New NMR-Based Methodology for Inferring the Presence of Movable Heavy Oil in Reservoir Layers*

Pedro A.Romero[1], Nestor Acosta[2], and Hiran Serrano[3]

[1]Baker Hughes Inc., Rio de Janeiro, Brazil (pedro.romero@bakerhughes.com)
[2]Baker Hughes Inc., Comodoro Rivadavia, Argentina
[3]YPF S.A., Comodoro Rivadavia, Argentina

Abstract

The present contribution is the result of the authors' several experiences in the NMR analysis of sandstone reservoirs with argillaceous-tuffaceous matrix belonging to geological formations of Cretaceous age. It is intended to highlight the advantages and synthetically show the main aspects of the use of NMR tools for characterization of movable heavy oil in continental clastic reservoirs of the Gulf of San Jorge Basin in Argentina. The methodology presented is for inferring the presence of movable heavy oil in reservoir layers of a fluvial environment. It is based on six main principal indicators:

- reservoir pressure
- development of spontaneous potential
- increase of the resistivity response of the layer
- the slope of the T2 log mean of the furthest right hand side lobe of the T2 distribution when plotted in depth
- the presence of water-based mud filtrate in the DT2 maps
- the NMR permeability

When these indicators are considered, the prediction of the layer can be forecast with high probability. This work specially describes how NMR derived properties improve the fluid typing in these reservoirs. The present approach has been validated with measured data from production tests.

Introduction

The San Jorge Basin is one of the main hydrocarbon producing basins of Argentina. The singularities of these reservoirs, their complex lithology and hydrocarbon characteristics drive the application of leading edge technologies in order to assess more accurately the quality of these reservoirs. Detecting productive reservoir layers in the Gulf of San Jorge Basin in Argentina has been a big challenge ever since. Among others factors, sedimentary environment, complex lithology and, last but not least, the diverse response of the formation and formation fluids to gamma ray and resistivity logging techniques respectively complicate the petrophysical evaluation of the layers. Therefore, new logging technologies that can reduce the risk of a failed interpretation of the reservoir are urgently needed. The expectation is to minimize the testing of wet layers and the associated cost of producing them, by a prior identification of those intervals which can drive an economical optimization of the reservoir management. The NMR logging technique has some inherent advantages that can be used for purposes of increasing the efficiency in the reservoir management. Some of these advantages are:

- Identification of bound and movable water and permeability (reservoir quality).
- Hydrocarbon Typing (heavy, medium, light oil and viscosity estimation).

Traditionally, fluid typing interpretation in the San Jorge Basin has been done, based on conventional logs together with the NMR derived MGTE interpretation. MGTE is a one dimensional representation, or 1D-NMR, that yields T2 spectra for different GTE (magnetic field gradient G times inter-echo time TE) values. MGTE layout displays three tracks of T2 apparent spectra corresponding to different GTE values, normally in increasing order from left to right, as can be seen in Figure 1. MGTE is basically qualitative, and may depend heavily on own ones criteria set by the interpreter.

NMR, thus being a nonconventional and expensive technology, is required to yield even more accurate information about the formation properties compared to conventional logging services and 1D-NMR. To increase the added value from NMR services, a 2D-NMR product has been developed, that displays a continuous log of map-like representations of the fluid diffusivity versus the T2 intrinsic spectra; the T2 intrinsic represents the transversal distribution obtained at zero magnetic field gradient. These representations, also called DT2 maps, play a key role in the development of a methodology for inferring the presence of movable heavy oil in reservoir layers (Figure 2).

A commonly used acquisition mode of NMR data using the MReX™ tool in the Gulf of San Jorge Basin has been the so called Fast PoroPerm plus Oil, which takes advantage of the specific polarization times of the formation fluids. This acquisition sequence has been proved to deliver very good results in terms of 1D- and 2D-NMR products having a very competitive logging speed.

Geological Reservoir Characteristics

Log data acquisition using a NMR tool with magnetic field gradient capability, provides the perfect application for sedimentary

deposits formed by clastic materials of a pyroclastic and volcanic nature, with significant variation in matrix compositions, cement minerals and pore size distributions. In some cases, the reservoirs of the Bajo Barreal formation show lower porosities, due to an increase of burial and diagenetic activities. Such porosity changes take place probably due to three main processes: mechanic compaction, grain dissolution by inter-granular contacts and pore cementation (Pitman et, al., 1991). These phenomena add some additional challenges in the analysis of reservoir quality. On the other hand, the characteristics of the multi-layer reservoir bearing hydrocarbons of different API gravities and viscosities make the evaluation of these reservoirs even more difficult. Therefore, the San Jorge Gulf Basin is probably the part of the world with the most nuclear magnetic resonance logs, a fact that makes possible the analysis and optimization of several interpretation approaches.

Traditional Methodology Used and New Proposal

Traditionally, and since 2004, the evaluation and production forecast of reservoir layers in the San Jorge Basin has been done by the visual analysis of the three MGTE tracks. For the Fast PoroPerm plus Oil MReX^{TM} acquisition mode, the GTE values are approximately: 13, 55 and 96.

Based on one's own experience, the log analyst estimates how the different shapes of the T2 apparent distributions may vary because of the GTE effect. Thereafter, the analyst completes the forecast table (Table 1), considering whether the layer passes or not the cutoffs set for porosity, permeability and, if available, the formation pressure. In addition, the water and oil spectra generated by SIMET™ (Simultaneous Inversion of Multiple Echo Trains), which is a forward modeling post-processing tool, provides an additional fluid typing capability complementing the analysis of different GTE spectra.

The newly developed methodology works adding 1D- and 2D-NMR information as follows:

1. Searching negative slope in depth of the T2 log mean (T2LM) for the extreme hand right side lobe of the MGTE spectral window only. Figure 3 shows possible slopes of the T2LM in depth, for the T2 spectral window right from the water line (vertical, blue line): when the slope is nearly zero (case A) the formation is wet, with no significant grain size changes. A positive slope (case B) also indicates water, and grain size changes from fine at the top, to coarse at the bottom. A negative slope (case C) indicates the presence of oil, as the water in the emulsion tends to be very sensitive to the GTE effect, exploited in the MGTE evaluation module. Because of the oil saturation profile, the higher oil saturation at the top of the layer, the higher the wbmf and therefore the emulsified fluid in the near borehole; this explains the origin of the negative slope, as more emulsified fluid should be expected at the top, than at the bottom.

2. Searching for the presence of water-based mud filtrate in the DT2 map: as the water-based mud filtrate (wbmf) may cause the building up of an emulsion with the formation oil, with the water phase relaxing close to the magnitude of bulk water (in seconds). Figure 4 shows the wbmf relaxing with a maximum T2 intrinsic peak at 2 s. The wbmf is characteristic for the presence of oil in the layer. However, care should be taken in avoiding misinterpretation of the wbmf image spot as movable water in big pores.

Discussion: Invasion of Water-Based Mud Filtrate

As a general assumption, the producing layers should have a higher permeability than the non-producing ones; but this alone does not necessarily contribute to differentiate oil from water production. For a given porosity and over-balanced conditions, wbmf might invade the formation having an NMR response which strongly depends on its interaction with the original formation fluid, oil or water. If the formation is totally water wet, the wbmf can mix with the formation water and/or displace oil and interact directly with the pore surface.

In water layers, the wbmf cannot be differentiated from the formation water, as there is no NMR contrast between both fluids in the mixture. In this case, the transversal relaxation of the water is expected to be dominated by the pore-surface-volume relaxation phenomenon, S/V. In oil-bearing layers, the wbmf does displace the oil, but is not kept attached to the pore walls; therefore it will not relax, due to an S/V process, but due to bulk relaxation effects, with main relaxation times above 1024ms. Depending on the strength of the coupling between the water diffusivity and the GTE factor, the shifts of the wbmf component in the T2 spectral window can be observed. It is important to understand that the GTE factor is defined by the data acquisition mode in which the tool has been activated, e.g. Fast PoroPerm plus Oil or PoroPerm plus Oil.

Conclusions

Because of the presence of fresh water, the formation resistivity is not fully reliable as a hydrocarbon indicator in the Gulf of San Jorge Basin, Argentina.

The high transversal intrinsic relaxation time, T2 intrinsic, of water-based mud filtrate, is a very significant indicator of an oil-bearing reservoir layer, as it shows the ability of the water to displace oil. Although it happens for over-balanced conditions, at draw-down, when the layers are put in production, similar behavior could be expected.

Bulk relaxivity and less S/V phenomena explain the signature of the water-based mud filtrate on the 2D-NMR of Diffusivity vs. T2intrinsic map, where the relaxation time is above 1024 ms. The T2 apparent spectra displayed for different GTE values reflect the diffusion enhanced relaxation of water-based mud signal when displacing oil.

In wet layers, there is no NMR contrast between formation water and water-based mud filtrate.

References

Acosta, N., 2008, Analysis of Nuclear Magnetic Resonance for characterization of continental clastic reservoirs, San Jorge Basin, Argentina: Naturalia Patagonic Science Magazine.

Acosta, N., P. Romero, G. Magenta, G. Potas, C. Cabrera, C. Coccia, L. Di Benedetto, and L. Ferreira, 2007, Methodology for characterization of a clastic reservoir based on correlations between electrofacies, NMR and image logs, A case study from San Jorge Basin: 10th. International Congress of the Brazilian Geophysical Society and EXPOGEF, Rio de Janeiro, Brazil,

Acosta, N., E. Estrada, and B. Saavedra, 2007, Porosity variations by diagenesis in reservoirs of the Bajo Barreal Formation, San Jorge Basin: Methodology of evaluation with logs: X Latin American and Caribbean Petroleum Engineering Conference, SPE # 108065, Buenos Aires, Argentina.

Breda, E., and M. Lucero (Repsol-YPF), 2005, Caracterización de los reservorios de la Formación Bajo Barreal Inferior Arenas y Tobas (Sección Tobácea), VI Congreso de Exploración y Desarrollo de Hidrocarburos, 1, p. 197-214. Mar del Plata, Argentina.

Chen, S., G. Hursan, D. Beard, and D. Georgi, SPE 84481: G.TE Correction for Processing Multigradient, Multiple –TE NMR Log Data. SPE, Texas, USA.

Domínguez, H., B. Saavedra, A. Corbelleri, and L. Sliwinsky, 2005, Uso de resonancia magnética nuclear para la caracterización de reservorios y fluidos en yacimientos de la Cuenca del Golfo San Jorge, Patagonia, Argentina: VI Congreso de Exploración y Desarrollo de Hidrocarburos, Mar del Plata, 1, p. 59-71.

Gómez, Hugo, Luis Stinco, Alejandro Nawratil, Javier Lopetrone, Pedro Romero, and Benito Saavedra, 2007, Correction of bound and free fluid volumes in the Timur-Coates permeability equation for the presence of heavy oil -A case study from the Gulf of San Jorge Basin, Argentina: SPE 107784, SPE 2007 SPE Latin American and Caribbean Petroleum Engineering Conference (LAPEC), Buenos Aires, Argentina, 15–18 April 2007.

Pitman, E.D., and R.E. Larese, 1991, Compaction of lithic sands: Experimental result and applications, AAPG Bulletin, v. 75, p. 1279-1299.
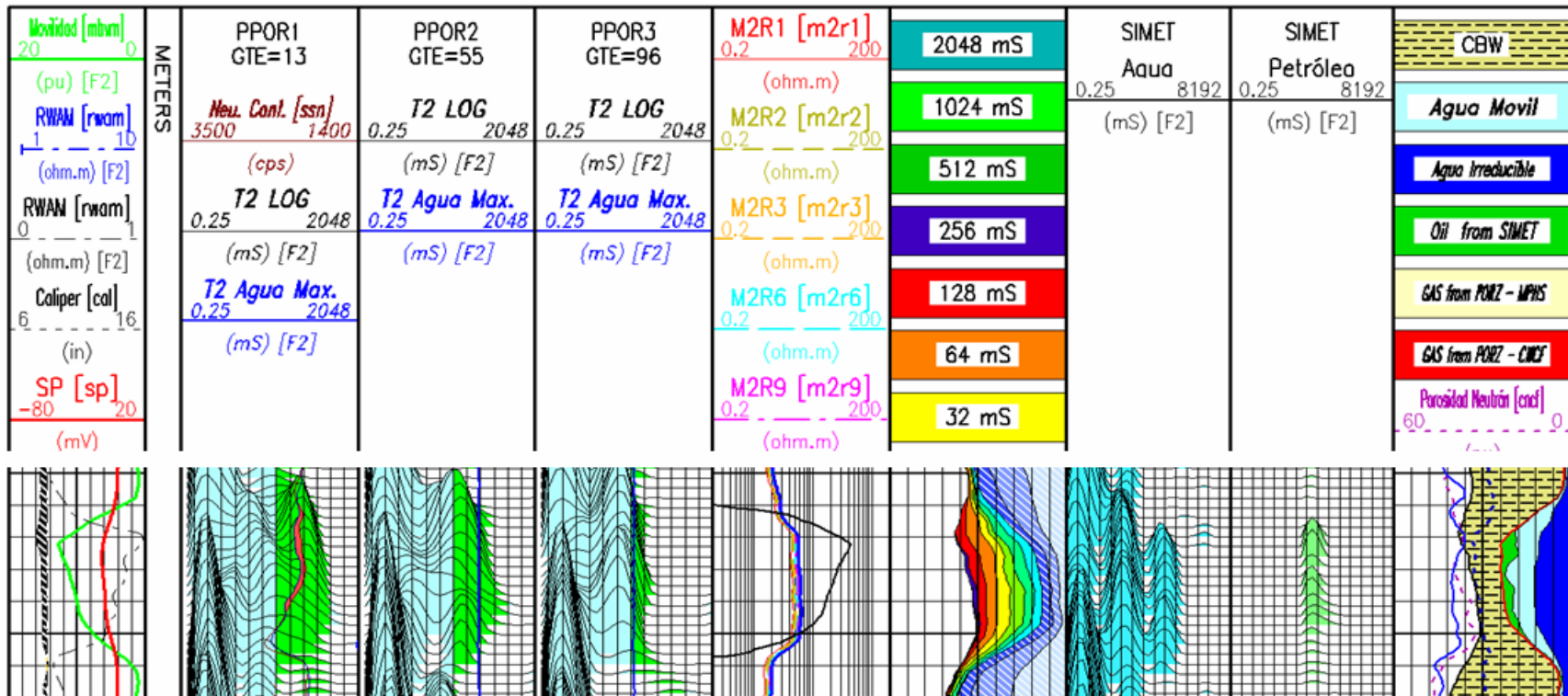
Figure 1. Traditional MGTE-SIMET NMR log display of a clastic reservoir of the Gulf of San Jorge Basin, Argentina.

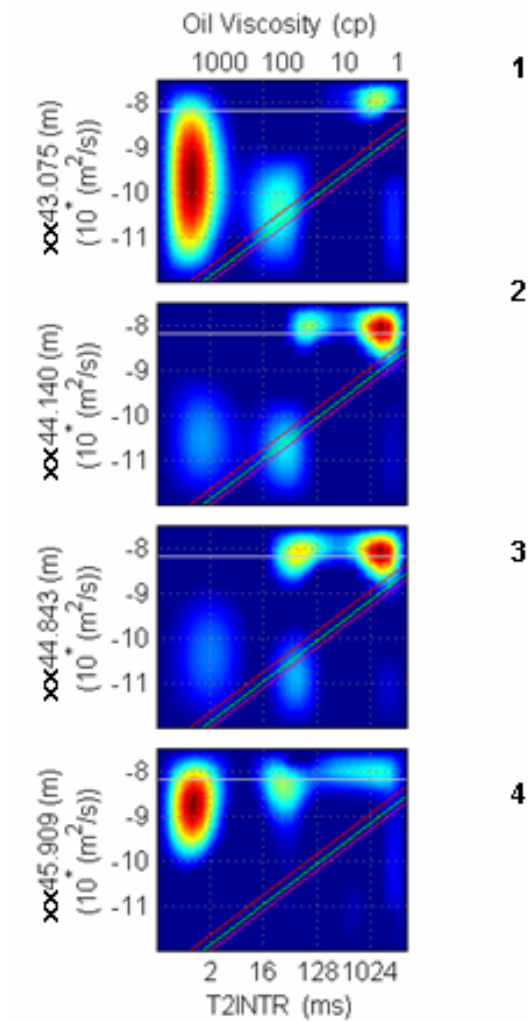Figure 2. Sequence of DT2 maps of an oil producing interval (1-3) with increasing water saturation. At the bottom depth (4) the layer is totally wet.
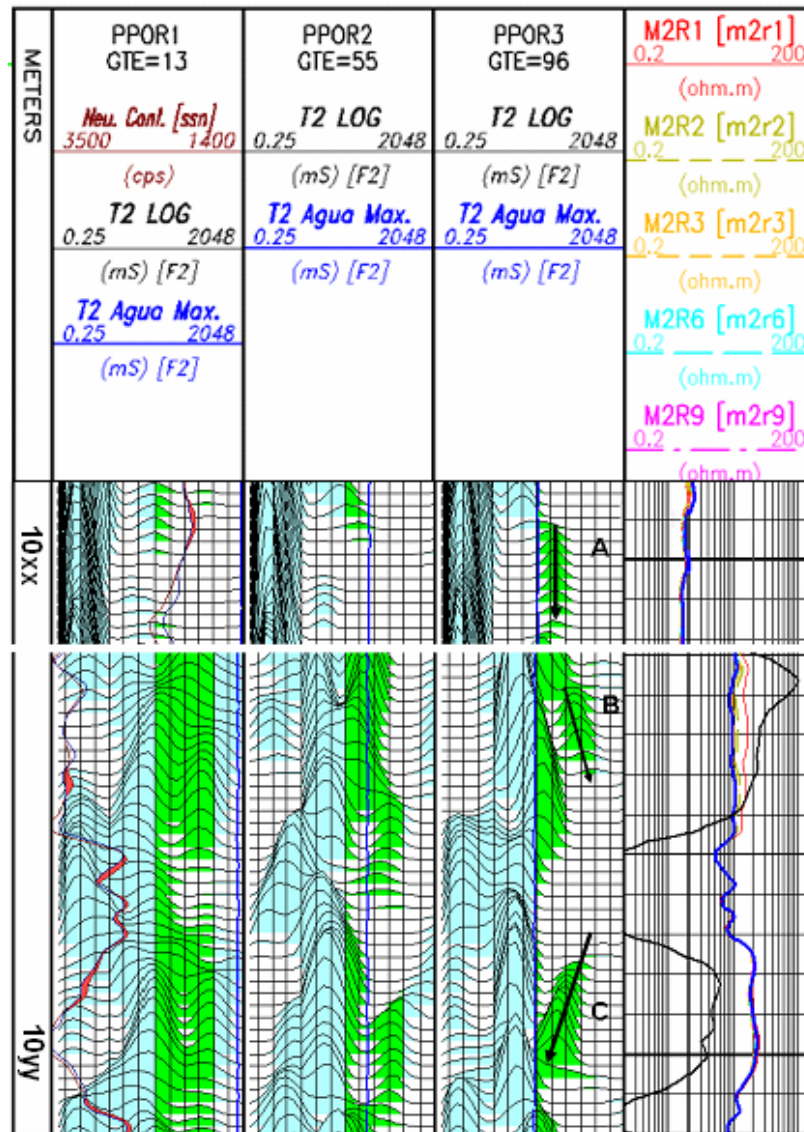
Figure 3. MGTE display with different slopes of the T2LM in depth for the highest lobes in the T2 spectral window. Layers A and B were wet. Layer C was tested to be oil bearing.
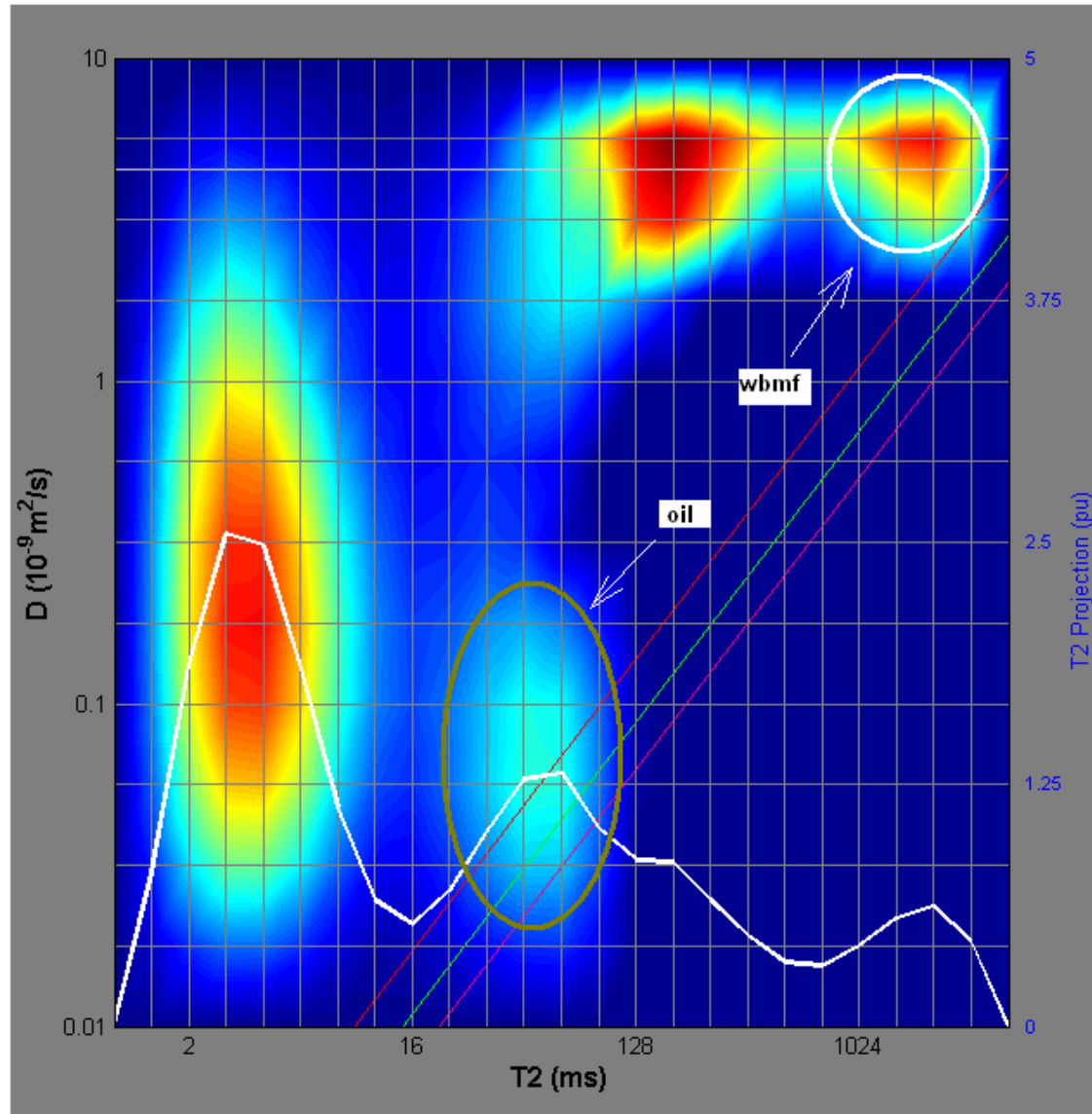
Figure 4. DT2 map showing oil- and water-based mud filtrate signals.

Layer No.	Top m	Bottom m	Perm. Thickn. m	K_TC max	K·h	MPHE max	MBVI max	MBVM max	M·h	RVAM max	M2RX ohmm	No entry	W	O	G	Hydr. Frac Recomme. (y/n)
51	1476.0	1479.0	0.0	0.4	0.0	14.9	12.2	3.3	0.0	0.7	16.8	X				
52	1481.0	1485.5	3.5	5.8	8.0	19.8	14.3	7.6	21.0	1.0	17.8		X			
53	1493.5	1494.0	0.0	0.0	0.0	11.3	9.2	2.1	0.0	0.8	15.7	X			?	
54	1500.5	1503.5	0.6	1.6	0.9	22.8	19.3	4.5	2.8	0.4	5.4	X				
55	1511.5	1517.5	4.6	4.6	11.5	20.6	14.4	7.0	26.6	0.9	16.7		X			
56	1526.0	1535.0	2.0	2.0	1.5	20.2	15.5	5.6	6.4	0.4	7.2		X		?	
57	1536.0	1540.5	2.2	1.8	2.8	16.6	12.3	5.6	10.9	0.7	15.7		wot			
58	1543.0	1549.0	4.3	7.0	14.9	16.0	10.4	8.1	27.3	2.1	59.4				X	
59	1550.5	1557.0	3.4	15.9	23.3	19.0	13.1	9.8	25.9	2.4	53.9		wot			
60	1559.0	1561.0	0.2	0.7	0.1	13.9	10.9	4.2	0.8	0.5	12.4	X				
61	1563.5	1567.5	0.0	0.4	0.0	14.5	11.8	3.5	0.0	0.6	20.8	X				
62	1572.0	1579.0	4.2	59.0	60.3	18.5	9.5	12.2	33.9	1.1	29.9				X	
63	1597.0	1605.5	2.9	2.3	3.8	15.9	10.8	6.0	14.5	0.8	20.7		X			
64	1613.0	1616.0	2.3	34.5	32.1	19.2	8.5	11.7	19.9	0.8	15.3		X	X		y(F?)
65	1617.5	1621.5	0.0	0.3	0.0	13.5	10.9	3.3	0.0	0.5	10.9	X				
66	1623.0	1625.5	0.6	0.7	0.4	15.6	12.3	4.3	2.7	0.3	9.2	X				
67	1636.5	1637.5	0.0	0.1	0.0	6.8	4.3	2.6	0.0	0.4	9.2	X				
68	1642.0	1646.0	2.7	52.4	57.3	15.2	4.5	11.5	23.1	1.8	50.3		wot			
69	1648.0	1653.5	0.2	0.5	0.1	13.4	10.1	4.1	1.1	0.4	13.4	X			?	
70	1667.0	1670.5	2.6	8.1	12.2	16.0	8.3	8.4	18.4	1.0	29.5		X			
71	1672.0	1674.5	1.3	1.7	1.5	11.1	5.9	5.5	6.9	1.0	22.7		X			
72	1683.0	1687.0	2.1	2.5	2.9	15.1	9.4	6.2	10.9	0.3	12.9		X			
73	1687.5	1690.5	0.0	0.2	0.0	10.4	8.3	3.3	0.0	0.6	19.1	X			?	
74	1693.5	1695.0	0.0	0.1	0.0	10.4	8.0	2.7	0.0	0.4	14.4	X			?	
75	1706.5	1714.0	2.3	57.9	36.3	16.9	8.3	12.3	19.2	0.6	17.1		X		?	

MReX Parameters

K_TC	Timur Coates Permeability
MPHE	Effective Porosity
MBVI	Irreducible Fluid Porosity
MBVM	Movable Fluid Porosity

Expected Fluid

X	Main fluid
x	Secundary Fluid
wot	With Oil traces

Hydraulic Fracture

y(F?) Yes, but depending on tested fluid

BAKER HUGHES   Baker Atlas   GEOScience

Table 1. Production forecast table for a well in the San Jorge Basin.