Sensitivity analysis of production parameters in multiphase flow simulations

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Abstract. With the development of oil fields in ever deeper water depths, the costs involved in exploration and production have grown drastically. Thus, to make projects more economically attractive, it is necessary to understand the factors that contribute to maximize production. In hydrocarbon production management, there are several parameters that involve fluid flow through the production system that can significantly impact field productivity. The value of these parameters may contain uncertainties that interfere in the platform's short-term decisions, such as: well opening and closing strategies, choke valve opening, injection parameters, among others. In this context, the proposed paper aims to evaluate the well test parameters and perform a sensitivity analysis to verify which parameters have the most impact on the well productivity, through a correlation matrix. The analyzed parameters are reservoir pressure, productivity index, gas-oil ratio, water cut and gas lift injection rate.

Keywords: Oil fields development, production management, multiphase flow simulations, sensitivity analysis.

1 Introduction

In the oil production management, it is important to understand and predict the production behavior throughout the oilfield life. For this, it is necessary not only to obtain well test data, but also to understand the geological, reservoir and multiphase flow models [1, 2, 3].

Through this information, another necessary step is to identify which factors involved in the production system have the most impact on oil flowrate, in order to maximize hydrocarbon production [4, 5, 6, 7, 8, 9, 10]. There are several factors that impact the oil flowrate in short and long term: changes in the oil production curves, paraffin deposits, hydrate formation, slugs [11, 12], allocation of subsea facilities, strategies for opening and closing production wells, lift gas injection flow, among others.

In this context, the present paper aims to evaluate the well test parameters and perform a sensitivity analysis with a correlation matrix to verify which parameters have the most impact on the well productivity. This is an initial step in a research project that aims to develop methodologies based on artificial intelligence techniques for planning and managing oil production and propose tools to support real-time decision-making in oilfields.

2 Methodology

2.1 Production management

To manage oil production, production tests are periodically carried out in each well in the field in order to identify production conditions, possible problems and analyze possible opportunities to increase production.

The production test of a given well is conducted by diverting its production to a test separator or a multiphase meter, maintaining production conditions. Water, oil and gas flows are measured in separate streams. In addition, other important production measurements are recorded such as fluid data and pressures and temperatures throughout the system (Tab. 1).

Upon completion of the production test, all information collected by the bulletin will be reviewed by a team of experts to verify the validity of the test. In general, tests are invalidated in case of very large changes in relation to previous bulletins, if it is verified that the test was not conducted correctly due to operational problems or even if the well is not stabilized during the test.

From the data collected in the well production test, the next step is to fit the multiphase flow models from the production data and finally, from the calibrated models, perform production optimization. Production control is carried out by varying the bottom hole pressure of the wells, for example, by changing the opening of the choke valve, or the gas lift injection rate and/or other artificial lift methods.

Table 1. Well production tests.

Pe: reservoir pressure (kgf/cm²); PI: productivity index (m³/day)/(kgf/cm²); API: oil density; dg: gas density; dgl: gas lift density; CO2: CO_2 content; P_PDG: bottom hole pressure (kgf/cm²); T_PDG: bottom hole temperature (ºC); P_TPT: wellhead pressure (kgf/cm²); T_TPT wellhead temperature (ºC); P_Sep: separator pressure (kgf/cm²); T_Sep: separator temperature (ºC); Qliq: Liquid flow rate (m³/d); Qoil: Oil flow rate (m³/d); Qw: Water flow rate (m³/d); Qgp: Produced gas flow rate (m³/d); Qgt: Total gas flow rate (m³/d); Qgl: gas lift flow rate (m³/d); GOR: gas oil ratio (m³/m³); WC: water cut (%)

Days	Pe	IP	API	dg	dgl	CO2	P_PDG	T_PDG	P_TPT	T_TPT	P_Sep	T_Sep	Qliq	Qoil	Qw	Qgp	Qgt	Qgl	GOR	WC
81	250,0	11,7	22,0	0,676	0,720	0,027	97,8	54,5	57,5	31,9	7,9	37,3	1254,4	1242,1	12,4	120908,0	348662,3	227754,3	97,3	1,0
100	200,0	16,1	22,0	0,676	0,720	0,027	98,4	54,8	57,6	32,2	8,2	50,2	1183,7	1168,9	14,8	112839,2	325609,8	212770,6	96,5	1,3
105	200,0	16,1	22,0	0,676	0,720	0,027	97,3	54,8	57,1	32,3	7,8	45,5	1201,2	1185,3	15,9	119830,5	336850,7	217020,2	101,1	1,3
127	192,3	16,1	22,0	0,696	0,658	0,019	95,2	54,9	56,0	32,0	8,1	43,8	1136,5	1113,6	22,9	101661,4	309252,1	207590,8	91,3	2,0
159	187,0	16	22,0	0,696	0,738	0,019	93,4	54,9	54,3	31,3	8,1	45,6	1097,0	1059,4	37,6	100877,6	308698,4	207820,7	95,2	3,4
167	183,1	16	22,0	0,696	0,738	0,019	93,0	55,0	54,5	31,8	8,3	36,0	1058,1	1026,1	32,0	97064,6	295975,7	198911,1	94,6	3,0
187	183,1	14,49	22,0	0,696	0,738	0,019	91,7	55,0	54,2	31,0	8,4	36,9	983,4	947,0	36,4	92011,0	293170,0	201159,0	97,2	3,7
218	173,0	14,49	22,1	0,68	0,713	0,017	87,9	54,9	52,3	29,6	8,2	45,2	903,7	863,3	40,5	98369,5	297559,3	199189,8	113,9	4,5
260	173,0	13,42	22,1	0,682	0,762	0,017	87,4	55,0	52,0	28,0	8,0	38,8	840,3	805,0	35,3	84276,2	284393,3	200117,1	104,7	4,2
268	173,0	12,79	22,1	0,682	0,762	0,017	86,7	55,1	51,5	27,3	7,7	44,8	816,0	771,2	44,8	82785,3	286402,9	203617,7	107,3	5,5
291	210,0	9,27	22,1	0,692	0,836	0,029	86,4	55,2	51,2	27,9	7,3	37,9	818,4	780,6	37,7	75071,3	271733,1	196661,8	96,2	4,6
331	210,0	7,75	22,0	0,69	0,698	0,029	95,3	55,6	55,2	35,5	7,7	44,8	642,9	623,4	19,5	59412,4	161656,3	102243,9	95,3	3,0
388	210,0	7,17	22,7	0,702	0,782	0,021	84,2	55,6	49,8	23,7	8,1	46,2	635,3	576,8	58,5	54908,6	271569,9	216661,3	95,2	9,2
444	220,0	6,21	22,7	0,702	0,669	0,021	88,4	56,0	52,2	29,9	8,6	39,3	577,0	521,9	55,1	53811,7	203967,8	150156,1	103,1	9,5
486	220,0	7,31	22,1	0,68	0,67	0,015	87,2	56,7	51,1	25,8	8,2	44,0	682,4	600,3	82,0	64031,9	292438,2	228406,4	106,7	12,0
497	208,0	7,75	22,1	0,68	0,681	0,015	86,1	56,7	50,4	26,2	7,7	35,7	669,9	567,0	102,9	72733,0	281098,0	208365,0	128,3	15,4
514	203,7	7,75	22,1	0,68	0,68	0,015	86,0	56,9	50,4	23,7	8,1	44,9	648,0	513,8	134,1	71557,9	305738,5	234180,6	139,3	20,7
559	203,7	7,25	21,7	0,731	0,664	0,027	86,4	57,3	50,6	23,2	7,9	41,1	604,3	505,9	98,4	59876,7	281520,0	221643,3	118,4	16,3
591	202,0	6,25	21,7	0,731	0,679	0,027	85,6	57,4	50,3	20,8	8,0	48,7	523,7	425,1	98,6	60788,9	289690,2	228901,3	143,0	18,8
670	202,0	5,98	21,7	0,716	0,69	0,018	29,0	29,0	29,0	29,0	29,0	29,0	29,0	29,0	29,0	29,0	29,0	29,0	29,0	29,0
992	179,7	5,98	22,3	0,678	0,666	0,011	77,5	57,0	45,2	15,1	8,0	50,1	432,5	335,9	96,6	36840,5	300198,4	263357,9	109,7	22,3
1045	295,0	2,18	21,8	0,678	0,659	0,007	77,6	57,2	45,8	14,3	8,0	39,8	311,0	237,4	73,6	37372,9	267696,0	230323,0	157,4	23,7
1083	289,0	2,055	21,8	0,678	0,723	0,007	95,5	57,0	57,8	16,3	8,0	42,5	271,5	205,4	66,1	43404,8	202392,5	158987,7	211,3	24,3
1166	271,3	2,01	22,3	0,728	0,723	0,019	79,4	56,7	46,5	13,5	8,2	42,5	258,3	175,0	83,3	19640,5	221001,1	201360,6	112,3	32,3
1191	271,3	1,93	23,3	0,698	0,65	0,014	77,1	56,9	44,5	11,4	8,2	37,0	249,7	163,9	85,8	25809,1	188391,0	162581,9	157,4	34,4
1250	261,5	2,14	23,3	0,698	0,667	0,014	77,0	56,6	43,3	15,7	8,1	13,8	262,6	177,6	85,0	18443,2	179564,2	161121,0	103,8	32,4
1328	261,5	2,14	24,0	0,701	0,685	0,004	0,0	0,0	46,7	7,5	8,1	10,9	824,0	525,3	298,7	24158,3	189477,2	165318,9	46,0	36,2
1391	261,5	1,5	26,3	0,659	0,801	0,006	0,0	0,0	45,8	9,5	7,9	43,1	180,4	118,3	62,2	8704,9	163563,9	154859,0	73,6	34,5
1425	261,5	1,12	22,2	0,661	0,676	0,006	82,8	56,3	48,9	5,4	7,8	30,9	135,2	96,2	39,0	10746,2	173169,9	162423,6	111,7	28,8
1500	276,2	1,78	22,2	0,661	0,833	0,006	87,7	55,4	51,5	9,2	7,7	39,8	227,9	154,6	73,3	22616,4	198861,8	176245,4	146,3	32,2

2.2 Multiphase flow simulation

The multiphase flow simulations are responsible for providing a numerical estimate of the production flow from the wells, as well as providing the system pressure and temperature loss. These last two information are important in the context of flow assurance to avoid deposition of paraffin, asphaltene and/or hydrate.

Another essential information for production management is the optimization of the artificial lift system, which is provided by multiphase flow simulations. In the present work, the well is equipped with a gas lift system. In this way, it is possible to verify the optimal gas injection flowrate, which returns the maximum oil flowrate from the well (Fig. 1).

In the present work, the simulations were carried out in PIPESIM® [13], which is a steady-state multiphase flow simulator. The first step was to model the well characteristics in the simulator. Next, the production parameters were calibrated according to the last available production test (Tab. 1). And then, the multiphase flow model was fitted with the production data. This model adjustment was performed based on data matching, looking for the vertical and horizontal flow models that returned the pressure drop value closest to the pressure data obtained in the production test (bottom hole and well head pressure). After performing this adjustment, the best correlations were identified:

- Vertical multiphase flow: Gray [14];
- Horizontal multiphase flow: Dukler, AGA & Flanigan [15].

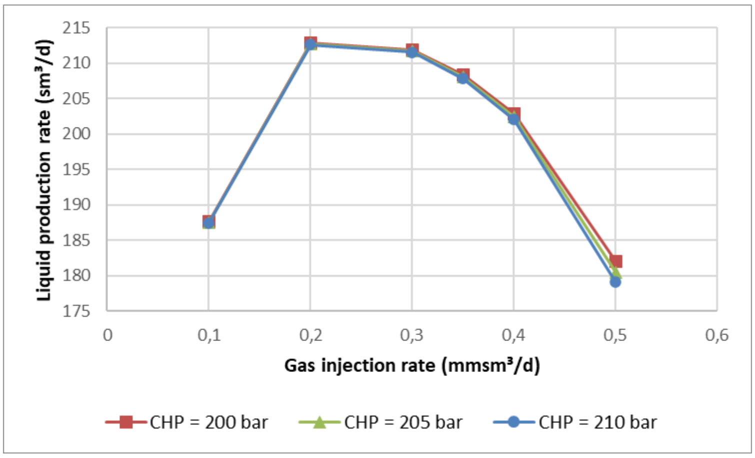

Figure 1. Gas lift.
CHP: surface gas injection pressure (bar)

3 Case Study

For the study, data from a real well in a Brazilian post-salt field were used. The well is positioned in a water depth of 1800 m and has a true vertical depth of 3000 m. The well is directly connected to the platform through a 2100 m of flowline, followed by a 2600 m of catenary riser. The system profile is represented in Fig. 2.

In terms of well completion, the well has a gas lift valve (GLI) at a measured depth of 2555 m, the packer at 2934 m and the perforated region at 3339 m. The production string has an internal diameter of 6 in and the flowline and riser have an internal diameter of 6 7/8 in.

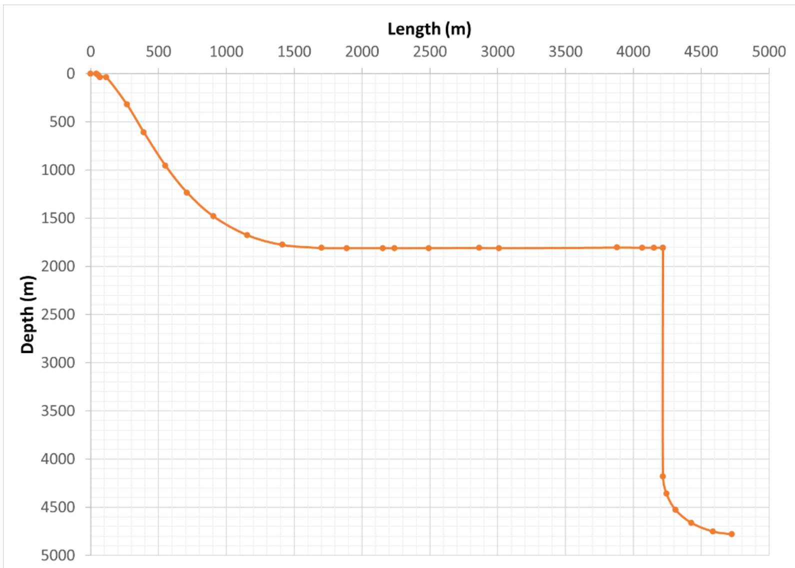

Figure 2. Production system profile.

Another extremely important information is the well's production history, along the other data from the production test. Thirty (30) tests were collected over 4 years of production (Tab. 1). The information of production test bulletin includes: reservoir pressure, productivity index, gas density, lift gas density, oil density, solubility ratio, CO_2 content, water cut, gas-oil ratio, gas- liquid ratio, bottom hole pressure and temperature (PDG), wellhead pressure and temperature (TPT), separator pressure and temperature, liquid, oil, water, produced gas, lift gas and total gas flowrate (Fig. 3).

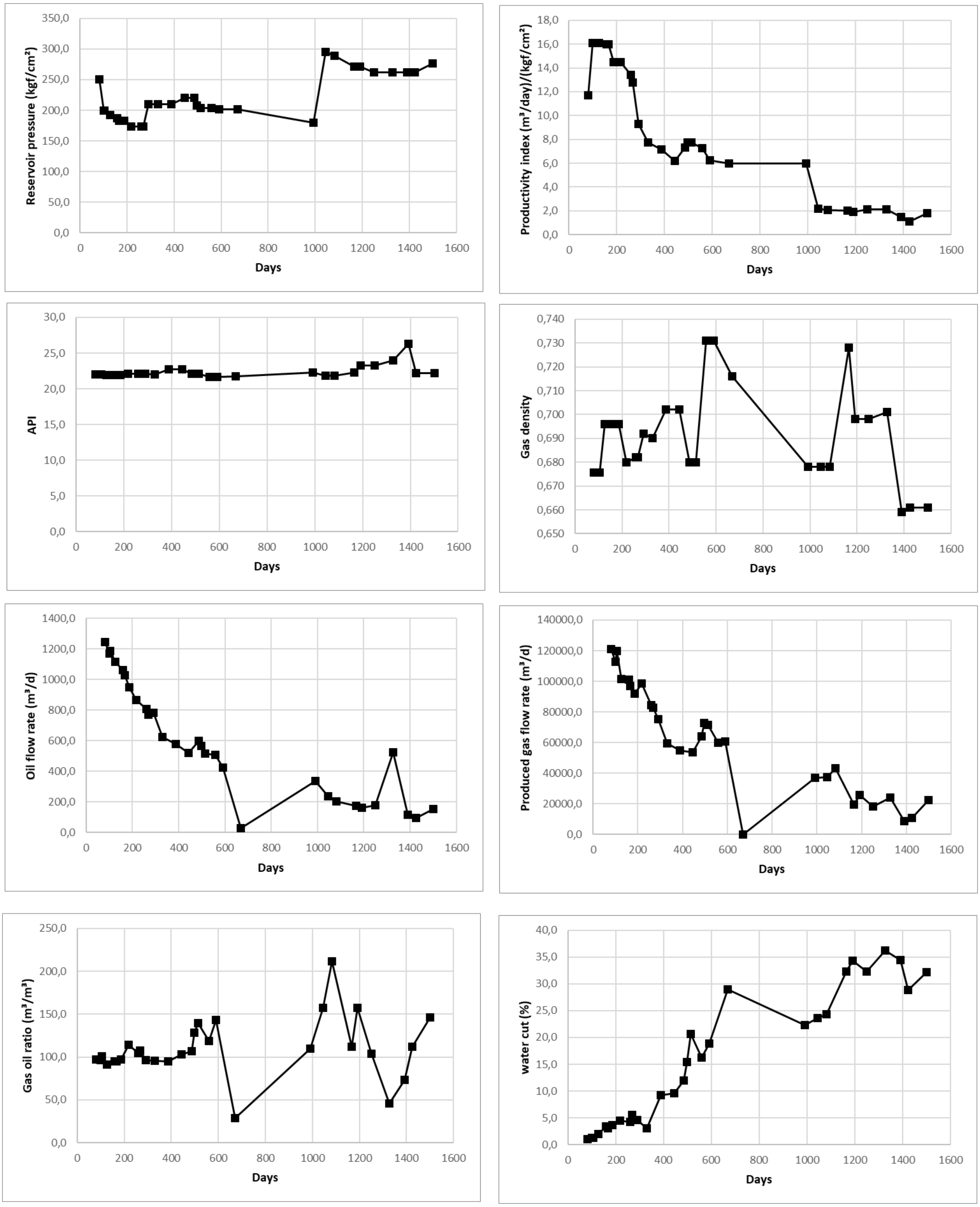

Figure 3. Well production parameters.

As mentioned in Chapter 2 , the multiphase flow model was adjusted with the last production well test and based on this calibrated model, a sensitivity analysis was performed to assess which parameters have the most impact on the well productivity. Among the parameters of the well test, the following were analyzed: reservoir pressure, productivity index (PI), gas-oil ratio (GOR), water cut (WC) and gas lift injection rate. For this analysis, the parameters were varied according to the range described in Tab. 2. The combination of parameters resulted in 1860 multiphase flow simulations.

Table 2. Well production tests.

Qgl (mmsm³/d)	WC (%)	GOR (sm³/sm³)	PI (sm³/(d*bar))	Pe (bar)
0,15	0	0	1	147
0,16	10	25	1,5	172
0,17	20	50	2	196
0,18	30	75	3	221
0,19	40	100	5	245
0,2	50	125	8	270
0,21	60	150	10	294
0,22		175	12	319
0,23		200	15	343
0,24		225	18	
0,25		250	20	
			22	

From the simulations, the Pearson correlation matrix [16] was generated, as shown in Fig. 4. With the result of the matrix, the parameter that most influences the flowrate is the productivity index (PI). This is very intuitive as this parameter reflects the well potential. PI is the ratio of the liquid flowrate to the pressure drawdown. Thus, the higher the PI, the greater the flowrate obtained by the well.

Reservoir pressure is the second most influential parameter and has a positive influence on production, as the greater the reservoir pressure, more energy the well has to produce.

Fluid parameters such as WC and GOR had the least impact, with WC having a negative impact on oil flow and GOR having a positive impact on gas flow, confirming the expected behavior. However, they still have significant importance in production management since the higher the WC, the greater the requirement for artificial lifting mechanisms.

An important data to analyze is the gas lift injection. It is worth noting that the correlation is positive with the liquid flowrate, however the gas lift injection presents a low correlation. The behavior of the gas lift injection follows Fig. 1, with productivity increasing as the gas lift increases, but up to a certain value. After the value that returns the maximum productivity, the injection of more gas in the system becomes harmful. This occurs because the gas increases the friction loss, as it flows at a higher velocity than the liquid, thus causing a loss of productivity. This behavior can cause divergence in the Pearson correlation matrix.

	Liquid flowrate (sm³/d)	*Oil flowrate (sm³/d)*	*Gas flowrate (mmsm³/d)*	*WC (%)*	*Gas injection rate (mmsm³/d)*	*GOR (sm³/sm³)*	*Reservoir Pressure (bar)*	*PI (sm3/(d*bar))*
Liquid flowrate (sm³/d)	1							
Oil flowrate (sm³/d)	0,995	1						
Gas flowrate (mmsm³/d)	0,795	0,797	1					
WC (%)	0,020	-0,078	-0,043	1				
Gas injection rate (mmsm³/d)	0,005	0,005	0,584	-0,001	1			
GOR (sm³/sm³)	0,043	0,039	0,189	0,020	-0,002	1		
Reservoir Pressure (bar)	0,185	0,186	0,141	-0,014	0,002	-0,035	1	
*PI (sm3/(d*bar))*	0,879	0,873	0,694	0,030	-0,014	0,073	-0,202	1

Figure 4. Pearson correlation matrix.

4 Conclusions

The present work was intended to show the impact of well test parameters in the oil production management. This study is the first step of a larger scope of research project that aims to develop methods based on artificial intelligence techniques for planning and managing oil production.

With the case study, it can be observed that the productivity index and reservoir pressure have a strong correlation with the production, followed by the fluid parameters (water cut and gas-oil ratio). Regarding the gas lift injection flowrate, it is worth noting that this parameter has a peculiar behavior with the liquid flowrate. The productivity increases as the gas lift flowrate increases, but up to a certain value, after the value that returns the maximum productivity, the injection of more gas in the system becomes harmful for the production.

Therefore, as a continuation of this project, it is intended to seek a surrogate model that represents the well behavior from the simulations carried out for the sensitivity analysis. With the surrogate model, it is possible to use it in an optimization model to maximize hydrocarbon production, achieving the optimum configuration for the gas lift injection.

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