Hydraulic Fracturing: Modeling & Optimization Using Latest Generation Logs and Conductivity Optimization Technologies.

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Abstract

Successful hydrocarbon production in the San Jorge Basin in Argentina is achieved with understanding the high variations in reservoir fluid properties, discriminating the complex lithology, and achieving the optimum hydraulic fractures. This paper outlines how state of the art logging tools and collaboration between the operating and service companies can deliver improved fracture results.

The multi-layered stratigraphic formations in the San Jorge Basin have long presented formation evaluation challenges with conventional well logging. These formations exhibit major inconsistencies and anomalous results in formation water salinity. In addition, the complex reservoir characteristics have required the use of hydraulic fracturing to improve the hydrocarbon production during the past fifteen years.

Nowadays, petrophysical evaluation of the reservoirs has been improved using the latest well logging technology such as Nuclear Magnetic Resonance (NMR) logs to identify and distinguish potential productive layers and zones to be stimulated.

Combining NMR logging technology with fracture height evaluation utilizing azimuthal shear wave slowness data, stimulation treatment pressure responses, and post-stimulation swab test results, provides sufficient data to calibrate geomechanical and hydraulic fracturing models. With advanced interpretation techniques and modeling, the optimum fracture can be designed and performance data from that fracture can be used to validate the theoretical models. This approach enhances the capability to design hydraulic fractures based on the reservoir conditions, with the optimum conductivity and fracture half-length to provide the required productivity over the life of the well.

Application of this process has resulted in improved well performance in the San Jorge Basin wells. The integration and interpretation of information between the operator and the service companies resulted in more accurate and optimized work flows and modeling for the complex and non-conventional reservoirs of the San Jorge Basin. As companies work together in a collaborative environment to address business challenges, solutions have been generated that no single company could have achieved alone.

Introduction

Height fracture evaluation has been carried out through several traditional methodologies, such as the use of temperature, electrical logs and radioactive tracers.

The main drawback to the use of temperature logs is the limited vertical resolution, though the method could be improved when these logs get combined with radioactive tracers. A qualitative relationship has been observed between radiation level and fracture width.

The simultaneous use of fullwave acoustic logs, spectral gamma ray and temperature has been examined and documented. This technique has shown the advantage of determining a continuous log for dynamic mechanical properties and hydraulic fracture effect on the acoustic waves. The absence of shear wave information has limited the use of this technique.

With the introduction of dipolar acoustic logging tools, and most recently, that with crossed dipoles, previous methods have been improved in terms of determining vertical extension, or height, of the hydraulic fracture. Mapping of the vertical extension is important when there is a possibility of contacting water zones or when hydraulic fractures are performed in multilayered reservoirs (Nikitin, 2006; Tellez, 2007)

The use of shear and compressional acoustic wave information to determine dynamic mechanical rock properties is essential for effective hydraulic fracture design and performance prediction. The use of shear wave anisotropy is important to accurate height fracture estimation and efficiency evaluation.

In the last few years, Cerro Dragon oilfield, operated by Pan American Energy, has increased production with respect to other fields in the San Jorge Gulf Basin; a key to this success has been the use of state-of-the-art technologies and continuous improvement processes, including composing this paper as part of the process of improving evaluation and understanding of the Cerro Dragon zone reservoir.

The first stage was technology implementation, such as Magnetic Resonance Imaging Log (Acuña, 2003; Stinco, 2004) which helped to improve formation evaluation and fluid identification in the reservoir, and nowadays is standard practice for characterization of Cerro Dragon zones of interest.

The second stage consists of understanding hydraulic stimulation development and behavior (shape/geometry) in productivity areas. This paper describes the methodology and technology implemented to that end, shaping a multidisciplinary team between operating and service companies to reach said aim.

Geographic and Geological Description

Cerro Dragon oilfield is located 85 km west of Comodoro Rivadavia town (**Figure 1**) on the west side of San Jorge Gulf Basin in the Chubut Province, Argentina.

The area in which Pan American Energy LLC operates is composed of approximately 50 different oilfields. Cerro Dragon oilfield has been under development and has operated since 1959.

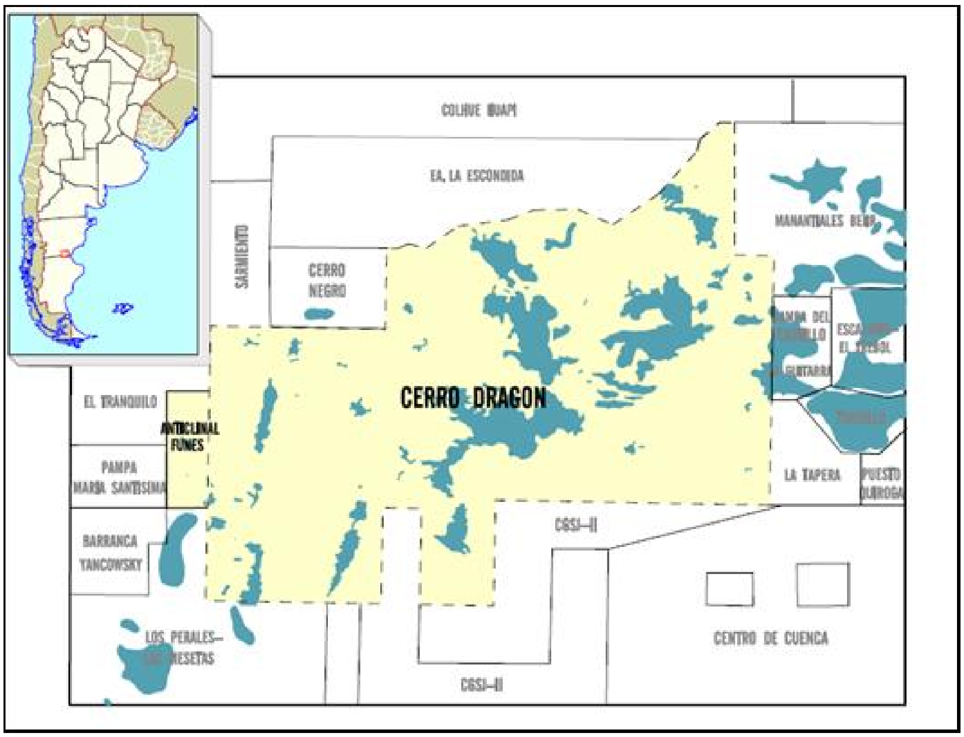


Figure 1 - Location Plan

Reservoir Geology

Cerro Dragon oilfield is composed of an area of 3,480 sq km. It was formed in a vast basin in the Mesozoic period. Its main filling took place in the Riftin stages of the late Jurassic period – early Cretaceous, its origin being mainly lacustrine (marshy) and fluvial.

The main productive formations are the Comodoro Rivadavia formation composed of shaly sand bodies, and the Mina del Carmen formation that consists of tuffaceous sands, tuffs and altered tuffs (**Figure 2**). The Comodoro Rivadavia formation has a 200-metre thickness on average in the study zone, of which approximately 90 metres belong to pay zone; the thickness of these sands varies between 1 to 8 metres.

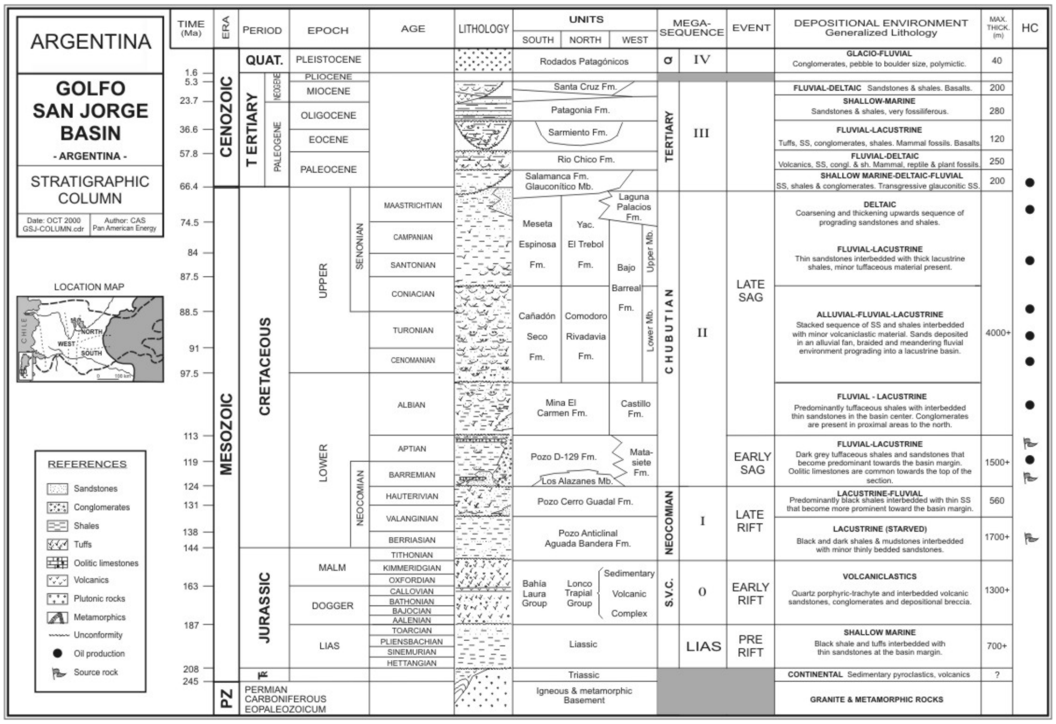


Figure 2 - San Jorge Gulf Basin Stratigraphic Column

Background

For many years, hydraulic fractures have been used in Cerro Dragon oilfield during well completion in order to obtain early hydrocarbon recovery. Just during 2007, more than 900 fracture jobs were performed in the whole field.

Fracture design criterion is based on previous evaluations and accumulated experience after performing more than 6,000 fracture jobs in the field; at present, there are two or three standard designs. Nowadays, with development of new, deeper reservoirs, the need to accurately understand the final geometry of stimulations has been identified in this geological environment, using available technology in the country to calibrate fracture simulators.

Work Methodology Description

The work methodology applied (**Figure 3**) was based on available information and from both operating and service companies' staff experience in the San Jorge Gulf Basin.

Selection of the zone to be stimulated was decided according to the Magnetic Resonance Imaging Log analysis, side wall cores, formation pressure by means of the selective formation testing tool (SFT), and zone correlation with neighboring wells. In some cases information on neighboring wells' swabbing tests was also included.

After selecting zones to be fractured, prior to hydraulic fracturing, a dipole sonic log was performed in cased hole (i.e, pre-frac log). This served as base log from which rock dynamic mechanical properties were determined. These properties together with the previously described well information were used for hydraulic fracture simulation and modeling.

Stimulation performance was carried out by means of a sensor at the bottom of the well to record treatment pressure during the operations, after which sensor information was recovered and analyzed. All the stimulations counted on two previous calibration pumping stages in order to obtain information such as zone closure pressure (Stress), permeability, fluid loss mechanism, formation pressure and near wellbore pressure.

After swab testing subsequent to stimulations, a second, "post-fracture" dipole sonic log was performed for later evaluation of the differences between both records and, in this way, to determine the height reached by the hydraulic fracture.

Fracture simulator matching was performed with bottom hole pressure memory gauge, analyzed calibration pumping data, and height determined by sonic log. In this way the final geometry of each stimulation fracture could be adjusted; and simulator consistency for all analyzed zones was observed.

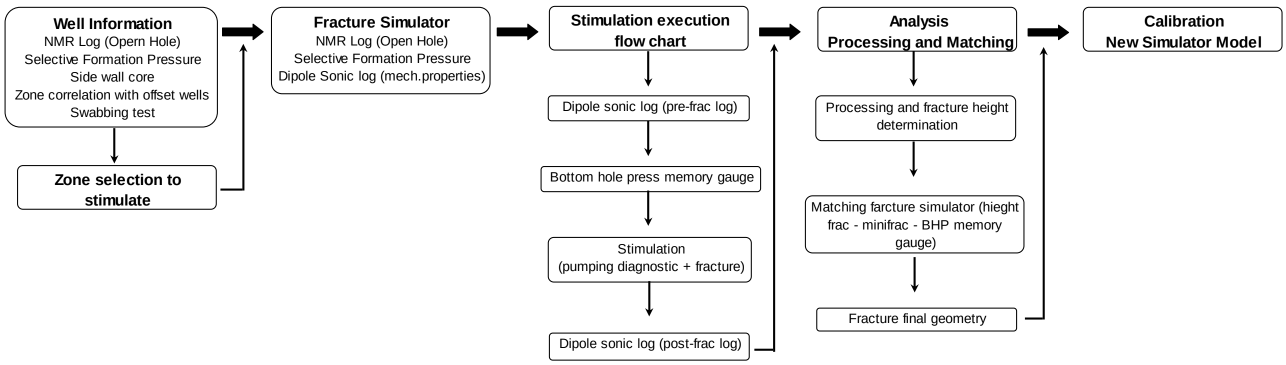


Figure 3 - Methodology Used

Fracture Height Determination

On performing hydraulic fracturing with proppant in any formation, a disturbance in the environmental geomechanical properties is generated. As a consequence of this disturbance, it is possible to determine fracture height by means of a dipole sonic log, obtained before and after stimulation. The analysis consists of determining the existing differences between transit time measurements of shear and compressional acoustic waves (S waves) (P waves) respectively.

At present there is vast experience and technical documentation about fracture height measurement based on acoustic wave shape differences (amplitude), transit time differences (Δt) and anisotropy differences obtained from shear wave analyses, etc. After "pre-fracture" and "post-fracture" dipole acoustic log processing, such analyses were contrasted (Δt and anisotropy) to evaluate the existing differences between them, which provided indicators that make it possible to determine the geomechanical disturbances generated by stimulation. Thus conditions were proper for defining hydraulic fracture height.

Figure 4 shows the reservoir thickness (9 m) 2447/2456m of one well that was perforated in section 2447-2455m to be fractured afterwards. In addition to reservoir identification in tracks 1 to 4, the comparative analysis is presented between different measurements and the pre- and post-fracture anisotropy determination, tracks 7 to 8. In this example, it is possible to determine that fracture height extends from 2438 to 2462 meters. All indicators above or below the estimated height have very little activity, confirming the homogeneity of the zone that has not been reached by the fracture.

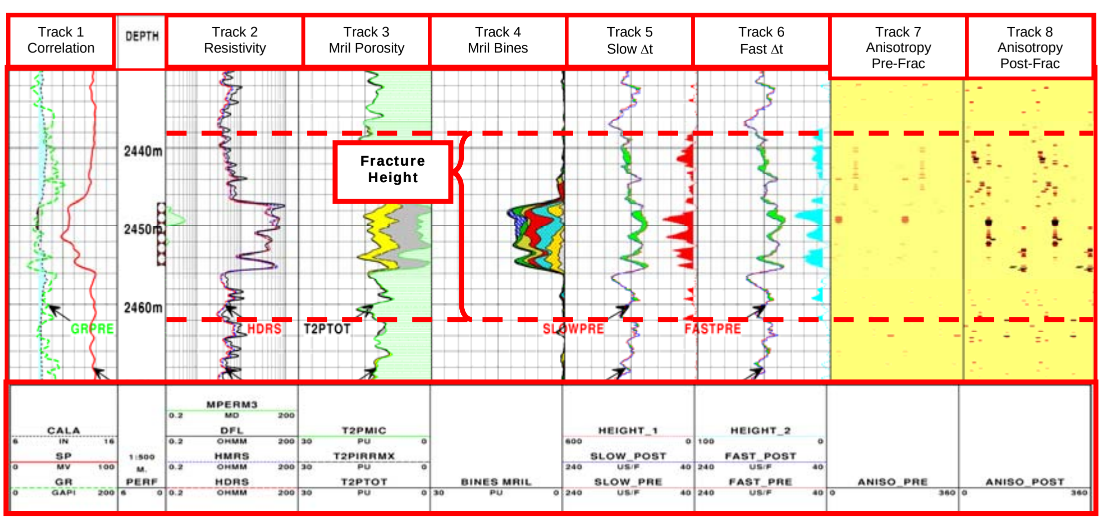


Figure 4 - Fracture Height Determination through "Pre-fracture" and "Post-fracture dipole Sonic Logs.

Case Studies

Hydrualic fracturing in five oilfields was performed using this methodology.Two frac jobs were developed in the Comodoro Rivadavia (CR) formation in wells XX-1057 and XX -985; and three others in the Mina del Carmen (MEC) formation in wells XX-1056, XX-1069, and XX-1081, the last two belonging to a reservoir that has a serious degree of alteration. Below is a detailed description of the three cases, MEC, CR, and MEC-altered, as well as a report on the remaining fields.

Well XX-1056

Final well configuration was: 5½-inch casing, 4spf (shot per foot) perforation, 90-degree phase and 32-gram charges. Well completion was developed through 2 7/8-inch tubing and packer for all stimulated zone development.

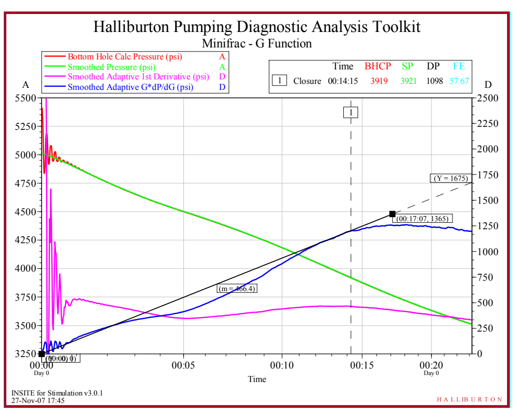
	Perforating Zone (m)		"h" Zone (m)	"h" Perf (m)	Avg Perm Log (mD)	Formation Press (SFT) (psi)	Porosity Log %
F5	2220.5	2227.5	7.0	7.0	1.331	1066	13.41
F4	2288.0	2300.0	12.0	12.0	0.479	2751	12.56
F3	2322.0	2331.0	9.0	9.0	1.104	2842	11.68
	2341.0	2344.5	3.5	3.5	0.525	1771	11.97
F2	2447.0	2455.0	10.0	8.0	0.205	2356	10.54
F1	2546.0	2549.5	5.0	3.5	0.697	2627	11.14

Table 1 - Petrophysical Characteristics of Fractured Zones.

For all stimulations, two diagnostic pumping stages were carried out in order to get information to match fracture simulator parameters. The first pumping stage was developed with water plus surfactant and clay stabilizer, with volumes of about 2,500 gallons injected, obtaining closure pressure values (Stress), reservoir pressure and fluid loss mechanism (Barrer, 1998; Craig, 2000; Chipperfield, 2000). **Table 2** presents information of such analyses that show the prevailing fluid loss mechanism (**Figure 5**) and reservoir pressure determination (**Figure 6**) that belongs to stimulation number 2.

	G Funcion Analysis				SQRT Analysis		
	Closure Press psi	C.P Gradient psi/ft	Closure Time hr.min.sec.	Leakof Mechanims	Closure Press psi	C.P Gradient psi/ft	Closure Time hr.min.sec.
F1	4680	0.560	0:16:04	HR	4488	0.537	0:19:05
F2	3919	0.487	0:14:15	HR	3862	0.480	0:15:15
F3	4050	0.529	0:12:45	HR	3826	0.499	015:53
F4	4098	0.544	0:14:39	HR	3907	0.519	0:18:02
F5	3592	0.477	0:02:30	NL	3386	0.450	0:03:32

Table 2 - Closure Pressure Determination ("G" Function and SQRT- Square Root Time)



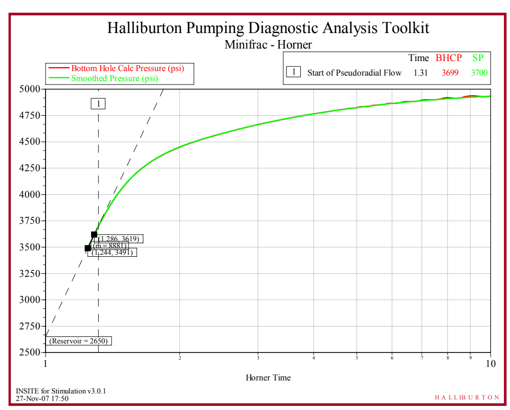


Figure 5 - "G" Function

Figure 6 - Horner's Method

The second pumping stage was developed with lineal gel, injecting volumes of about 3,500 gallons, and was finished with a SDRT (Step Down Rate Test) (Weijers, 2000) in which four changes were carried out, with the aim of determining near wellbore frictions, as well as validating the determined values in the previous pumping (Figure 7 – Fracture 2).

In **Table 3**, values determined with the surface sensor during operation are presented, as it was also possible to analyze the information on bottom hole pressure memory gauge, subsequent to information recovery. Friction differences observed between analyses developed with surface and bottom hole sensors are due to pumped fluid friction effects in the pipeline (surface sensor). Analyzing pumping with bottom sensor information obtains fluid effect friction independence in the pipeline.

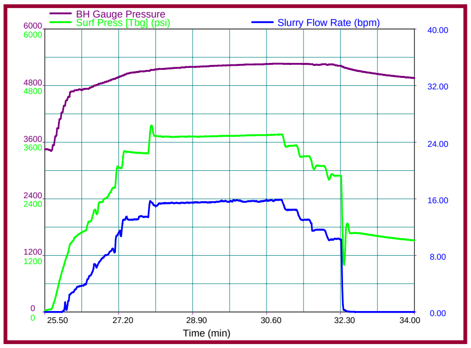


Figure 7 - Pumping Record with surface and bottom hole sensor.

STEP DOWN RATE TEST Analysis					
SURFACE SENSOR	**F1**	**F2**	**F3**	**F4**	**F5**
Perforation Friction	42	23	37	365	46
Near Wellbore Friction	325	354	247	270	39
Total Friction	367	377	284	635	85
BOTTOM HOLE SENSOR	**F1**	**F2**	**F3**	**F4**	**F5**
Perforation Friction	55	46	4	28	35
Near Wellbore Friction	41	4	14	24	111
Total Friction	96	50	18	52	146

Table 3 - Near Wellbore Friction Analysis

Information on pumping has allowed parameter-matching in the fracture simulator. In **Table 4** initial values for the design can be observed as well as the measured data in the pumping.

	STRESS (psi)		FORMATION PRESSURE (psi)	
Frac Stages	**Dipole Sonic Log**	**Minifrac (measured)**	**SFT**	**MINIFRAC (Horner Plot) (measured)**
F1	4478	4584	2627	3111
F2	4282	3890	2356	2650
F3	3717	3938	2842 1771	2586
F4	3909	4000	2751	2594
F5	3438	3489	1066	2391

Table 4 - Design Parameters Validation vs. Measured values

All stimulations were carried out with fluid as the basis of borate of low polymer charge, and with resined coated sand (RCS) 20/40. Said stimulations were developed according to programmed treatments, with information validation from previous pumping stages. **Table 5** shows the results of each of the stimulations, which were finished according to the programmed design; it is important to mention that in Fracture 2, owing to pressure response, the total number of sacks to be mixed was modified.

	FRACTURE STAGES				
	F1	**F2**	**F3**	**F4**	**F5**
Avg. Pump Rate (bpm)	14.3	15.0	16.5	15.0	18.0
Avg. Pressure (psi)	3971	4210	3784	3588	4450
ISIP (psi)	2262	2092	1683	1961	1586
Frac Gradient (psi/ft)	0.71	0.70	0.66	0.70	0.66
Max Propp Conc (ppg)	6.0	8.0	8.0	8.0	8.5
PAD Percentage (%)	42	54	49	52	48
Proppant Designed (sks)	72	480	563	540	318
Proppant in formation (sks)	85	429	576	546	377
sks/m Designed	21	60	45	45	45
sks/m in Formation	24	54	46	46	54
Performance	OK	OK	OK	OK	OK
Slug	YES	YES	YES	YES	YES

Table 5- Main fracture Variables Report.

Dipole sonic logs showed fracture height values (**Figure 8**), which were taken into account to calibrate the simulator. In **Table 6**, such obtained values can be observed.

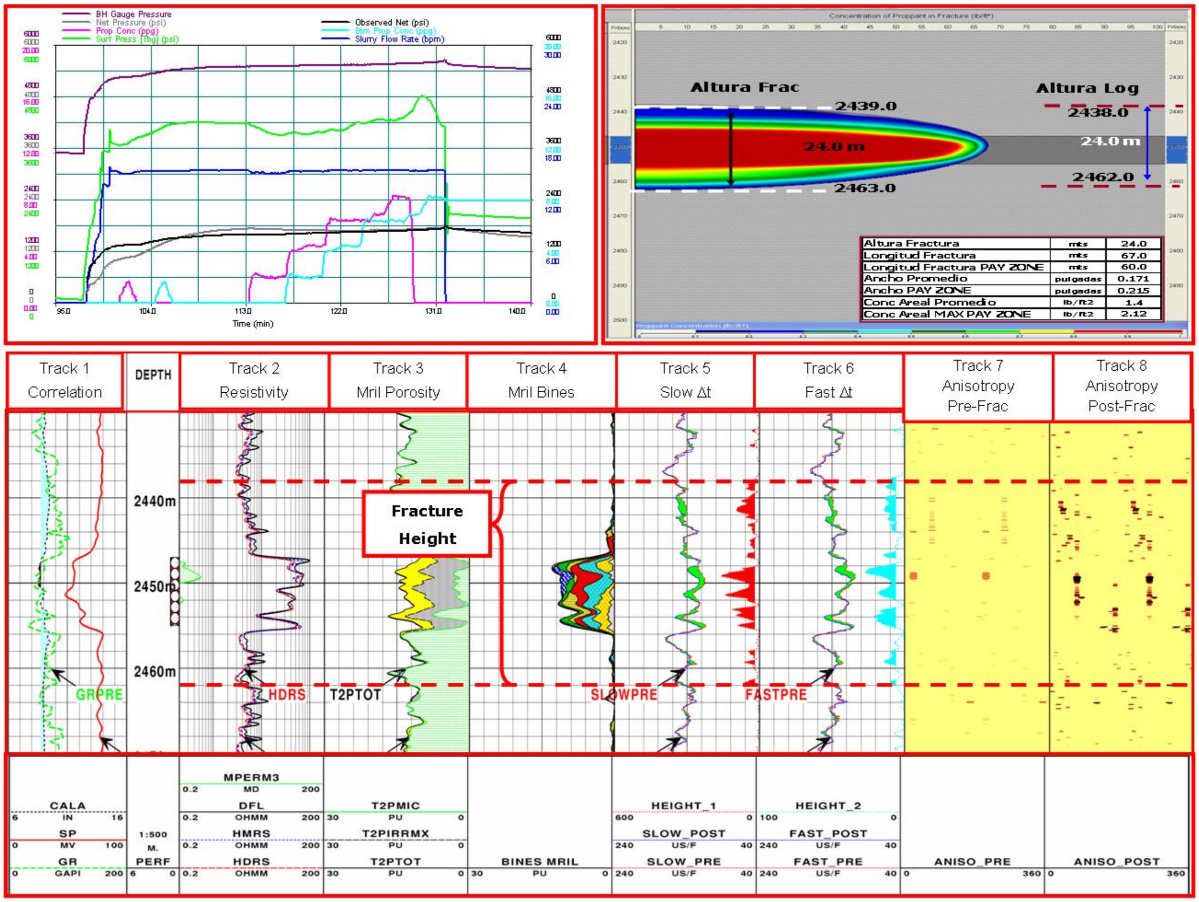


Figure 8 - Fracture Number 2 Final Geometry, Determination and Matching.

HEIGHT FRACTURE (m)						
Stage	**Perforating Zone**		**Dipole Sonic Log**		**Matching simulator**	
F5	2220.5 2227.5	7.0	2210.0 2234.0	24.0	2214.0 2233.0	19.0
F4	2288.0 2300.0	12.0	2274.0 2310.0	36.0	2270.0 2305.0	35.0
F3	2322.0 2331.0 2341.0 2344.5	9.0 3.5	2310.0 2352.0	42.0	2318.0 2356.0	38.0
F2	2447.0 2455.0	8.0	2438.0 2462.0	24.0	2439.0 2463.0	24.0
F1	2546.0 2549.5	3.5	2534.0 2544.0	10.0	2535.0 2556.0	21.0

Table 6 - Fracture Height Measurement

In Table 6, only the first fracture shows different conduct. In the dipolar sonic log analysis, it was observed that the fracture would have developed above the perforated zone, the reason being that post-fracture swab testing showed normal flow rate, indicating that the fracture itself had developed in the perforated zone.

Final geometries obtained with bottom hole pressure matchings (BHP- Memory Gauge) and height in the fracture simulator are shown in **Table 7**. Individual analyses of each fracture are presented in the Appendix to this paper.

	FRACTURE STAGES				
	F1	F2	F3	F4	F5
Frac Height (m)	21.0	24.0	38.0	35.0	19.0
Frac Length (m)	45.0	67.0	86.4/49.5	69.4	69.6
Average Width (inch)	0.064	0.171	0.148/0.110	0.150	0.183
Avg. Propp. Conc. (lb/ft2)	0.53	1.4	1.21/0.90	1.23	1.49

Table 7 - (Matched) Fracture Final Geometry.

Well XX-1057

Final well configuration was: size 5 ½-inch casing, 6 spf perforation, 90-degree phase and 32-gram charges. Well completion was carried out using 2 7/8-inch tubing and packer to develop all the other stimulated zones. Two fractures were performed in this well in the Comodoro Rivadavia formation, and formation characteristics in the studied zones are presented in **Table 8**.

	Perforating Zone (m)		"h" Zone (m)	"h" Perf (m)	Avg Perm Log (mD)	Formation Press (SFT) (psi)	Porosity Log %
F2	2152.0	2154.5	2.5	2.5	2.676	2297	9.8
F1	2421.0	2424.0	3.0	3.0	2.114	3490	12.3

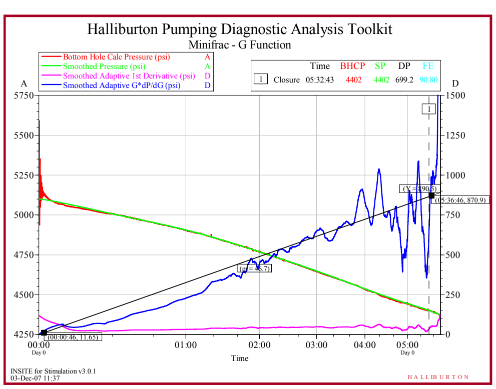
Table 8 - Petrophysical Characteristics of fractured zones.

For all stimulations, two diagnosis pumping stages were carried out in order to get information to match fracture simulator parameters. The first pumping was done with water plus surfactant and clay stabilizor; the injected volumes were about 2,000 gallons, thus obtaining closure pressure values (Stress), reservoir pressure and fluid loss mechanism.

In **Table 9**, the information pertaining to said analyses that show predominant fluid loss mechanism (**Figure 9**) can be observed, as well as the reservoir pressure determination (**Figure 10**) that belongs to stimulation number 1.

	G Funcion Analysis				SQRT Analysis		
	Closure Press psi	C.P Gradient psi/ft	Closure Time hr.min.seg.	Leakof Mechanims	Closure Press psi	C.P Gradient psi/ft	Closure Time hr.min.seg.
F1	< 4402	< 0.554	> 5:32:43	HR	< 4402	< 0.554	> 5:32:43
F2	3319	0.470	0:41:34	HR	3177	0.450	0:57:14

Table 9 - Closure Pressure Determination (“G” Function and SQRT- Square Root Time)



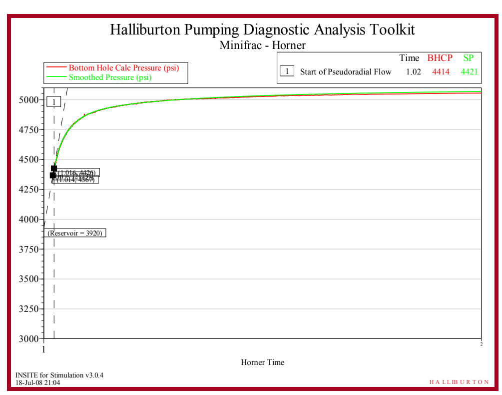


Figure 9 - “G” Function **Figure 10 - Horner’s Method**

The second pumping was performed with lineal gel, with injected volumes of about 3,000 gallons, and was finished with a SDRT (Step Down Rate Test) in which four changes were carried out. The aim was to complete determination of near wellbore frictions, and also to validate the determined values in the previous pumping stage (**Figure 11** – Fracture 1).

Table 10 presents the values determined with the surface sensor during the operation; it was also possible to analyze the information from the bottom hole sensor of the well after the information was recovered.

STEP DOWN RATE TEST Analysis		
SURFACE SENSOR	**F1**	**F2**
Perforation Friction	121	91
Near Wellbore Friction	314	241
Total Friction	435	332
BOTTOM HOLE SENSOR	**F1**	**F2**
Perforation Friction	46	106
Near Wellbore Friction	97	97
Total Friction	143	203

Table 10 - Near Wellbore Friction Analysis

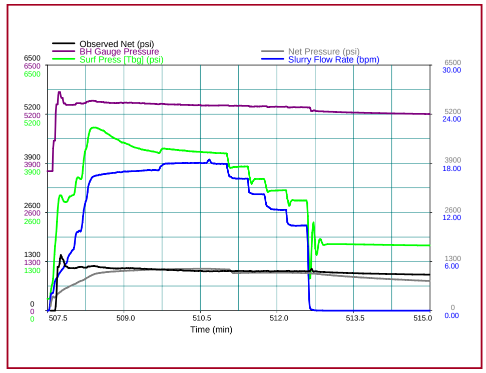


Figure 11. Pumping Record with Surface and Bottom Hole Sensor

The observed differences in friction between the analyses performed with the bottom hole and surface sensors correspond to friction effects of the pumped fluid in the pipeline (surface sensor). Analyzing the pumping with the bottom hole sensor data obtains effect independence of fluid friction in the pipeline.

Information from pumping permitted matching parameters in the fracture simulator. The values determined for the design and the data measured through pumping can be seen in **Table 11**.

	STRESS (psi)		FORMATION PRESSURE (psi)	
Frac Stages	**Dip. Sonic Log**	**Minifrac (measured)**	**SFT**	**MINIFRAC (Horner Plot) (measured)**
F1	4478	< 4402	3490	3918
F2	4167	3177	2297	2649

Table 11 - Validation of Design Parameters vs. Measured Values

All the stimulations were performed with fluid made with borate of low polymer charge and with resined coated sand (RCS) 20/40. Stimulations were carried out according to programmed treatments, with the information validation obtained in the previous pumping stages.

Results of each of the stimulations, which were finished according to the programmed design, can be seen in **Table 12**.

	FRACTURE STAGES	
	F1	**F2**
Avg. Pump Rate (bpm)	15.0	14.5
Avg. Pressure (psi)	3570	2760
ISIP (psi)	2100	1206
Frac Gradient (psi/ft)	0.70	0.61
Max Propp Conc (ppg)	7.0	7.0
PAD Percentage (%)	35	33
Proppant Designed (sks)	209	153
Proppant in formation (sks)	205	159
sks/m Designed	60	61
sks/m in Formation	59	64
Performance	OK	OK
Slug	NO	NO

Table 12 - Summary of Main Fracture Variables

Dipole sonic log analysis showed fracture height values (**Figure 12**), which were taken into account to calibrate the simulator. In Table 12 these obtained values are presented.

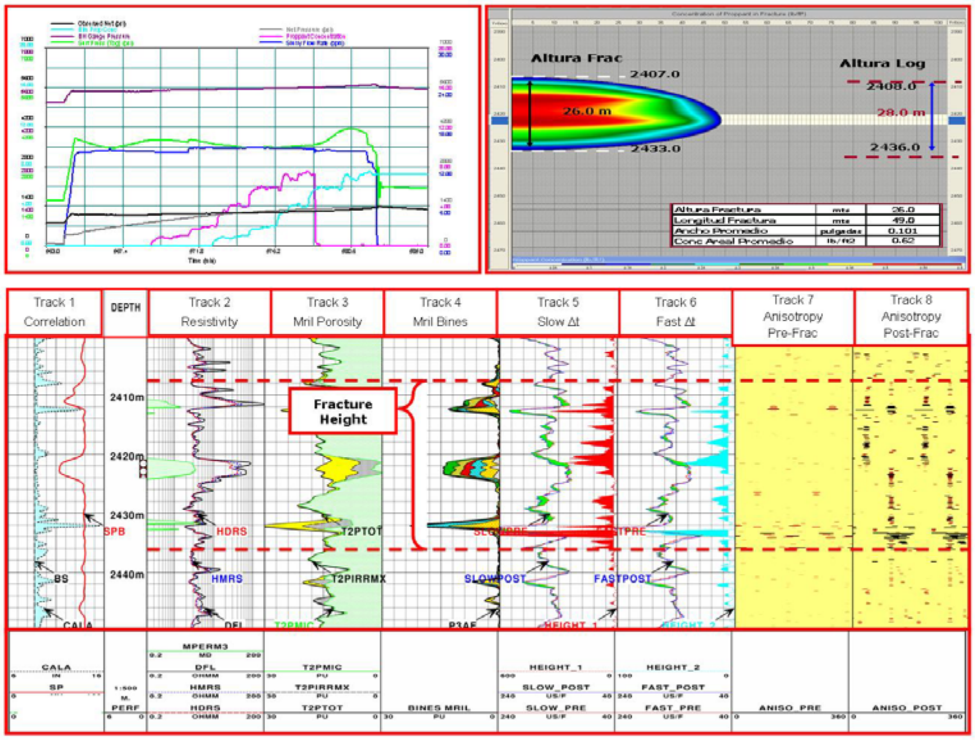


Figure 12 - Fracture Number 1 Determination, Matching and Final Geometry

HEIGHT FRACTURE (m)						
Stage	**Perforating Zone**		**Dip. Sonic Log**		**Matching simulator**	
F2	2152.0 2154.5	2.5	2138.0 2170.0	32.0	2136.0 2166.0	30.0
F1	2421.0 2424.0	3.0	2408.0 2436.0	28.0	2407.0 2433.0	26.0

Table 13. Fracture Height Measurement

Final geometries obtained through bottom hole pressure matching (BHP – Memory Gauge) and height in the fracture simulator are reported in **Table 14**.

	FRACTURE STAGES	
	F1	**F2**
Frac Height (m)	26.0	30.0
Frac Length (m)	49.0	42.0
Average Width (inch)	0.101	0.083
Avg. Propp. Conc. (lb/ft2)	0.62	0.52

Table 14. Fracture Final Geometry (matched)

Well XX-1069

Final well configuration was: 5½-inch casing, perforated at 4 spf, 90-degree phase and 32-gram charges. Well completion was performed through 2 7/8-inch tubing and packer to carry out all the stimulated zones. Nine stimulations were programmed in this well, eight being developed in the Mina del Carmen formation (altered reservoir).

Prior to stimulations, diagnosis pumping stages were conducted to determine zone variables such as closure pressure (Stress), reservoir pressure, and permeability values, and to determine near wellbore friction values. These stages were performed with lineal gel, treated water and fracture fluid; injecting volumes of about 3,500 gallons. Some determined values from pumping stages can be observed in **Table 15**.

	Perforating Zone (m)		"h" Perf (m)	STRESS (psi) Dip. Sonic Log	STRESS (psi) Minifrac	Leakoff mechanims
F9	1626.5	1632.0	5.5	3320	3000	NL
	1633.0	1636.0	3.0			
F8	1692.0	1694.0	2.0	3450	3350	TE
	1695.0	1698.0	3.0			
F7	1719.0	1727.5	8.5	3730	3550	PDL
F6	1770.0	1782.0	12.0	3900	3200	HR
F5	1816.5	1818.5	2.0	3580	3200	HR
	1820.0	1822.0	2.0			
	1824.0	1827.0	3.0			
	1829.0	1831.5	2.5			
F4	1892.0	1897.0	5.0	4030	3380	NL
	1898.5	1901.0	2.5			
	1904.5	1908.5	4.0			
F3	1964.0	1977.5	13.5	4060	3660	HR
F2	1997.0	2006.0	9.0	4296	3800	HR
	2020.0	2032.0	12.0			
F1	2062.0	2064.0	2.0	4550	3780	HR
	2068.0	2073.0	5.0			

Table 15 – Design Parameters Validation vs. Measured Parameters

All stimulations were developed with fluid made with borate low polymer charge and white sand 20/40 in the first four zones, and 16/30 in the remaining stimulations, adding a Conductivity enhancement in the first six fractures.

It is important to mention that while F3 fracturing was underway, the treatment was modified because of pressure response, as well as a modification occurring in F7 stimulation; a screen-out was produced, and based on subsequent analysis of previous pumping in F8, it was decided not to fracture the zone. The main information pertaining to stimulations is shown in **Table 16**.

	FRACTURE STAGES								
	F1	F2	F3	F4	F5	F6	F7	F8	F9
Avg. Pump Rate (bpm)	11.3	13.4	13.4	12.2	11.1	12.4	12.5	13.2	17.2
Avg. Pressure (psi)	2780	3111	3000	2530	2240	2190	3030	3115	3200
ISIP (psi)	1320	1450	1320	1250	1300	1020	s/d	s/d	1565
Frac Gradient (psi/ft)	0.63	0.66	0.64	0.64	0.66	0.61	s/d	s/d	0.73
Max Propp Conc (ppg)	8.0	8.0	8.0	8.0	8.0	8.0	4.0	s/d	8.0
PAD Percentage (%)	45	58	30	25	30	43	30	s/d	63
Proppant Designed (sks)	300	745	540	390	400	430	328	200	450
Proppant in formation (sks)	298	745	420	387	402	429	77	s/d	460
Performance	OK	OK	OK	OK	OK	OK	S.O.	NO FRAC	OK

Table 16 – Summary of the Principal Fracture Variables

Height determination with sonic log (Figures 13 and 14) showed the following values, presented in **Table 17**; the determined values can be observed, as well as those obtained in the matching of the fracture simulator, showing very good consistency in the whole well.

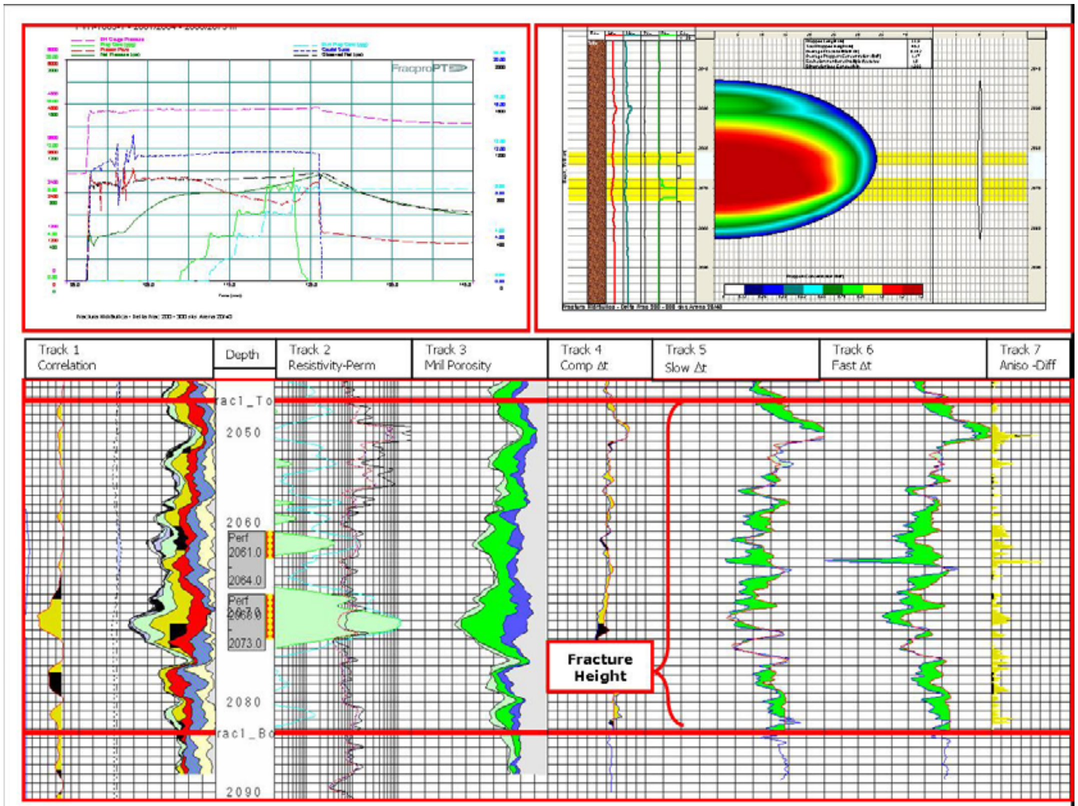


Figure 13 - Fracture Number 1 Determination, Matching and Final Geometry

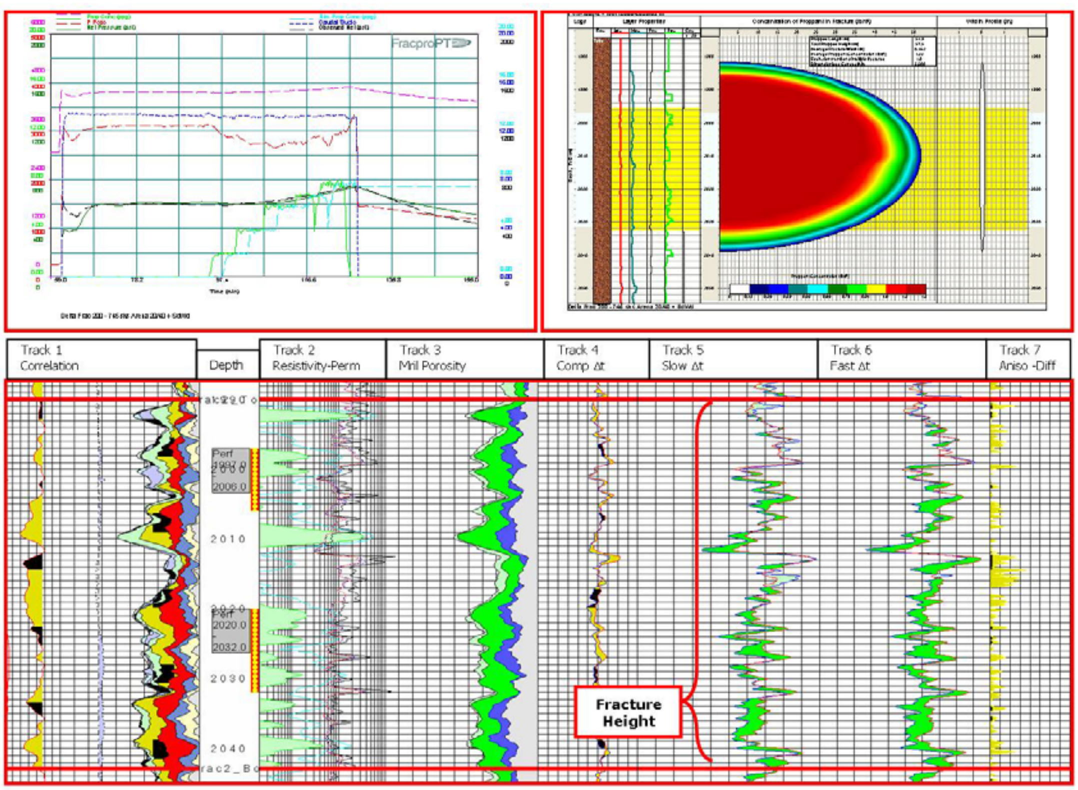


Figure 14 - Fracture Number 2 Determination, Matching and Final Geometry

HEIGHT FRACTURE (m)				
Stage	Perforating Zone		Dip.Sonic Log	Matching simulator
F9	1626.5 1636.0	9.5	49.9	54.0
F8	1692.0 1698.0	5.0	12.3	24.0
F7	1719.0 1727.5	8.5	26.4	25.0
F6	1770.0 1782.0	12.0	55.4	59.0
F5	1816.5 1831.5	9.5	45.7	39.0
F4	1892.0 1908.5	11.5	49.9	50.6
F3	1964.0 1977.5	13.5	43.1	41.3
F2	1997.0 2032.0	21.0	52.9	59.0
F1	2061.0 2073.0	7.0	36.9	45.0

Table 17 – Fracture Height Measurement

Final geometries obtained with bottom pressure matching (BHP – Memory Gauge) and height in the fracture simulator are reported in **Table 18**.

	FRACTURE STAGES								
	F1	F2	F3	F4	F5	F6	F7	F8	F9
Frac Height (m)	45.0	59.0	41.3	50.6	39.0	59.0	25.0	24.0	54.0
Frac Length (m)	34.0	52.0	41.9	40.5	35.8	37.8	31.0	s/d	70.7
Average Width (inch)	0.142	0.162	0.174	0.130	0.183	0.130	0.082	s/d	0.19
Avg. Propp. Conc. (lb/ft2)	1.16	1.33	1.43	1.06	1.5	1.06	0.67	s/d	0.69

Table 18 - Fracture Final Geometry (matched)

Wells XX-1081 and XX-985

The remaining wells went through the same analyses as those described. The Appendix contains the tables corresponding to the analyses performed, as well as the stimulations graphs that have been added. It is necessary to mention that in well XX-985 only the fracture height estimate could be developed in the zones which belong to Fractures 2, 3 and 6 since the sonic record was affected owing to bad cement conditions in other study zones.

Adimensional Productivity Index Analysis (Well XX-1056)

To select the fracture design to be used, the a-dimensional productivity index was used during the simulation stage prior to actual operations.

The referenced theory by Economides (Romero, 2002) describes the correlation between "proppant number", "a-dimensional conductivity" and "a-dimensional productivity index".

For each productive interval, fractures with 20, 45, and 60 sks/m layer thickness were simulated, and the best designs selected for each zone.

Note that in this first stage, the productivity index was used with a selective criterion of the kind of treatment. The following step was to compare said designs with those ones actually obtained.

The later analysis with information on fracture height, post-matching and fracture simulator calibration made it possible to determine the actual productivity index of each of the treatments. In **Figure 15** the results are presented for each of the intervals, designated DESIGN (Pre-sonic) vs. REAL (Post-sonic).

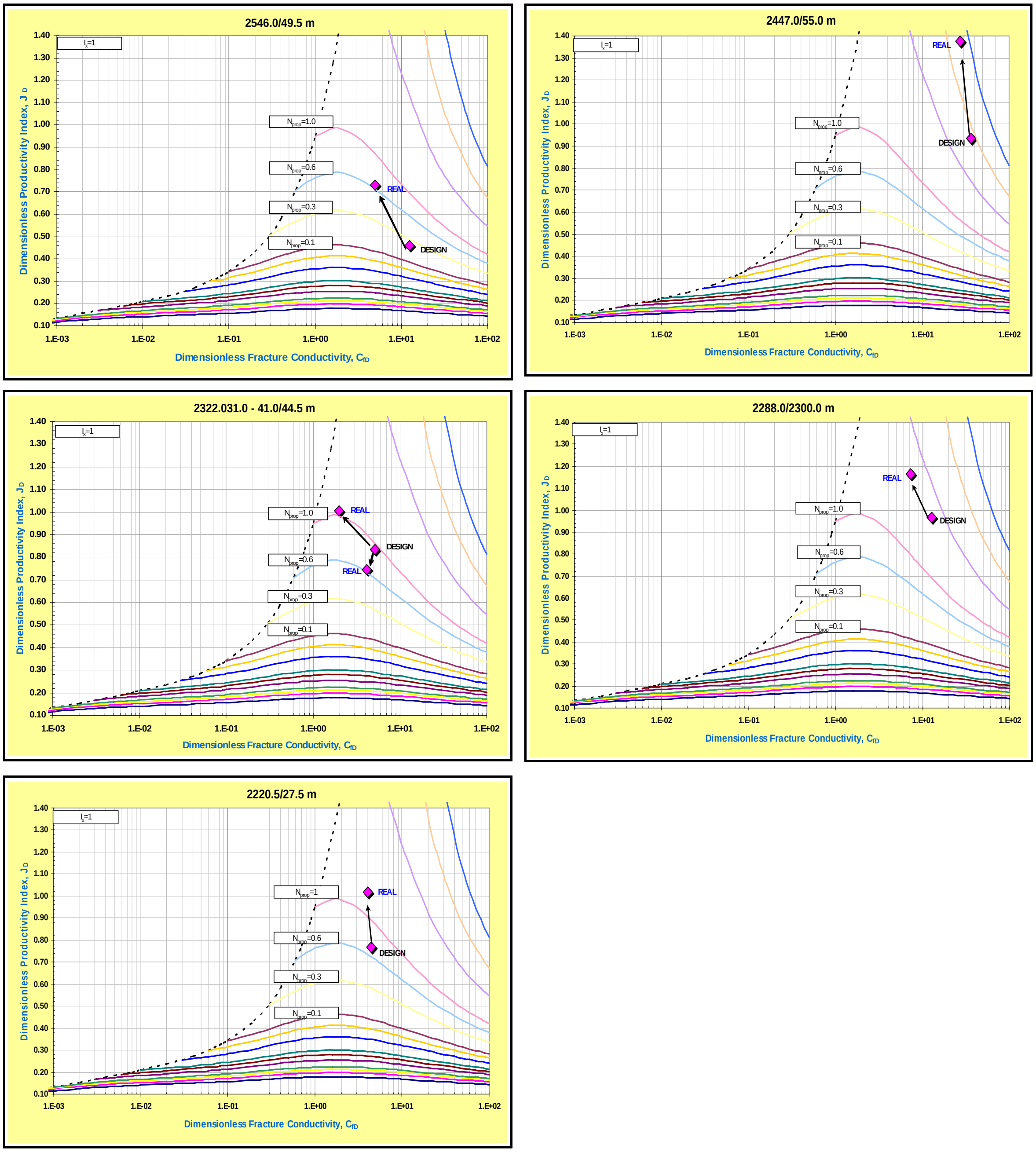


Figure 15 - Adimensional Productivity Index

The conclusion of this comparison is that productivity indices during the first stage of the design were underestimated with respect to the results obtained at the end of the operation. This is likely due to a parameter combination such as fracture length and its conductivity which may have been ranked a certain way during the design stage and in reality, turned out to be better than expected.

Conclusions

Dipole sonic log utilization to determine fracture height has shown consistency in most wells, making this a valid tool for such variable analysis.

Stress values determined from the sonic log were very close to those obtained in calibration pumping stages.

Final fracture matching in the MEC formation has been achieved by modifying the original Dynamic Young Modulus value by 30 to 35 percent, as well as modifying values of 12 for the composite layering effect (variable from fracture simulator). In the CR formation it was necessary to match the composite layering effect to values from 18 to 23.

In terms of the analyses carried out, greater understanding of final geometries for each fracture treated was possible. In the Mina del Carmen formation, fractures are well contained although the same does not apply in the MEC-altered reservoir since it has larger height growth. For the CR formation, it was observed that the fractures present greater growth in height than the others.

With the information obtained in this case study, two fracture simulation models could be defined for each of the analyzed formations, further increasing certainty and credibility of results.

Productivity analysis developed for well XX-1056 showed important application potential; a fracture simulator validation is necessary for further matching in order to optimize treatment designs.

As a result of this paper, modifications to the stimulation design criteria have been put into practice and are being evaluated.

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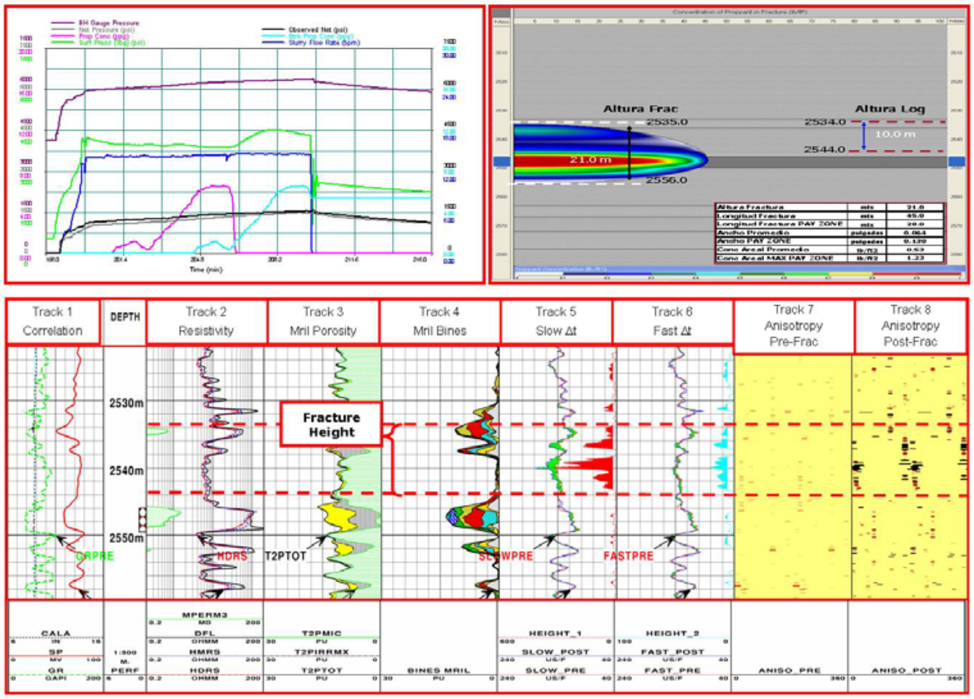
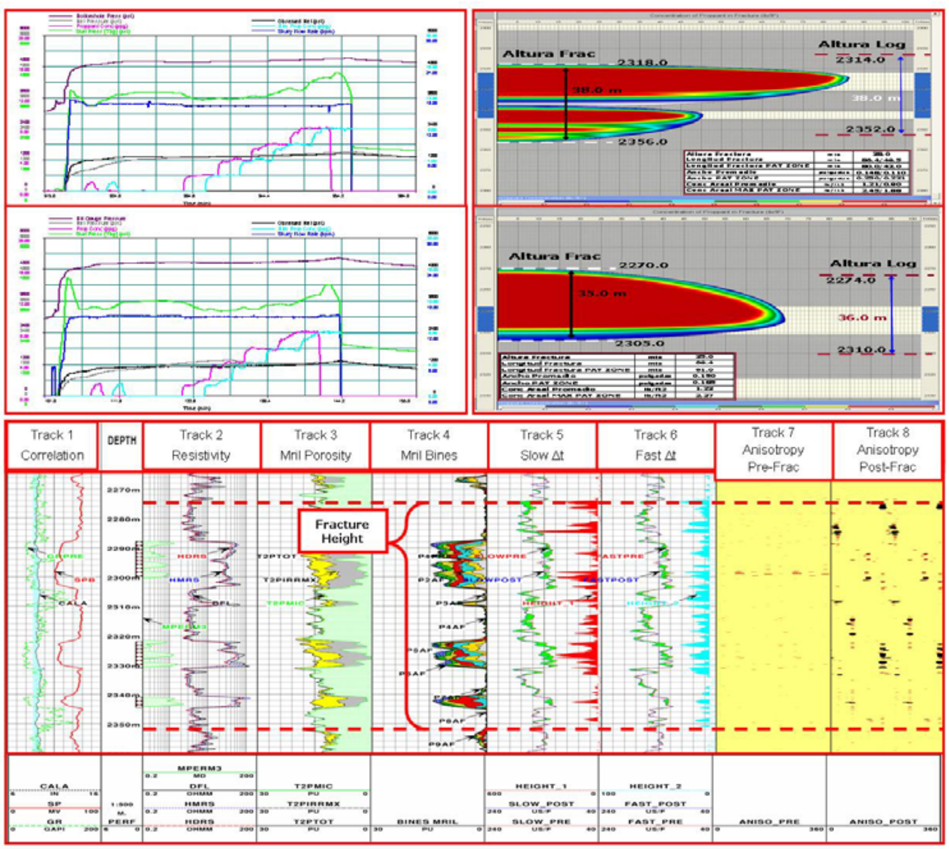
Appendix

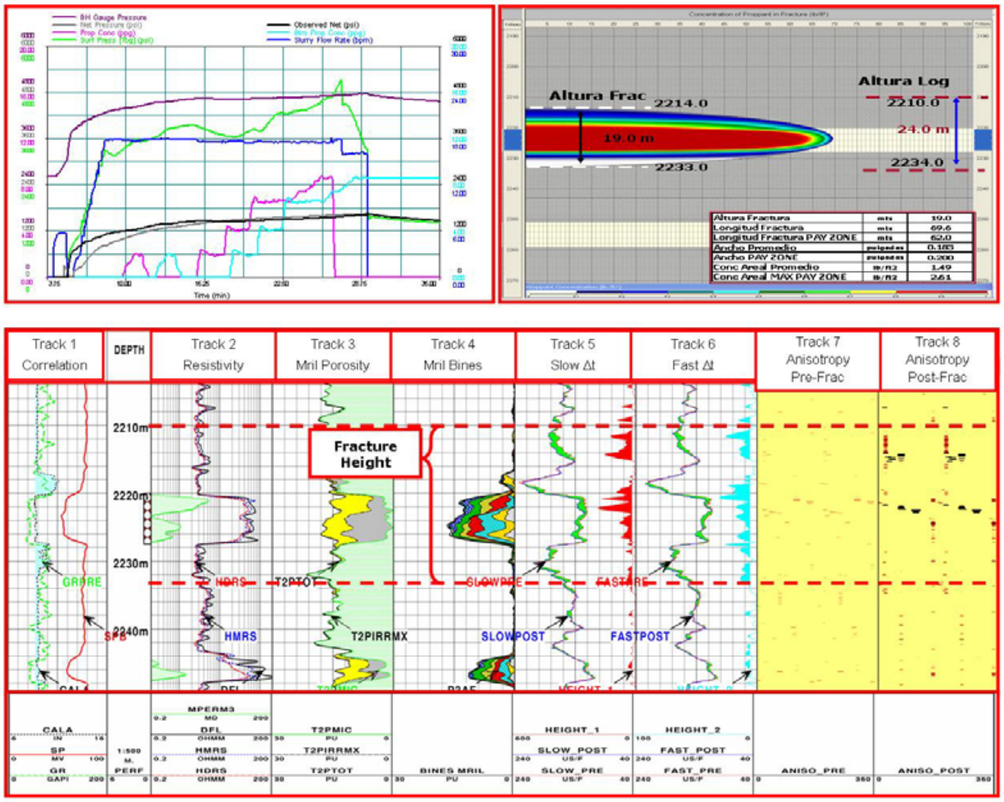
Well XX-1056



Fracture N. 1 – Determination, Matching and Final Geometry



Fracture N. 3 and 4 – Determination, Matching and Final Geometry



Fracture N. 5 – Determination, Matching and Final Geometry

Well XX-1081

	Perforating Zone (m)		"h" Perf (m)	STRESS (psi) Dip. Sonic Log	Minifrac	Leakoff mechanims
F7	1855.0	1858.0	3.0	3632	3619	HR
F6	1923.5	1937.5	14.0	3719	3916	PDL
F5	1962.0	1966.0	4.0	3969	3808	PDL
F4	1991.0	1999.0	8.0	3619	3753	HR
	2000.0	2020.0	20.0			
F3	2041.0	2047.0	6.0	4074	4009	HR
	2050.0	2055.0	5.0			
F2	2082.0	2084.5	2.5	4473	4265	HR
	2089.0	2092.0	3.0			
F1	2342.0	2345.0	3.0	4544	4694	HR

Design Parameters Validation vs. Measured Values

	FRACTURE STAGES						
	F1	F2	F3	F4	F5	F6	F7
Avg. Pump Rate (bpm)	13.8	12.4	16.5	16.0	12.3	16.6	11.9
Avg. Pressure (psi)	4890	3370	3760	3300	3240	3880	3050
ISIP (psi)	2660	2260	1660	1430	s/d	2330	2000
Frac Gradient (psi/ft)	0.78	0.77	0.69	0.66	s/d	0.81	0.77
Max Propp Conc (ppg)	7.0	8.0	8.0	8.0	8.0	6.0	7.0
PAD Percentage (%)	53	42	75	53	44	80	36
Proppant Designed (sks)	178	342	530	667	192	540	165
Proppant in formation (sks)	175	341	482	665	177	400	163
Performance	OK	OK	OK	OK	S.O.	OK	OK

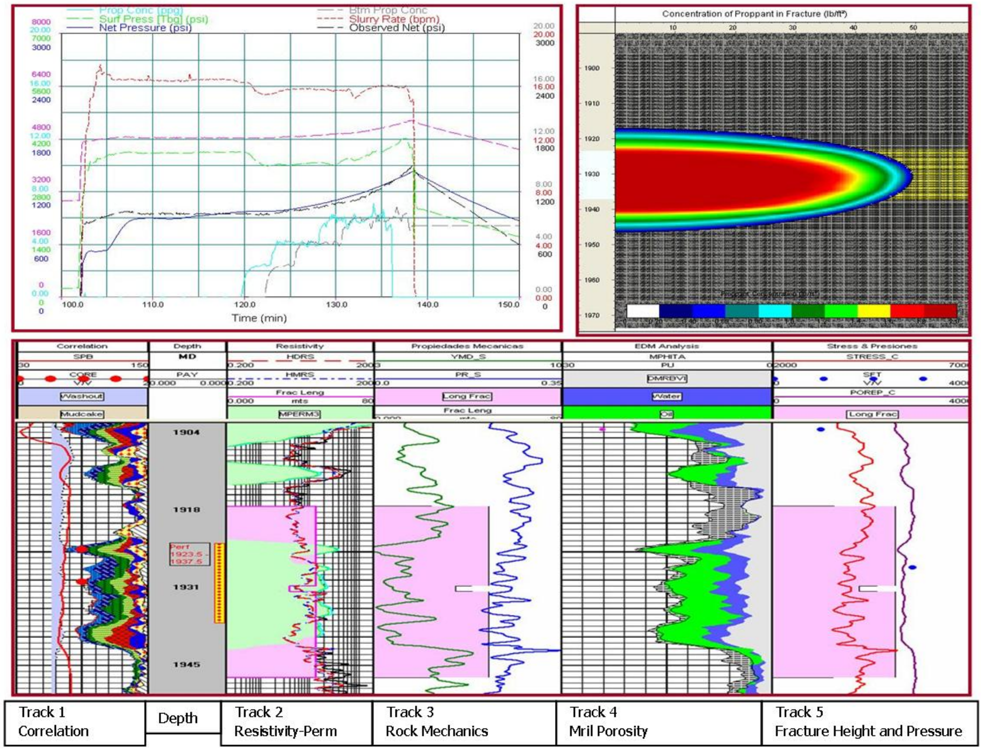
Summary of Main Fracture Variables

HEIGHT FRACTURE (m)						
Stage	Perforating Zone		Dip.Sonic Log		Matching simulator	
F7	1855.0 1858.0	3.0	1837.0 1860.0	23.0	1839.0 1869.0	30.0
F6	1923.5 1937.5	14.0	1906.0 1939.0	33.0	1916.0 1947.0	31.0
F5	1962.0 1966.0	4.0	1952.0 1972.0	20.0	1951.5 1974.0	22.5
F4	1991.0 1999.0 2000.0 2020.0	8.0 20.0	1975.0 2031.0	56.0	1972.0 2034.0	62.0
F3	2041.0 2047.0 2050.0 2055.0	6.0 5.0	2033.0 2068.0	35.0	2026.0 2066.0	40.0
F2	2082.0 2084.5 2089.0 2092.0	2.5 3.0	2071.0 2103.0	32.0	2075.0 2107.0	32.0
F1	2342.0 2345.0	3.0	2332.0 2354.0	22.0	2330.0 2354.5	24.5

Fracture Height Measurement

	FRACTURE STAGES						
	F1	F2	F3	F4	F5	F6	F7
Frac Height (m)	24.5	32.0	40.0	62.0	22.5	31.0	30.0
Frac Length (m)	65.0	36.0	45.2	68.0/39.3	35.0	49.5	31.0
Average Width (inch)	0.066	0.152	0.181	0.093/0.129	0.152	0.198	0.112
Avg. Propp. Conc. (lb/ft2)	0.94	1.77	2.04	1.0/1.47	2.17	2.37	0.91

Fracture Final Geometry (matched)



Fracture N. 6 – Determination, Matching and Final Geometry

Well XX-985

	Perforating Zone (m)		"h" Zone (m)	"h" Perf (m)	Avg Perm Log (mD)	Formation Press (SFT) (psi)	Porosity Log %
F6	1765.0	1768.0	5.0	3.0	2.183	2452	21.83
	1773.0	1778.0	7.0	5.0			
	1782.5	1785.5	3.5	3.0			
	1788.0	1794.5	7.0	6.5			
F3	2182.5	2188.0	6.0	5.5	1.827	3588	10.95
F2	2326.5	2329.0	3.0	2.5	6.003	3538	12.19

Petrophysical Characteristics of Fractured Zones

	G Funcion Analysis				SQRT Analysis		
	Closure Press psi	C.P Gradient psi/ft	Closure Time hr.min.seg.	Leakof Mechanims	Closure Press psi	C.P Gradient psi/ft	Closure Time hr.min.seg.
F2	4872	0.638	0:05:09	HR	4681	0.613	0:07:49
F3	4738	0.661	0:02:18	NL	4475	0.624	0:03:34
F6	3557	0.609	0:06:45	HR	3370	0.577	0:11:26

Closure Pressure Determination (“G” Function and SQRT- Square Root Time)

STEP DOWN RATE TEST Analysis			
SURFACE SENSOR	F2	F3	F6
Perforation Friction	12	94	29
Near Wellbore Friction	375	307	252
Total Friction	387	401	281
BOTTOM HOLE SENSOR	F2	F3	F6
Perforation Friction	134	79	38
Near Wellbore Friction	185	248	61
Total Friction	319	327	99

Near Wellbore Friction Analysis

	STRESS (psi)		FORMATION PRESSURE (psi)	
Frac Stages	Dipole Sonic Log	Minifrac (measured)	SFT	MINIFRAC (Horner Plot) (measured)
F2	4328	4681	3588	3528
F3	4182	4475	1693	2711
F6	3585	3370	2452	2704

Design Validation vs. Measured

	FRACTURE STAGES		
	F2	F3	F6
Avg. Pump Rate (bpm)	14.3	14.1	16.4
Avg. Pressure (psi)	4085	4595	3050
ISIP (psi)	2465	3115	1952
Frac Gradient (psi/ft)	0.76	0.87	0.77
Max Propp Conc (ppg)	5.2	8.5	10.0
PAD Percentage (%)	59	53	54
Proppant Designed (sks)	85	262	899
Proppant in formation (sks)	91	257	901
sks/m Designed	28	48	43
sks/m in Formation	30	47	43
Performance	OK	OK	OK
Slug	YES	YES	YES

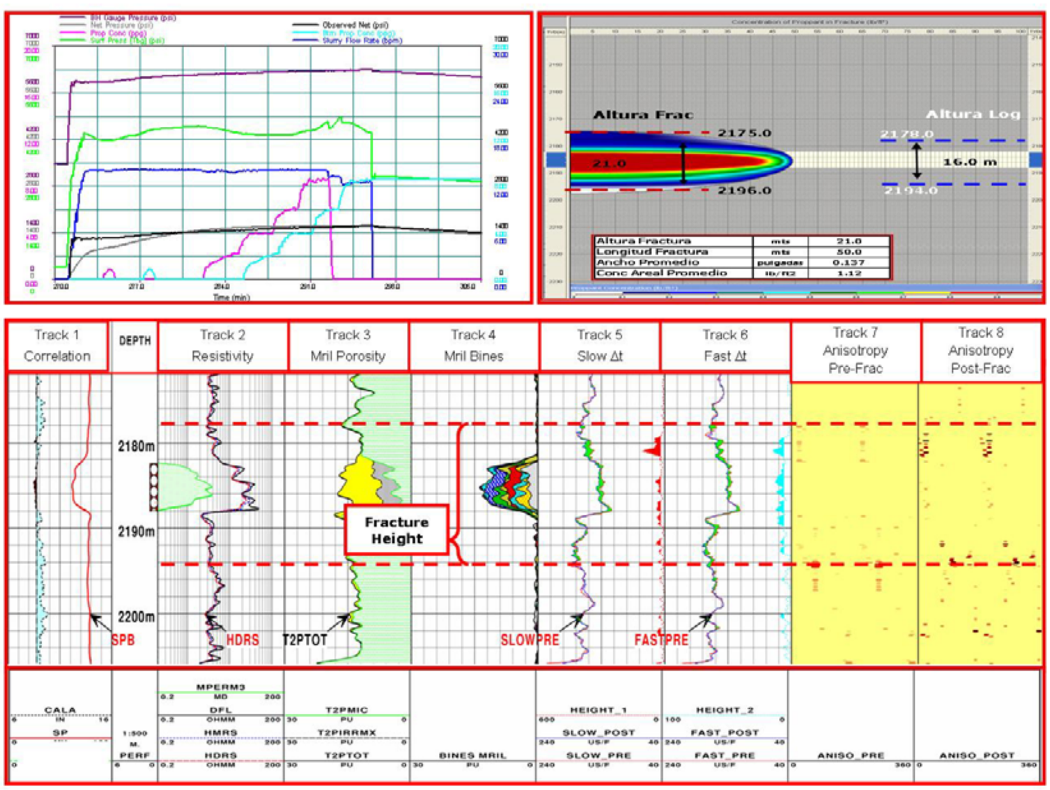
Summary of Main Fracture Variables

HEIGHT FRACTURE (m)						
Stage	Perforating Zone		Dip. Sonic Log		Matching simulator	
F6	1765.0	3.0	1757.0	39.0	1760.0	38.0
	1768.0					
	1773.0	5.0				
	1778.0					
	1782.5	3.0				
	1785.5					
	1788.0	6.5				
	1794.5		1796.0		1798.0	
F3	2182.5	5.5	2178.0	16.0	2175.0	21.0
	2188.0		2194.0		2196.0	
F2	2326.5	2.5	2320.0	20.0	2318.0	18.0
	2329.0		2340.0		2336.0	

Fracture Height Measurement

	FRACTURE STAGES					
	F2	F3	F6			
			Perf-1	Perf-2	Perf-3	Perf-4
Frac Height (m)	18.0	21.0	20.0	33.0	35.0	36.0
Frac Length (m)	33.5	50.0	40.0	36.0	23.0	20.0
Average Width (inch)	0.082	0.137	0.14	0.23	0.2	0.14
Avg. Propp. Conc. (lb/ft2)	0.67	1.12	1.11	1.81	1.57	1.1

Fracture Final Geometry (matched)



Fracture N.3 – Determination, Matching and Final Geometry