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LIQUID UNLOADING OPTIMIZATION FROM GAS WELLS WHICH EXPLOIT DEPLETED RESERVOIRS

1. INTRODUCTION

Well liquid loading is one of the most important aspects in natural gas exploitation, which must be constantly monitored, mostly in mature reservoirs. The extension of this phenomenon is observed, as the natural gas reservoirs are depleting, thus substantially reducing the reservoir pressure.

Liquid impurities influx can come mainly from two different sources:

- porous - permeable thin layers intercalated between gas saturated layers, which were perforated, but unidentified by geophysical surveys;
- adjacent layers above or below target operating accessed due to improper cementing column.

Early recognition of the signs that indicate well liquid loading and selecting the appropriate lifting system can eliminate problems before decreasing production and degradation of the layer.

There are three common symptoms specific to all wells starting to load with liquid:

- Differential pressure between the tubing and casing by packer less completion;
- Slowing the water production from the well, while decreasing flow;
- Variations in the predicted production decline curve.

When these symptoms appear you should quickly implement the appropriate lifting technology to avoid flooding the well.

In case of mature gas fields, while the natural energy used to eliminate well impurities is continuously decreasing, it requires the use of technologies which make the exploitation to continue in optimum conditions.

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2. LIQUID UNLOADING METHODS AND TECHNOLOGIES

Worldwide were tested and are used a number of methods, technologies and equipment's that optimize liquid unloading during natural gas exploitation processes. Some of these methods are based exclusively on the gas energy, but in some cases a specific type of completion is demanding. On the contrary, other methods use the external sources of energy and a special well completion. From another perspective these methods allow two ways for liquid continuous and intermittent unloading.

The mostly used liquid unloading methods, based on their energy, are the following:

- Producing wells at rates greater than the critical flow - continuous discharge;
- Controlled periodic discharge to surface - intermittent discharge;
- Soap introduction - intermittent discharge;
- Equipping wells with automatic devices- intermittent discharge;
- Equipping wells with plunger lift - intermittent discharge;
- Equipping wells with small diameter tubing (velocity string) - intermittent discharge;
- Equipping wells with liquid evacuation – accumulation cells - intermittent discharge.

The mostly used liquid unloading methods, based on additional energy from external sources, are the following:

- Equipping wells with depth pumps - continuous discharge;
- Equipping wells with gas ejector - continuous discharge;
- Equipping wells for artificial lift - continuous gas - lift continuous discharge.

Among the methods presented above it will be selected the appropriate production technology based on the reservoir potential energy, well completion and gas-liquid ratio.

3. CANDIDATE WELLS SELECTION FOR A SPECIFIC LIQUID UNLOADING TECHNOLOGY USE

It is extremely useful to know when well liquid loading begins, as alternatives liquid unloading solutions to be accessed at the appropriate time.

Decisional aspect regarding liquid unloading optimal alternative selection from gas wells involves the following considerations:

- increasing productivity;
- the period that well will produce with selected technology;
- pressure drops in the gathering system;
- technical - economical evaluation in similar operating conditions.

The first step for selecting a particular technology relates to wells investigation and evaluation in order to accurately determine the productive parameters:

- static pressure;
- dynamic pressure;

– gas-liquid ratio;
– gas flow;
– liquid flow.

To select the most interesting wells, candidates for rehabilitation or liquid unloading, meaning their re-completion and the use of other production technologies, we consider that a production and technical expertise is needed, and for this purpose we developed the scheme shown in figure 1.

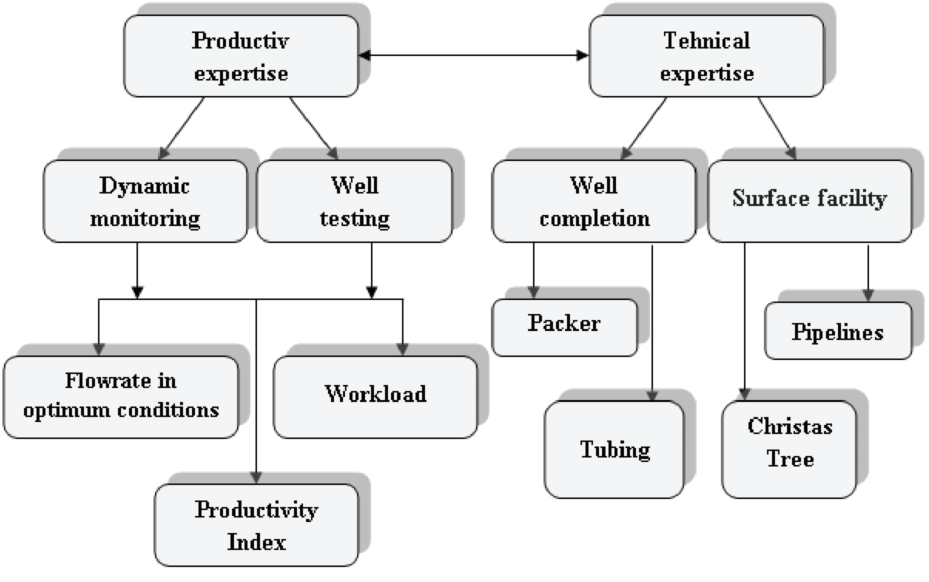

Fig. 1. General scheme – Candidate wells selection for rehabilitation.

Initially, the well should be tested and monitored in stabilized dynamical regime, under the existing conditions and conditions that allow producing it without liquid loading. After that well should be investigated hydrodynamic making a reservoir pressure build up test. All these tests and measurements will show the productive potential, but also the grade of impurities and liquids loading.

Along with this, should be evaluated the technical aspect, in terms of depth and surface equipment. For example, to examine whether a well equipped with packer allows the use of any technology or packer retrieval is required. The flow section must be constant without the disturbing variations of diameter valves, nipples, pipes.

Equipment's type and design used to unload liquids is determined by each reservoir characteristics, mainly by the energy level and flow capacity. As an example, for the wells which are producing from low permeability reservoirs, the liquids are lifted to the surface irregular, due to reduced flow rates and variation in time of the well and pipeline pressures.

4. EVALUATION OF LAYER-WELL SYSTEM BEHAVIOR; WELLS WATER LIFTING OPTIMIZATION

4.1. Critical parameters determination

The major problem in managing natural gas mature fields is that the amount of liquid impurities is increasing, which in terms of energy depletion cannot be eliminated naturally. During this period, for avoiding liquid accumulation and subsequent flooding, wells must produce at minimum flow, called the critical flow, under whose value is not possible to bring the accumulated liquid to surface.

The wells may produce without liquid loading if in tubing is obtained an ascending gas velocity greater than the drop velocity limit in free fall. Factors from which are depending the critical velocity and critical flow are dynamical bottom hole or wellhead pressure, flow section diameter, liquid and gas density, water superficial tension.

Critical velocity v_c and critical gas flow Q_{gc} can be obtain using Turner relations:

$$v_c = \frac{k\sigma^{0,25}\left(\rho_a - \rho_g\right)^{0,25}}{\rho_g^{0,5}} \tag{1}$$

$$Q_{gc} = \frac{k' v_c A_t p_s}{T_s} \tag{2}$$

where:

k	=	6.584 in SI;
σ	–	Water superficial tension, N/m;
ρ_a, ρ_g	–	Water density, respectively gas density, kg/m^3;
k’	=	0.2462 in SI;
A_t	–	tubing cross sectional area, m^2;
p_s	–	surface tubing pressure, kPa;
Z	–	Compressibility factor;
T_s	–	surface absolute temperature, K;
v_c	–	critical velocity, m/s;
Q_{gc}	–	critical flow, m^3/day.

Considering these relationships we developed a Microsoft Excel spreadsheet program for determining the two critical parameters, customizing it by using the gas mixtures specific densities which form the Transylvanian Basin Reservoirs.

The results are transformed into a density - temperature variation curve, under 1 bar pressure conditions (figure 2).

It is noted that the density values obtained in the laboratory for the most important 20 fields, at 0, 15 and 20°C temperature are very close, which allows using it in calculus an average value which characterizes this reservoir type. This polynomial curve type shows a clear density behavior trend in order to reduce it as the temperature increase.

As we presented before, to estimate critical velocity has been used an average density, respectively 0.683 kg/m^3, specific for the Transylvanian Basin gas mixture, under surface conditions.

From the laboratory tests made to reservoir waters we observe their density variation in a relatively extended domain, determined by mineralization degree, temperature, pressure, dissolved gas fraction. It is noted however, that soaps composition used for cleaning wells from fluid impurities influence their density level. Laboratory tests show for reservoir water density a representative domain between 1016 - 1140 kg/m^3. In these conditions, to estimate critical velocity may be use the water density value corresponding to each reservoir.

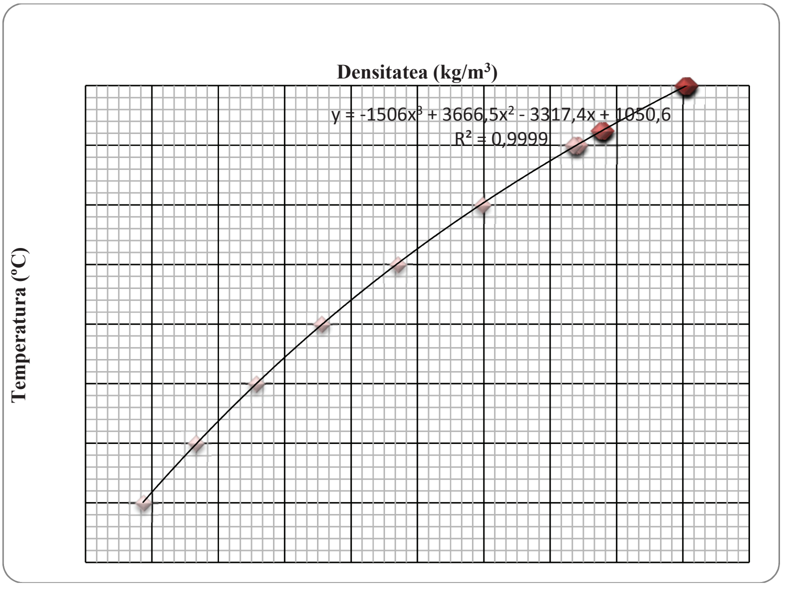

Fig. 2. Density - temperature variation at 1 bar pressure

Further, in Table 1, we present the Microsoft Excel spreadsheet program for the critical velocity and critical flow estimation, for 11 wells that produce in Filitelnic field, respectively the layers XI+XII North Buglovian, XI+XII South BuglovianI, XIII Badenian North, XIII+XIV South Badenian.

Table 2 shows the comparative values of previously calculated critical flow rate and the flow rate at which produce effectively every well and also the impurities amounts removed daily. It is apparent that excepting well 7, the other wells are producing with lower critical flows, which allows the liquid impurities accumulation, as confirmed by the big differences between pressure values recorded in tubing and casing, and the extremely low water quantities removed daily.

We select 2 wells form Table 2, A and B, which will make the analysis subject in the next subchapter.

Table 1

Critical parameters estimation

Well	σ	ρ_a	ρ_g	critical velocity	A_t	p_t	Z	T	critical flow rate
	N/m	kg/m^3	kg/m^3	m/s	m^2	kPa		K	m^3/day
1	0,073	1,14	0,683	3,405	0,003	0,67	0,9979	288	5863
2	0,073	1,14	0,683	3,405	0,003	0,52	0,9979	288	4541
3	0,073	1,14	0,683	3,405	0,003	0,79	0,9979	288	6904
4	0,073	1,14	0,683	3,405	0,003	1,08	0,9979	288	9450
5	0,073	1,14	0,683	3,405	0,003	0,54	0,9979	288	4725
6	0,073	1,14	0,683	3,405	0,003	0,82	0,9979	288	7175
7	0,073	1,14	0,683	3,405	0,003	1,30	0,9979	288	11375
A	0,073	1,14	0,683	3,405	0,003	1,20	0,9979	288	10500
B	0,073	1,14	0,683	3,405	0,003	1,25	0,9979	288	10938
8	0,073	1,14	0,683	3,405	0,003	1,04	0,9979	288	9100
9	0,073	1,14	0,683	3,405	0,003	1,00	0,9979	288	8750

Table 2

Flow and impurities values

Well	Qcritical	Q	Impurities
	m/day	m^3/day	l/day
1	5863	4000	10
2	4541	2500	20
3	6904	2600	20
4	9450	5100	20
5	4725	3100	140
6	7175	1100	0
7	11375	23000	150
A	10500	8000	0
B	10938	8300	0
8	9100	7600	20
9	8750	6700	60

4.2. Case study – reducing tubing flow sectional area – sensitivity analysis

The starting point for this approach is the very different behavior of the reservoirs with relatively low energy levels and an accentuate depletion decline. Further, on this issue, we selected two wells for study which produced from XIII+XIV Badenian Filitelnic field, located in the Transylvanian Basin. The two wells are completed with 72.8 mm (2 7/8 in) tubing diameter and have operational problems due to fluid accumulation.

Candidate wells for this study were selected after history matching analysis in the point of dynamical parameters terms. We simulated the production behavior for different tubing diameters with the help of specialized software that actually allows performing a sensitivity analysis to determine the optimal operating point.

Using this software involves in the first step the well configuration by defining the direction component parts layer - well - surface facilities, respectively perforations, tubing, choke, flow line. In the second step, based on flow and pressure values the reservoir performance curve is generated. Further is made the nodal analysis for a point situated in the perforations and various tubing diameters: 38.1 mm (1 1/2 in), 50.8 mm (2 in), 60.1 mm (2 3/8 in) and 72.8 mm (2 7 /8 in).

The last step generates the reservoir and well (equipment) performance curves on the same graphic and the intersection point represents the optimal operating point of the layer - well system.

4.3. Well A Filitelnic

This well is producing from Badenian XIII+XIV and since the beginning of operation, in 1991, it produces with a considerable difference of pressure, between tubing and casing, which increases recently, as the history matching presented in Figure 3. It is also noticeable the mode of liquid impurities unloading fluctuations.

Liquid level measurement into the well indicates the presence of foaming water over approximately half the tubing length as shown in figure 4. The well is treated with soap substances, but the reservoir energy is not enough for unloading the fluid impurities from the well. The pressure difference between the tubing and the casing was maintained at approximately 17 bar, a rather high value.

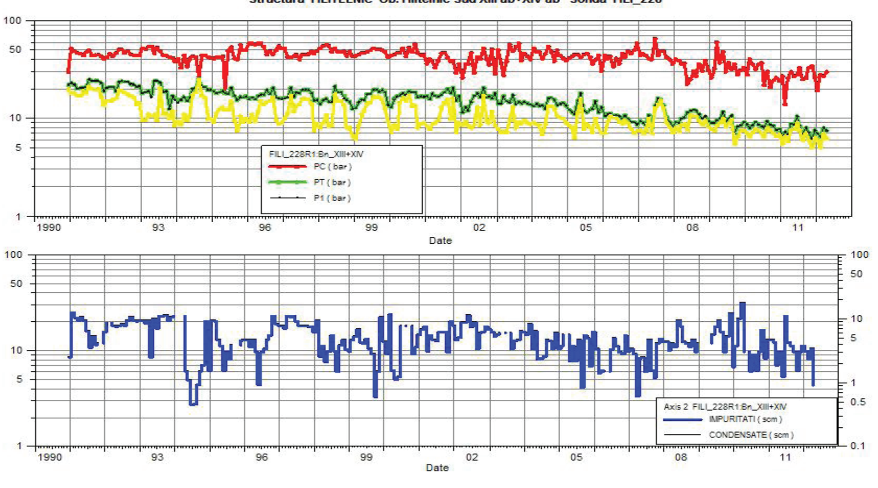

Fig. 3. History matching - well A production behavior

Obiectiv:	Bn XIII+XIV Sud		
Data mas:			
Pt/Pc:	12	29	bar
P1/P2:	11	10,5	bar
Perforatur	2550	2815	m
Tubing:	2 7/8	2756	inxm
Oglinda:		2815	m
Sablonat:	0-	2756	m
Tz:		70,84	°C
Debit:		8000,0	mc/zi
Duza:			
Dens. apa	1025		

H	P	ρ teor.	ρ real.	Ha / Ht	H inter.
m	bar	kg/mc		%	m
0	11,04	7,67			
1000	12,95	8,40	19,1	1,09	10,88
1500	14,48	9,10	30,6	2,15	10,75
2000	26	15,92	226,6	21,14	105,72
2400	30,15	18,19	108,5	9,07	36,29
2600	34,29	20,51	207,0	18,66	37,32
2700	36,51	21,74	222,0	20,01	20,01

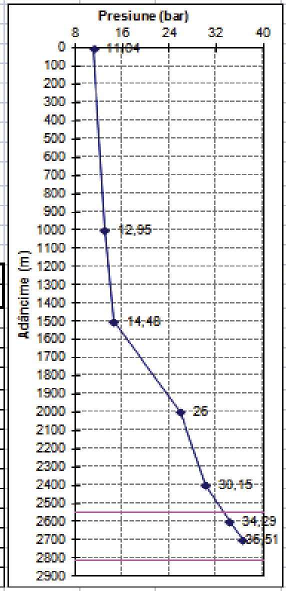

Fig. 4. Well A liquid level estimation

Sensitivity analysis for the four tubing diameters and Figure 5 performance curves reveals the following:

- for the tubing size of 38.1 mm (1 1 /2 in) the well flow rate is in the range (9700 m³/day, the minimum flow rate which allows water unloading - 24.000 m³/day, the optimal flow rate at which the well can be produced);
- for the tubing size of 50.8 mm (2 in) the well minimum flow rate which allows water unloading must have the value of 24.000 m³/day and is situated inside the reservoir performance curve, but extremely close of it;
- for the tubing size of 60.1 mm (2 3/8 in) the well minimum flow rate which allows water unloading must have the value of 26.120 m³/day and is situated inside the reservoir performance curve, but extremely close to the limit;
- for the tubing size of 72.8 mm (2 7/8 in), the currently well tubing completion, well minimum flow rate which allows water unloading must have the value of 26.800 m³/day a value that is situated inside the reservoir performance curve, but extremely close to its limit;

From those mentioned above we can conclude that the last three tubing diameters allow the water unloading from the well at very close minimum rate between 25 – 26 m³/day. The tubing fitting of 38.1 mm (1 1/2 in) is the most favorable, because the well liquid unloading in this case starts at 9.7 m³/day rate. The well currently produces with approximately 8000 m³/day rate, a lower flow than the critical flow rate, and fitting this tubing would allow the removal of liquid impurities and recording the performance in exploitation, meaning a substantial increase in output and achieving a 5.65 m³/zi/bar productivity index.

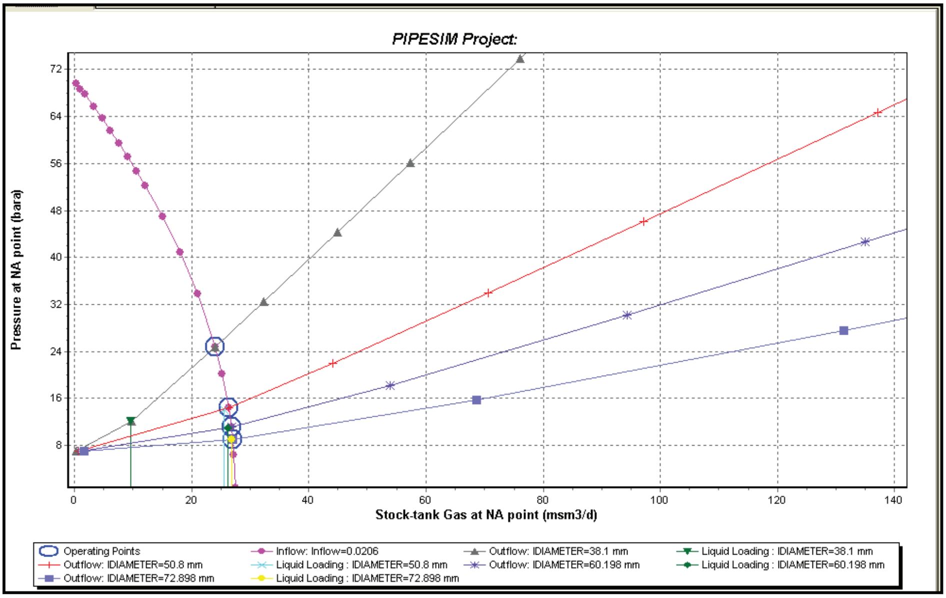

Fig. 5. The correlation layer - well A, for different tubing diameters

Well B Filitelnic

This well produce from Badenian XIII+XIV and as the history matching shows in Figure 6, since 1993, we could observe a different behavior, in maintaining an appreciable difference between tubing and casing pressure, but also a degradation of liquid impurities unloading method, to decrease the amount of unloaded water.

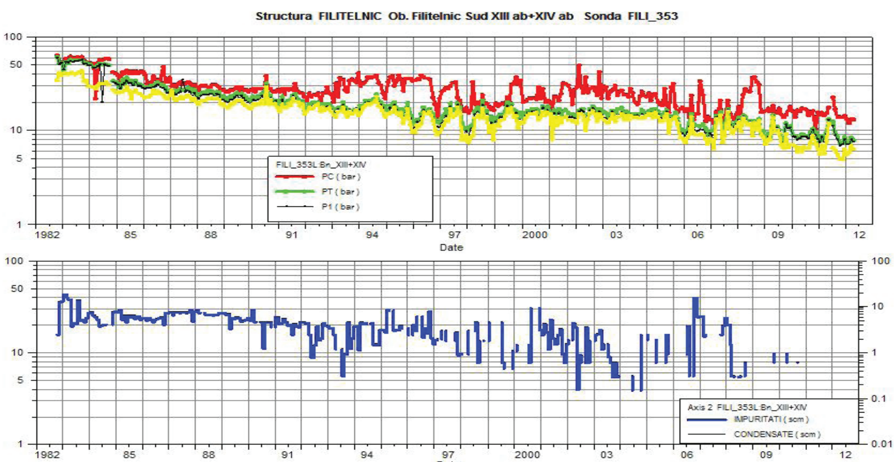

Fig. 6. History matching – well B behavior in exploitation

The loading with impurities has been determined by measuring the level of fluid in the well, with special measuring equipment. Graphical representation of the pressure profile recorded into the well is shown in Figure 7. This measurement indicates a clear liquid level well, approximately 1/3 of the length of tubing. While the well is being treated with soap substances, this method does not allow complete lifting impurities from the liquid surface.

Obiectiv:	Bn XIII+XIV Sud		
Data mas:			
Pd(mas):	12,5	17,7	bar
P1/2:	11,5	10,5	bar
Perforatur	2520	2788	m
Tubing:		2766	inxm
Oglinda:		2789	m
Sablonat:	0-	2770	m
Tz:		77,34	°C
Debit:		8300,0	mc/zi
Duza:			
Dens. apa	1025		

H	P	ρ teor.	ρ real.	Ha / Ht	H inter.
m	bar	kg/mc		%	m
0	13,47	9,41			
1000	16,39	10,60	29,2	1,89	18,91
1500	17	10,59	12,2	0,16	0,79
2000	31,36	19,14	287,2	26,96	134,80
2300	42,1	25,40	358,0	33,48	100,45
2520	56,39	33,88	649,5	62,28	137,01
2650	66,04	39,58	742,3	71,40	92,81
2770	75,56	45,16	793,3	76,42	91,71

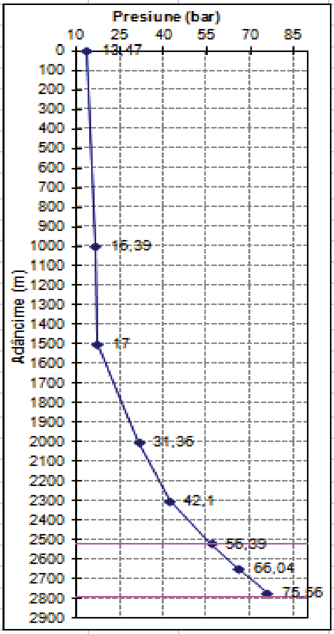

Fig. 7. Liquid level measurement in well B

Sensitivity analysis for the four tubing diameters and Figure 8 performance curves reveals the following:

- for the tubing size of 38.1 mm (1 1 /2 in) the well flow rate is in the range (8000 m^3/day, the minimum flow rate which allows water unloading - 15.300 m^3/day, the optimal flow rate at which the well can be produced);
- for the tubing size of 50.8 mm (2 in) the well minimum flow rate which allows water unloading must have the value of 19.940 m^3/day and is situated outside the reservoir performance curve;
- for the tubing size of 60.1 mm (2 3/8 in) the well minimum flow rate which allows water unloading must have the value of 37.960 m^3/day and is situated outside the reservoir performance curve too;
- for the tubing size of 72.8 mm (2 7/8 in), the currently well tubing completion, well minimum flow rate which allows water unloading must have the value of 76.840 m^3/day a value that is situated far outside the reservoir performance curve.

From those mentioned above we can conclude that completing the well with tubing of 72.8 mm (2 7/8 in) does not allow the complete well liquid impurities unloading, the flow rate of 8300 m^3/day been much lower than the critical flow. For larger tubing diameter the well is charged with liquid impurities, and their complete removal is produced at high flow rates and pressures. A favorable completion is that with tubing of 38.1 mm (1 1/2 in), which enables efficient operational behavior, to increase well flow with 6.000 – 7.000 m^3/day.

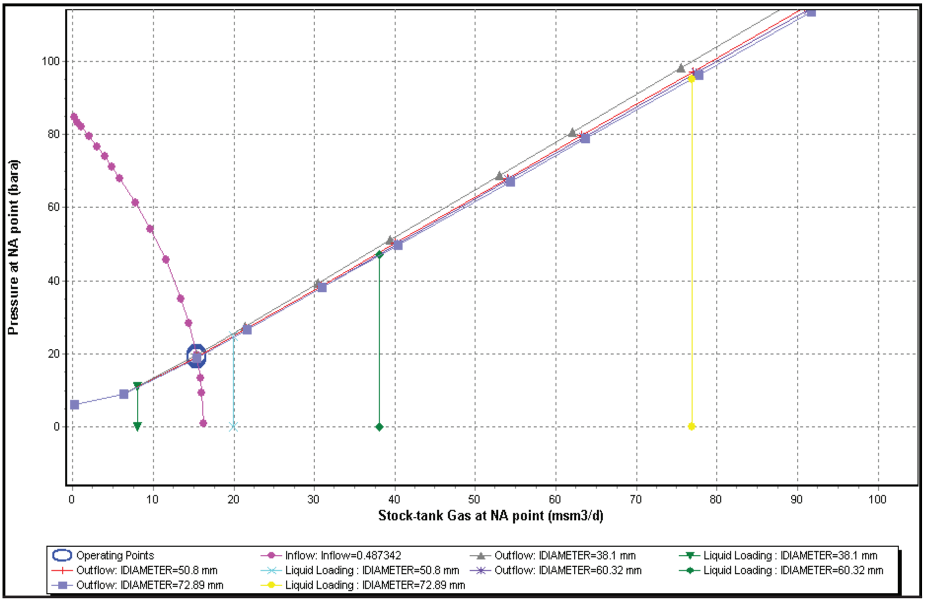

Fig. 8. The correlation layer - well B, for different tubing diameters

5. CONCLUSIONS

Liquid flow increase during mature reservoir exploitation, but only a part of this quantity is naturally unload by gas stream and the other part tend to accumulate to the bottom hole. In these condition's, the formation back pressure will increase continuously, causing continuous dropping and accentuated gas flow rate until liquid loading will stop the production by well flooding.

In the beginning of the reservoir exploitation, gas is produced at the surface with liquid and then gas velocity becomes insufficient to lift the fluid that means to get accumulate gradually in the well. In order to remove the water using the gas stream, for preventing water accumulation into the well, it is necessary that the water particles to have a higher velocity than the critical velocity, so the gas flow will have a value higher than the critical flow rate.

For determining the optimal operating point it is needed to evaluate and optimize the layer - well system behavior in exploitation of the well by representing reservoir performance curves. This allows the most appropriate tubing size selection so the water unloading from wells in a superior flow rate than critical flow rate conditions to be ensured.

Early recognition of the signs that indicate liquid loading wells and selecting the appropriate lifting system can eliminate problems before decreasing production and degradation of the layer.

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