AGH DRILLING, OIL, GAS • Vol. 33 • No. 2 • 2016

http://dx.doi.org/10.7494/drill.2016.33.2.531

Florinel Şuţoiu*, Ion Foidaş*, Mihail Avramescu*

OPERATIONS FOR IMPROVING THE GAS FLOW IN THE WELLBORE ADJACENT ZONE

1. INTRODUCTION

During the whole period of a natural gas reservoir exploitation, from the start of production until the total reservoir energy depletion, may apear some phenomena which by their nature can affect the natural gas flow from the layer into the well.

When the productivity of a well decreases, the production team will attempt to increase productivity through intervention and appropriate treatments. If they decide to work over the well, they must identify and implement a treatment program that creates conductive flow paths between the reservoir and the borehole.

The flow resistance greeted by gas in the adjacent borehole may have multiple causes, for example formation damages or mechanical problem etc.

The formation damage problem is recognized, when the well is producing with low productivity relative to what they are capable of producing and then evaluating possible mechanical problems in these wells. Geology, petro physics and reservoir engineering play important roles in quantifying the productive potential of a given well. Once a well is diagnosed as underperforming, the reasons must be determined.

In the majority of cases, geological elements are those which definitive influence the behaviour in exploitation of those reservoirs, so the existence of some traps due to the continuity and discontinuity character of the porous-permeable medium or to some reservoir parameters with low values, drasticaly reduces the posibility of extraction of a bigger volume of geological gas resource.

A low-permeability reservoir is one that has a high resistance to fluid flow. In many formations, chemical and/or physical processes alter the reservoir rock over geologic time. Also the exploitation performances of gas reservoirs, through different wells, are

* SNGN Romgaz SA, Romania

major affected because of the skin factor. This produces an increased flow resistance in the adjacent zone of the borehole which is a plus to the resistance caused by the hydrodynamic imperfection to the mode and open degree of the productive layer.

During the maturity stage of natural gas reservoirs, a special attention is granted to prevention and control of this unwanted effects which may affect natural gas flow from the reservoir into the well, through different operations.

The stimulation of these productive layers through different operations aiming the reduction of geological nature constraints, thereby become a complex approach having the finality the increasing of exploitation performances itself.

Therefore, well stimulation may be required for reservoirs that are not performing optimally. The justification for stimulation is always an economic justification, where the increased productivity is weighted against the cost of the treatment.

All available information on the well such as well logs and records, reservoir characteristics and information on the completion and previous workovers should be collected and analyzed. The historical information is the key to identifying potential formation damage mechanisms. All of these data must be assessed before damage mechanisms can be identified and/or treatments are recommended. Data collection, analysis and integration programs require a great deal of effort, scrutiny and innovation.

In Romgaz were tested and are used a series of stimulation technologies of the productive layers. From there historic we conclude that perforations or re-perforations using deep penetration tools and acidizing are applied with success to the productive wells.

Regarding the increasing of the recovery factor for wells with high water income or for wells with mixed flow regime or with water drive regime, were successfully tested the polymer injection technology that helps to maintaining or optimising the productive wells.

2. PERFORATING AND RE-PERFORATING TECHNOLOGY

It is often seen that perforation operation usually doesn't get much importance during completion. Perforations can significantly affect the total completion efficiency. This activity can create negative effects, like damaging the formation permeability around perforation tunnels. These damage and perforation parameters, like penetration length, penetration hole size, number of shots, and the angle between holes, have a direct impact on pressure drop near a well and therefore, on production. The main objective of perforating is to optimize these parameters and mitigate induced damage.

Perforation length usually is thought to be the most important characteristic in a perforation design. Surprisingly, there are cases in which perforated length does not make a significant difference in well productivity. The perforation diameter also may influence the productivity ratio, especially in high productivity wells. Perforation diameter is dependent on charge design and the clearance of the gun in the casing. In instances such as sand control operations, unstable formations, and wells that are to be hydraulically fracture stimulated, the perforation diameter is important enough to dominate perforator selection. Flow through an open perforation should not be a restriction in the flowing system [1].

According to studies, by increasing perforation diameter above 0.25 in there is a very small increase in the productivity. Because of that the performance of shaped charges are usually based on the degree of perforation length; usually deep penetrating shaped charges are preferred [2].

As the guns are detonated, creating holes in the casing, cement, and the formation, particles from the charge; liner particles, charge case particles and mud are pushed into the formation as debris. This large energy released powderizes formation rock grains, making a low-permeability crushed zone around the perforation cavity and hindering fluid movement.

After perforation, flowing the well can help in cleaning the debris from the perforations due to the resulting drawdown between the wellbore pressure and the formation pressure, but as the drawdown decreases with time, the cleanup process through the perforation also gradually decreases. There are many other ways to remove the damage and improve the flow capacity. One of them is the pressure differential between the wellbore and the formation during the perforation process, which depends upon required reservoir formation strength and permeability. Underbalance perforating is the fundamental techniques to clean the perforation and improve productivity [2].

Underbalance perforating, or perforating with the pressure in the wellbore lower than the pressure in the formation, generally is acknowledged to be one of the best methods for creating open, undamaged perforations in which the permeability is high enough to create sufficient flow rate to break the crush zone loose and carry it out of the perforation tunnel. In a simplified view, the initial underbalance surge and the subsequent flow clean up the perforations across the interval.

The pressure differential required to remove damage from a perforation is affected by pressure, flow rate, and formation integrity. Initially, pressure differentials for underbalanced perforating were established by trial and error, but a connection finally was spotted relating underbalance pressure and flow to formation permeability [1].

In Romgaz, during the exploitation period of natural gas reservoirs we faced different problems which by their nature affected the natural gas flow from the layer into the well. Once it has been established that a well is producing below its potential and the mechanical reasons are eliminated as a potential cause of poor production, the production team tried to eliminate the formation damage applying a re-perforation methodology to restore the flow between the reservoir and the borehole.

Post re-perforation analysis clearly shows that the main causes of formation damage (skin): deep mud filtrate invasion and perforation tunnels lined with crushed rock material, were effectively minimized or by passed by using new deeper penetrating charges and a controlled dynamic underbalance perforating technique.

Deep-penetrating charges can also increase the effective wellbore radius and reduce the need for additional perforating operations, acid washes or other perforation cleanup techniques.

2.1. Example: Well A

Well history

Well A was brought on production in 1981. Well was worked over in 2006 to replace the old completion with new packer and SSD (Sliding Sleeve Door) completion, open new layer IX to produce through casing and re-perforate the existing producing layer XI a (XI b and XII are covered by a fish, the 2 7/8" old parted tubing).The recorded top of fish was at 2449 m. The production increased from 11 kscm/d to 35 kscm/d after work-over operation. Since February 2007, the well had been producing commingle through tubing by opening the SSD.

Faster decline trend was observed and a CT (Coiled tubing) acidizing was done in January 2008 to improve production (Fig. 1). Production has been fairly flat since.

The last PLT (Production Logging Tool) was performed in 2010 with 100% allocation factor for package VIII+IX+X, no contribution from Package XI+XII (Tab. 1). The Slickline operation was performed in 2010, to check the SSD condition and to set the mechanical plug in the selective nipple. The well was producing only from package VIII+IX+X through SSD up to tubing side with 7 kscm/d before re-perforation.

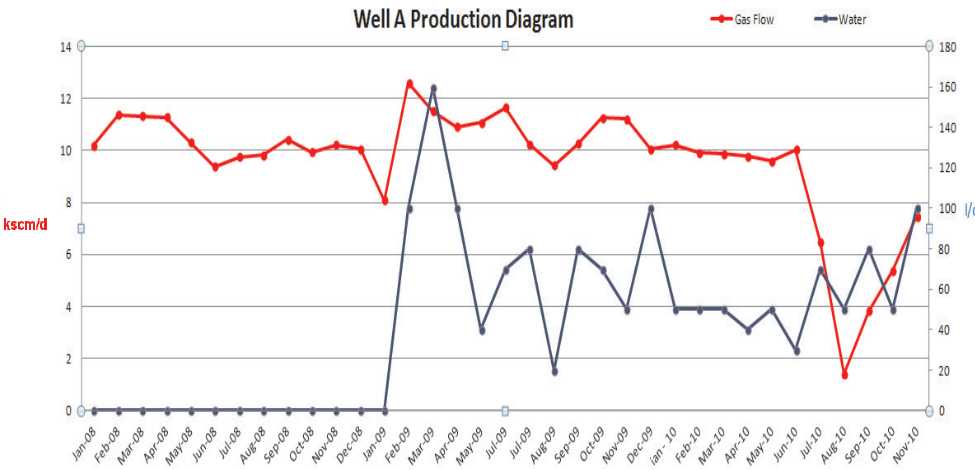


Fig. 1. Well A production history

Table 1

PLT survey results at well A

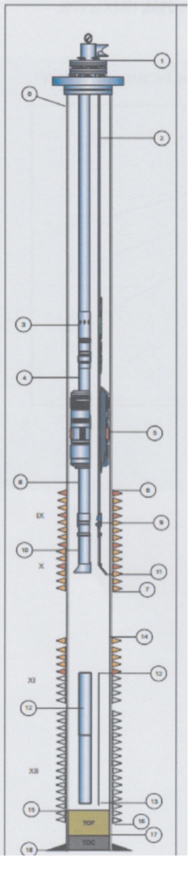
Year	PLT results			
	VIII+IX+X		XI+XII	
	Allocation factor	Gas rate	Allocation factor	Gas rate
	%	kscm/d	%	kscm/d
2009	89	8.1	11	1.1
2010	100	7.6	0	0

Well parameters

Reservoir pressure (VIII+IX+X):	37 bar
Reservoir pressure (XI+XII):	66 bar
Flowing Bottom hole Pressure (at 2448 m):	13.5 bar (PLT 2010)
Flowing Bottom hole Temperature (at 2448 m):	61°C (PLT 2010)
Gas Production Rate:	7 kscm/d
Water Production Rate:	100 litres/d
TOF (58 mm and 47 mm):	2433 m (2010)
PBTD:	2623 m (workover 2010)

The objective of the operation

The main objective of this operation was to selectively re-perforate both packages (VIII+IX+X and XI+XII) in underbalanced condition using a snubbing unit with total expected incremental gas production of 10 kscm/d (Fig. 2).



Layer	Top Perf.	Base Perf.	Meters
IX a	2124	2128	4
	2129	2131	2
	2132	2135	3
	2136.5	2140.5	4
	2143	2148	5
	2157	2160	3
IX b	2178	2183	5
	2199	2202	3
X a	2237	2252	15
	2255	2261	6
	2265	2268	3
	2293	2295	2
X b	2340	2342	2
	2349	2352	3
	2353.5	2356.5	3
	2365	2367	2
XI a	2400	2408	8
	2408.5	2410.5	2
Total			75

Fig. 2. Well diagram after re-perforation operation

The operation program

The re-perforation interval planned to berealised in both Packages are shown in Figure 2.

The best available gun for this well re-perforation was 2 7/8" HDS, Power Jet Omega 2906, HMX, because at the time of operation the 3.67" HSD, Power Jet Omega 3506, HMX wasn't available.

Results

After re-perforation the gas flow rate started to rise gradually month by month reaching values over 35 Skcm/d, when the well was cleaned out. The gas flow rate exceeded the Romgaz team expectations, the operation being a successful one (Fig. 3).

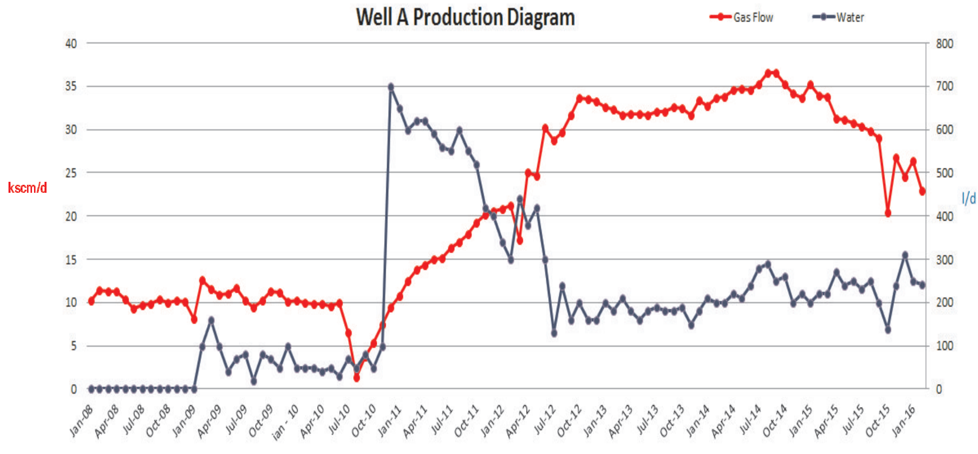


Fig. 3. Well A production evolution (before and after re-perforation)

3. ACIDIZING WASH TECHNOLOGY (WELLBORE CLEANOUT)

For many years, reservoir teams have sought ways to avoid early abandonment of oil and gas wells as a result of formation damage and low natural permeability in reservoirs. Such abandonments have caused incalculable loss of revenue resulting from the hydrocarbons left behind. Recovery can often be improved using stimulation techniques for removing or bypassing the formation damage in the near-wellbore area, or by partly increasing the formation's natural permeability, or, in many cases, both. Formation damage–plugging or partial plugging of perforations, or plugging of the rock matrix by debris from the well and from well operations–restricts the flow of hydrocarbons into the wellbore.

Identifying the causes of formation damage and preventing it from happening have been the subjects of much research. Well operations still, however, continue to cause some degree of damage to the formation in the near-wellbore region. Most of the field operations, namely well drilling, well completion, production, and well stimulation are potential sources for formation damage.

Well productivity can be adversely affected by formation damage in the near wellbore or by low natural permeability of the reservoir rock. Damage may be caused by drilling operations or the effects of long-term production.

There are various methods used to combat formation damage. One of them is acidizing. Acids may be used to reduce damage near the wellbore in all types of formations. Inorganic, organic, and combinations of these acids are used in variety of well stimulation treatments.

Therefore, acidizing represents a treatment with a stimulation fluid containing a reactive acid, used primarily to remove drilling damage and increase permeability near the well-bore.

Using acid may also help to remove the damage that blocks perforations and pores in the near-wellbore area.

The type of acid for a stimulation treatment depends on many factors, including the severity of the damage, the type of rock, its natural permeability and on downhole conditions. A number of options are available for acid-stimulation techniques, including:

- matrix acidizing,
- wellbore cleanup,
- acid fracturing.

Wellbore cleanup

Damage, or potential damage to perforations, tubing and the area immediate to the wellbore caused by formation fines, mud or cement filtrate, scale and debris from well operations may be removed by exposing the well to acid over a period of time (soaking), followed by some form of agitation.

Acid can be circulated across the openhole or perforated interval using coiled tubing, allowinga short soaking period. The coiled tubing string is worked up and down through the interval, and the spent acid is returned through the annulus. A second method is to apply pressure against the perforations, followed by rapid release of pressure by opening the bleedoff valve at the pumping unit – a method known as back surging. This technique is primarily effective when the reservoir pressure is greater than the fluid hydrostatic pressure. A further approach involves spotting acid across the perforations and swabbing back, either through tubing or casing.

Treatment normally, involves injecting formic acid (also called methanoic acid – $HCOOH$ or HCO_2H) into the formation in different concentrations depending of the rock content.

The type concentration of the acid chosen has to be compatible with the formation nature that it has to be treated. Incompatible concentrations acid would cause secondary formation damage. (for example the results of the acidizing operation can be: allowing the sand to get into the borehole, caused by sever dissolution of the cement).

Therefore, careful observation and measurements in the laboratory were done before and after acidizing process to identify changes in permeability of the core samples.

3.1. Example: Well B

The objective of the operation

The objective of this intervention was to increase the well productivity by unlocking the bottom of perforations and by dissolving any solid precipitation that built in the annulus of tubing and casing. Therefore, the purpose of the operation was to improve flow from the reservoir into the wellbore. The used chemicals was formic acid and the equipment used was the coiled tubing. The intervention consisted in the following steps:

- Cleaned the wellbore to PBTD with nitrified water (with the jetting nozzle).
- Kicked off the water.
- Spuded the acid and left it about 6 hours (the decision was made after we analyzed the rock sample from the formation, testing its reaction in time with the acid, at the reservoir temperature).
- Kicked of the acid solution.

Well history

Well B (Fig. 4) producing from XI package and it was never acidized. Well was worked over in 2009. It was perforated at 1018–1050 m depth and it was put into production with a gas rate of 19 kscm/d. After a while, by monitoring the dynamic daily parameters, we observed the well flow started to decrease; the well producing below its potential. This led to a carefully analysis of integrity of the well.

During last drifting operation we found a restriction in the bottomhole, therefore we would like to perform a nitrified water wash before the acidizing operation.

Last rigless operation in Well B was a FGS operation in January 2015, the drift tagged the 1026 m (where PBTD is at 1050 m) and no fluid level. The proposed scale dissolution treatment using formic acid was to enhanced the well productivity by creating an optimum gas flow path and allowing the well to deliver at its maximum potential. After the FGS we estimated that the producing perforated interval was approximately 8 m from a total of 32 m.

Well parameters

Reservoir pressure (XI):	29 bar
Flowing Bottomhole Pressure (XI):	13.37 bar (FGS 2015)
Flowing Bottomhole Temperature (1026):	43.36°C (FGS 2015)
Gas Production Rate:	3 kscm/d
Water Production Rate:	150 litre/d
THP/CHP:	12 bar/20 bar
TOF (47 mm and 32 mm):	1026 m (2015)
Perforations:	1018–1050 m
PBTD:	1050 m (workover 2009)

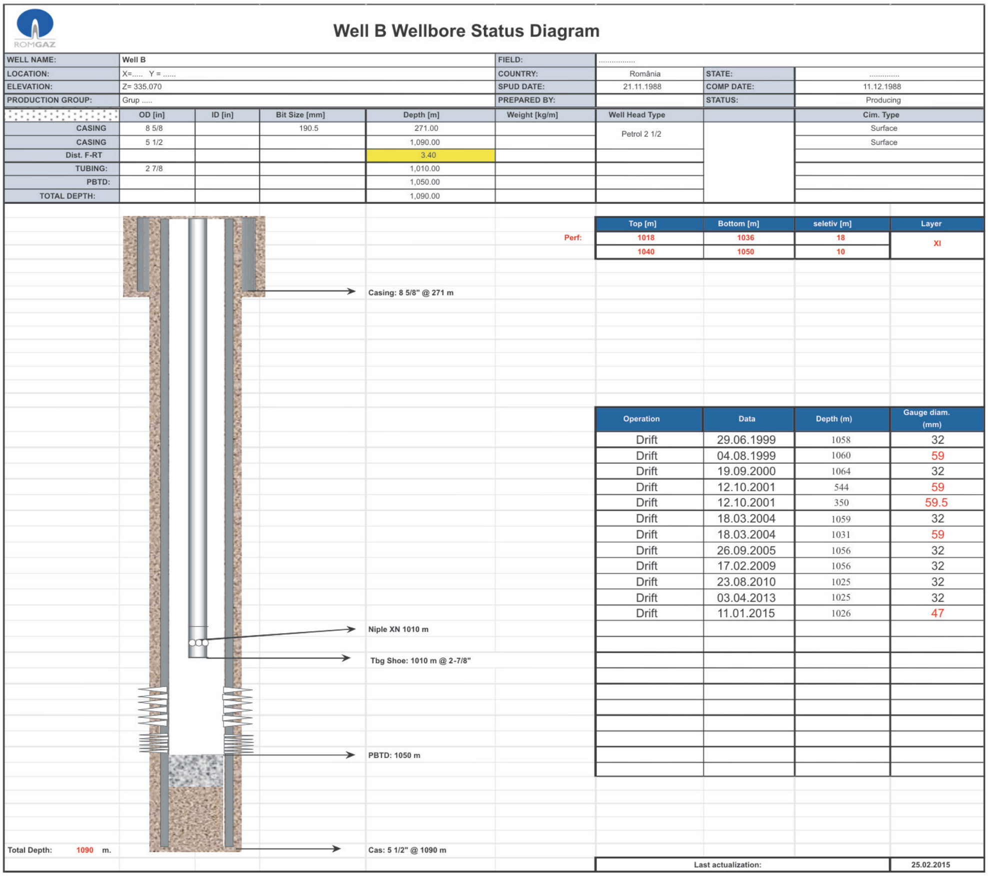


Fig. 4. Well B schematic

The operation program

The operation program accomplished the following objectives:

- Ran the pipe in the hole to 1010 m with CT. Performed a washing by pumping 10 000 l of stabilized water while pumping N_2 in the same time.
- Kicked off all the fluid left in the well.
- Spoted the formic acid solution (16% concentration), by pumping it through the CT.
- Left the solution for soaking about 6 hours.
- Agitated the solution every 3 hours, by pumping through CT N_2.
- Ran the CT in the hole and kick off the acid solution.
- Put the well into production.

The parameters for all nitrogen kick off operations were calculated based on the assumption that it is full of liquid solution (Figs 5 and 6). This represents the worst case scenario and ensured sufficient volume of liquid nitrogen on location to complete the required kick off operation and wellbore cleaning. The calculation have been made with the plug back total depth (1050 m). The fluids were displaced from the well through tubing-CT annulus.

N2 Calculator Variabile	Imputs/Results Calculation Format	Imputs/Results Format SI Format
Well Depth - in **(ft)**	3,444.87	1050.00 m
Mud weight **(ppg)**	8.50	1.02 SG
Bottomhole pressure **(psi)**	1,522.02	104.87 bar
Pomped nitrogen wellhead pressure **(psi)**	2,365.00	163.10 bar
Bottomhole temperature **(°C)**	43.36	43.36 °C
Average temperature **(°C)**	31.68	31.68 °C
N2 Volume Factor **(scf/bbl)**	833.15	150.065 m3/m3
Casing Capacity **(l/m)**	12.40	12.40 l/m
Annular Capacity **(l/m)**	8.23	8.23 l/m
Tubing Capacity **(l/m)**	3.02	3.02 l/m
Tubing Lengthi **(m)**	1,010.00	1,010.00 m
Casing Length **(m)**	1,050.00	1,050.00 m
Tubing Volume **(bbl)**	19.19	3.05 m3
Annular Volume **(bbl)**	52.28	8.31 m3
Casing Volume (From Tubing end to PBTD) **(bbl)**	3.12	0.50 m3
N2 Volume Required for Tubing **(scf)**	15,984.44	649.78 l
N2 Volume Required for Casing and Annular **(scf)**	46,159.52	1876.42 l
Total N2 Volume Required (+10% loses) - **(scf)**	68,358.36	2778.82 l
Total N2 Volume Required **(litres)**	2,778.82	2,778.82 l
Total volume of liquid N2 (litres)	3,778.82	**3,778.82 l**

Fig. 5. Nitrogen volume calculated for clean-out operation

Calculator N2 Variable	Imput/Results Calculation Format	Imput/Results SI Format
Acid Level Depth - in **(ft)**	137.79	42.00 m
Mud Weight **(ppg)**	8.50	1.02 SG
Bottom Hole Pressure **(psi)**	60.88	4.19 bar
Pumped N2 Wellhead Pressure **(psi)**	500.00	34.48 bar
Bottom Hole Temperature **(°C)**	43.36	43.36 °C
Average Temperature **(°C)**	31.68	31.68 °C
N2 Volume Factor **(scf/bbl)**	197.00	35 m3/m3
Casing Capacity **(l/m)**	12.40	12.40 l/m
Annular Capacity **(l/m)**	8.23	8.23 l/m
Tubing Capacity **(l/m)**	3.02	3.02 l/m
Tubing Length **(m)**	2.00	2.00 m
Casing Length **(m)**	42.00	42.00 m
Tubing Volume **(bbl)**	0.04	0.01 m3
Annular Volume **(bbl)**	0.10	0.02 m3
Casing Volume (from Tubing end to PBTD) **(bbl)**	3.12	0.50 m3
N2 Volume Required for Tubing **(scf)**	7.48	0.30 l
N2 Volume Required for Casing and Annular **(scf)**	635.00	25.81 l
Total N2 Volume Required (+10% loses)- **(scf)**	706.73	28.73 l
Total N2 Volume Required **(litres)**	28.73	28.73 l
Total volume of liquid N2 (litres)	1,028.73	**1,028.73 l**

Fig. 6. Nitrogen volume calculated for kick off acid

The final volume of liquid nitrogen included 1000 l to compensate for the dead volume of the truck and the nitrogen spent to perform pressure test of the line.

The well was kicked off any accumulated liquid in the wellbore then was kicked off a second time to remove the acid solution from the well after acidizing operation.

Some additional nitrogen was required for agitation of the acid, but that was covered because we asked for a nitrogen full (8000 l) tank for the entire operation.

After the cleaning operation a formic acid solution was pumped in the well through CT and left for soaking 6 hours. The solution was prepared by mixing 325 litres of 25% formic acid with 165 litres of fresh and clean water. The target of concentration was 16% concentration of acid (Fig. 7).

INPUT					
ID Casing	4.778	inch	PBTD	1050	m
ID Tubing	2.44	inch	Tubing Shoe	1010	m
OD Tubing	2.875	inch	Top of perforation	1018	m
			Above top of perforation	10	m
Concentration of acid-Before	0.25	%	Final acid column depth	1008	m
Concentration of acid-After	0.166		Acid column length	42	m
OUTPUT					
			Casing capacity	11.57241	l/m
			Tubing capacity	3.017945	l/m
			Tubing displacement (steel volume)	0.09592	l/m
			Final Volume of Solution	485.85	l
			Final Volume of Acid	322.60	l
			Final Volume of Water	163.25	l
Name of teh well	Well B		Drum of acid	0.32	units

Fig. 7. Acid volume calculation

Results

The acidizing operation was a success, the well started to produce with a satisfactory gas flowrate. This increased from a value of 3 kscm/d to a value of 9 kscm/d immediately after the operation (Fig. 8).

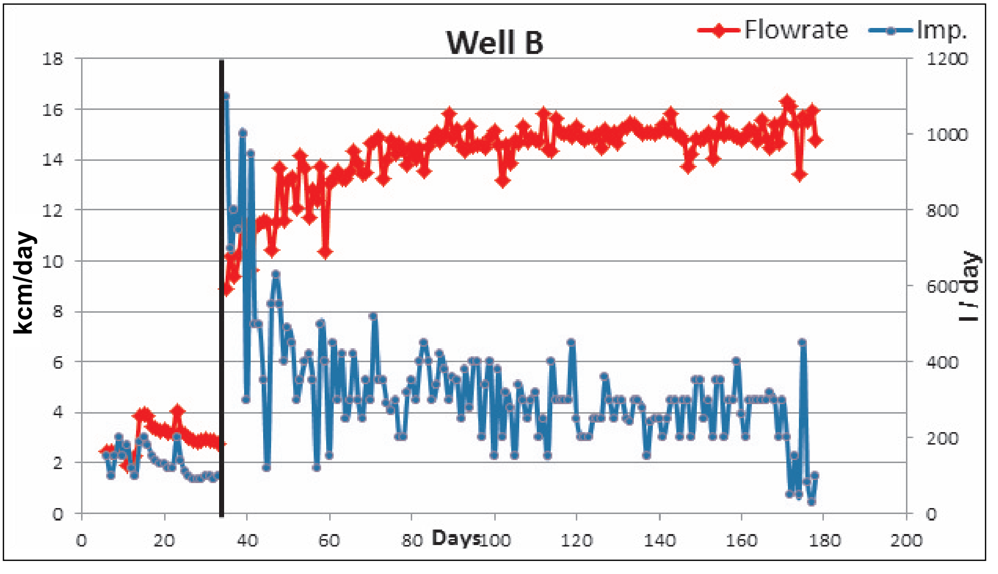


Fig. 8. Well B flow rate diagram (before and after operation)

As is shown in Figure 8, during several days after the operation the well cleaned out all the mechanical and liquid impurities, the gas flowrate continuing to increase to an average of 15 Scm/d.

We consider the acidizing operation a success even if the wellbore adjacent zone was affected in a manner that the well starts to produce with water. The average water flow-rate stabilized at 300 l/d after several days with high values.

4. WATER SHUTOFF USING THE POLYMER INJECTION TECHNOLOGY

Coping with excess water production is always a challenging task for field operators. The cost of handling and disposing produced water can significantly shorten the economic producing life of a well. The hydrostatic pressure created by high fluid levels in the well also is detrimental to gas production. The two major sources of excess water production are coning and channeling. Water coning is common when a reservoir is produced by a bottom water drive mechanism.

Almost all gas reservoirs produce water. In mature or old fields, most of produced fluid is water, with gas representing a few percent of total production. A continuous increase in water production is thus a normal behavior in the lifetime of a field.

The causes of excessive water production are multiple.

Identifying appropriate source of water produced is the first step. Geophysical investigations are necessary to find out: the distribution of current saturation (PNN), Casing status integrity (MIT), cement integrity behind the casing (RBT) etc.

Polymer injection technology is used, in order to stop the water flow from the porous and permeable formations into the borehole. Also this technology is used to combat massive loss of circulation, insulate cracks, prevent the sewage of water between injection wells and production wells, prevent the formation of water cones etc.

The technique consists of bullhead injection of polymer solutions into existing completions, usually without zone isolation. The polymer can be swelled or weakly cross linked in situ to increase permeability reduction to water. Each process covers a specific domain of temperature and salinity. All systems are designed to affect gas relative permeability only slightly.

The polymer injected into the open interval invades the different layers surrounding the wellbore with a deeper invasion of the higher permeability layers, which are frequently the main water producing zones. This type of product adsorbs on the formation rock almost irreversibly and induces a selective reduction of the relative permeability to water with respect to the relative permeability to gas [3].

Due to hydration water, polymer adsorption increases the irreducible water saturation. Furthermore, for a formation producing both gas and water, a reduction of permeability to water induces automatically an increase in water saturation in the zone invaded by the relative permeability modification. The combination of these effects, both inducing an increase in water saturation, decreases gas permeability. Thus in practice it is very important to evaluate these unfavorable water saturation effects and to minimize them whenever possible. As a consequence, relative permeability modification treatments are more suitable in wells having zones with high gas saturation surrounding the wellbore than in wells where all zones produce at the same water cuts.

Due to the reduction of both water and gas permeability, reduction permeability modification treatments always induce a loss in the well productivity index.

Several factors have to be taken into account for relative permeability modification candidate well selection:

1) Heterogeneity

For both permeability and saturation issues, strong vertical heterogeneity is a positive factor for the choice of a candidate well. The presence of both highly gas-saturated and highly water-saturated layers producing together is preferable than having all the layers producing at the same water cut. Also, a strong permeability contrast between the layers is advantageous because the placement of the gel will be favored.

2) Crossflow

When there is crossflow between the layers, water can rapidly bypass the gel in place and therefore will return to the same rate as before treatment. Crossflow is thus a negative factor for candidate choice.

3) Technical constraints

The gel should withstand reservoir conditions for long periods of time. Thermal stability is often a major factor for treatment selection.

4) Economical constraints

Water shut off treatments are usually considered as workover operations. A candidate well should have a potential of incremental gas production sufficient to cover treatment cost and make significant profit.

5) Logs

Log analysis is a good indicator of the configuration of the part of the reservoir surrounding the wellbore. Resistivity logs give the saturation of the different layers. Gamma-ray logs point to the presence of shale barriers and help to evaluate clay vertical distribution. Whenever possible production logs are run before and after the gel treatment in order to identify the contribution of each individual layer in terms of total fluid flow and water production [4].

4.1. Example: Well C

The objective of the operation

The objective of this intervention was to stop or to decrease the water flow from the formation in to the borehole. This was planned by increasing permeability reduction to water without affecting in a serious manner gas relative permeability, using the technology of injecting polymer.

Well history

Well C producing from V package (Fig. 9).

Well was worked over in 2014. It was perforated in the same package, above at 718–746.5 m (selective). Was put into production with a gas rate of 7.1 kscm/d with 12 000 l water/ day.

Well parameters

Reservoir pressure (XI):	25 bar
Flowing Bottomhole Pressure (XI):	12 bar
Flowing Bottomhole Temperature (1026):	36°C
Gas Production Rate:	7 kscm/d
Water Production Rate:	12 000 litre/d
THP/CHP:	12 bar/22 bar
Perforations:	718–752 m
PBTD:	752 m (workover 2014)

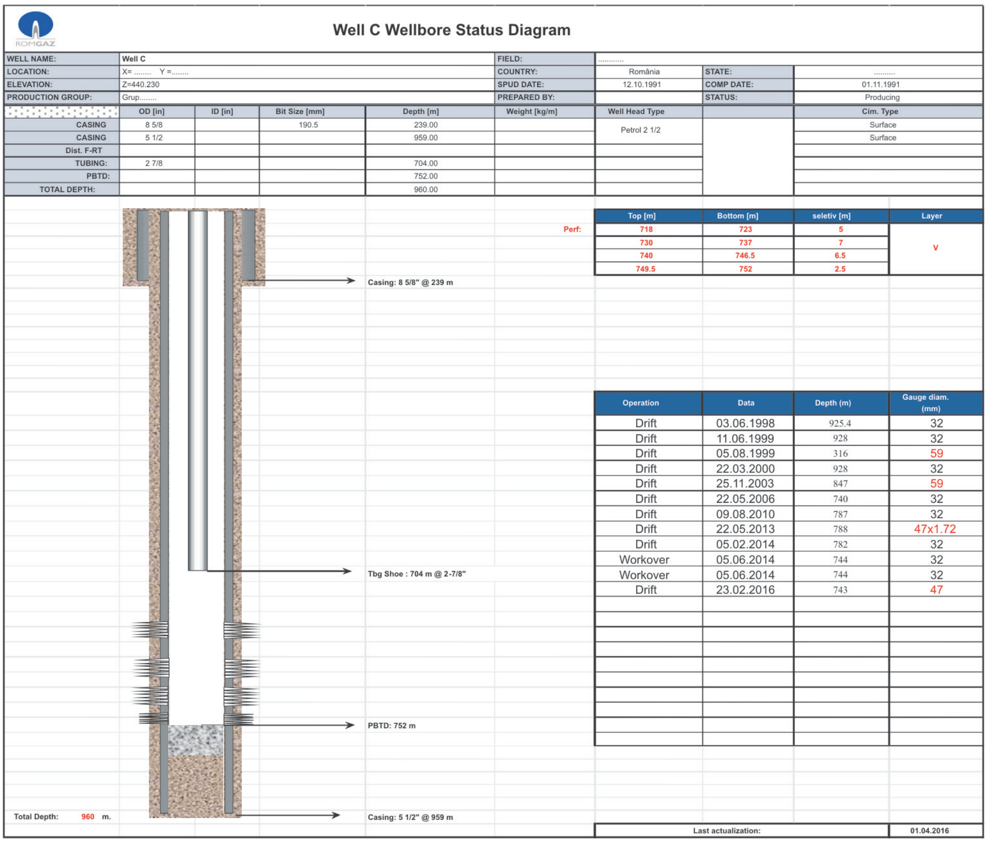


Fig. 9. Well C schematic

The operation program

Considering the amount of water produced by the well, we decided to make some complex investigations (Fig. 10).

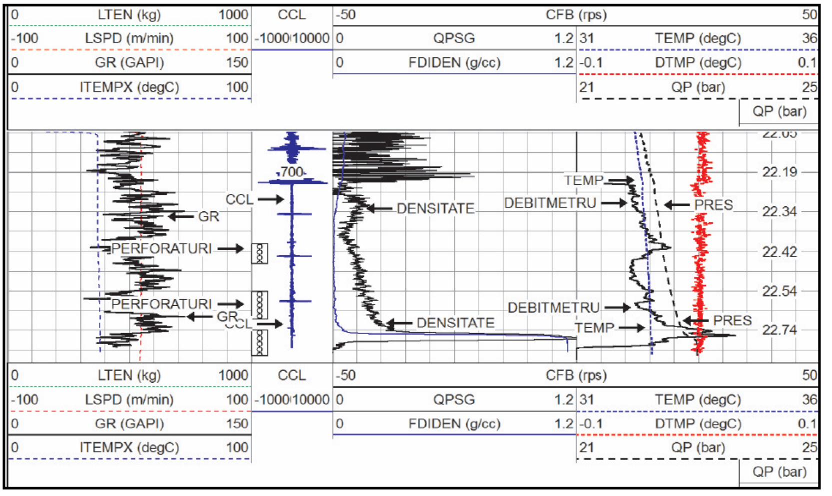


Fig. 10. Well C production logg

The PLT investigation made on 0–744 m showed us that there is water flowing from the below perforations (744–746.5 m depth).

We investigated also the integrity of the casing with MIT. The investigation revealed that there are no reasons to concern about the well integrity. Therefore the amount of water flowing in the well does not come from possible leaks in the casing.

The RBT investigation revealed that the casing has low adherence with formation on the perforated interval (Fig. 11).

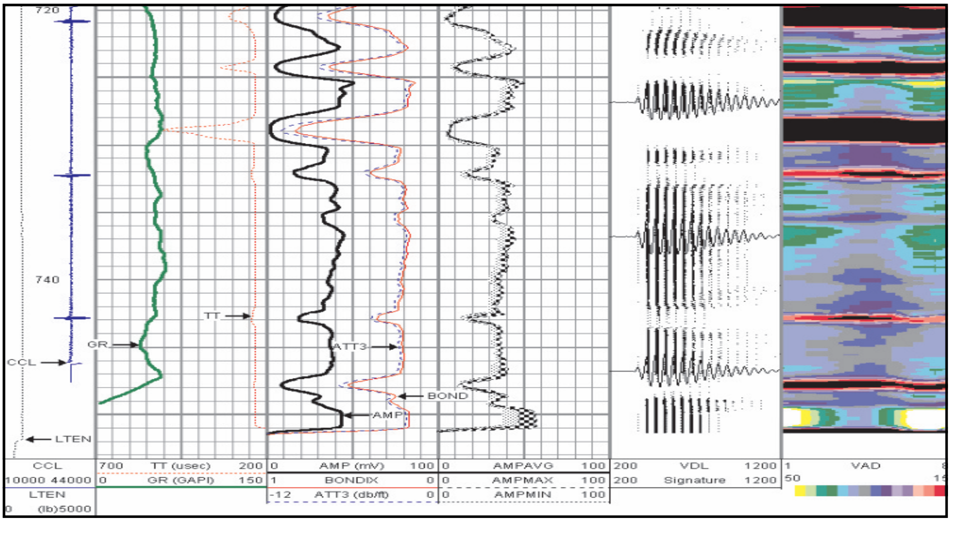


Fig. 11. Well C cementing integrity logg

Considering that the PNN investigation showed us a satisfactory value of gas saturation of about 50%, we took the decision to keep in production this perforated interval, applying on this package the technology of polymer injection to reduce the relative permeability for water (Fig. 12).

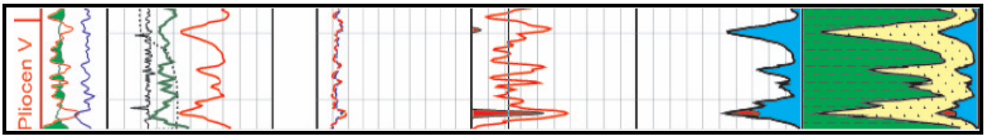


Fig. 12. Well C PNN logg

Therefore we made a technical perforation on 752–749.5 m range with 3 3/8" BH Gun. In this perforations we injected the polymer with 100–350 flow rate and 30–90 bar pressure. The total amount of polymer injected was 80 m^3.

Results

After the injection we put the well in production and we obtained a gas flow rate of 5 kscm/d. The water production decreased to 70 l/d (Fig. 13).

Even the gas flow rate decreased, we consider the operation a success because we succeeded to stop the water, otherwise the well would had been flooded in short time.

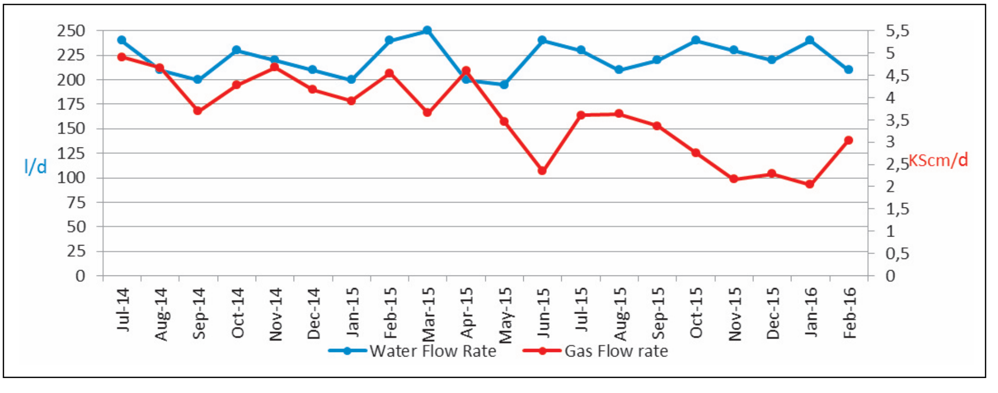


Fig. 13. Well C production diagram after polymer injection

5. CONCLUSIONS

Results obtained applying all of these stimulation technologies in Romgaz's wells, encourage us to continue to use modern methods to enhanced the gas recovery in our fields, especially if we consider that fields we exploit are in maturity stage.

Expertise and knowledge acquired about the behavior of the wells after using this kind of operations helped us to improve reservoir management and learned us to choose the best candidates and the best technology to optimize and to keep in production fields with a high level of depletion.

Considering the cost of this kind of operations is less than a workover, we appreciate the efficiency being maximum, even we are talking about the polymer injection technology, which does not increase the gas flow rate, but provides a method to reduce the water income helping us to add gas production after applying it, instead the well be flooded.

REFERENCES

[1] King G.E.: *Petroleum Engineering HandBook*. Vol. IV, Ch. IV, SPE, 2006.

[2] Farid J.: *Importance of perforation process and its techniques*. Nova Scotia, February 2012.

[3] SPE 106042: *Using Microgels to Shut Off Water in a Gas Storage Well*. SPE, 2007.

[4] SPE 56740: *Water Shutoff by Relative Permeability Modifiers: Lessons from Several Field Applications*. SPE, 1999.