A COMPREHENSIVE METHODOLOGY TO ANALYZE THE IMPACT OF THE SAND CONTROL TECHNIQUE ON THE EFFICIENCY OF AN HORIZONTAL WELL

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Abstract. *Sand production in unconsolidated formations has brought heavy injury for the oil and gas industry around the world. Million dollars have been invested in sand control techniques. Among the several sand control systems existing, Open Hole Gravel Pack (OHGP) is the one adopted for horizontal well completions in the offshore Brazilian fields. With the experience in the development of such fields, some assets start to consider the adoption of less conservative sand control strategies, such as the use of stand alone premium screens (SAS).*
The present work proposes a methodology for evaluating the impact of the sand control technique in the productivity or injectivity of a horizontal well. Several parameters, such as damage rate (DR) and productivity or injectivity index per horizontal effective length (PI/Lef) were used to compare similar wells equipped with different sand control techniques.
The main goal of the study is to address the following questions: Is there any formation damage due to the gravel pack during production lifetime of a well? The wells equipped with stand alone screen exhibit formation damage? Wells equipped with OHGP have the same performance when compared with wells equipped with SAS? Stand alone completion is a good alternative path for multilateral and extend reach wells?

Keywords*: sand control, stand alone, gravel pack, productivity index*

1. INTRODUCTION

Maximizing well productivity / injectivity is pursued by many ways: through sand management (Mathis 2003, Oyeneyin et al, 2005), sand and water management (Nguyen et al, 2007), by using suitable completion fluids (Milhone, 1983) to prevent well completion damage, by ICD screens implementation (Fernandes et al, 2006; Wibawa et al, 2008) or during drilling operations using sophisticated tools in horizontal well placement technology (Altman et al, 2007). The specific topic of this paper deals with the impact of sand control strategy on well completion efficiency.

Different operators have different views on the criteria of investing on sand control techniques or sand management in onshore environments. On offshore scenarios, especially in deepwaters, it seems that there is a common sense that sand production is a major issue and should be avoided. All the efforts should be spent to minimize equipment erosion and production interruptions to clean surface separation systems. PETROBRAS defined that all offshore wells in non consolidated sandstones should be equipped with adequate sand control techniques.

Perforation of cased and cemented horizontal sections did not appear as an economical alternative and, consequently, open hole completion with sand control techniques was the path to follow for horizontal wells. Tiffin et al (1998) defined a criterion for screen type selection, while Bennett et al (2000) stated that, for offshore wells with water depths greater than 500 m, openhole gravel packs with and premium screens are recommended. This guideline is based on the concept that, for long life cycle wells, additional barriers to prevent production interruption and avoid or postpone workover jobs should be considered.

The first horizontal wells in unconsolidated sands in Campos Basin were completed with Stand-Alone-Syntherized screens. At that time the industry were not capable to support the requirement of an additional barrier for sand control in open hole horizontal sections. Motivated by the increasing demand for the activity and by failures in the wells equipped with syntherized screens, the service companies rapidly developed more reliable sand control solutions for the offshore environments: premium screens and gravel pack tools were soon available and the strategy proposed by Bennett was promptly adopted as a global criterion for offshore fields in PETROBRAS.

Since, then, around 270 open hole horizontal gravel pack operations were performed with 93% of placement success and no sand production cases (Marques et al, 2007). With the experience in HOHGP operations, long horizontal sections were considered: today 18 wells with horizontal sections longer than 1000 m were successfully gravel packed.

Figure 1 highlights horizontal lengths for the majority of the 250 successful wells gravel packed in PETROBRAS. Figure 2 illustrates completion efficiency evolution on gravel packed horizontal wells.

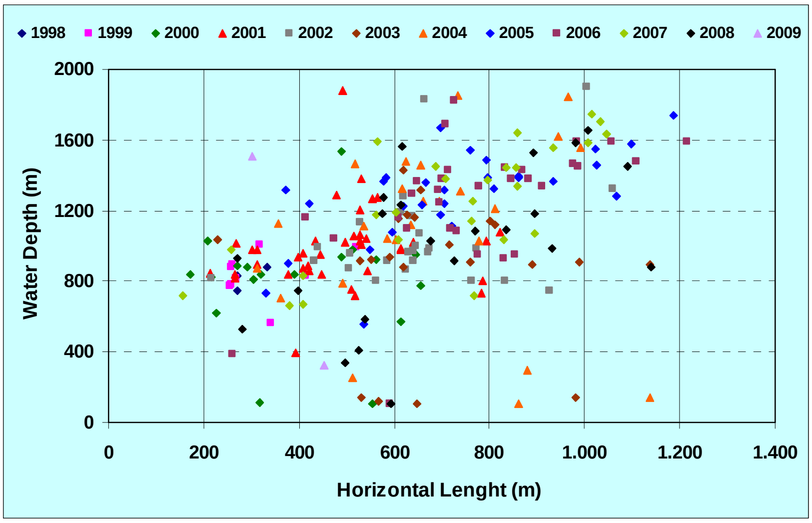

Figure 1. Typical Horizontal lengths of Brazilian wells

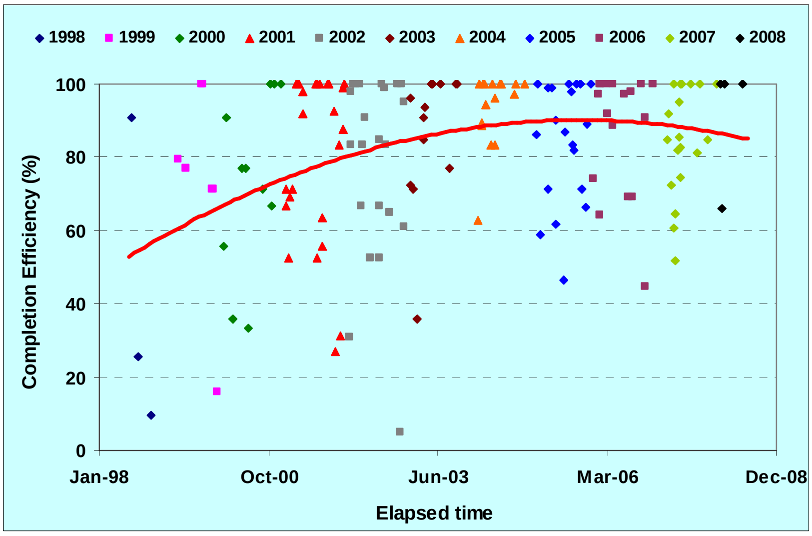

Figure 2. Evolution of Completion Efficiency in HOHGP (Campos Basin) as a Function of Time

In the early 2000's, the industry started to offer expandable screens as possible alternatives for sand control in offshore scenarios. The results in PETROBRAS, were considered very poor with 7 screens installed and 3 failure cases, consequently, the use of this alternative was discontinued.

The stand-alone technology (SAS), i.e. the isolated use of screens to complete the horizontal portion, promotes faster assembly (without washpipes) and does not include gravel pumping and all its implications (tool marking, circulation tests, fluid logistics for stimulation boat, gravel displacement, reverse, etc.), resulting in cheaper operations. On the other hand, shorter lifetimes and higher failure rates are expected (McLarty 1997; Perdeu 1996; Bennet et al, 2000; Tiffin et al, 1998; Rogers, 1971). Mathisen et al (2007) proposed new sand control selection criteria, which flexibilizes the strategy proposed by Bennett (2000). According to Mathisen et al (2007), 230 screens have already been installed by Hydro Oil Energy, more than 95% in horizontal oil and gas wells. From 230 screened wells, 13 have failed, caused by partial plugging, erosion or plugging during clean up.

More recently, technology interchange agreements with other operators brought to PETROBRAS the interest of analyzing the possibility of using stand alone premium screens as the sand control strategy for some specific situations, such as very long horizontals where HOHGP placement would be unfeasible, multilaterals (Sotomayor et al. 2001) and injector wells in uniform sands. In Brazil, SAS systems have been adopted in consolidated offshore reservoirs, such as Mexilhão and Golfinho. Besides, 7 SAS premium screens have been run in injector wells in unconsolidated sandstones.

The main goal in this article is to propose a methodology that would allow the analysis of the impact of the sand control technique on the productivity/injectivity of horizontal wells. The strategy is to compare injection / production history of wells drilled in similar reservoir sections and completed with different sand control techniques. Since

PETROBRAS has a very limited history in designing SAS completions in non consolidated sands, the data analysis will mostly include wells where the OHGP operation failed compared with nearby gravel packed horizontals.

2. METHODOLOGY

The following parameters were considered as representative of well productivity/injectivity behavior:oil flow rate, BSW, productivity or injectivity index (PI/II), productivity or injectivity index per effective horizontal reservoir section and damage ratio (DR =PI_{ideal}/PI_{real}).

The main issue in the analysis is to uniformize the estimation of Productivity and Injectivity Indexes. Since different source of data are available in different assets, depending on managing organization and technology available at the period of each well completion, 3 different strategies were adopted:

2.1. Strategy 1: Calculation of PI/100m by estimating static pressures (P_E) from "build-up" or "fall-off" periods

Step 1: Plot dynamic bottom pressure (P_{WF}) obtained through PDG sensor (Pressure Downhole Gauge) and flow rate along the time (Figure 3).

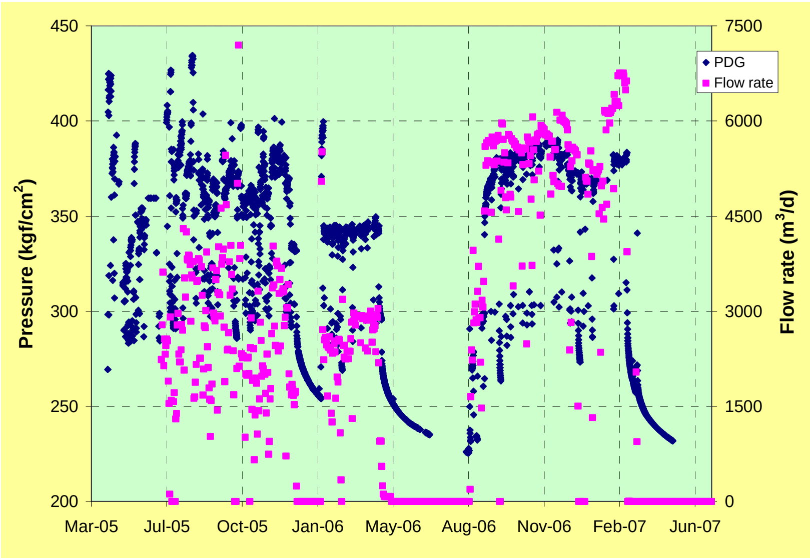

Figure 3. Typical pressure and flow rate curves

Step 2: Identify build-up periods, for producer well or fall-off periods for injector wells, as illustrated for an injector well in Figure 4.

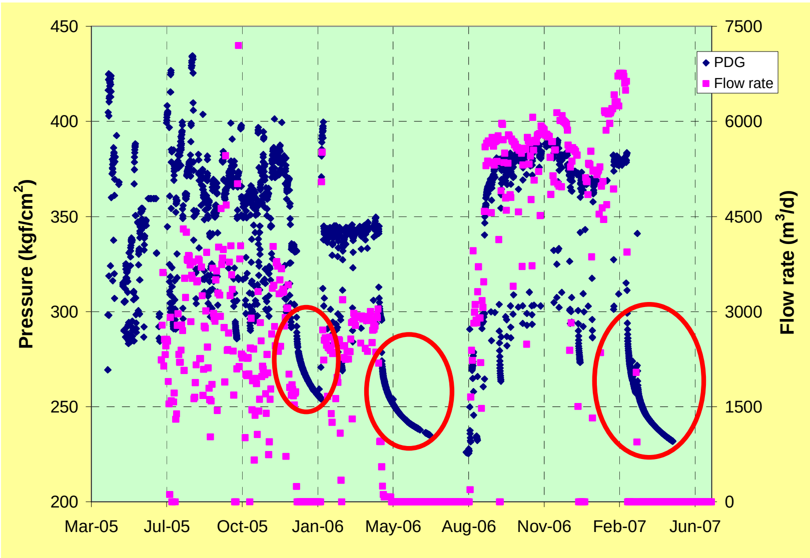

Figure 4. Identifying fall of periods of an injection well

Step 3: Estimate reservoir static pressure by extrapolating values provided by PDG sensors at a stop production/injection period. Daily flow rate and downhole average pressure is calculated using the period just before well production or injection interruptions (Figure 5).

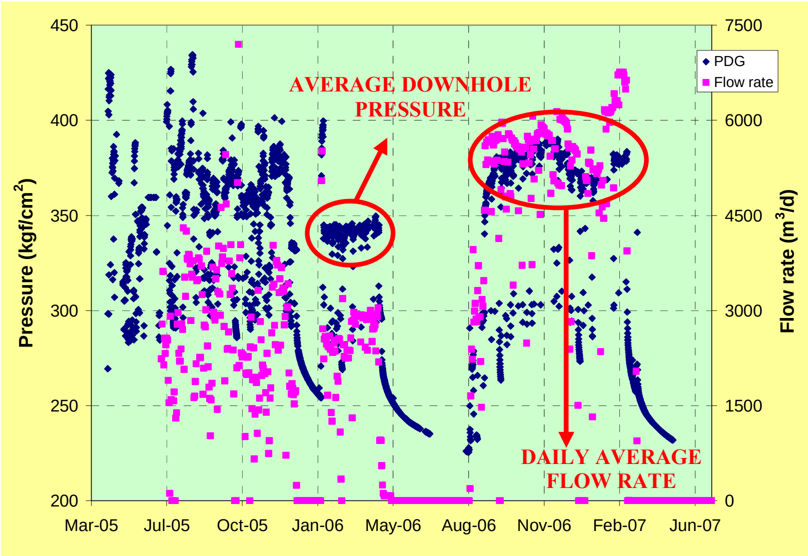

Figure 5. Estimating static pressure

2.2. Strategy 2: Obtaining PI/IIs through daily production data, based on P_{WF} and P_S data obtained from production or formation tests.

Step 1: Estimate the reservoir static pressure (P_S) at the well along the productive time from production tests.

Step 2: Plot a P_S curve along the time and obtain a proper polynomial fitting, as illustrated by Figure 6.

Step 3: Estimate P_S at a given time of the production period through the fitted curve (Figure 7).

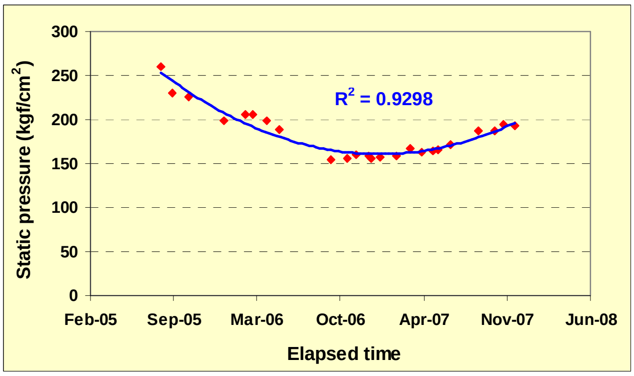

Figure 6. Static pressure fitting

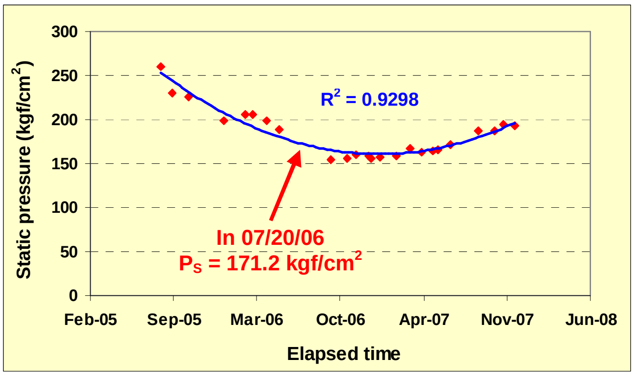

Figure 7. Estimating static pressure in a specific date

Step 4: PI/II are estimated using flow rate and produced time (from production data) and estimated static pressure by Eq.1:

$$\frac{\mathrm{PI}}{100\mathrm{m}} = \frac{Q_{LIQ} \cdot 100}{\left(P_S - P_{WF}\right) \cdot L_{EF}} \qquad (1)$$

2.2. Strategy 3: Calculation of PI/100m or II/100m through PI or II obtained by Production or Injection Tests:

Step 1: Through of well potential adjustment obtained from flow simulator with static pressure data obtained from reservoir simulation.

Step 2: With P_{WF} obtained by PDG sensor, calculate PI or II/100m with data obtained by PLT – Production logging Tool.

3. CASE STUDIES

The proposed methodologies were applied to correlate pairs of wells from 6 offshore fields in Campos and Espirito Santos basins. Table 1 illustrates the SAS wells and the correlate wells completed with OHGP.

Table 1 – SAS and OHGP correlate wells

Field	SAS Well	OHGP Correlate Well
A	AP1	AP2 AP3
B	BI1	BI3
		BI4
		BI5
	BI2	BI6
		BI7
C	CP1 CP2	CP3
		CP4
		CP5
		CP6
		CP7
D	DI1	DI2
		DI3
	DP1	DP2
		DP3
		DP4
E	EP1 EP2	EP3 EP4
F	FP1	FP2
	FI1	FI2

An initial search was performed in order to identify wells equipped with SAS. Currently, Petrobras has 34 SAS wells completed in unconsolidated sands, being 10 Stand Alone Premium screens and 6 Stand Alone Syntherized screens in both injector and producer Campos and Espirito Santo Basins wells. Beyond these wells other 18 wells remained stand alone due to an operational problem in the gravel packing operation. Only 5.9 % of the SAS wells presented sand control failure, all associated with old fashioned screen types. No sand failure events were associated with high quality premium screens. Table 2 shows horizontal effectivity length (Lef), damage ratio on reservoir and PI /II values for the some of the wells evaluated. Following, a case study was performed to identify which impacts the sand control technique imposes on productivity / injectivity indexes.

Table 2: L, DR and PI / II transient data

Field	Well	Lef (m)	DR	PI or II ($m^3/d/kgf/cm^2$)
A	AP1*	261,3	ND	10
	AP2	199,9	1,30	60,9
	AP3	657,5	ND	107,4
B	BI1*	467,8	2,70	45,5
	BI2*	553,0	1,01	402,2
	BI3	460,1	10,90	15,5
	BI4	463,9	4,10	90,1
	BI5	407,9	1,02	82,8
	BI6	393,7	1,18	126
	BI7	455,7	1,99	152,6
C	CP1*	448,4	1,04	14,4
	CP2*	391,5	1,07	34,2

	CP3	319,0	0,73	21,3
	CP4	525,0	0,95	60,8
	CP5	465,0	ND	20,7
	CP6	340,0	0,65	15,8
	CP7	657,0	1,13	59,3
D	DI1*	234,8	ND	18,5
	DP1*	357,1	0,86	78,6
	DI2	448,5	ND	12,5
	DI3	463,0	ND	ND
	DP2	179,2	ND	55,9
	DP3	324,2	ND	ND
	DP4	245,1	1,53	60,2
E	EP1*	982,0	1,00	30,1
	EP2*	731,0	1,19	37,6
	EP3	862,0	0,60	11,9
	EP4	1011,0	ND	ND
F	FI1*	ND	ND	ND
	FI2	ND	2,10	13,0
	FP1*	750,0	0,70	176,1
	FP2*	818,0	1,46	120,6

ND – not disposible

Field A

In field A, 3 producer wells were considered: 1 SAS well (AP1) and 2 correlate gravel packed wells (AP2 and AP3). Figure 8 shows flow rate variation in function of time, obtained by production tests. Significative changes on BSW during the production impair the analysis. Premature water production can provoke fines migration and, consequently, screen plugging. Besides fines migration, other factors can motivate oil flow rate reduction such as scale, relative water permeability in oil, emulsion formation causing pressure drop in production tubing, and water presence in tubing, due its bigger specific gravity.

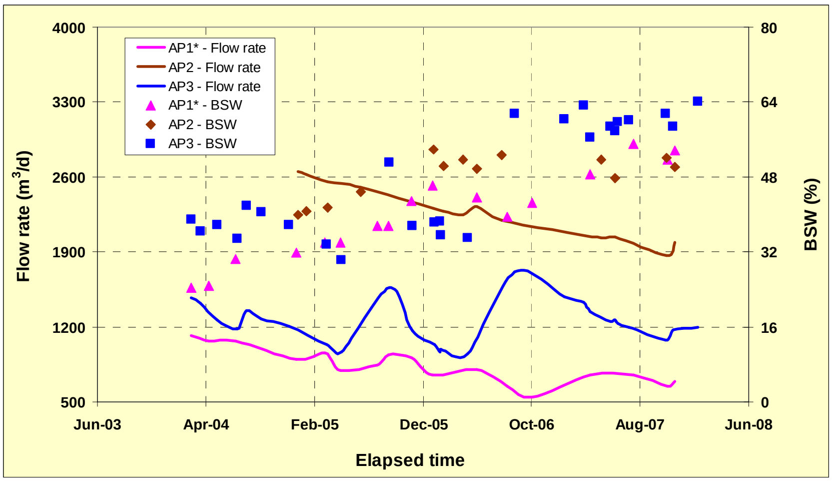

Figure 8. Production data behavior for wells of field A

Figure 9 shows the PI/100m behavior along the time. Two abrupt enlargements in PI/100m value are observed in September 2005 and one year later (red highlights). These increases were caused by increment in BSW value after scale removal operations. Comparing the three wells behavior, it is possible to assert that AP1 presents the smaller fall in PI/100m value although, in absolute values, represents less productivity. Wells equipped with gravel pack (AP2 and AP3) presented decline on PI/100m value about 75 and 65% of initial value (1º production test), respectively, and on AP1 this value was only 50%.

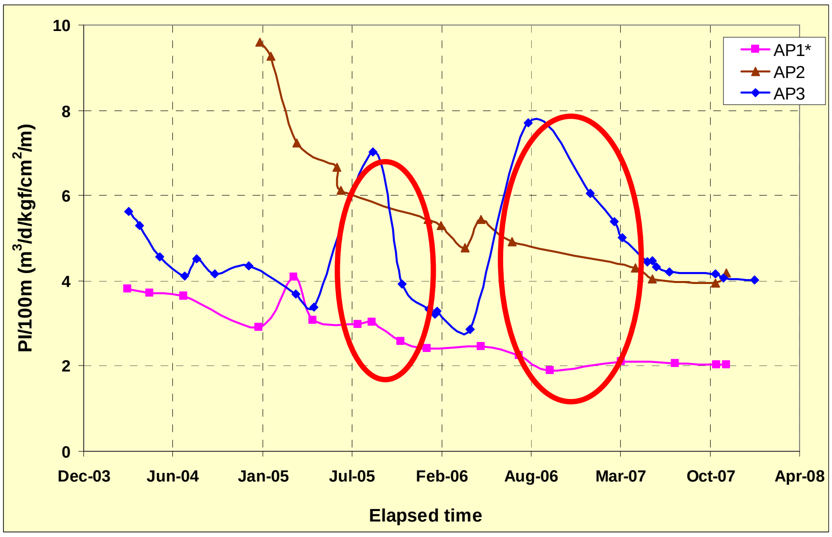

Figure 9. PI/100 along the time for field A

Field B

Field B wells comparison was made with limited production and downhole pressure data. In fact, there were few wells with PDG sensor working properly. Furthermore, little information can be obtained for the majority of the wells. The well completed only with screen (BI1) presented a better result in terms of transient II (402.2 (m^3/d)/(kgf/cm^2)). Until this date, the well is injecting according to prediction. However in June, 2007, PDG signal was lost. The correlate wells BI3 and BI4 are not equipped with PDG sensors, but have sustained the injection capacity along the time. The transient II obtained by injectivity test was around 120(m^3/d)/(kgf/cm^2). Due to the scarce information generated it was only possible to evaluate this well performance through methodology 1. Figure 10 illustrates a graph of II/100m along the time. Despite of the small amount of data used to generate Figure 10, a trend in II/100m values can be observed. The BI2 SAS well showed a tendency of maintaining the injetivity along the time while OHGP wells represented by BI4 and BI6 presented a decline trend. BI2 presented a larger value of injectivity.

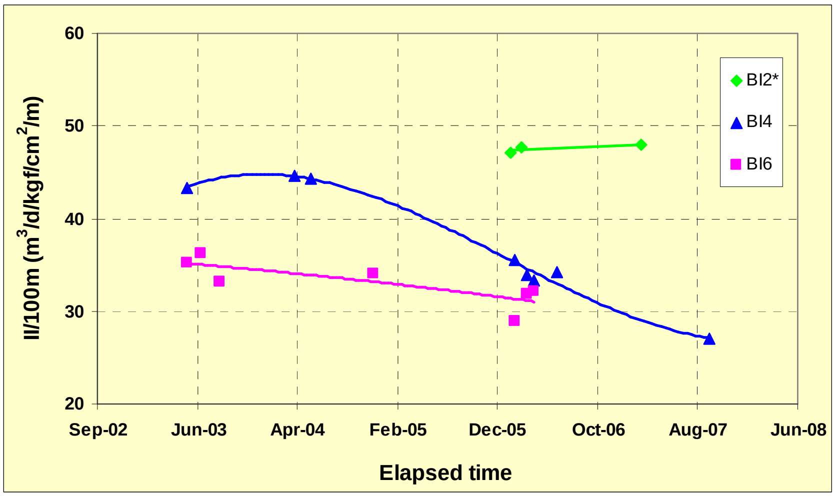

Figure 10. II/100m along the time for field B

Field C

7 wells from field C were considered, being 2 SAS. It was possible to use the three methodologies proposed in this work due to the large amount of information available. Figures 11 to 13 detail results.

From the analysis of Figure 11, the following comments can be drawn:

- CP2 SAS well showed increasing PI/100m tendency in the analyzed period. The same fact happened, with minor intensity, with CP5.
- Well CP1 showed low values of PI/100m, as wells as CP3, equipped with OHGP, however this well has presented

BSW value about 10%, since the end of 2006.

- Comparing the behavior of wells IP/100m value along the time, one SAS well (CP1) and four OHGP wells (CP3, CP4, CP6 and CP7) presented tendency of maintaining the productivity. CP2 SAS well and CP5 OHGP presented productivity increase.

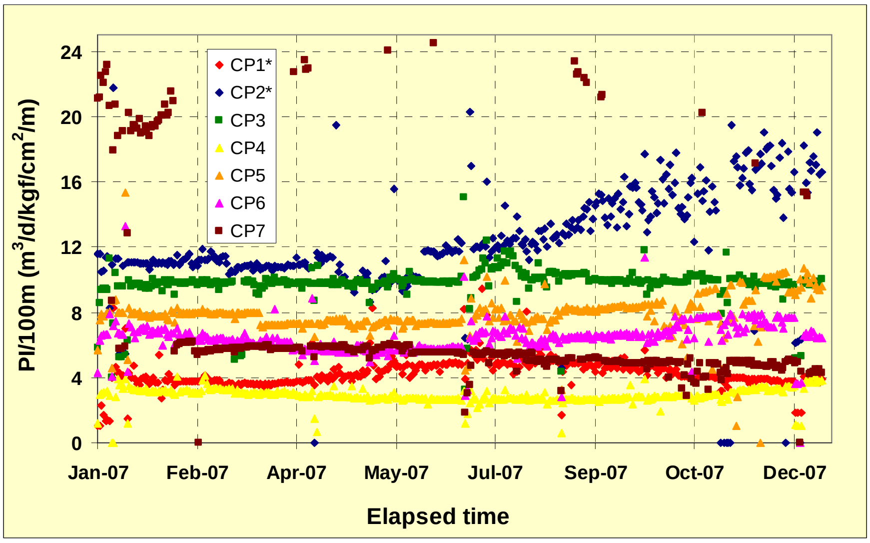

Figure 11. PI/100m along 2007 – methodology 2

Figure 12 shows a graph built through data obtained at build-up periods to extrapolate P_S and then, calculate PI/100m.

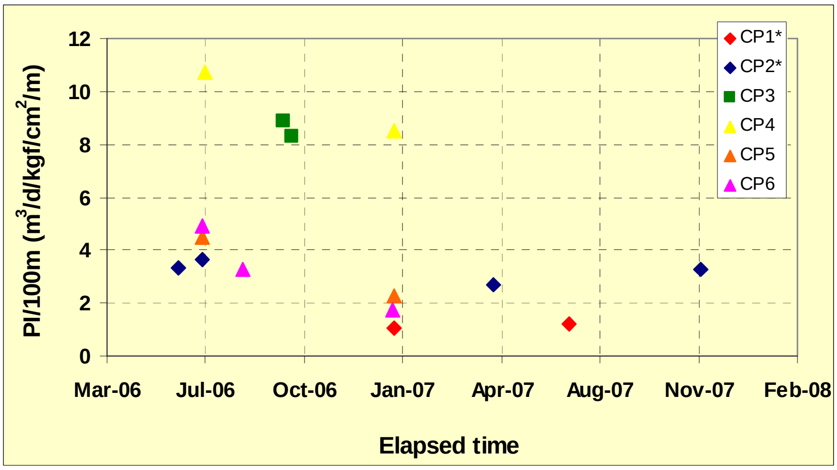

Figure 12. PI/100m using build up period to extrapolate P_s

Although the analysis has been performed with a few number of wells and with limited data, SAS wells showed a *plateau* tendency in terms of productivity while OHGP wells presented decline trend along the time.

Results obtained for methodology 3 are shown in Figure 13. IP/100m values based on production tests shows similar tendency between SAS and OHGP wells. In terms of absolute values of IP/100m, the both sand control techniques showed equivalent results. CP4 can be considered less representative since it has producing with a 10% BSW.

Field D

Damage ratio (DR = II_{ideal} /II_{real}) is the main parameter used to define the extent of the reservoir permeability drop during its productive life. This variable can be used not only in the comparison between sand control techniques as in evaluation of completion efficiency. DR data values were obtained, from injection tests, for the some of the wells evaluated. Analysis of Figure 14 indicates that DI1 (SAS) well presented less DR than OHGP wells (DI2 and DI3).

Figure 15 indicates that the SAS well (DI1) had absolute II/100m values above the values from the OHGP wells. Figure 16 (methodology 2) reinforces the previous remark.

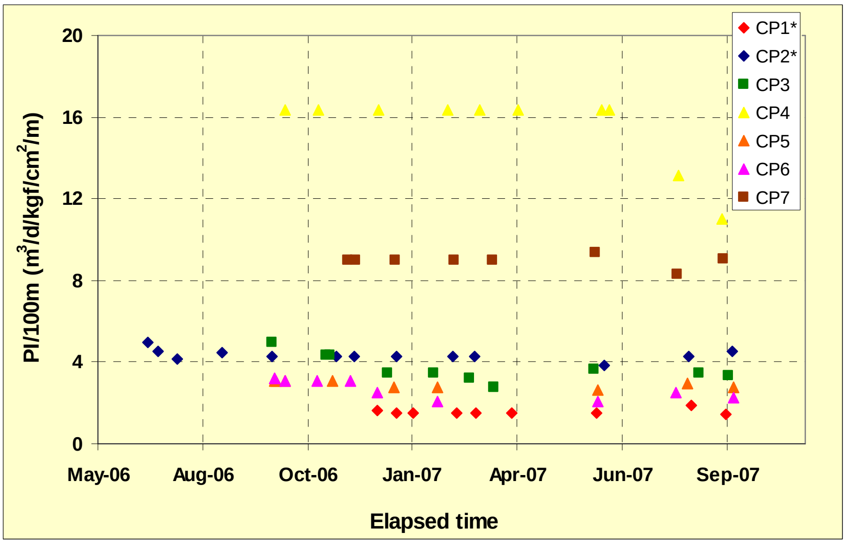

Figure 13. PI/100m along the time – methodology 3

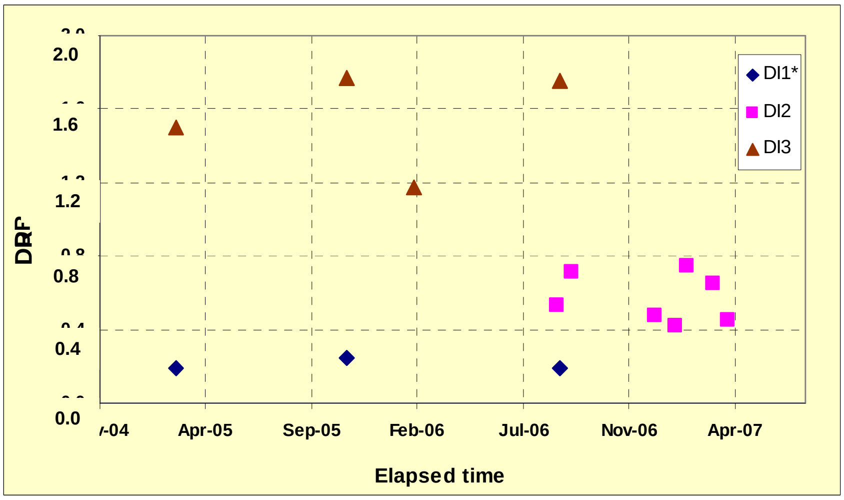

Figure 14. DR along the time

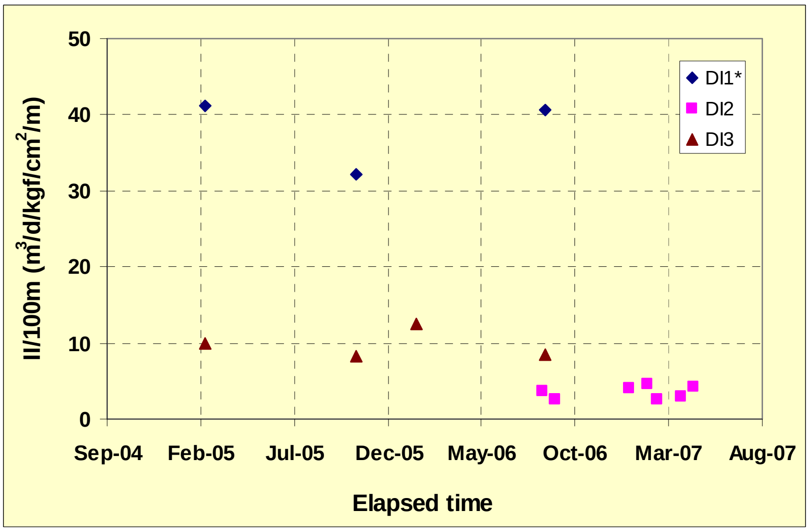

Figure 15. II/100m along the time – methodology 3

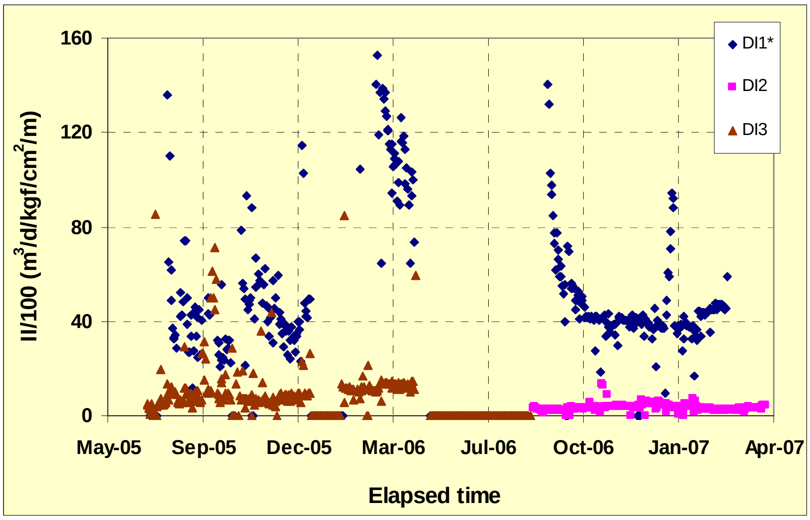

Figure 16. II/100m along the time – methodology 2

The same methodology was used for the producer wells of field D, but as the SAS well (DP1) is not equipped with PDG sensor, it was only possible to compare the results in function of the variable PI': a productivity index considering a pressure drop between the reservoir and well head (P_{WH}-P_{WF}). Using PI', not only the drawdown on formation is considered but also, the pressure drop between borehole and the well head. The pressure at well head is registered by a sensor at the WCT (Wet Christmas Tree) – called TPT sensor. Through Ps data and P_{WH} data source it was possible to obtain PI'. Figures 17 and shows P_S and PI/100m behavior along the time presented by the producer wells of field D.

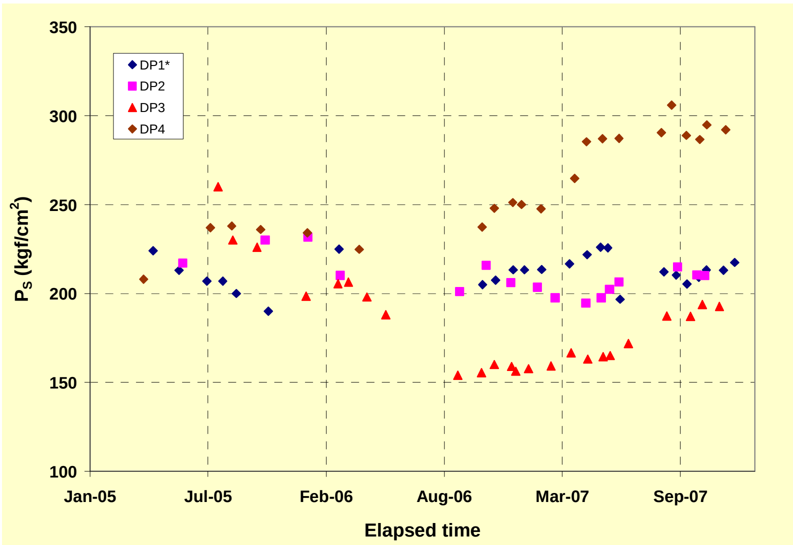

Fig 17 – P_S behavior for producer wells of Field D

Figure 17 shows that, at the initiation of productive life of the wells, the estimated P_S in that region is similar for all wells (between 205 a 225 kgf/cm^2). As the producer wells are not affected at the same way by the nearby injector wells, P_S around the producer wells presented different tendency as seen in Figure 17. It is possible to observe that at some periods of time, P_S increases or decreases rapidly, basically due to the increase or decrease in injection flow rate of the injector wells.

Through Ps and flow rate data obtained by production tests and P_{WH} obtained by TPT sensor, it was possible to calculate PI'/100m. Figure 18 shows that for DP1 SAS well, the productivity has increased since started the water production. Other process variables can be affected the final result in terms of PI'/100m such as artificial lift. This method to evaluate the impact of sand control technique in productivity showed less stout than when used PDG sensor.

Field E

4 producer wells from field E were evaluated in this work (2 SAS and 2 OHGP). In this field, the wells were completed with different kinds of lift methods. The producer wells from the Field E have the productivity somewhat

affected by the artificial lift method. From Figure 19 is possible to see the increase in flow rate due to the change in lift method. Table 3 summarizes the initial production date by each lift method.

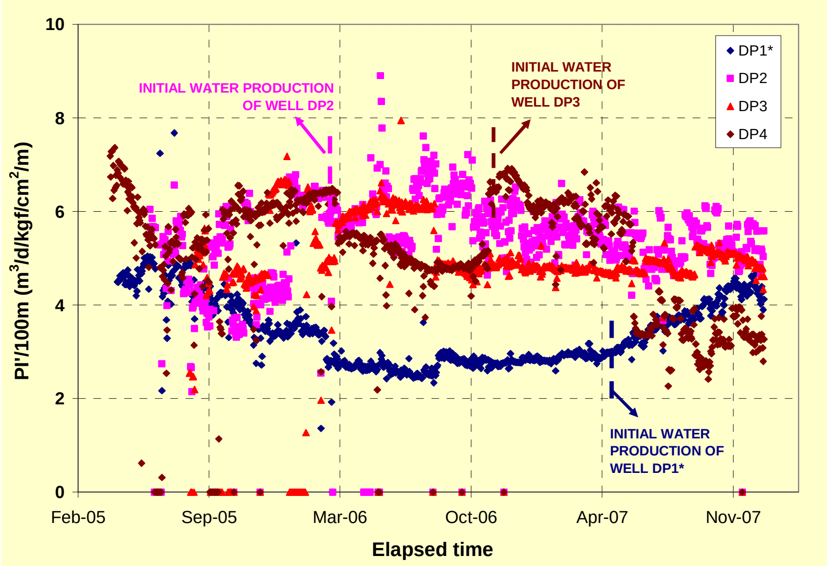

Figure 18. PI'/100m along the time for producer wells of Field D

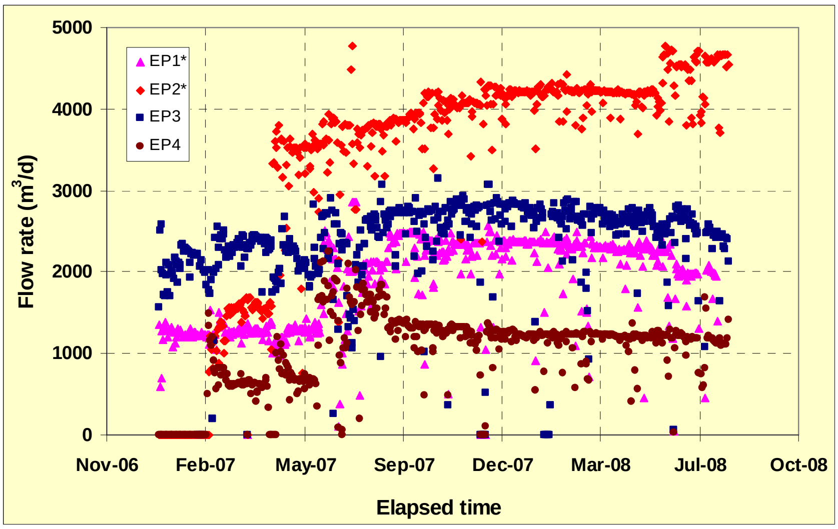

Figure 19. Flow rate behavior for producer well of Field E

Table 3 – Lift method initial production date

WELL	LIFT METHOD		
	Natural	ESP	Gas Lift
EP1	12/29/06	N/A	06/14/07
EP2	02/19/07	07/01/08	06/12/07
EP3	12/17/06	N/A	06/13/07
EP4	02/21/07	04/25/07	N/A

Figure 20 illustrates the IP/100m plots obtained from production tests (Methodology 2). The wells can be divided in two groups, according to their productivities: wells EP2 and EP3 with PI/100m values around 6 ((m^3/d)/(kgf/cm^2))/m. Well EP2 is only equiped with a screen and producing by BCS while well EP3 is gravel packed and producing by continuous gas lift. Both production rate and drawdown from well EP2 are larger than in well EP3, resulting in similar PI/100m values.

In relation to the second group of wells (EP1 and EP4), results indicate higher PI and production rates for the SAS well (EP1).

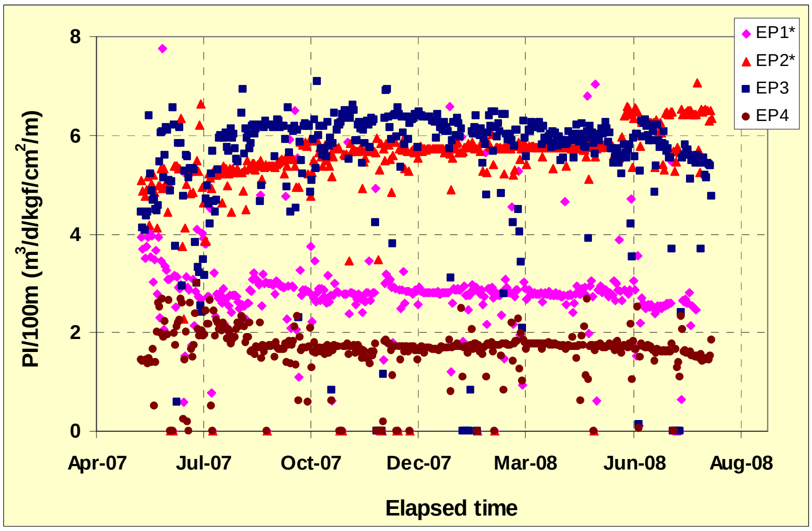

Figure 20. PI/100m along the time

Field F

In Field F were analized only the correlate producer wells, FP1 equipped only with screens and FP2 with OHGP. Injector wells were not their injection historic evaluated due to the low data number, PDG absence and correlate wells little representatives.

Despite of the premature water production, it is possible to conclude that, in the two production wells considered, the OHGP well (FP2) presented higher PI/100m while the SAS well presented smaller decline tendency (Figure 21).

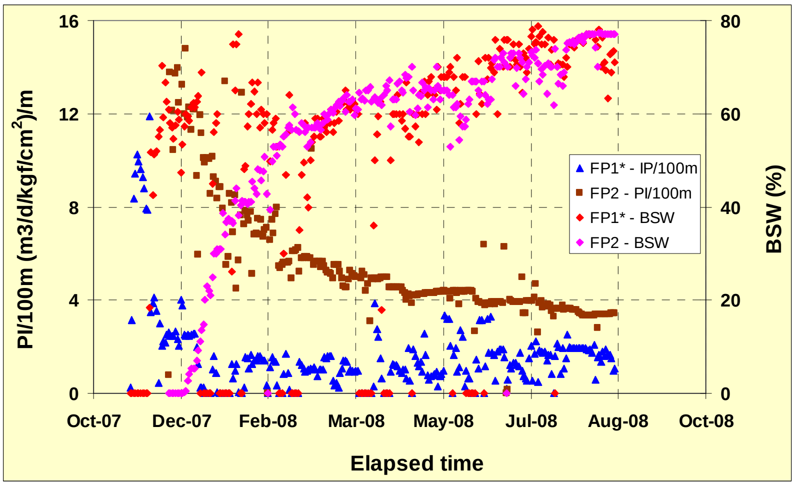

Figure 21. PI/100m along the time for producer wells of field F

4. CONCLUSIONS

- Although with minimum tradition of designing stand alone premium screen completions, the data available in PETROBRAS allowed an initial study in the effect of the sand control technique on the productivity (PI) or injectivity indexes (II) of correlate wells.
- A comprehensive set of 3 methodologies was proposed to evaluate the impact on the productivity / injectivity of wells equipped with different sand control techniques. Although data analysis indicates equivalent results for different methodologies, the use of PDG data leads to more reliable results. Absence of PDG sensor in the well makes the analysis less realist.
- No sand control failure was observed in SAS premium screens. Since several events are recent, not too much can be said about longevity.
- OHGP and SAS completions showed similar performance. Differences in PI/II values reported should not be considered very representative. OHGP should be faced as an additional barrier in situations where workover costs justify.
- SAS completions should be faced as interesting alternatives for lower revenue projects or in situations where

OHGP may be technically or economically unfeasible (long horizontals, multilaterals). Injector wells should be also an attractive alternative for SAS application.

- Future data analysis approaches include the evaluation of long term productivity of gravel packed wells with conventional and lightweight propants.

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