhole formation losses and not to other causes (such as plugging of drill string, stand pipe pressure variations).

To enhance the formation evaluation process the gas readings have been utilized as well, to identify any gas increase in correspondence of the open fractures and more permeable zones identified. For this purpose a dedicated software routine has been developed; the algorithm enable us to synchronize the gas readings from the bit to surface allowing to promptly identify the gas peaks associated with the fracture in a time plot.

Field Application – MGR–6

The reservoir evaluation technique has been applied for the first time in Bolivia in the Margarita Field while drilling MGR-6. The system has proven to deliver crucial downhole data utilizing surface parameters; the results have been analyzed with downhole data acquired after the well was drilled, and it proved to be the only source of real-time information of open fractures while drilling.

The two fractures sets, the biggest with high apertures (low frequency) and the micro-fractures (high frequency) were clear, according with the different responses of the flow data. The time plot (Figure 5) shows the detection of fracture at 3767.3 m.; the behavior of the delta flow (in green) shows a sharp decrease followed by gradual recovery back to the baseline, indicating the presence of a main open natural fracture. The time required by the solid particles to seal the fracture is around 5 minutes, providing the information showing the high aperture and permeability of the fracture.

In addition, the gas readings, synchronized at the bit, indicate the increase of gas associated with the fracture. The background noise of the delta flow is around 6 gpm, confirming the high accuracy of the meter and its capability to detect minor micro-losses events.

The example below (Figure 6) illustrates the detection of a micro-fractured interval starting from 3917.9 m.; the response of Delta Flow shows a smooth decrease due to the mud invasion into the micro-fractures. The mud loss stops at 3919.0 m., indicating the end of the permeable zone. The gas readings show the increase of gas associated with the micro-fractures zone.

The instantaneous decrease and consequent increase of Delta Flow indicates a mechanical fracture induced by the bit at 3813.9 m. (Figure 7). The fracture was detected by the FMI log after the well was drilled, and thanks to this technique it was not considered as a permeable fracture.

Conclusion

Conventional geophysical and petrophysical methods have strong limitations in the evaluation of naturally fractured reservoirs. The accurate monitoring while drilling of micro-losses associated with fractures provides important data to characterize fractured reservoirs, to identify pay zones, and to support testing decisions.

The most important advantages of this technique are listed below:

- It has been recognized as the only method to identify open fractures in real-time while drilling.

- The data acquisition does not require any rig downtime (such as e-logs). It is a cost-effective solution.

- The system enables us to detect only the conductive fractures which are the real driver of the permeability; closed fractures by recrystallization or pressure-solutions processes are not identified.

- Capability to identify mechanically induced fractures and to identify different sets of fractures in terms of aperture and permeability.
- Being a surface solution, it does not increase the risk of operations.
- The system accuracy is independent of borehole conditions or mud conditions.
- Whenever e-logs cannot be run or their results are uncertain, it provides a valid dataset to characterize the reservoir.
- The use of high-resolution flow meters enables us to identify kicks at a very early stage, improving the safety of the operations.
- The productivity impairment of natural fractures due to the mud invasion can be prevented or reduced optimizing the mud weight.
- The completion strategy, formation testing, coring and selective acid jobs can be optimized.

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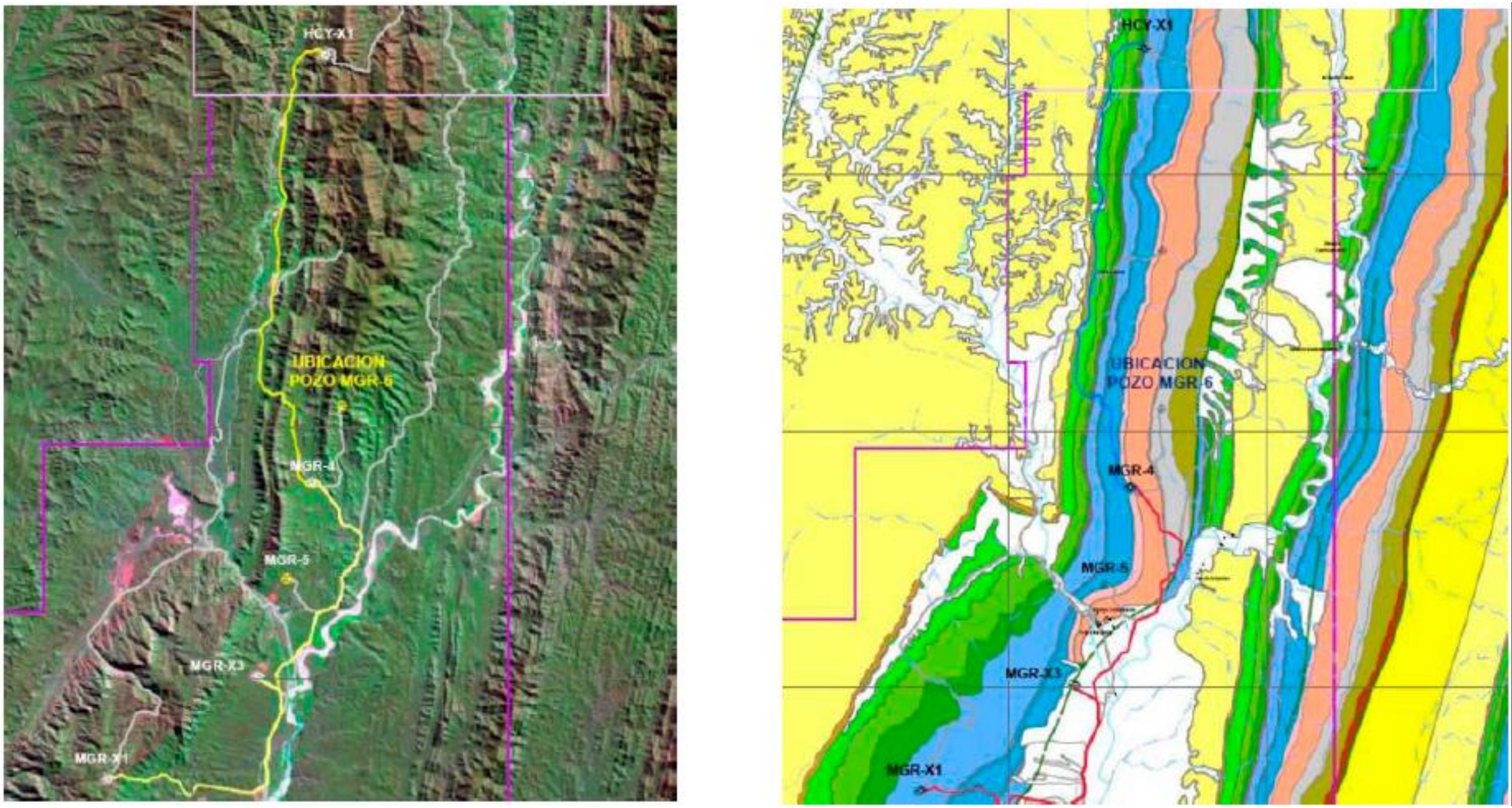

Figure 1. Satellite image and geological map of the location of MGR-6 well.

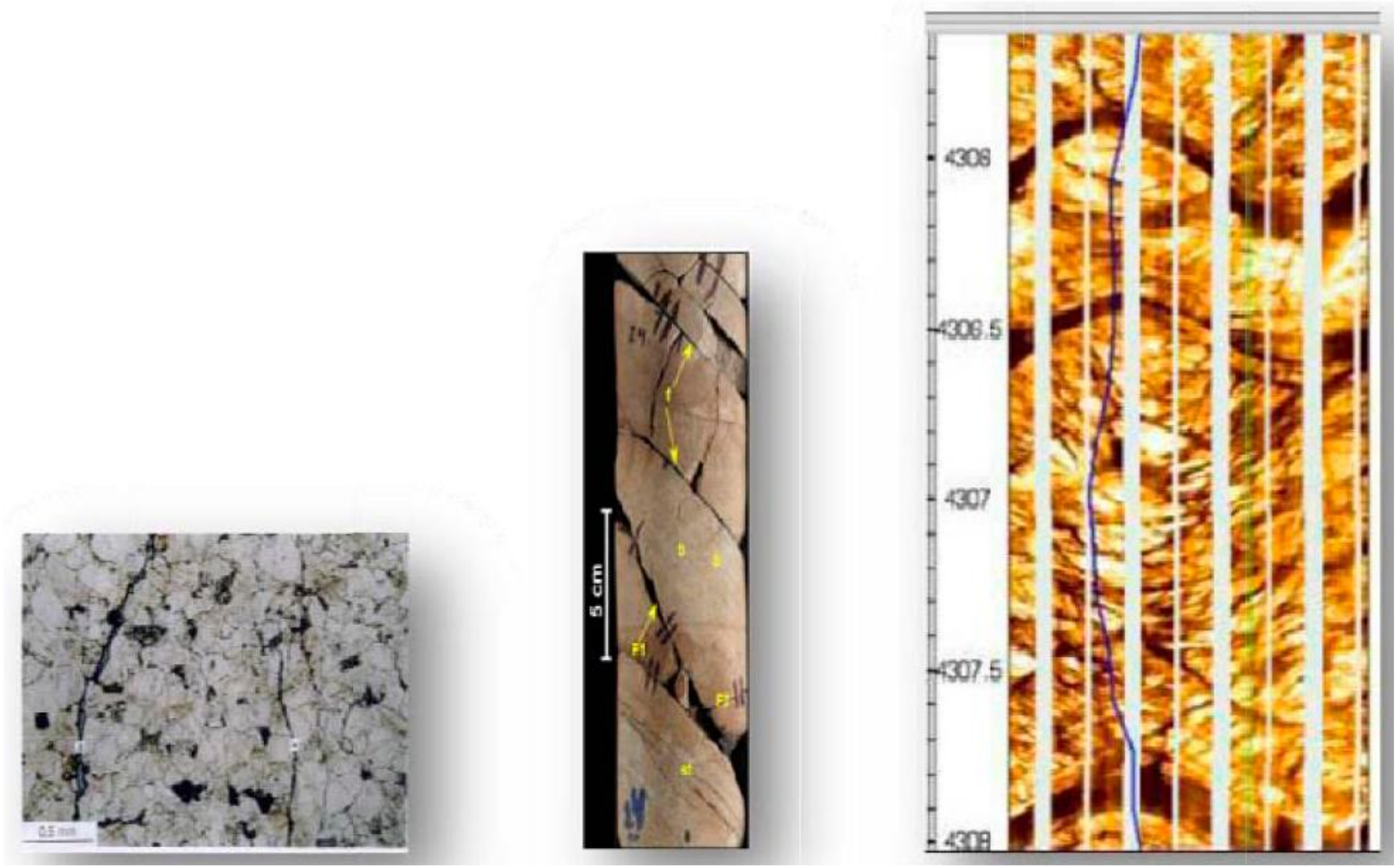

Figure 2. Multi-scale fractures.

Figure 3. Electromagnetic flow meter.

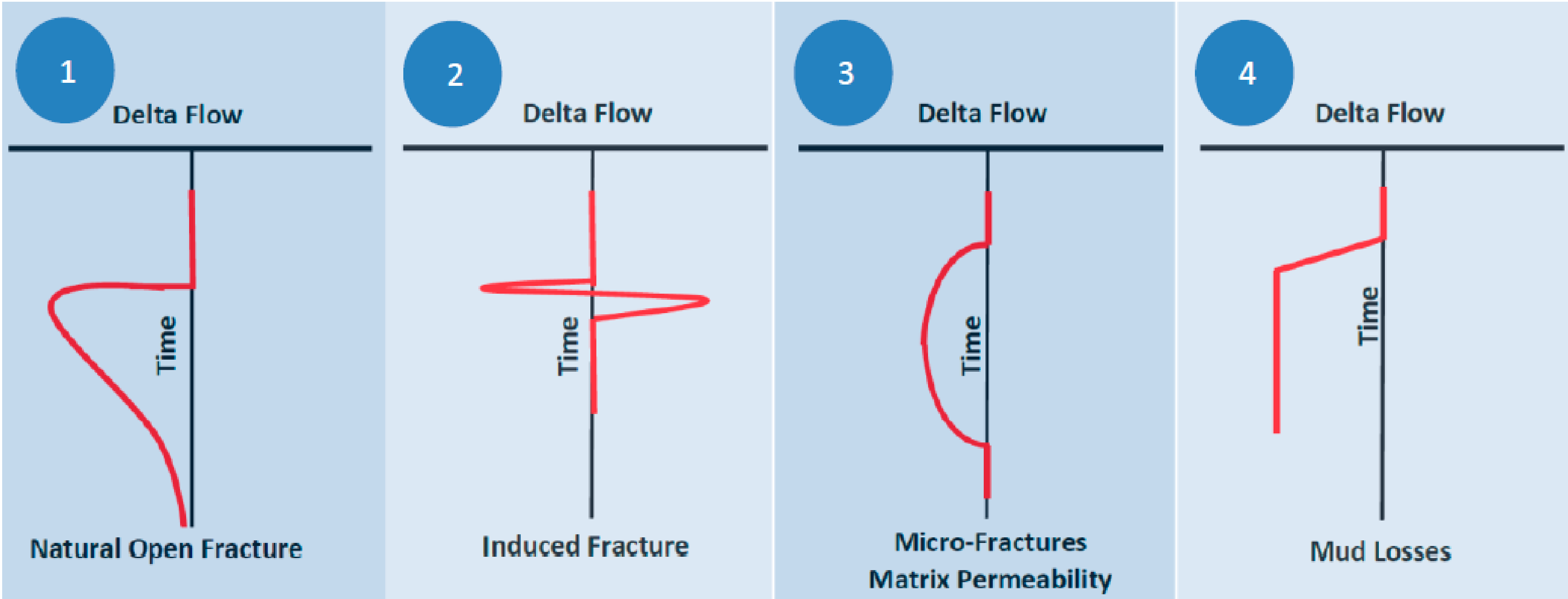

Figure 4. Delta flow trend and fractures/permeability downhole events.

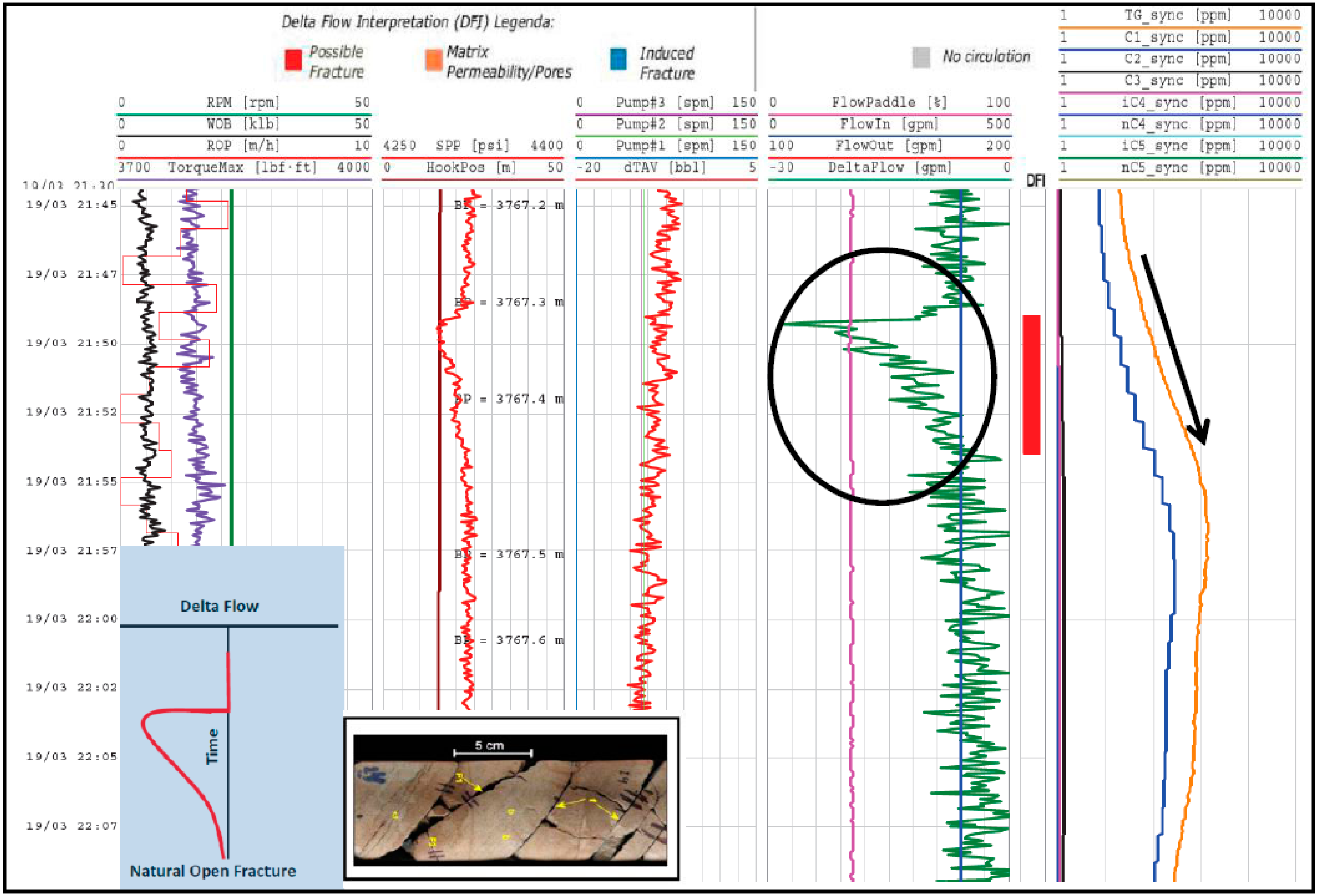

Figure 5. Detection of main fracture with high permeability using advanced flow monitoring data.

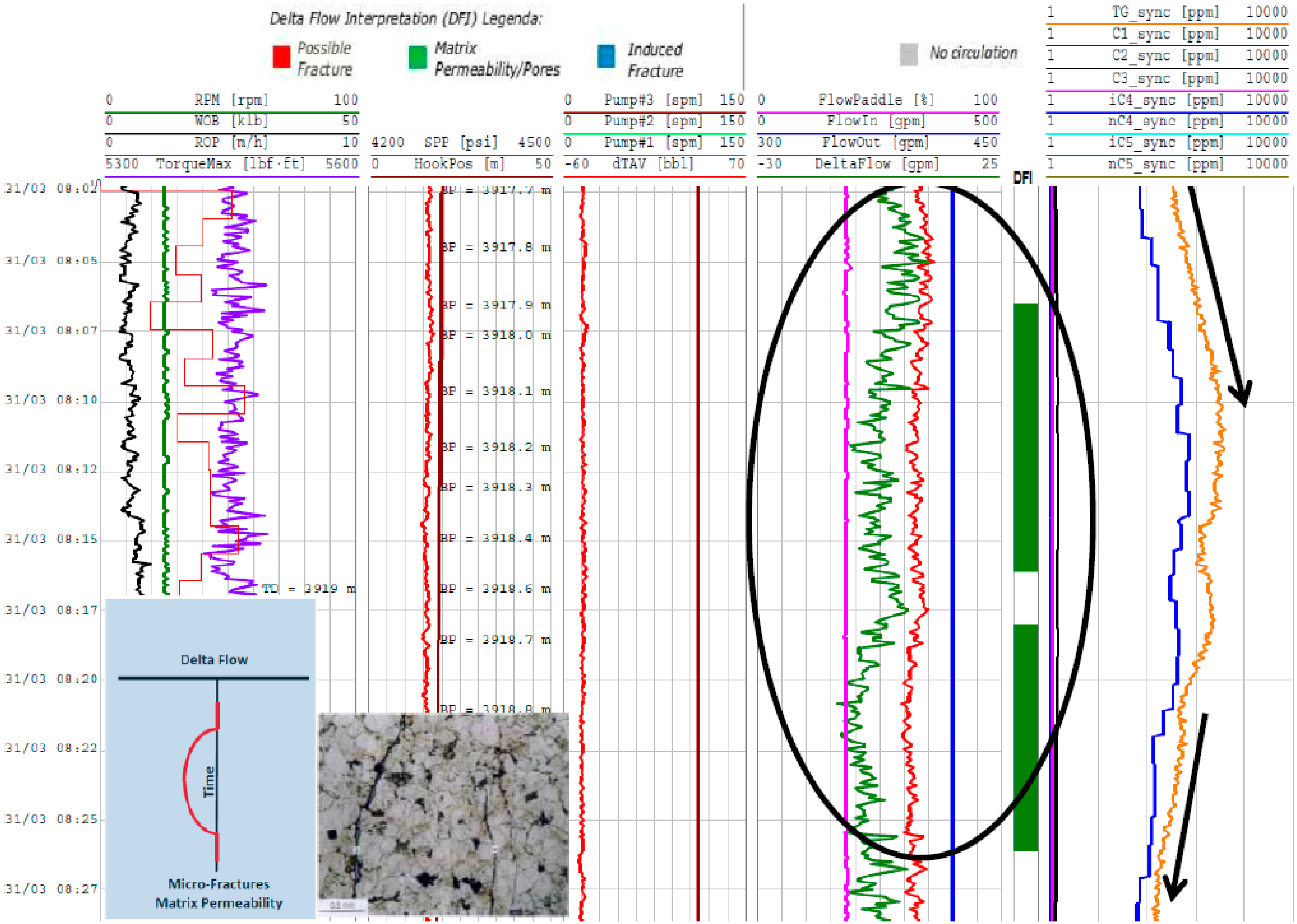

Figure 6. Detection of micro-fractured zone using advanced flow monitoring data.

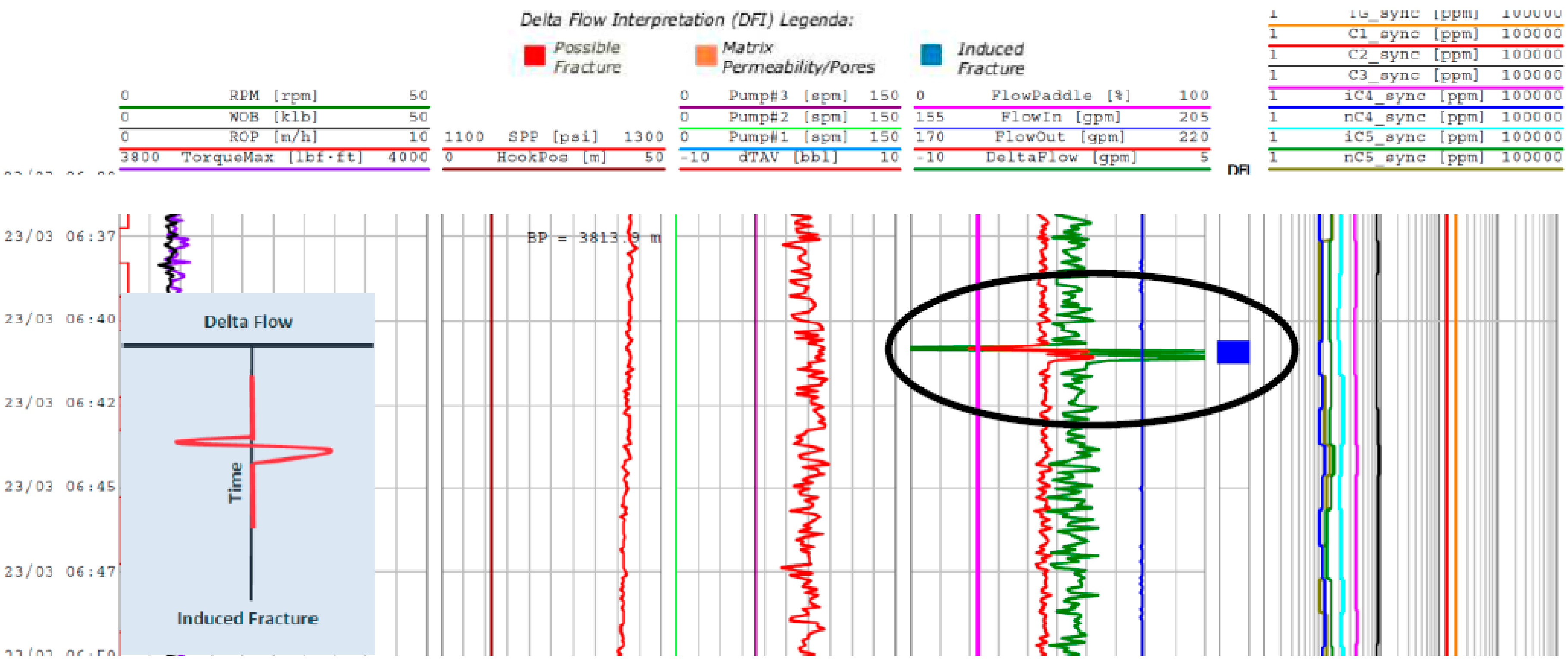

Figure 7. Detection of mechanically-induced fractures using advanced flow monitoring data.