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**INTEGRATING NEW DATA ACQUISITION
TO DEVELOP TIGHT GAS RESERVOIR
OF A MATURE FIELD
THROUGH MULTILAYER FRACTURE STIMULATIONS**

1. INTRODUCTION

Laslau Mare is a brown gas field situated in the central part of the Transylvania Basin, in Romania (Fig. 1). It is formed by multi-layered clastic reservoirs of Upper Miocene age, grouped in six production packages. They are natural depletion gas reservoirs, with a current recovery factor of approximately 74.5% per total field. The depth of the gas saturated reservoirs varies between 1800 m and 3200 m TVD.

The reservoirs are formed of sandstones with carbonate cement, interbedded with shale layers. The formations become more compacted and tighter with depth increase, resulting in very low permeability values, specific to unconventional reservoirs: 0.3–0.6 mD on average. Due to the reduced productivity, the deeper reservoirs have a lower recovery factor (65%) compared to the shallower ones (~80%). As a result, the deeper reservoir presents a higher interest for reserves development, with more attractive remaining recoverable gas volumes.

From the six production packages, only four are producing at the moment: B, D-E-F, G-H and I-J (Fig. 2). The subject of the current paper is package I-J, situated at 2700–3000 m depth.

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Fig. 1. Laslau Mare field location

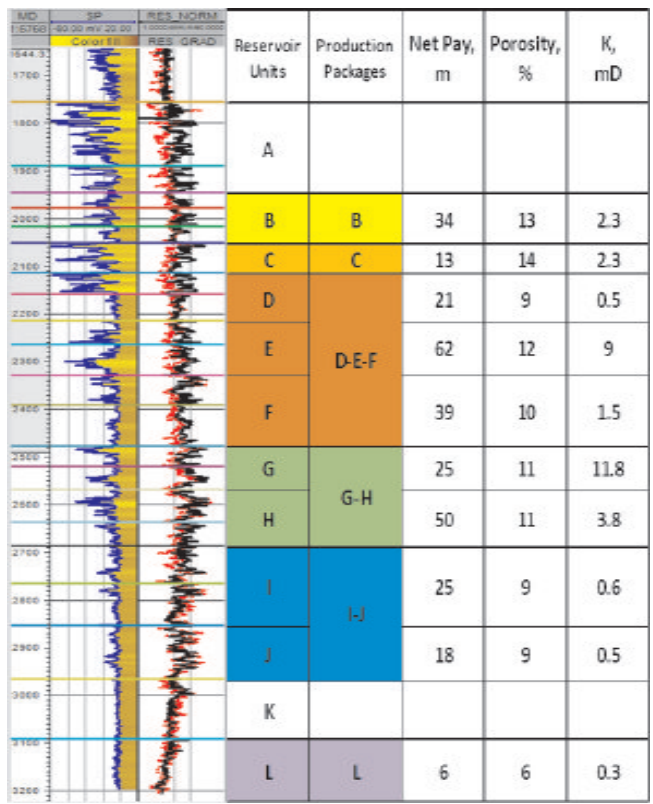


Fig. 2. Type log from Laslau Mare filed, showing reservoir units and production packages

2. RESERVOIR DATA ACQUISITION

The majority of the wells were drilled between 1960 and 1990 and have only basic logs: SP and resistivity curves. Some new log data was acquired in the past 10 years from WO operations (cased hole logs) and 2 deepenings (open hole logs) and it was used to update and improve the reservoir models. Nevertheless, the reservoir data was still limited for planning a more intensive development of this tight reservoir.

One new infill well was drilled in 2014, in the central area of the field (Fig. 3). This offered an excellent opportunity to record special logs and extract side-wall cores, in order to get new good quality data for a better characterization of the reservoir properties.

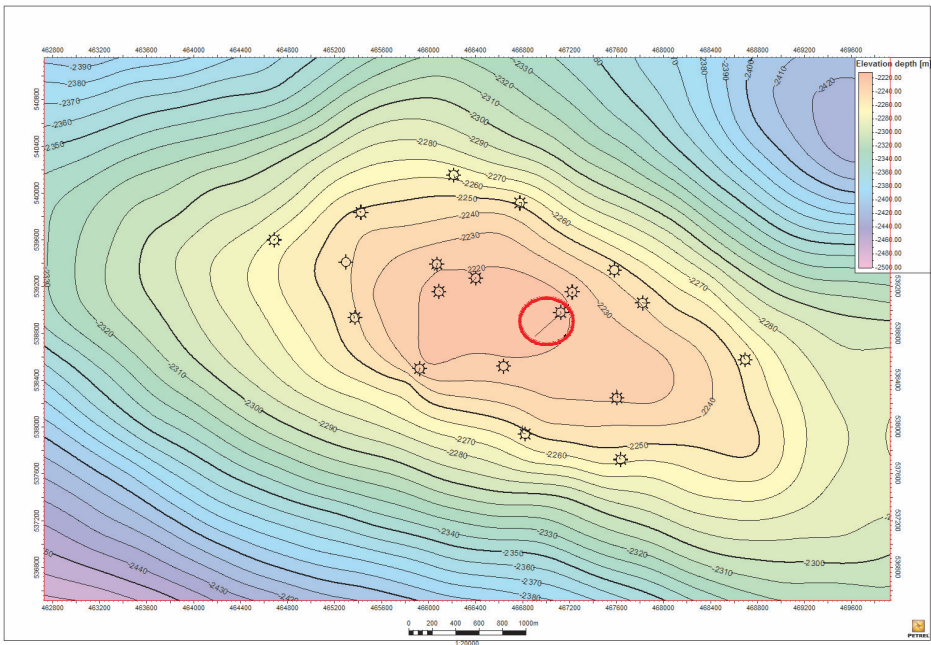


Fig. 3. Structural map for top of reservoir I-J

Besides the standard open hole logs (GR, Caliper, DLL, Density, Sonic and Neutron logs), the special logs recorded were: Formation Microimager (FMI), Dipole Sonic and PressureXpress Tool (XPT). The main purpose for the special logs acquisition was to obtain data required for geomechanical properties, for building the Mechanical Earth Model to be used later for frac operation design. For the same purpose, a number of 14 side-wall cores were planned to be extracted.

The Formation Microimager was used for the interpretation of sedimentary and tectonic features visible inside the borehole: bedding, cross beddings, resistive fractures, discontinuous conductive fractures, erosional surfaces, faults and breakouts (Fig. 4). The summary of the interpretation results is presented in Table 1.

Table 1
FMI interpretation results

Feature	Count	Mean Dip Angle [°]	Strike Direction
Discontinuous conductive fractures	51	21.2	Scattered strike distribution
Resistive fractures	5	47.4	NNE-SSE and ENE-WSW
Faults	14	36.2	Scattered strike distribution
Breakout	6	90	WSW-ENE and WNW-ESE

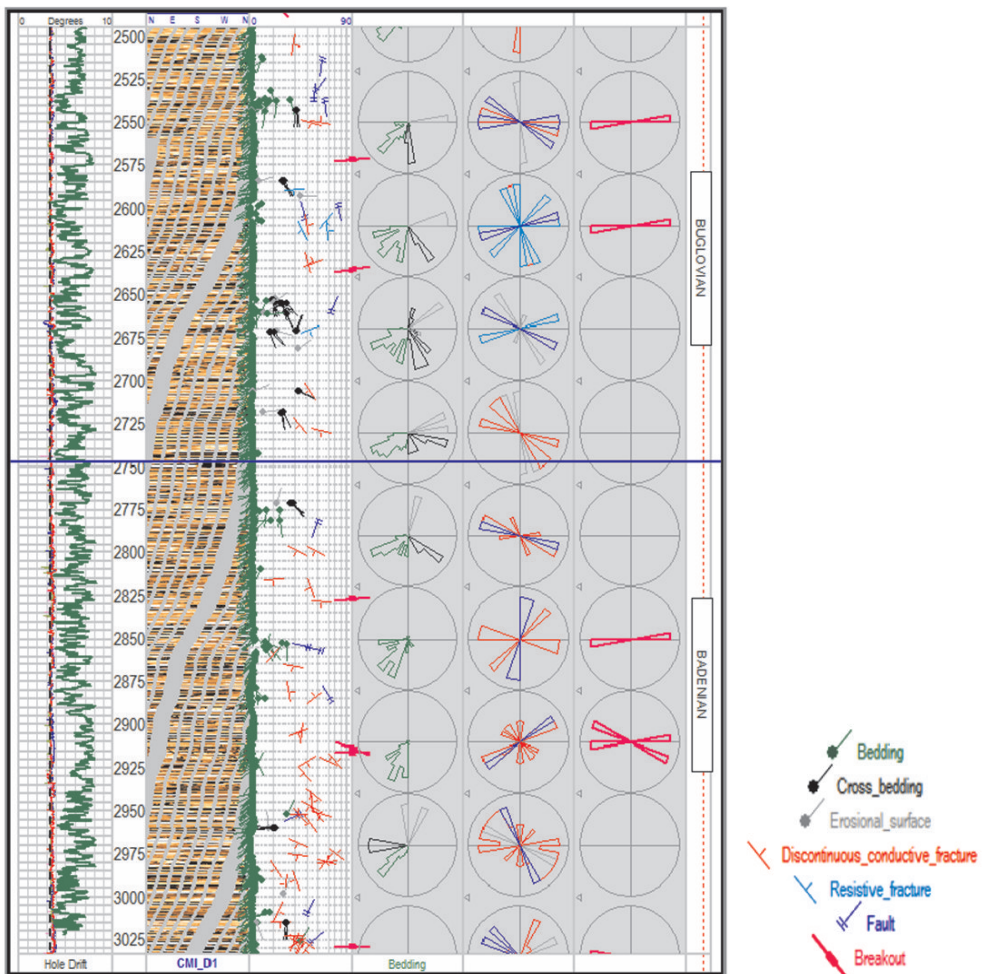


Fig. 4. Formation Microimager log with interpretation

No drilling induced fractures have been identified, but few short intervals with borehole breakouts have been recognized throughout image data from the well. The borehole conditions are very good. Based on calipers reading no stress direction could be obtained.

The purpose of recording the Dipole Sonic logs was to determine the presence, orientation and magnitude of anisotropy and to estimate elastic rock properties for wellbore stability and hydraulic fracture design. The parameters computed from the log measurements are: Compressional and Shear slowness, Velocity Ratios, Poisson Ratio, Bulk Modulus, Shear Modulus and Young Modulus. These parameters are used for building the mechanical earth model (MEM).

A number of 13 sidewall core samples were recovered from the 14 that were planned. One core could not be recovered due to mechanical issues. The device used for coring was a rotary Mechanical Sidewall Coring Tool (MSCT) which cuts plugs with a typical size of: 2 in. (50.8 mm) long \times 0.92 in. (23.4 mm) diameter (Fig. 5).

The core samples were shipped to a lab specialized in geomechanical tests on sidewall cores, in order to determine the mechanical properties of the formations:

- Compressive strength measurements.
- Ultrasonic velocity measurements.
- In-situ stress velocity.
- Dynamic anisotropic properties at in-situ stress.
- In-situ stress in the absence of the tectonic deformation.



Fig. 5. Mechanical Sidewall Coring Tool

Another special log recorded in the new well was the PressureXpress Tool (XPT). This tool is used for acquiring formation fluid pressures and the fluid mobility.

3. MECHANICAL EARTH MODEL

For the well IJ-01 is planned to execute a frac stimulation operation in order to increase the reservoir productivity. For a proper operation design is essential to have a reliable Mechanical Earth Model (MEM) for the reservoir. This model is based both on special logs (Dipole Sonic and Formation Microimager) as well as on geomechanical properties determined from core tests (in our case, sidewall cores).

The typical workflow and the input data are presented in Figure 6.

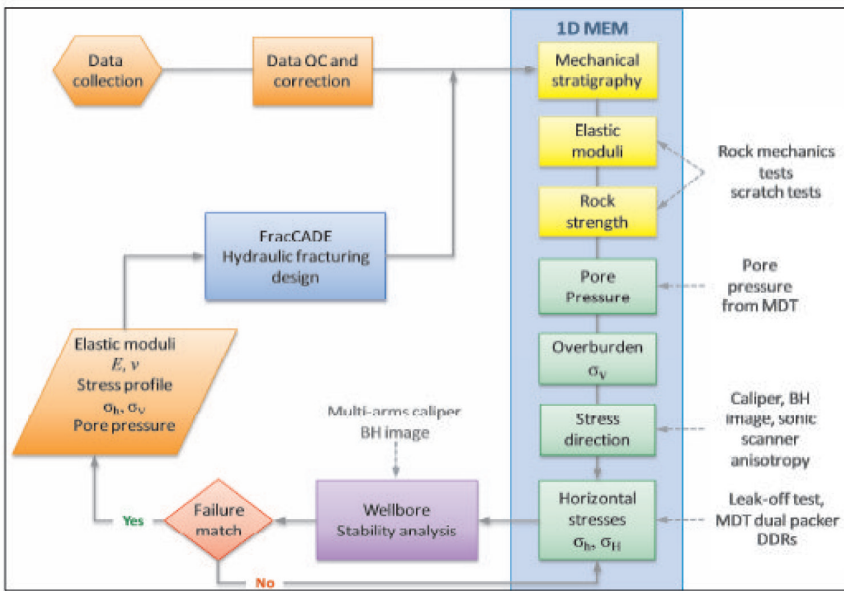


Fig. 6. Typical workflow for MEM for frac operation design

The conclusions of the preliminary report, based on log data only, are:

- Based on current MEM normal stress regime is expected across analysed interval, with the overburden stress being the major in-situ stress. This stress regime allows for vertical hydraulic fracture plane.
- Several low angle faults interpreted on image across perforated interval, including in lower most reservoir interval as well as in an aquifer, appears to be micro-faults. In normal fault stress regime these low angle faults are not considered likely to be reactivated but may add to some tortuosity.
- Minimum horizontal stress is close to Maximum horizontal stress. Low anisotropy is expected based on current rock strength prediction and low level of wellbore failure observed.

- Depletion in sands leads to much lower stress compared to shale intervals. Under depleted pore pressure conditions shale offer fracture containments from observed stress contrasts.

4. STATIC MODEL AND PETROPHYSICAL PROPERTIES FOR RESERVOIRS I-J

The static reservoir model was created based on 3D seismic and old wells' log data. Later, it was improved with the new logs' petrophysical interpretation. After drilling the IJ-01 infill well in 2014, better quality log data was available for updating the static model. Additionally, new data was obtained from core analyses executed on some old core samples.

More reliable petrophysical properties for the I-J reservoir were obtained from the new well logs, compared to the previous interpretations made on old logs (Figs. 7 and 8).

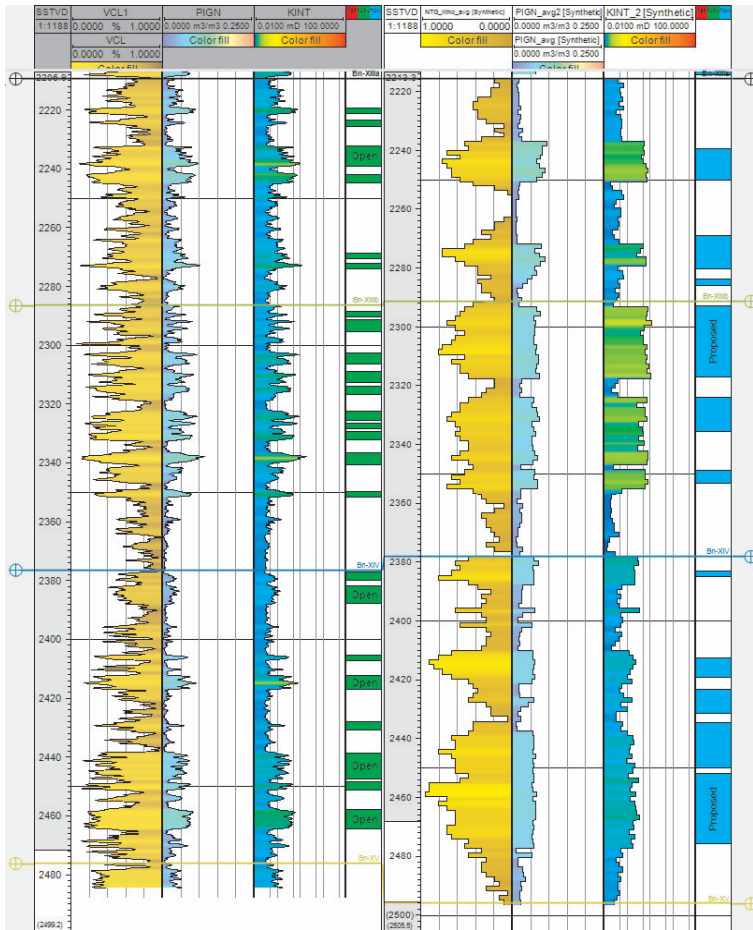


Fig. 7. Reservoir properties from new logs compared to old model

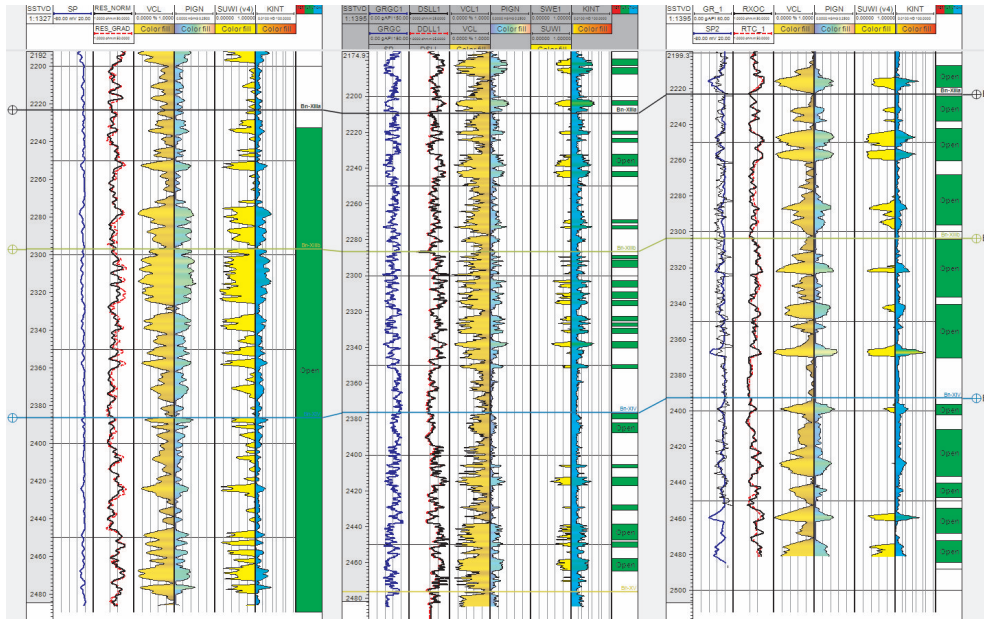


Fig. 8. Well section IJ-01 well and neighbor wells

Based on the new information the property models, especially the permeability distribution, were improved. This update leads to more reliable production forecasts for new wells and for frac simulations.

5. RESERVOIR PRESSURE LOG XPT

XPT PressureXpress Tool was run in the well to acquire formation fluid pressures. A total of 13 settings were performed at 9 suggested depths; representative formation pressure was determined at 3 depths (Fig. 9) in reservoirs I-J, while it could not be determined at the remaining 6 depths due to tight/dry formation response.

The I-J reservoirs still show high pressures in comparison with other reservoirs in the field, which ensures an acceptable value of the productivity index of the wells.

These 3 recent static pressures were compared with the historic pressure data base from this production package and the static pressure tendency numerically simulated, to validate the results from XPT Log. The Figure 10 shows the comparison graphic, where the last three points (in black circles) corresponds to reservoir pressure measured in IJ-01; the highest value of those points matches perfectly with the reservoir pressure I-J trendline from numerical simulation.

The reservoir pressure recorded after the drilling of the new well helped to update the dynamic reservoir pressure in the area; the new points were incorporated in the dynamic model in order to get more control in the pressure history match.

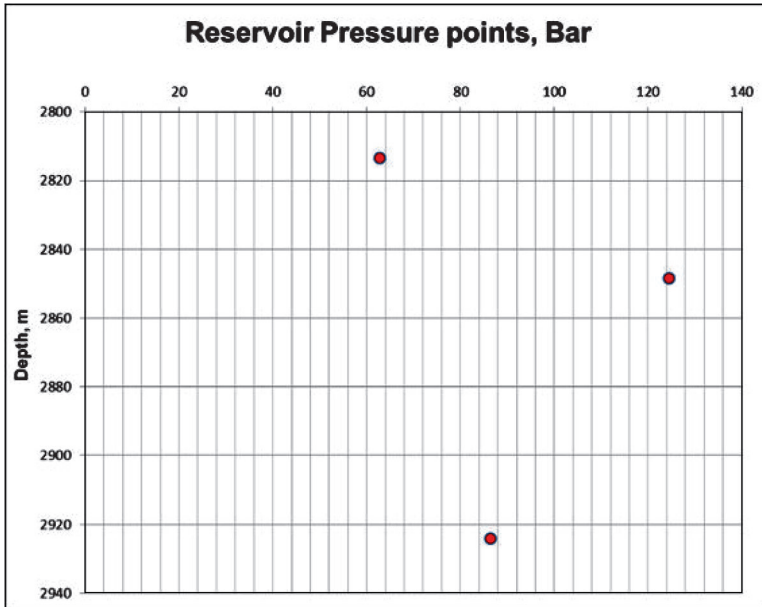


Fig. 9. XPT Reservoir pressure measurements in reservoirs I-J

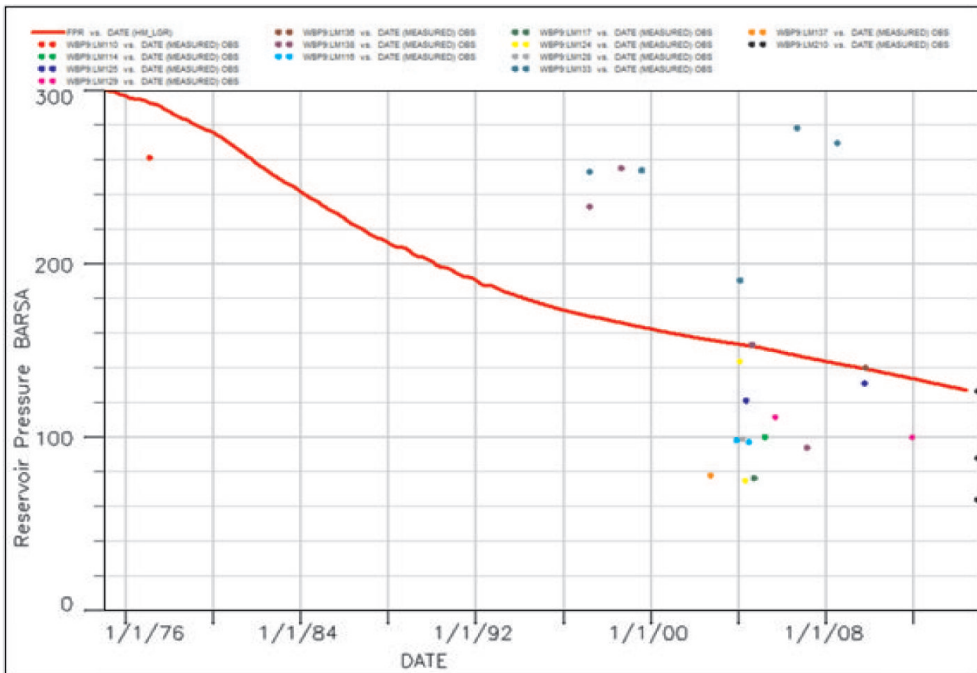


Fig. 10. XPT results and historic pressure data in reservoirs I-J

6. GAS PRODUCTION FORECASTS FOR IJ-01

The gas production forecasts were done using two methodologies.

Gas Production forecast based on DCA

The historic gas production data in the area plays a main role in this methodology where the decline rate analysis (DCA) is imperative to identify the decline rate by well according the historic data, Table 2 shows the neighbor wells, their gas production rates, cumulative gas productions and decline rates. The procedure to estimate the decline rate in the vicinity of IJ-01 was by weighting the neighbor wells decline rates by cumulative production; the resulting decline rate in the area is 13.64 % annual nominal.

Table 2
Gas production and DCA results for neighbor wells

Neighbors Wells	Qg_06-2014	Gp_06-2014	Decline Rate	Decline Rate weighted by Gp
	[Kscm/d]	[Mscm]	[%]	[%]
U-02	11.5	674.6	16.0	10793.6
U-03	6.9	209.1	3.1	648.2
U-04	7.7	5.6	18.7	104.7
U-05 Cmg (11%)	3.0	235.6	29.0	6832.4
U-06	9.0	183.2	8.0	1465.6
U-07 (Open Int)	14.9	117.4	10.8	1267.9
U-08	9.6	192.3	5.0	961.5
Total		1617.8		13.64

Using the gas production rate of IJ-02, an existent well, as an initial gas production rate and the average weighted decline rate of the neighboring area, it was possible to estimate the gas production forecast for IJ-01, shown in the Figure 11.

Gas Production forecast based on Simulation

The gas production forecast for IJ-01 coming from numerical simulation considers the gas production reference of IJ-07, which is the highest gas production contributor in the area of IJ-01. The initial gas production rate for IJ-01 in the simulation scenario is 14 kscm/d. Figure 12 shows the production profile.

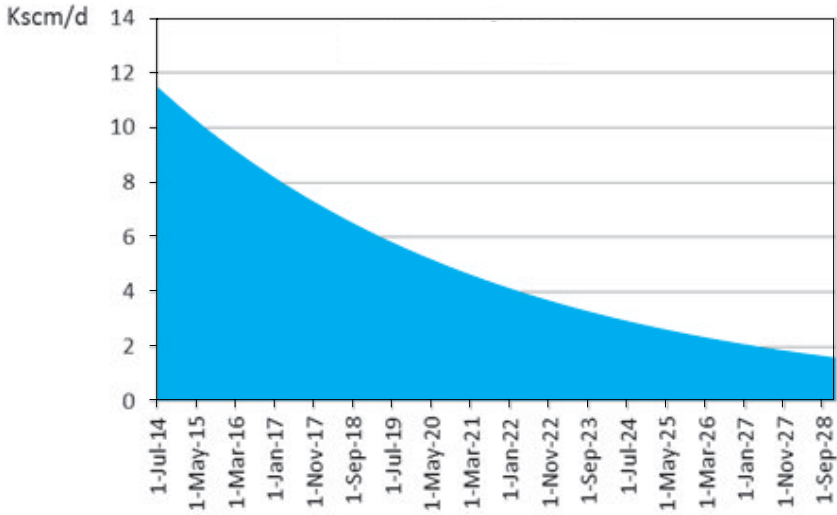


Fig. 11. Gas production forecast based on DCA, reservoirs I-J

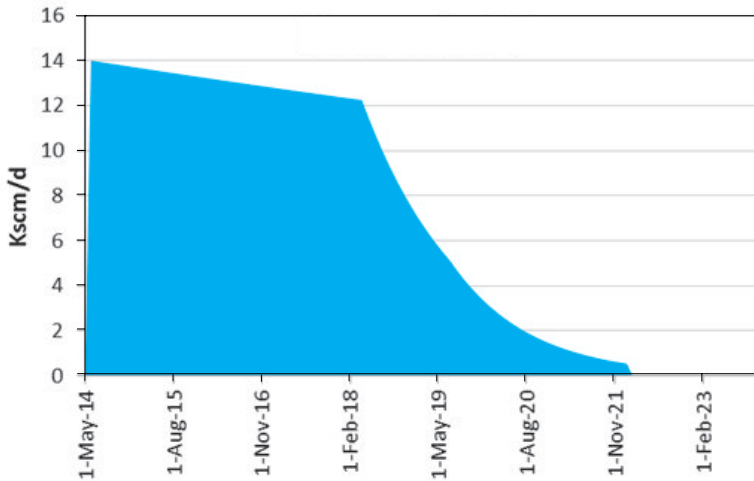


Fig. 12. Gas production forecast based on numerical model, reservoirs I-J

Real Gas Production profile

This well is completed in two horizons, as a dual completion. The first PLT showed that the gas production rate coming from reservoirs I-J is 43% of the total production. Using this contribution to split the gas volume produced by the well, we obtained the gas production profile shown in Figure 13.

A comparison of gas production forecasts and gas production reported is showed in Figure 14.

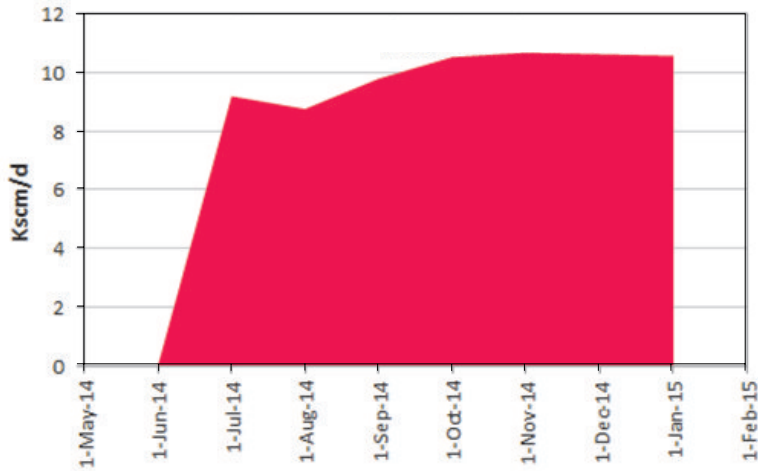


Fig. 13. Real gas production profile in well IJ-01

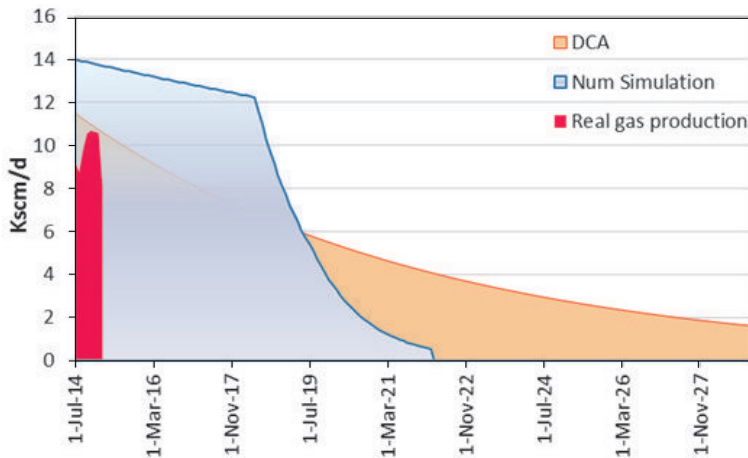


Fig. 14. Gas production forecast and gas production rate IJ-01

7. DESIGN FOR MULTISTAGE FRACTURE OPERATION IN IJ-01

The frac stages have been evaluated creating a local refinement grid around the well and designing a fracture simulation scenario (Fig. 15). Based on the new data, ten frac stages were defined and simulated in the deeper tight gas reservoir. The results pointed out one stage as being the best in terms of cumulative production and it was chosen as the only final target for frac. The initial plan was to do multistage frac stimulation, but the idea was discarded after evaluating the operational feasibility.

Ten (10) stages have been analyzed and simulated in order to identify the best options. Below is the proposed staging and fracture design with optimized stages (Fig. 16).

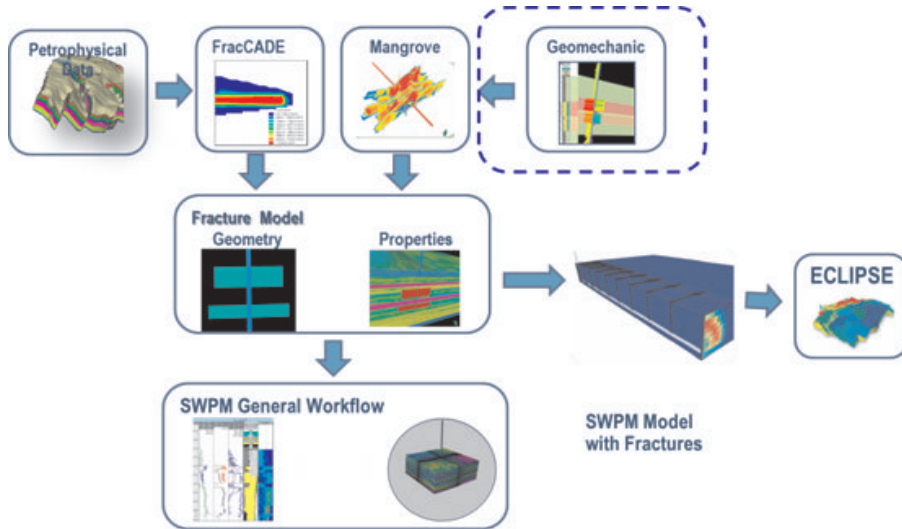


Fig. 15. Advanced fracture stimulation workflow

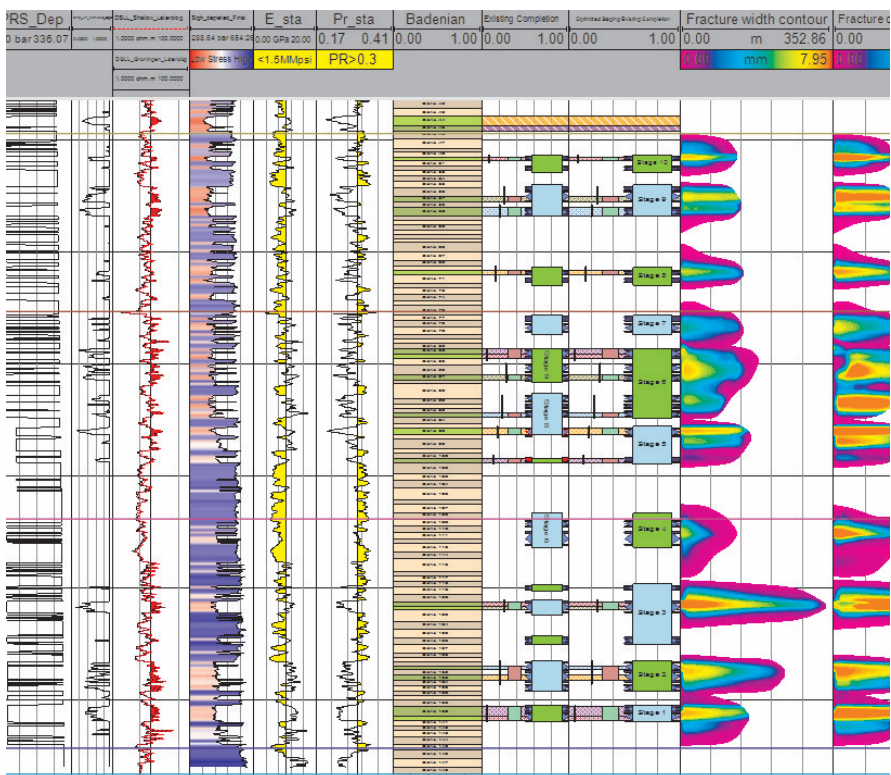


Fig.16. Multistage fracturing design in IJ-01

8. NUMERICAL SIMULATION MODEL DESIGNED FOR FRACTURING IN IJ-01

A local refinement grid was used to model the fracture dimensions and to capture fracture properties. It was designed to reproduce the gas production incremental effects after the fracturing intervention in IJ-01.

The global grid is approximately $50\text{ m} \times 50\text{ m}$ in I and J directions and 6 m in Z direction. For local grid refinement can be used as many divisions as required; simulation run time generally increases with increasing numbers of cells. In this case, the local refinement grid is approximately $10\text{ m} \times 10\text{ m}$ around the infill well (Fig. 17).

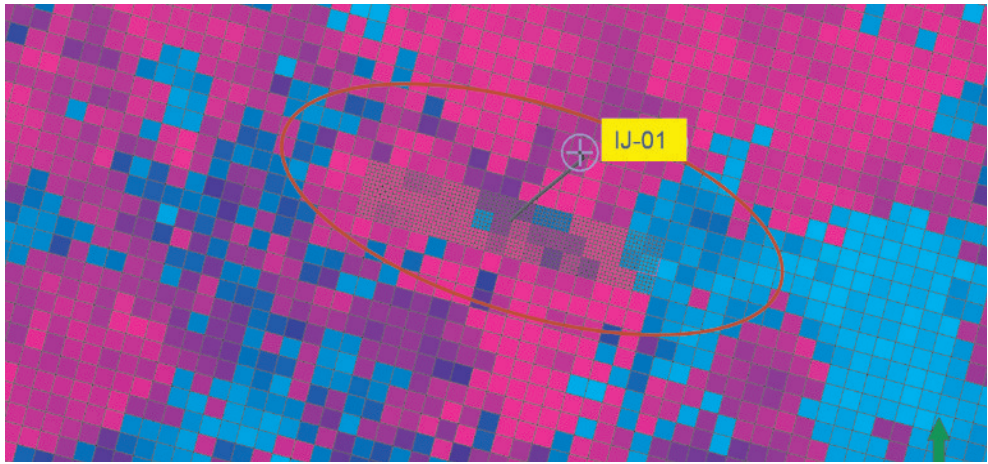


Fig. 17. Local grid refinement near to IJ-01

The fractures generated are assumed to propagate in the X direction, which means the fracture length gets captured with X divisions and fracture width with Y divisions.

The new population of static properties such as: porosity, net to gross and permeability have been included in the dynamic model to generate a better gas production forecast for this infill well and for other wells in the future.

The static properties play an important role in order to incorporate the fracture properties, for instance Fracture conductivity = fracture permeability * fracture width and, by applying this formula and the fracture data, 63 mD was obtained for stage 3.

The thickness relationship $NTG = 1$, simply reflects the fact that the fracture has 100% vertical connectivity. The porosity is an important adjustment to ensure the true fracture pore volume is retained in the simulation model.

The fracture dimensions used in the numerical models are presented in Table 3 below.

Table 3
Multistage fracture dimensions for IJ-01

Frac No.	Frac top depth	Frac bottom depth	Frac height	Frac halflength	Frac conductivity	Frac width
	[m]	[m]	[m]	[m]	[md. m]	[mm]
1	3002.17	3009.85	7.68	164.71	869.27	2.37
2	2982.53	2996.26	13.73	247.12	762.99	2.43
3	2948.28	2975.3	27.02	352.21	631.03	2.58
4	2916.69	2931.89	15.2	205.75	340.58	0.72
5	2878	2894.69	16.69	167.22	813	2.28
6	2843.46	2874.31	30.85	187.42	843.23	2.93
7	2828.55	2837.11	8.56	148.7	660.69	1.33
8	2807.14	2815.11	7.97	154.21	838.71	1.75
9	2770.38	2784	13.62	147.73	865.45	2.99
10	2756.94	2765.06	8.12	137.39	511.5	1.63

9. NUMERICAL SIMULATION RESULTS

For well IJ_01 ten (10) scenarios were run to evaluate the production response individually by stage. The fracture performance data for each stage was supplied by the stimulation team in a Fracture design program and the data was used as an input into the fracture model.

A schematic diagram containing all the stages analyzed is shown in Figure 18, where we can see a formation profile in front of the well IJ-01.

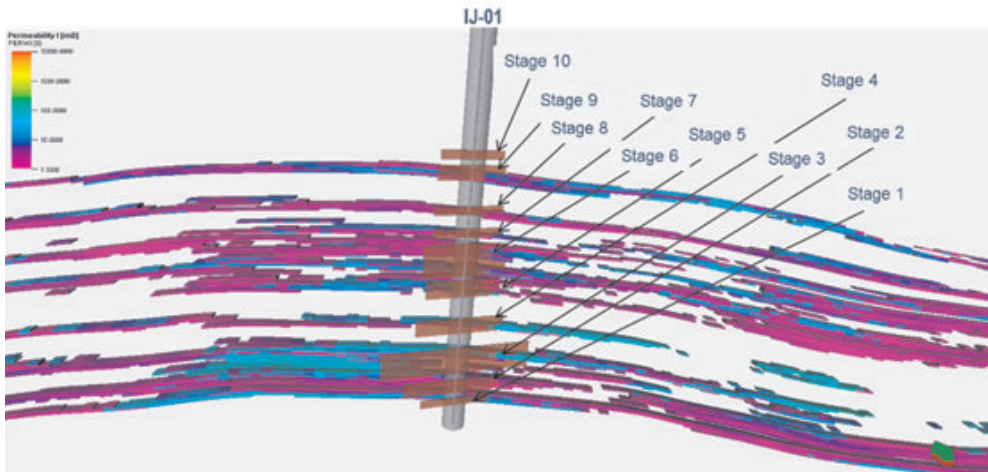


Fig. 18. Schematic diagram of all frac stages in well IJ-01

The graphical output of the results provides a comparison between the stages that were run separately. The graphic helps a quick identification of the most promising stage, where the highest gas production rate is evaluated (Fig. 19).

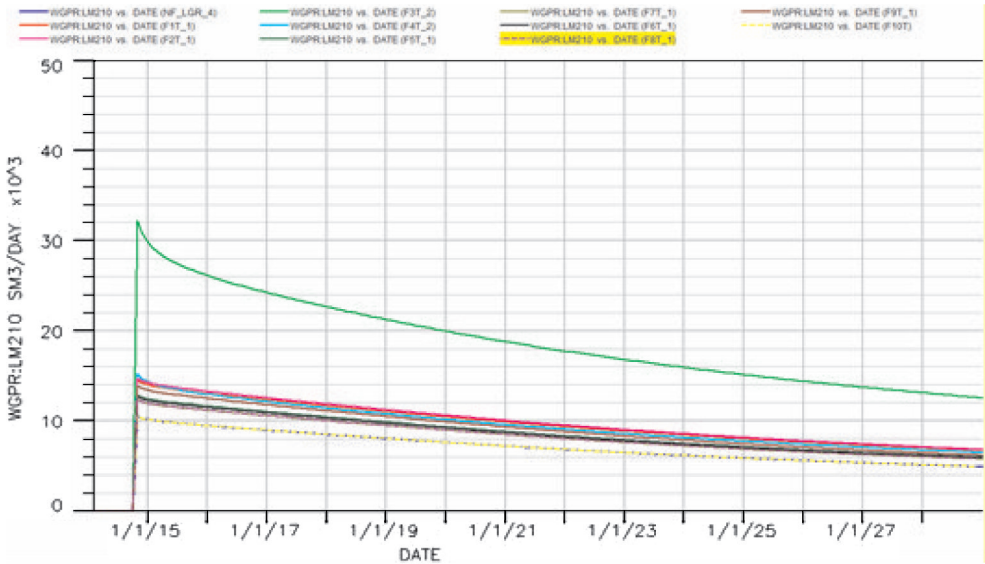


Fig. 19. Gas production rate of all frac stages in well IJ-01

The gas production results are presented in Table 4, showing the incremental initial gas production rate by stage. The incremental forecast is achieved by subtracting the non-frac scenario.

Table 4

Incremental Initial gas production rate from fracture numerical model

Stage	Initial gas rate [Kscm/d]
FRAC3	21.730
FRAC4	4.681
FRAC2	4.202
FRAC1	3.927
FRAC9	3.359
FRAC5	2.337
FRAC6	2.177
FRAC8	1.863
FRAC7	1.842
FRAC10	0.000

The results were ranked from highest to lowest initial gas rate. As we can see, the stages 3 and 4 are the most attractive and profitable for fracturing.

The cumulative gas production results shown in Figure 20 were evaluated until December 2028. An analysis like this helps the technical team to identify the best formation intervals and stage to be stimulated through frac job.

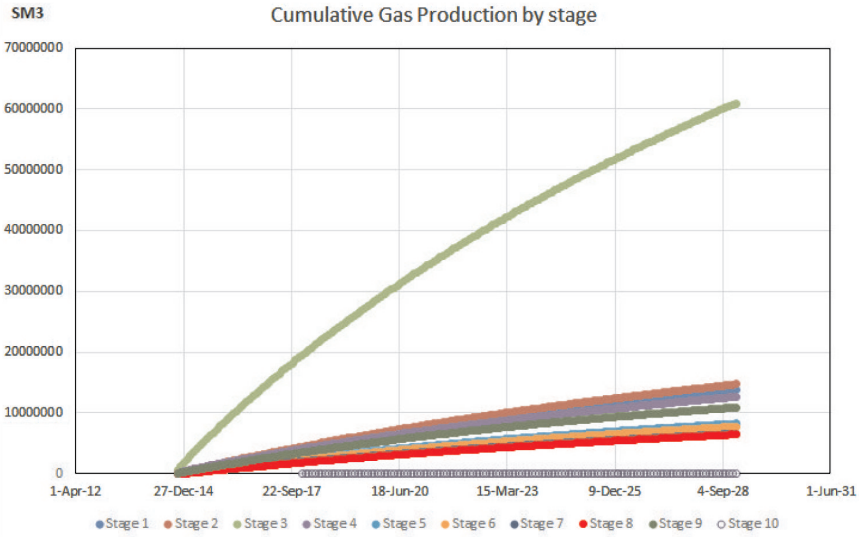


Fig. 20. Cumulative gas production of all stage in IJ-01

The gas production results are shown in the table below (Tab. 5), containing the incremental cumulative gas production by stage. The incremental forecast is achieved by subtracting the non-frac scenario.

Table 5

Incremental cumulative gas production from fracture numerical model

Stage	Cum Prod., Mscm. Dec 2028
FRAC3	60.920
FRAC2	14.709
FRAC1	13.817
FRAC4	12.674
FRAC9	10.908
FRAC5	8.236
FRAC6	7.763
FRAC8	6.605
FRAC7	6.562
FRAC10	0.005

The results were ranked from highest to lowest cumulative gas rate. As we can see, the stages 3 and 2 are the most attractive and profitable for fracturing.

In order to mitigate the risks during the fracturing operation, the technical decision has been taken to execute the operation in only one stage: number 3.

10. PLT RESULTS

Two PLTs were performed in the infill well. The first one was meant to identify the gas contribution from each of the two production packages, and the second ones' objective was to have a reference line of the production from each perforation in the deeper package, for a better post fracturing job evaluation.

The first PLT was done in August 2014 and the results showed the contribution percentage for reservoirs I-J was 43% and the rest was associated with the upper reservoirs.

The second PLT was executed in January 2015 and had the purpose of identifying the water risk in the deeper layers and also the production contribution of the major perforation intervals. Additionally, the new PLT proved that the production contribution from the package I-J has decreased to 28%, compared to the 43% before (Tab. 6).

Table 6
Production percentages by interval, in reservoirs I-J

Zones m	Qw res. B/D	Production %	Qg res. B/D	■ W ■ O ■ G
2757.5-2759.5	0.00	2.48	100.80	■
2762.0-2764.0	0.00	4.56	185.22	■
2771.0-2778.0	0.00	0.73	29.76	■
2781.0-2784.0	0.00	0.00	0.00	
2808.5-2810.5	0.00	0.00	0.00	
2812.0-2814.0	0.00	0.00	0.00	
2829.0-2831.0	0.00	11.81	479.85	■
2832.0-2836.0	0.00	3.75	152.23	■
2843.5-2847.5	0.00	0.00	0.00	
2850.0-2854.0	0.00	3.58	145.33	■
2855.0-2858.0	0.00	12.37	502.69	■
2864.0-2867.0	0.00	0.40	16.34	■
2868.0-2870.0	0.00	0.00	0.00	
Zones m	Qw res. B/D	Production %	Qg res. B/D	■ W ■ O ■ G
2871.0-2874.0	0.00	0.00	186.74	■
2878.5-2882.5	0.00	0.00	536.70	■
2892.0-2894.0	0.00	0.00	263.76	■
2920.0-2923.0	0.00	0.00	0.00	
2925.0-2931.0	0.00	0.00	30.01	■
2949.0-2951.0	0.00	0.00	44.22	■
2956.0-2961.0	0.00	0.00	1389.00	■
2972.0-2975.0	0.00	0.00	0.00	
2983.0-2992.0	0.00	0.00	0.00	
2993.0-2996.0	0.00	0.00	0.00	
3002.5-3005.2	0.00	0.00	0.00	

During the operation, we discovered that below 2970 m the pressure curve started to increase with 1 bar/10 m which represents water in the corresponding zones (Fig. 21). Based on that, the stages 1 and 2 need to be isolated by a bridge plug before the frac operation. Regarding the production contribution percentage results, the PLT advises that the best contributor layer is the middle perforated interval of Stage 3.

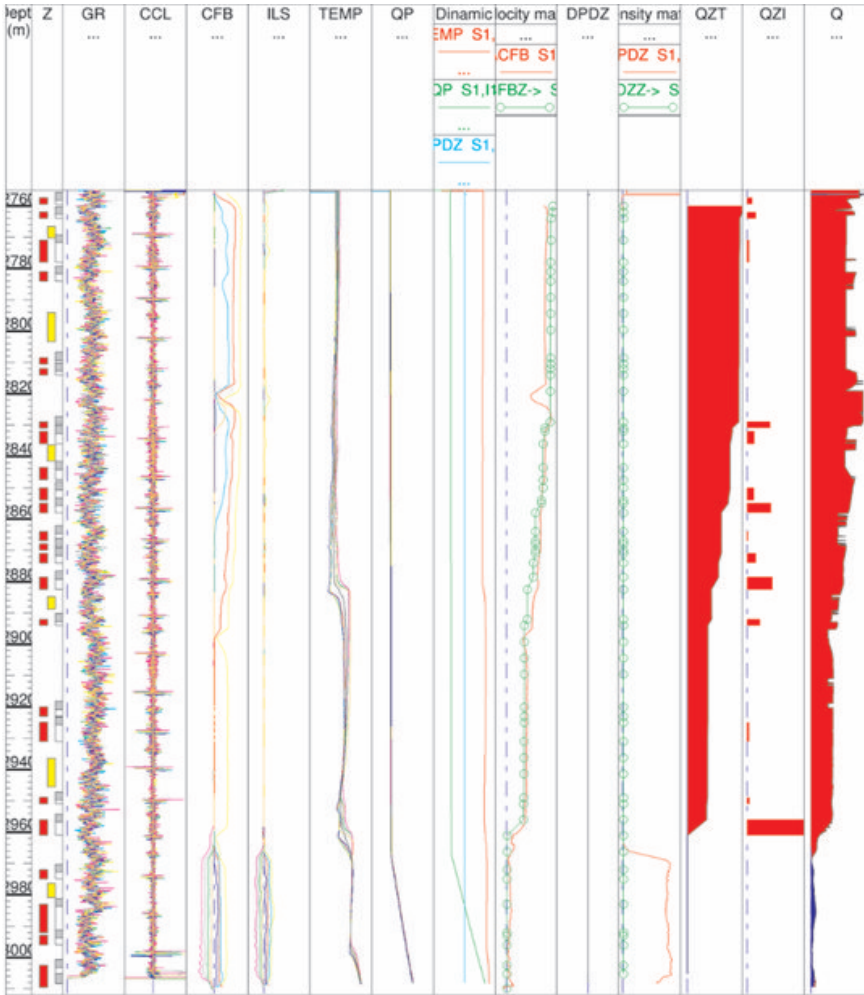


Fig. 21. Water evidence in the bottom of the formation from PLT

11. CONCLUSIONS

The acquisition of new logs and side-wall cores was very important for the design and numerical simulation of the frac operation. Based on the new data, the static and dynamic

reservoir models were improved, and the simulation results are more accurate in the area of well IJ-01 compared to the previous model.

The frac stimulation technology was discussed for a longer time as a solution for this type of tight reservoir, but the old well completions and lack of geomechanical data did not allow to be executed before. The drilling of the infill well offered the opportunity to acquire the needed data, design and test the frac technique in our reservoir.

In the fracture numerical simulation two perspectives were analyzed: incremental initial gas rate and cumulative gas production. Based on the results, from the incremental initial gas rate analysis, the best two options to be stimulated are the stages 3 and 4. From cumulative gas production perspective, the highest contribution comes from the stages 3 and 2.

To mitigate the uncertainty and reduce the operational risks, the technical team had decided to go for one frac stage, to evaluate the real production response. For this reason, it was chosen stage 3.

The stimulation operation is expected to increase the productivity of the well in the tight reservoir. In case of positive results, the multistage frac operation should be considered as a common practice in the future for all the new infill wells drilled in reservoir I-J.

The fracturing should be performed cyclically in the same well, and the gap time should be evaluated based on the performance of this first frac job, because the effect of the fracture is not permanent.

Recommendations

1. The permeability measured during buildup tests should be used to calibrate the permeability distribution coming from log data and correlations.
2. The permeability calculated from XPT log should be used to validate the permeability distribution coming from log data and correlations.

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