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Injector-Well Completion Designs for Selectively Waterflooding Up to 18 Zones in a Multilayered Reservoir: Experiences in the Cerro Dragon Field

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Abstract

The Cerro Dragon asset, located in the highly mature area of Golfo San Jorge Basin, Argentina, has around 30 producing structures; each one containing from 20 to 50 separate, highly heterogeneous, reservoir horizons, from 6 to 30 feet thick. From 1999 to 2005 proved reserves increased threefold and non proved reserves increased fourfold, moreover, oil production grew from 48,000 BOEPD to over 116,000 BOEPD, largely due to optimization and expansion of waterflood projects.
The aim of these projects was to increase the water injection rate from 248,000 BWPD to 714,000 BWPD along with the 1999 average of 5 reservoirs accessed per injector-well to an average of 12, with a maximum of 25, in 2005, keeping at the same time the highest possible control over the injected-water flow rate on each layer.

In an experimental process started in 2000, injector-well completions were designed and tested in several wells with different reservoir properties. The experience acquired with the analysis of these completions was used to improve them as well as to develop new ones. Today, this process continues, testing and enhancing new designs to fulfill the needs of the upcoming waterflooding projects.

This paper shows the experience acquired from 401 injector-well completions over the past 6 years, discuss the successes and problems encountered with each completion design under different reservoir conditions (i.e. differential pressures between layers). In addition, it contains information about the procedures and technology used to reduce the completion set up cost and to extend its useful life by solving leakage problems without replacing the completion installation.

The mayor achievement at this point of the process have been successfully running an injector-well completion of a total of 19 packers and 18 injector mandrels (with an average of 12 packers and 12 mandrels out of 48 completions ran on the first half of 2005).

The objective of this paper is to serve as a reference guide for injector-well completion designs in multilayered fields where a vertical expansion of the waterflooding projects is intended.

Introduction

The Cerro Dragón field is located in the Golfo San Jorge basin, in the provinces of Chubut and Santa Cruz, Argentina. It has an area of 860,000 acres, being exploited since 1958.
The field currently has 2240 oil and gas producing wells with an average depth of 7500 feet. Actual production rate (January 2006) is 90,574 BOPD, 804,170 BFPD and 257 MMscf/D. About 46% of the oil production comes from 46 secondary recovery projects comprising 402 injector wells and a total water injection rate of 714,000 BWPD. Almost all of the injector-wells as well as the producer-wells are completed with a 5 ½ in. casing.

Golfo San Jorge Basin is a Mesozoic extensional basin filled with Jurassic lacustrian and Cretaceous fluvial deposits with Tertiary compression and wrenching superimposed on earlier extensional features. The main reservoir consists of Middle to Late Cretaceous sandstones of the Comodoro Rivadavia Formation that average about 20 % porosity and 10-50 md permeability. A secondary reservoir consisting of altered tuffaceous sandstones and siltstones is also present in the upper part of the Cretaceous aged Mina Del Carmen (tuffaceous) Formation. The main hydrocarbon source is the lacustrian shale of the Mid to Lower Cretaceous D-129 Formation. Hydrocarbon traps consist of tilted horst blocks, faulted anticlines and structurally enhanced stratigraphic pinch-outs. Oil and gas producing layers are generally found in the Comodoro Rivadavia and Mina Del Carmen Formations from 600 to 8700 feet deep. There are about 30 producing structures each containing 20 – 50 separate reservoir horizons, 3 - 26 ft thick. Within many of the structures there is a high degree of fault induced compartmentalization. In total, there are more than 9000 separate, highly heterogeneous reservoir units.

Understanding the benefits of accessing more reservoirs per injector-well

Water injection in Cerro Dragon began as early as 1969, but primarily as a means of water disposal more than an effort to manage reservoir pressure. In 1991 investments on waterflooding projects start growing towards a better reservoir exploitation, increasing reserves and secondary recovery oil production **(Fig. 1)**.

By 2000 the profitability of the secondary recovery investments on the field was well known and, having the global oil price recovered from its 1998 drop down, new investments in waterflooding projects were made. This time, at a faster pace, as it can be seen in **Fig. 2** by the growth of the water injection rate and the amount of injector wells. Not only had the pace of the projects growth changed at that time, but also their objectives. Up to 2000 waterflooding projects had been expanding horizontally but not vertically; from 1991 to 2000 the average amount of reservoirs acceded per injector-well was fixed at five reservoirs out of and average of 30 reservoirs passed over, but didn't flooded, by the injector-well. So from this time on waterflooding project's objective was to expand vertically as well as horizontally. This way, acceding more reservoirs per well, would yield a bigger profit since the well would be more efficient and more reserves would be added (from 1999 to 2005 proved reserves were doubled and non proved ones increased fourfold).

Fig. 3 shows injector-wells' average amount of packers, injector mandrels, selectively flooded zones and well's depth throughout the years. It can be seen here as well, how from 2000 on, the injector-well's designs changed radically from an average of 5 packer and 5 injector mandrels design towards a more and more packers and injector mandrels design every year. Nowadays new tools are still being experimented with and new completion's designs developed seeking to improve injector-well efficiency by selectively flooding more reservoirs.

Mechanical-set packers' completion

The injector-well completion used from 1978 to 2000 combined a retrievable mechanical production packer with several retrievable tension tandem packers to isolates the injection zones. 2.875 in. injector mandrels in between packers were used to lodge a wire line-set 1.5 in. valve which enables to control the water flow rate injected to the zone between packers (**Fig. 4**).

Mechanical packer and tandem packer description

Setting mechanisms. The mechanical packer need to be set first as it has an anchoring system and the tension tandem packers don't. The first one is set by rotating the tubing right-hand 4 to 5 turns then applying weight and straining up the tubing. With the mechanical packer fixed to the casing, the tubing is strained up with about 20,000 lbf and then hanged from the well-head to retain the strain, and in this way, by a pressing mechanism acting over the packing elements of the tandem packers, an effective seal is obtained.

Releasing mechanisms. The tandem packer need to be released first by slacking off the tubing to release tension applied over the packer and then rotating each packer 1 to 3 turns to the right to lock the setting system, then, to release the bottom packer the tubing must be strained up about 3,000 lbf and turned right-hand 6 to 8 turns.

Completion experience

This completion serves perfectly well to isolate and flood up to 6 zones even nowadays with an average well-head injection pressure of 2500 psi. But having a completion with more than 5 tension tandem packer is unadvised by the packer's supplier because of the stress that the packing element of the upper packer suffer when setting the completion. The upper packer is the first to have its packing element pressed when straining up the tubing, thus, this packing element rubs against the casing all the way up until all the lower packers have their packing elements pressed as well. Is for this that the more tension tandem packers the completion has the more the upper packers' packing elements will suffer and the more the effectiveness of the seal will be compromised. Also for this is that the upper tension packer has 2 packing elements while all the rest has 1 packing element. However the stress the tandem packers' packing elements will suffer depends too, on some well's properties such as well's depth, temperature and injection pressure, and this parameters could be so that enable to set in that injector-well more than 5 tandems without having any problem on the packing elements. Since 1978 there have been done 356 injector's completions using these mechanical packers, 143 were composed of 7 packers or more and 206 composed of 6 packers or less. 24 % of the firsts had to be re-completed because of the failure of the packing elements seal while only 15% of the seconds had this problem. Our experience tells us that despite there were cases were a successful completion was achieved with more than 5 tension tandem packers and 1 mechanical packer, therefore selectively flooding more than 6 zones, the completion with these packers is not advisable to selectively flood more than 6 zones (1 mechanical packer and 5 tandem packers; Fig. 4).

Mechanical and hydraulic packers' completion

In order to access more reservoirs per injector well in 2000 a completion combining hydraulic and mechanical packers with tubing fishing On-Off tools was developed and used ever since. The tubing on-off tool enabled to increase the number of packers ran down per injector-well completion by doing so in stages of an average of 4 to 6 packers and injector mandrels, running down the hole and setting each stage separately. **Fig. 5** shows a typical 3 stages completion.

Completion's tools description

Hydraulic packer. The packer is 5.25 ft long and it is set by applying hydraulic pressure inside the tubing, moreover, the setting mechanism works without any movement of the tubing, enabling simultaneous packer setting in stacked installations. Each packer also counts with an anchoring system that prevents the packer to move once it is set and fixed to the casing. These two features are particularly useful when it is needed to isolate zones very close to each other (13 – 16 ft) where the movement of the packer during or after being set could cause the isolation to fail because of misplacement of the packers. To release the packer, tension must be applied to the tubing with a surface value equal to the addition of the tubing weight plus the cut value of the release system.

Hydraulic packer with rotational release system. The packer is 4.5 ft long and it is set by applying hydraulic pressure to the tubing. It also counts with a setting mechanism that works without movement of tubing and an anchoring device that fixes the packer to the casing once it is set. This enables, as the hydraulic packer before, to fix the packer on a very precise depth. The packer's release system works like the mechanical packer's seen before, the tubing must be strained up about 3,000 lbf over tubing weight and then turned right-hand 6 to 8 turns.

Tension tandem packer. This is the same packer described previously with a length of 1.64 ft. In this completion, instead of using a mechanical packer as the anchoring point to strain up the tubing and set the tension tandem packers, the hydraulic packer with rotational release system is used. There are two main reasons to use this packer and not other, first it doesn't need any movement of the tubing to be set and fixed to the casing where the mechanical packer does need it and that movement can cause the on-off tool to be disconnected and leak. The second reason is that the rotational release system enables to strain up the tubing as necessary, in order to set the tandem packers, without any risk of releasing the packer; the hydraulic packer released by straining the tubing could not be used for this purpose.

Tubing fishing On-Off Tool. It enables tubing connection and disconnection, keeping a seal at connection position. It is full-bore and designed to leave tubing either with weight, tension or neutral. A "J" system enables for connecting the tubing and hanging the lower string from the upper string. When used on injector-well completions to connect one stage to the other, once the packers of the first stage are set and fixed to the casing the upper stage is ran down the hole with a flat connector instead of a "J" connector at the lower part of the stage, so that an effective seal can be obtained between the two stages while leaving the above stage mechanically free from the below stage. In this case, to pick up the lower stage, it is needed to pull out the upper stage first and then set a "J" connector on the tubing and run this down to fish the lower stage.

Injector Mandrels. The more used are the 2.375 in. injector mandrels with a 1.5 in. regulator valve pocket. Also used for some wells are the 2.875 in. mandrels with an either 1.5 in. or 1 in. valve-pocket as well as the 2.375 in. mandrel with a 1 in. pocket. The reason for mostly using the 2.375 x 1.5 mandrels responses to the fact that most of the wells have a 5.5 in. casing. 2.875 x 1.5 mandrels are used in 7 in. casing wells (26 out of the 402 injector-wells on the field have a 7 in. casing). Mandrels with 1 in. valve pocket are used for wells with restrictions problems where a lesser diameter of the tools is preferred in order to be able to pass through these restrictions (dog legs, casing damage). However 1.5 in. valve-pocket mandrels are preferred, whenever it is possible, because of the greater robustness of the 1.5 in. valves which made the wire-line operations easier and more efficient.

Why to complete the injector-well in separated stages of packers

As it has been stated before the amount of tension tandem packers to be used for an efficient seal to be obtained shouldn't exceed 5, so to selectively water-flood more reservoirs a different kind of packer had to be used. The hydraulic packer described above was used for this purpose, but besides its advantages, discussed above, this packer also has a limitation. As its release system requires to strain up the tubing to a certain cut value, when used stacked, the cut value of each packer on the completion could add up and exceed the pulling capability of the rig tower operating the completion. The amount of hydraulic packers that can be stacked together at a certain length depends on several factors. A 2.375 in. tubing stretch more than a 2.785 in. tubing under the same strain, thus a completion with the first tubing could have the packers closer to each other without having the cutting value of the release system adding straight up. Also for the same reason the larger the separation between packers the more packers that can be stacked since the tubing will stretch more under the same strain. The cut value of the release system is configurable and this affects the minimum separation limit as well. But despite the limitation imposed by the release system there is a way to still run down as many packers as necessary by using the on-off tool described before and setting each stage separately. In this way, each stage is fixed to the casing and stays mechanically free from one another, so that non strain is transmitted from one stage to the other when the installation needs to be released. Of course, the downside of this solution is that for each stage, one tubing run of the rig tower is needed thus raising the cost of the completion.

Looking to address and diminish this side effect, by the end of 2004 an **automatic on-off tool**, was developed. This on-off tool differs from the standard on-off in that it doesn't need the tubing to be rotated in any direction to connect or disconnect the tubing, instead, the connection and disconnection operation is done by simply applying weight over the on-off and then pulling the tubing up. It has an automatic "J" system that when weight is applied the on-off automatically connect the tubings, and when weight is applied again the "J" system shift to the disconnect position, maintaining the seal until the upper tubing is pulled up. This enables to run two stages of a selective installation in only one tubing run because it eliminates the need to use a flat connector to obtain the mechanical freeness between the upper and lower stage while keeping the hydraulic seal (mechanical freeness is needed to avoid release cut values of both stages' packers adding up). To set a two-stage completion using this on-off, the bottom stage of packers needs to be set first by applying hydraulic pressure inside the tubing, thus all the packer must be configured for that purpose. Then with the lower stage fixed to the casing, weight must be applied so that the "J" system of the on-off tool at the bottom end of the upper stage shifts to the disconnect position, leaving the upper tubing mechanically free from the lower tubing, then without pulling the tubing up, in order to maintain the on-off tool hydraulic seal, the rest of the packers can be set by applying hydraulic pressure. To summarize, what this automatic on-off tool makes possible is to reduce the runs needed for the completion to one per every two stages of the selective installation. This tool has been used over every completion done, ever since it was developed, as a standard to reduce completion costs.

Completion experience

Since the year 2000 there have been done 173 injector's completions using this design. From 2000 to 2003 90 completions were done, 85 with two stages and an average of 10 packers, and 5 completions with 3 stages and an average of 13 packers. In 2004 and 2005 the aim was to increase even more the number of selectively flooded zones (Fig. 3). So out of 83 injector-wells completed with this design, there were 46 with 2 stages and an average of 10 packers, 34 with 3 stages and an average of 14 packers, and 3 were completed with 4 stages, 2 with 16 packers and one completed in 01/26/2005 with the maximum number of packers ran down by this kind of completion so far, which is 19 packers with 18 injector mandrels, thus selectively flooding 18 zones.

The average completion design used over this 173 completions done with these tools since 2000 consist of an upper stage combining one hydraulic packer, rotationally released, with 5 tension tandem packers; and one, two or three lower stages, as necessary, each assembled with 4 hydraulic packers as seen in Fig. 5. In between packers, an injector mandrel with its valve is used to regulate the injection rate. The reason for using tension tandem packers on the upper stage instead of just adding another hydraulic packer's stage is solely economic. Tension tandem packers work fine and they are more economical than the hydraulic packers.

Technically the design doesn't have any limitation in the number of packers that can be run, while it is done by adding more stages of hydraulic packers; only one stage of tension tandem packers can be used since they need the tubing to be strained up and hung from the well head to be set. However each stage increases the cost of the completion, even using the automatic on-off tool, so it is a matter of cost / benefit solution since, as it will be presented ahead in this paper, there are other completions more suitable for selectively water-flooding a large number of zones.

Last two years completions development

During 2004 and 2005 several completion designs using different kind of packers were tried out and experimented with looking forward to develop a completion capable of selectively flood the same amount of zones the hydraulic-mechanical completion does, but without the need to complete the well in separate tubing runs. Another drawback of the hydraulic-mechanical completion is the length of the hydraulic packers with anchoring system, this makes the whole installation more rigid which could be a problem when it is been ran down a hole with dog legs or casing's damages. Therefore, the aim also was to develop a reliable completion which could be more flexible to run pass dog legs and/or casing's damages restricting the path. Having many of the injector-wells been converted from old producer-wells restricting casing's damages is a recurrent problem during the injector-well completions in Cerro Dragon field.

Hydraulic packers' completion

The firsts packers to be experimented with at the beginning of 2004 were two hydraulic packers, one of them with an anchoring mechanism and very similar to the one used in the hydraulic-mechanical completion but shorter (hydraulic packer used on the hydraulic-mechanical completion is 6.3 ft length) and the other one without any anchoring system.

Completion's tools description

Hydraulic packer. A 4 ft length packer with and anchoring system and a setting mechanism that works, without any movement of the tubing, by applying hydraulic pressure inside it. To release the packer, enough tension must be applied to the tubing in order to cut the release-mechanism's shear-screws.

Hydraulic tandem packer. This is almost the same packer as the one described above but without the anchoring system which left the packer with a total length of 2.8 ft. The lack of an anchoring device is why this packer is designated as a tandem packer. Also is this lack of anchoring which enable this packer to be stalked in any necessary amount, according to the zones to isolate. Not having an anchoring system the only force opposing to the straining of the tubing during the release operation is the friction of the packing elements against the casing, this force is not a problem to be overcome by a rig tower pulling up, so the tandem packers will be eventually moved up till the cut values are reached and they are released, therefore the sum of the cutting values of each packer won't happen in this kind of selective installation.

Completion experience

The first completion design tried out with these packers combined two hydraulic packers on the ends of the selective installation with several hydraulic tandem packers in between them as shown in **Fig. 6**. The setting operation consists of the bottom hydraulic packer being set and fixed to the casing and then straining up the tubing about 6,000 lbf and setting all the rest of the hydraulic tandem packers and fixing the upper hydraulic packer. To do this, bottom packer's release system cut value has to be smaller than the rest of the other packers cut value.

Since most of the packers in this completion design are tandem packers of only 2.8 ft, the selective injection installation end up having a much greater flexibility than the mechanical-hydraulic completion seen before, therefore enables to pass through casing restrictions, completing injector-wells otherwise impossible to complete.

Technically there is no limit in the amount of tandem packers to be used in between the two anchored packers but, as it will be explained ahead, there are some considerations regarding zone's pressures to take into account when deciding whether to use this design or not. The maximum number of hydraulic tandems used so far in a completion was 12, with 2 hydraulic packers, one on each end of the selective installation (Fig. 6). This completion ran down the 06/06/2004 on Z-132 well is still working perfectly fine without any leakage problem. However, despite the capability of this completion to run down as many packers as needed in only 1 stage, it was found useful to split the completion in 2 stages, connecting them by an automatic on-off tool and using anchoring hydraulic packers in both ends of each stage as shown in **Fig. 7**. With this, still only one run of the rig tower is needed to set the selective installation and in addition, having an on-off tool in the middle of the installation, enables to pull out, repair and run back down the upper stage, in case any problem appear on it, without having to move the lower stage. This is an additional benefit that could be exploited or not, but always good to have it since the cost involved is only the cost of the automatic on-off tool and the gain is not having to release and re-set a perfectly working part of a waterflooding selective installation. To understand the significance of this benefit it is good to remind here that most of the injector-wells in Cerro Dragon are aged wells, about 20 years old, and each time they are completed and tools pass down and up through the upper part of the casing where there is no cement behind it, there is a chance of damaging it and causing a restriction so no more tools could be deployed thus leaving the well unusable. This explains why a mean to diminish the amount of tools passing through the casing becomes a benefit in this field.

The experience done with this kind of completion in Cerro Dragon consists of 32 completions ran down along 2004 and 2005.

Limitation of the anchored ends design

Out of these 32 completions done following the design explained, 15 of them had to be re-completed because of a failure on the selective installation. Nine of the selective installation failures were passage restriction inside the 2 3/8 in. tubing, making impossible for the wire-line tools to pass through the selective installation and therefore, to measure and / or regulate the flow rate passing through each injector mandrel. The other 6 failures were leakage through one of the hydraulic packers and defective seal of the packing elements.

From the analysis of each of the fifteen wells having the same failure it was found out that there was a common factor in those 15 wells that wasn't present on the rest of the wells where the completions worked fine. This factor was that at the completion of these 15 wells new zones were opened (perforated) to be flooded together with other zones already been flooded by a previous installation, meaning that these wells' completions were vertical expansions of already existing injector-wells. Then, as each zone is isolated by packers, some of the packers ended up by being in between a zone pressurized by years of water injection and a zone with normal or below normal reservoir pressure, if already being produced in a nearby producer-well. The packer was, therefore, subject to differential pressures, and when this difference of pressures was present in between a tandem packer (none anchoring system) that packer acted as a piston moving towards the zone with smaller pressure. Hence if the lesser pressure zone is the one above the tandem packer, then the tubing above it will be subject to a compression force and the tubing below it to a strain force. This compression forces over the tubing whether downward or upward makes the tubing to buckle, as it was observed from several of the tubings pulled out of each of the 15 wells.

Knowing this limitation, the design could be perfectly used for waterflooding projects where the reservoir pressures are normal and differential pressure between zones correspond to the water column height only. When the pressures of the zones to flood are other than this, detailed calculations of the resulting forces over the packers should be done before deciding to use this completion in order to assure its effectiveness. If the zones' pressures are not well known it is not advisable to use this type of completion. In general, this completion is used in Cerro Dragon for mature waterflooding projects where pressures are stabilized and not used for injector-well completions where the waterflooding project is being vertically expanded.

Multiple anchoring-packers completion design

Analyzing the behavior of the 2 3/8 in. tubing under tension and compression forces along with the packer supplier's technical stuff, a new completion design was develop where anchored packers must be placed at a distance from each other not farther than 689 ft and not closer than 197 ft. The first length restriction attends the buckling problem by assuring a length between anchored points shorter enough so that not any tandem, between those two anchored points, could be pushed enough to compress the tubing to the point it would buckle. The distance was calculated for 2 3/8 in. tubing under a compression force generated by the thrust of a 2 3/8 in. tandem packer sealing a 5 ½ in. casing under 1500 psi of differential pressure. The second length restriction attends the adding up of the release system's cut value problem, and it is the minimum distance between anchored packers, calculated to be able to release the installation having a cut value for each packer of 30,000 lbf.

A scheme of this completion design can be seen in **Fig. 8.** The ends of each stage could have whether anchored hydraulic packers or tandem hydraulic packers but it is advisable to have anchored packers above and below the tubing on-off tool connecting two stages in order to avoid the risk of a tandem packer moving and disconnecting the on-off tool and the resultant leaking problem.

From out of sixteen injector-wells completed following this design 6 had to be re-completed because of leakages through packers and failure of the packing elements' seal. The buckling problem of the 2 3/8 in. tubing was solved but another problem arose. Analyzing these wells it was understood that the cause of the problem was, again, the differential pressure acting over the hydraulic tandem packers. The tension force applied over the tubing by a tandem packer were, in these wells, in between certain zones, enough to reach the release system's cut value of the packers below that tandem packer, thus releasing that packer and losing its seal. This was the reason why 6 of 16 completions failed prematurely.

Therefore, this design could be used, without having any buckling problem, to complete wells where the differential pressure in certain zones is larger than normal but not enough to thrust the tandem packers with the necessary strain to release the other packers. For Cerro Dragon's injector-wells this is a differential pressure lesser than 1500 psi, this is, using 2 3/8 in. packers with their release system set for 30,000 lbf running in a 5 ½ in. casing. Another option could be to identify those zones where differential pressure could reach this value and use anchored packers to isolate those zones

instead of tandems; only if the distance between zones enables to do so.
Again, if the zones' pressures are not well known it is not advisable to use this type of completion because of the high risk of failure due to the causes already explained.

Hydraulic packers with rotational release system's completion

By the start of 2005 the limitations of the hydraulic packers' completion described before were well known and the focus was on the development of a completion that offered the same advantages of that hydraulic completion, less stages, more packers and more flexibility, but also was able to withstand any differential pressure existing between zones.

First hydraulic-set rotationally-released completion design

The first step towards these objectives was a selective installation assembled totally by hydraulic packers with rotational release system (same packers described previously on this paper) and a **telescopic joint** below each packer **(Fig. 9).** The reason for using a telescopic joint below each packer is that since the release system of the packer requires to turn the tubing right-hand 6 to 8 turns, if several packers had to be released at once and no telescopic joints were present, all the torsion forces need to release each packer would add up together making the final torsion force required too high for the rig tower to achieve and thus, the selective installation impossible to release.

Telescopic joint, when closed (weight applied), enables the tubing to be rotated freely, no torsion is transmitted from the upper tubing to the lower one, and when opened (tubing strained up) torsion is transmitted.

Setting operation. To set this completion, the bottom packer has to be set first by applying enough hydraulic pressure inside the tubing, then weight has to be applied for all the telescopic joints to get closed and finally the rest of the packers should be set by applying a higher value of hydraulic pressure. To set the bottom packer before the rest of the packers, the bottom packer's setting value must be set below the rest of the packer's value.

Completion experience

Three completions were done following this design on wells where the other completions failed and they have worked perfectly. No further completions where done following this design because the main goal was to experiment with it and make a first step towards the completion it will be presented ahead. Therefore, the maximum number of packers ran down on a completion like this, in Cerro Dragon, was of only 5.The rotational release system of the packers plus the use of the telescopic joints enables, in theory, to stack as many packers as necessary without any problem to release the completion.. Furthermore since all the packers count with an anchoring system, there isn't any movement of the packers that could buckle the tubing or release the packers. The differential pressure limitation was therefore surpassed by this completion; however it is not very flexible, in fact a lot more tools are added to the whole installation because of all the telescopic joints needed, thus making the design more rigid and not suitable for aged wells where restrictions could be present. Furthermore, the use of more tools derives as well on a more expensive completion.
To conclude, the completion worked as expected fulfilling part of the requirements, but because the completion to be presented next, counts with the same advantages and some more, is better recommended instead.

Next step on hydraulic-set rotationally-released completion design

Having the experience made from the previous completion design the next step was to work along with a local tool's provider to obtain the tools for a completion which could attend the specific requirements of being able to withstand differential pressures; to isolate as many zones as needed, running the completion in only one tubing run; being flexible and being economical. Thus a new packer and on-off tubing tool was developed.

Completion's tools description

Hydraulic-set rotationally-released packer with split mandrel. This packer is 4.6 ft long, set by applying hydraulic pressure inside the tubing without any movement of it and also counts with an anchoring system to be fixed to the casing once set. To release it, tubing weight must be set on neutral at the packer depth and then turn it right-hand 3/4 to 1 turn. One of the differences with the previously seen packer is that this one, only needs 3/4 to 1 turn to be released instead of 6 to 8, making the selective installation easier to be released. The other difference is the packer's split mandrel, which enable to keep the tubing above the packer without transferring rotational movement to the tubing below until that packer is released. This characteristic enables the packers to be released one by one without the problem of torsion forces adding up, therefore, an injector-well could be completed with as many of these packers as needed in only one tubing run and without the need of telescopic joints.

Hydraulic-set rotationally-released tandem packer with split mandrel. This is the same packer as the one described above without the anchoring system, thus the packer length is of 3.5 ft.

Rotating on-off tool. This tubing on-off tool operates in the same exact way as the standard on off tool explained before, but counts with an additional mechanism that enables the on-off not to transfer rotational movement until a mechanism is activated. To activate this mechanism enough weight has to be applied over the on-off tool in order to shear some screws and lock the upper tubing with the connector, thus granting the capability to transfer rotational movement to the lower part of the selective installation. The use of this device between two stages of a selective installation using rotationally released packers ensures that the upper stage could be released independently from the lower stage.

Setting procedure

To set a tow stages selective installation using these tools, the bottom packer must be configured for a hydraulic setting value lower than the rest of the packers of the two stages in order for the bottom packer to be set and fixed first when hydraulic pressure is applied. With the bottom packer fixed to the casing, tubing should be strained up about 7000 lbf and in that moment a higher value of hydraulic pressure should be applied to set and fix the rest of the completion's packers.

Completion experience

Four injector-well completions have been done, using these tools. The firsts two of the completions done combined the packers with anchoring system and the tandem packers in a design similar to the one used for the multiple anchored points hydraulic packers completion shown in Fig. 8. One difference with that completion design is that the rotating on-off tool is used between the two stages instead of the conventional automatic on-off. The other difference is that the minimum distance restriction between anchoring-packers is not present in this completion since the packers are released by rotation of the tubing and count with a split mandrel, therefore, no forces of any kind will add up during the release of the installation and therefore packers and tandem packers could be used as close as necessary to each other. The only restriction to the design is the maximum length between anchoring-packers having one or more tandem packers present between them; the restriction prevents the tubing to buckle for the reasons explained previously on this paper for hydraulic packers' completions. It is important to note that unlike the hydraulic packers' completion, differential pressure acting over a tandem packer in this completion won't be able to release any of the other packers because of the release system being rotational. Therefore, in theory, this design could be use for any type of injector-well's completion, whether it was a vertical expansion's completion, a mature waterflooding project's completion or a new project's completion.

However, despite the differential pressures won't have an effect over the packer release system and won't buckle the tubing if maximum distance are complied, they will do move the tandem packer, rubbing its packing elements against the casing. This will be so in a degree according to the distance between the tandem packer being moved and the anchored packers, thus the effect over the packing elements and their sealing capabilities will vary. It is important to notice at this point, that the movement of the tandem packers between zones with abnormal pressures will occur each time a regulator valve of an injector mandrel next to the tandem packer is released and set, each time the surface injection pumps are turned off and back on, in general, each time an injection pressure fluctuation occur. Therefore, it is advisable to reduce the number of tandem packers used to complete injector-wells where high enough differential pressures could be present and whenever the flexibility loss, for using packers with anchoring system instead, is acceptable. However, if flexibly is crucial and tandems must be used for that matter, it is advisable when fixing the selective installation to leave it under strain. This is done by configuring the bottommost packer's setting system to be activated with a lower pressure value than the rest of the packers of the completion and applying enough hydraulic pressure so that the packer is set and fixed to the casing before the others, then the tubing should be pulled up until the desire tension over string weight is reached and in that moment the rest of the packers need to be set and fixed in order for the whole stage to retain the strain applied. In Cerro Dragon field the usual strain to leave the selective installations with in these cases is about 10,000 lbf. In this way the remaining tension in the tubing increases the resistant towards the movement of tandem packers by differential pressures, thus restricting their capability to move and to buckle the tubing. To achieve maximum flexibility, it should be used only 2 anchoring packers one on each end of the installation and complete the rest with tandem packers. A design similar to the one shown in Fig. 6 but using hydraulic-set rotationally-released anchoring-packer and tandem-packers with split mandrels instead. This completion should be done with the knowledge that if there are differential pressures in the well between zones there will be certain movement of the tandems packers, thus affecting their sealing capabilities in some degree and deriving over a period of time on a leakage problem of the selective installation and its consequent need of replacement. Of course that this is not desirable and the possibility of the tandem packers loosing its sealing capabilities would be only acceptable in wells where the passage restriction is so bad that not other completion design will pass through it.

Keeping in mind the previously stated about reducing the amount of tandem packers used on a completion and since the two well's casings presented no passage restrictions, the last two of the four completions done using these tools were assembled exclusively by packers with anchoring system. The recommended design combines two stages of the necessary amount of packers connected by a rotating on-off tool as shown in **Fig. 10**. So far, in Cerro Dragon, the maximum number of packers ran down on a completion following this design is of 14, but technically, there is no limitation and it has been already planed completions, with this tools, of up to 19 anchoring-packers for the first half of 2006. As for the design combining anchoring packers with tandem packers the maximum amount of packers ran down on a completion, in Cerro Dragon field, is of 11, combining 4 anchoring packers with 7 tandem packers in 2 stages connected by a rotating on-off tool and of course complying with the maximum length between anchoring packers' restriction.

Leakage temporary solution

As a mean of extending the useful life of injector-wells' selective installation, by the start of 2005 a wire line-set tool similar to a patch, has been being used with very good results in Cerro Dragon field. The patch consists of an inside-tubing anchoring device and two tubing-packers. For the patch to be set inside the tubing where the leakage problem is, it requires two separate wire-line runs. The first run fix the anchoring device below the leaking zone and the second one is to get down and set the two tubing-packers, connected by a 1.315 in. tubing, around the leaking zone. **Fig. 11** shows a scheme of how the patch works bypassing a tubing on-off tool leakage. The patch enables to postpone the replacement of the selective installation by a rig tower, by temporary solving the problem. This is very useful in Cerro Dragon where there are 2642 operating wells and only 33 rig towers and the wells could have to wait a long time before the replacement can be done.

The standard operation before setting a patch is to pull out all the injector mandrels' regulator valves that will be left below the patch, and replace them with new valves. This is done because once the patch is set no wire-line tool can pass through it, thus no replacements of the mandrel's valves can be conducted then. However if necessary, the patch can be wire-line removed and pulled out, then the below valves replaced and then the patch re-set.

Injector-well completion recommendations

When assembling a selective installation, is always advisable to calibrate each tubing and tool in the surface before putting them in the hole. Also with the selective installation in the hole, ready to be set, whether it was the whole installation or just a part of it, 1 or 2 stages, it is advisable to calibrate it again with a wire-line caliper. These standard operations in Cerro Dragon implied an additional expenditure for the completion but save a lot more when a pass restriction is found because at the time of the calibration the solution is fast and cheap but if the restriction is found once the selective installation is already set and fixed to the casing the solution implies pulling the whole installation out and repairing all the packers which cost is a lot higher.

Working with selective installations of and average of 12 packers, not only means there will be 12 packers on the well's location waiting to be sent down it will also be 12 injector-mandrels, some on-off tools and lots of pup joints, so there is an important provability of misplacing a tool when assembling the installation. To reduce this provability there was implemented as standard procedure to dispose all the tools forming the selective installation over the ground in the order they have to be sent down, according to the selective installation's design for that well, before proceeding with the assembling.

For the reason explained before in this paper, the use of the automatic on-off tool has been adopted as standard for all the completion designs except for the rotationally-released completion which use the rotating on-off tool. For a 4 stages completion, like the hydraulic-mechanical mentioned before in this paper, the first and second stage will be connected by an automatic on-off as well as the third and fourth stage, the connection between the third and the second stage will be done by a standard on-off tool, thus the completion will be done with 2 tubing runs, each run carrying 2 stages connected by automatic on-off tools. For the more recent completion designs where there are no limitation to the number of packer each stage can hold, the use of an automatic on-off tool is also adopted as standard because it enables to run 2 stages in still only one tubing run plus it grants the benefits explained before of the upper stage being able to be replaced without having to move the lower stage if this last one is working fine. The common criterion is to split the selective installation design in 2 stages of approximately the same amount of packers each.

Finally, it is advisable when using all kind of hydraulic-set packers on the uppermost stage, to use a standard tubing on-off tool at the top of it. If a leakage appear some place over the tubing above the selective installation, having an on-off above it will grant the possibility to replace the tubing without having to move a perfectly working selective installation. An additional advantage is that if a leakage appear on the uppermost packer of the installation, the tubing can be disconnected and pulled out to be then ran down holding another packer placed right above the on-off upper connector so that it can be set just above the leaking packer, thus solving the problem without having to move any stage of the selective installation **(Fig. 12).**

Conclusions

As it could be seen in this paper, there are a lot of possibilities when it comes to injector-well completions, each of them has its advantages and disadvantages. From all the completions experimented with in Cerro Dragon the hydraulic-set rotationally-released split mandrel packer completion looks most promising because it complies with all the mayor requirements. It presents no limitation to the amount of zones to isolate, all the installation can be ran down in one tubing run, flexibility is good because of the packer's dimensions, it has no problem dealing with differential pressure and it has an average cost. However only 4 completions have been conducted following this design so far and despite the results were very good there is still much to be tested before jumping to conclusion.

Nevertheless, the others designs, seen here too, are far from being discarded, in this matter it is important to understand that the knowledge of the well's zones pressure expected from the zones already being flooded and the zones to be perforated to start flooding as well as the well's casing conditions are critical factors to take into account when deciding what completion design to use in an injector-well. As an example it could be said that there won't be a logical course of action trying to complete an injector-well, which is known to have a dog-leg on certain depth, with the hydraulic-set rotationally-released split mandrel packer completion if that well is part of a mature waterflooding project were pressures are stabilized and no abnormal differential pressures are expected. Instead, for that well a hydraulic completion like the one shown in Fig. 6 would be much more suitable because of the packers being shorter. However if that same well is known for having high differential pressure in certain zones or is part of a waterflooding project's vertical expansion, then a completion using the hydraulic-set rotationally-released split mandrel tandem packer and anchoring-packers as the one explained before on this paper for maximum flexibility, should be used instead.

To conclude, it is advisable to analyze properly the well characteristics in order to be able to design a completion perfectly suited for the well properties, instead of trying to use only one type of completion design for all injector-wells.

Acknowledgments

The authors thank the management of Pan American Energy LLC for the permission and encouragement to publish this paper.

SI Metric Conversion Factors

ft	x	3.048*	E - 01 =	m
in.	x	2.54*	E + 00 =	cm
psi	x	6.894757	E + 00 =	kPa
bbl	x	1.589873	E - 01 =	m^3
lbf	x	4.448222	E + 00 =	N

* Conversion factor is exact.

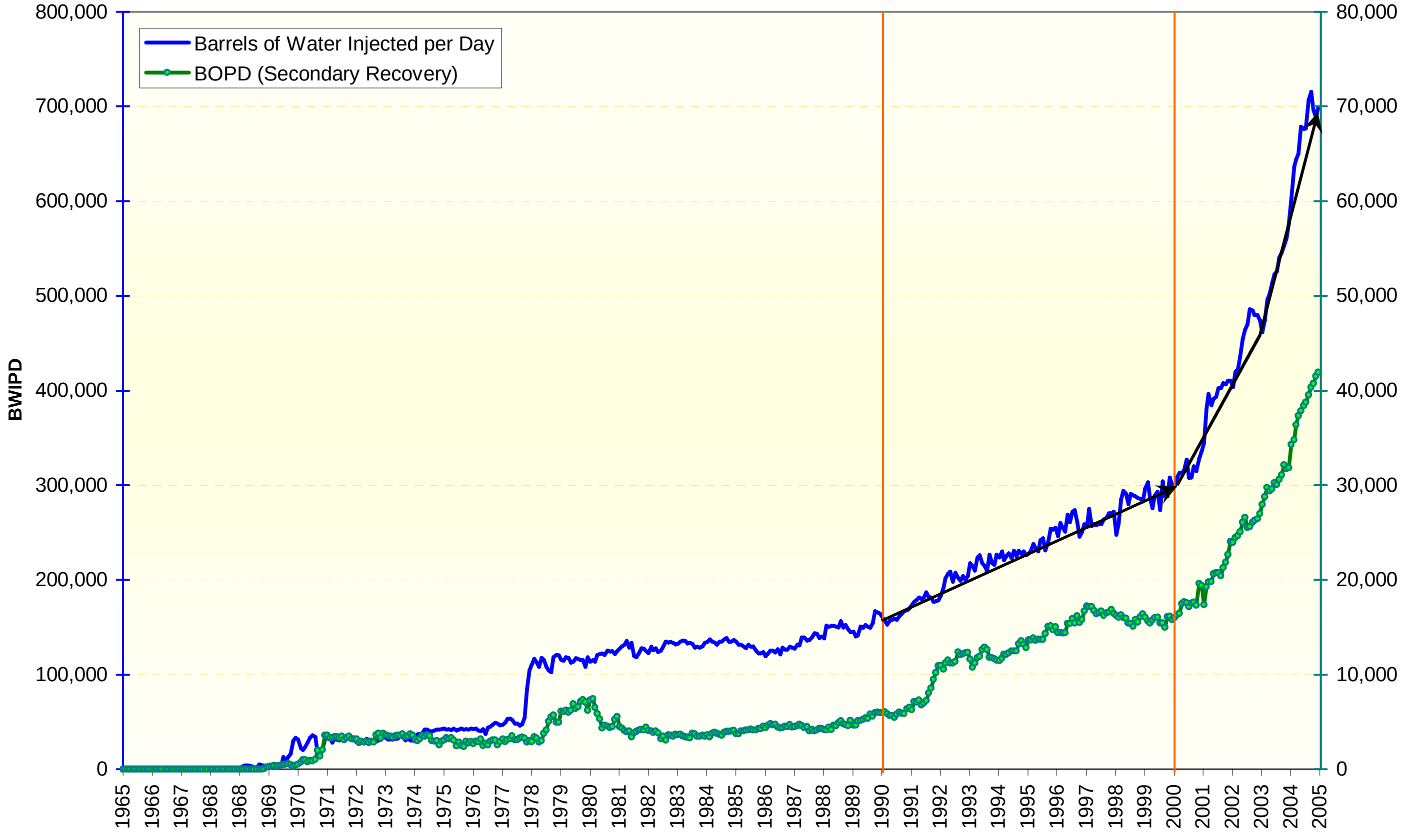

Fig. 1 – Injected water and secondary recovery oil production

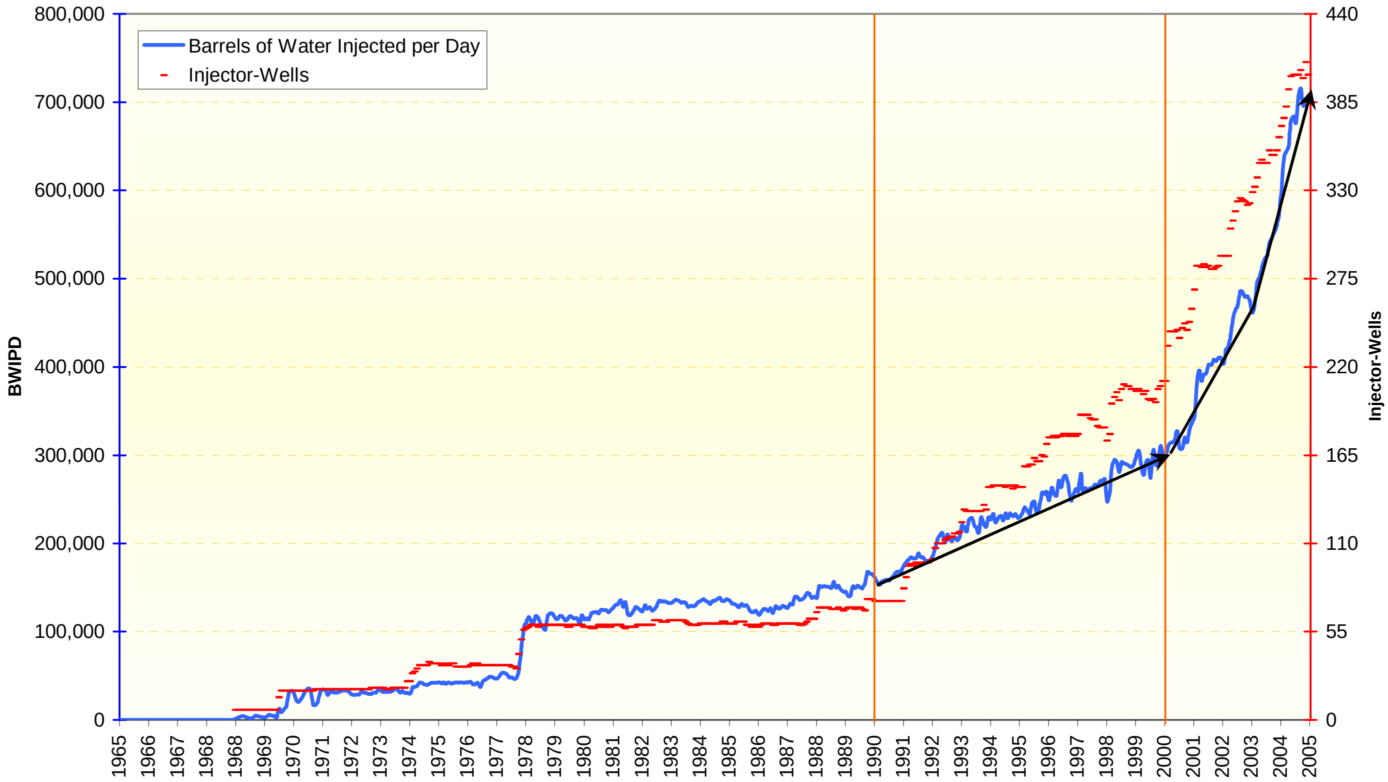

Fig. 2 – Waterflooding development

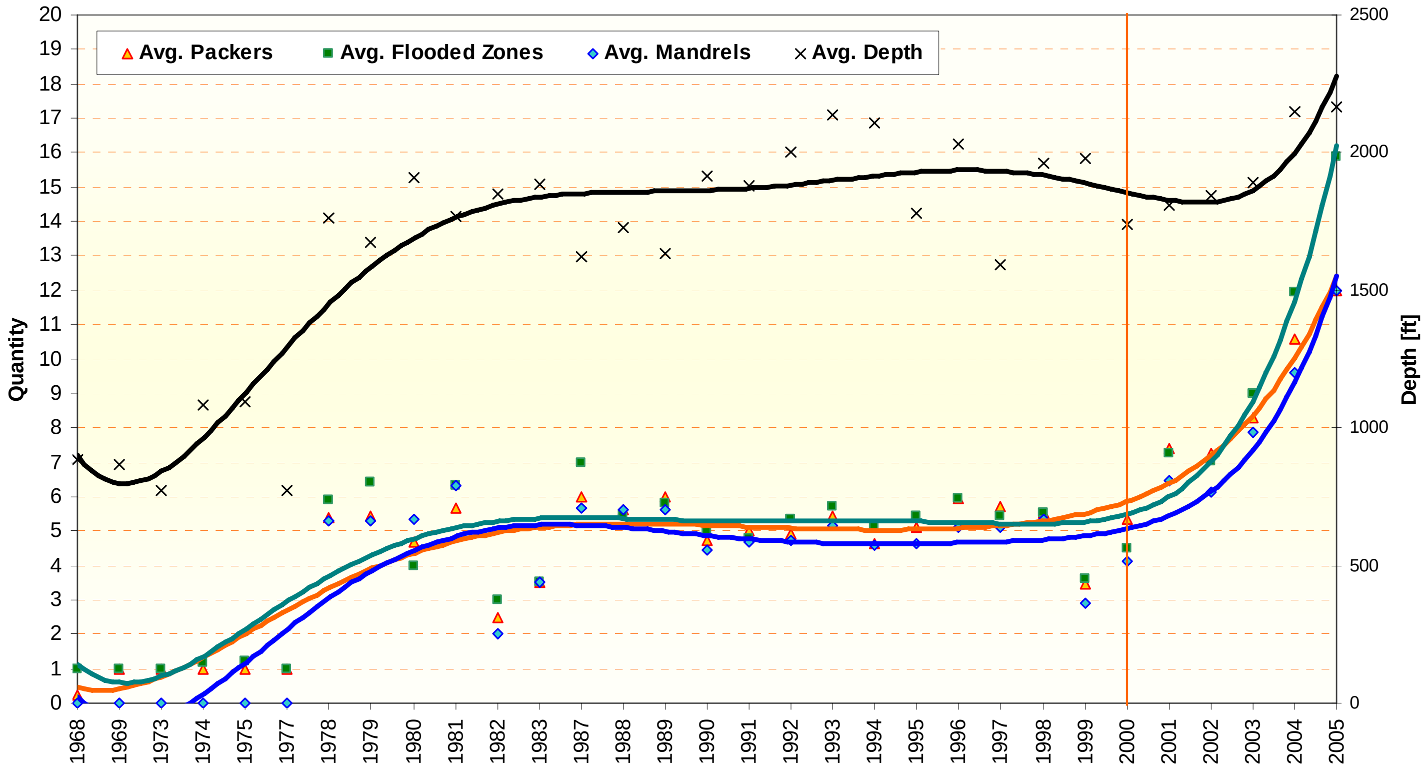

Fig. 3 – Injector-wells evolution

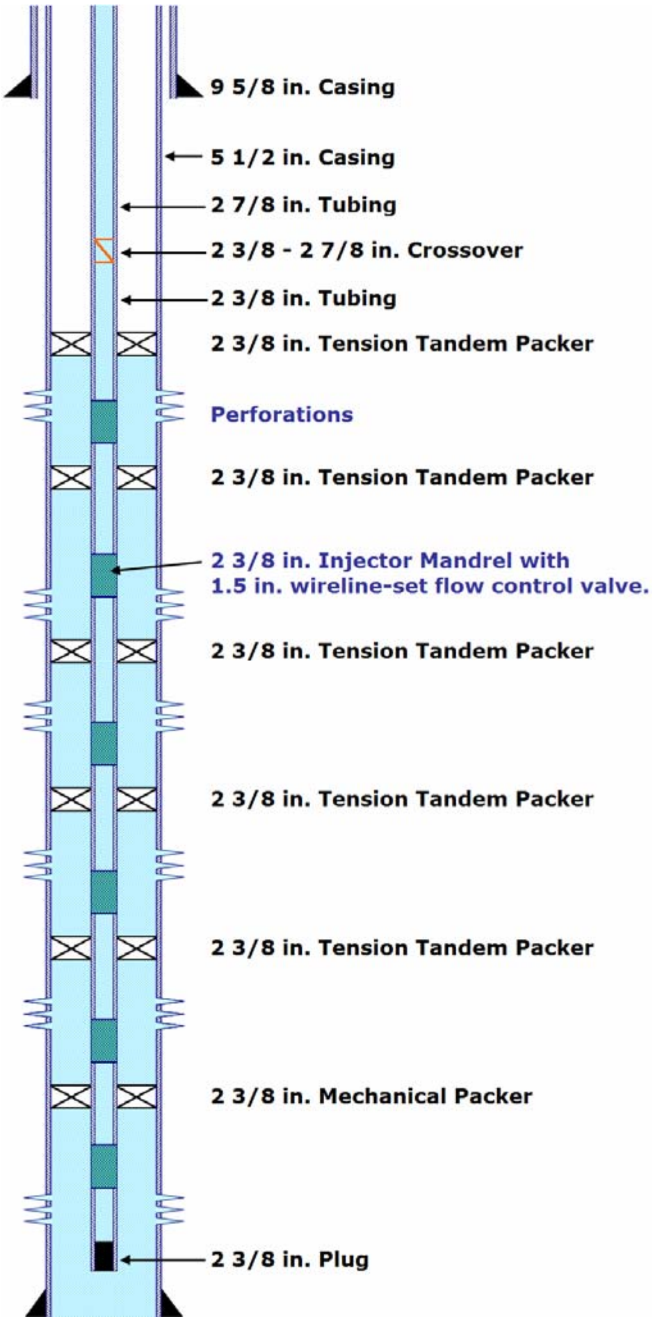

Fig. 4 – Mechanical Packers Completion

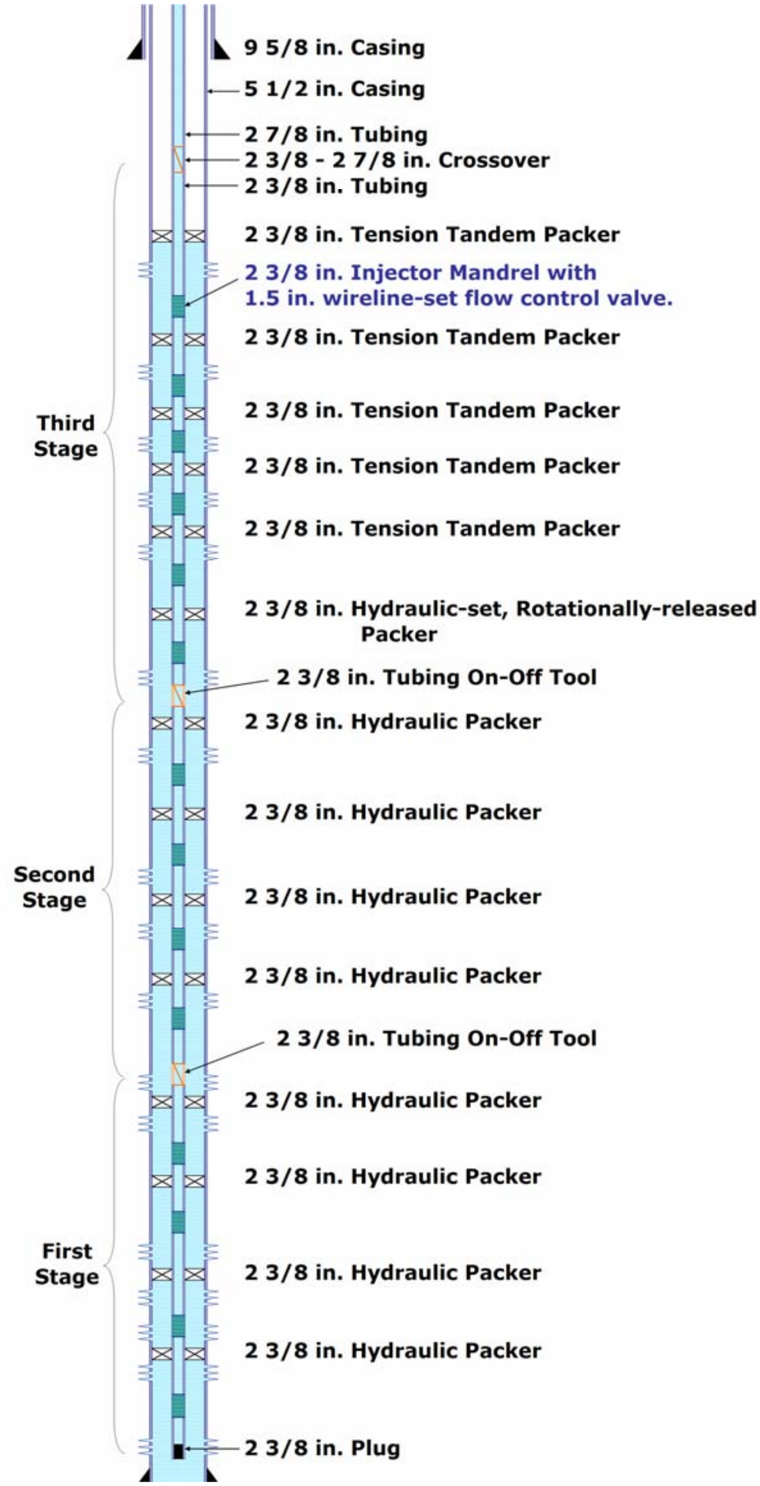

Fig. 5 – Mechanical and Hydraulic Packers Completion

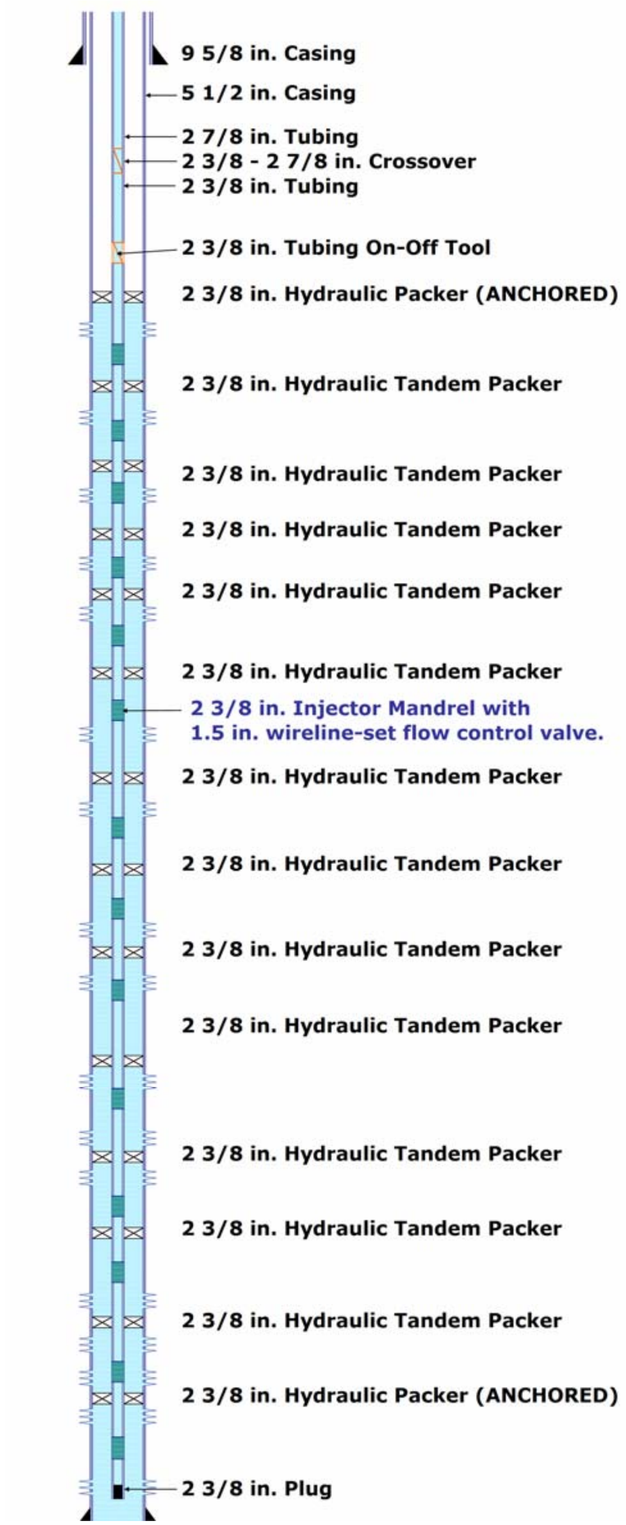

Fig. 6 – Hydraulic Packers Completion; two anchored points

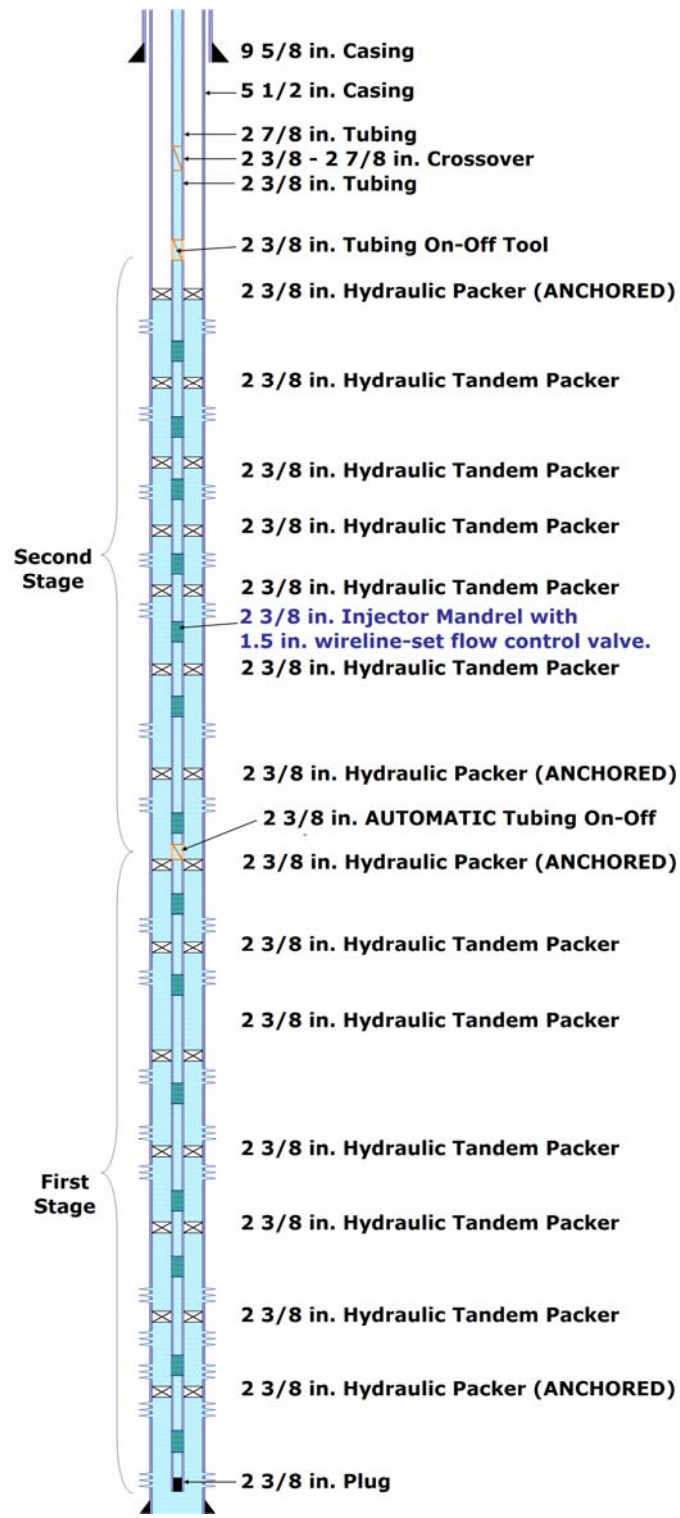

Fig. 7 – Hydraulic Packers Completion; anchored ends; two stages; 1 tubing run

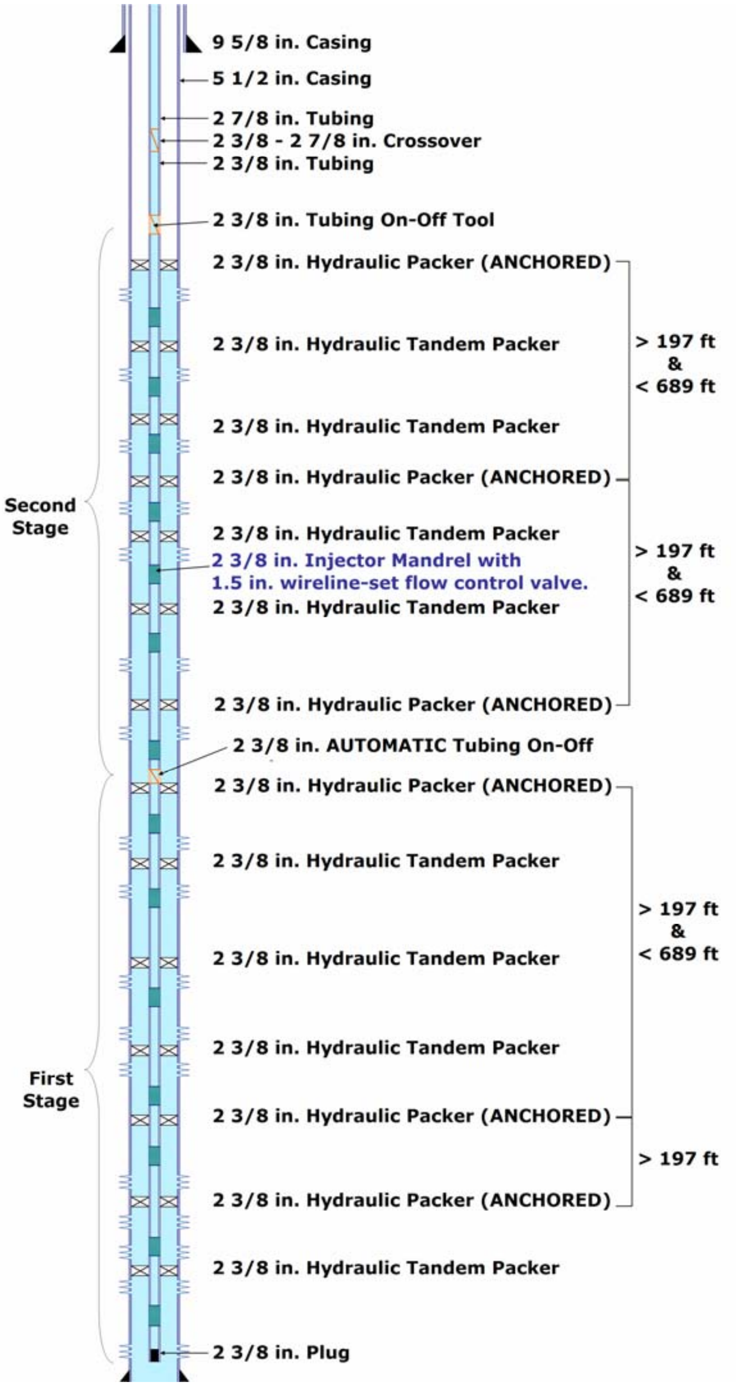

Fig. 8 – Hydraulic Packers Completion; multiple anchored points; two stages; 1 tubing run

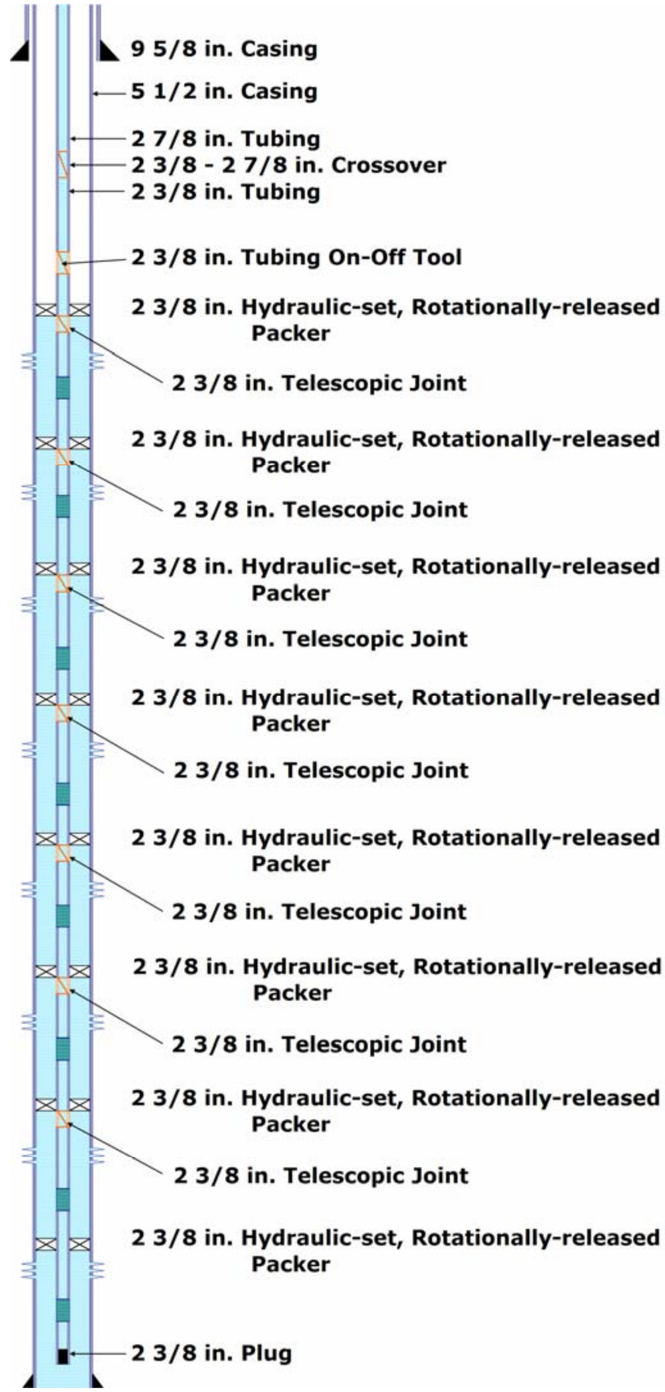

Fig. 9 – Hydraulic-set rotationally-released completion with telescopic joints

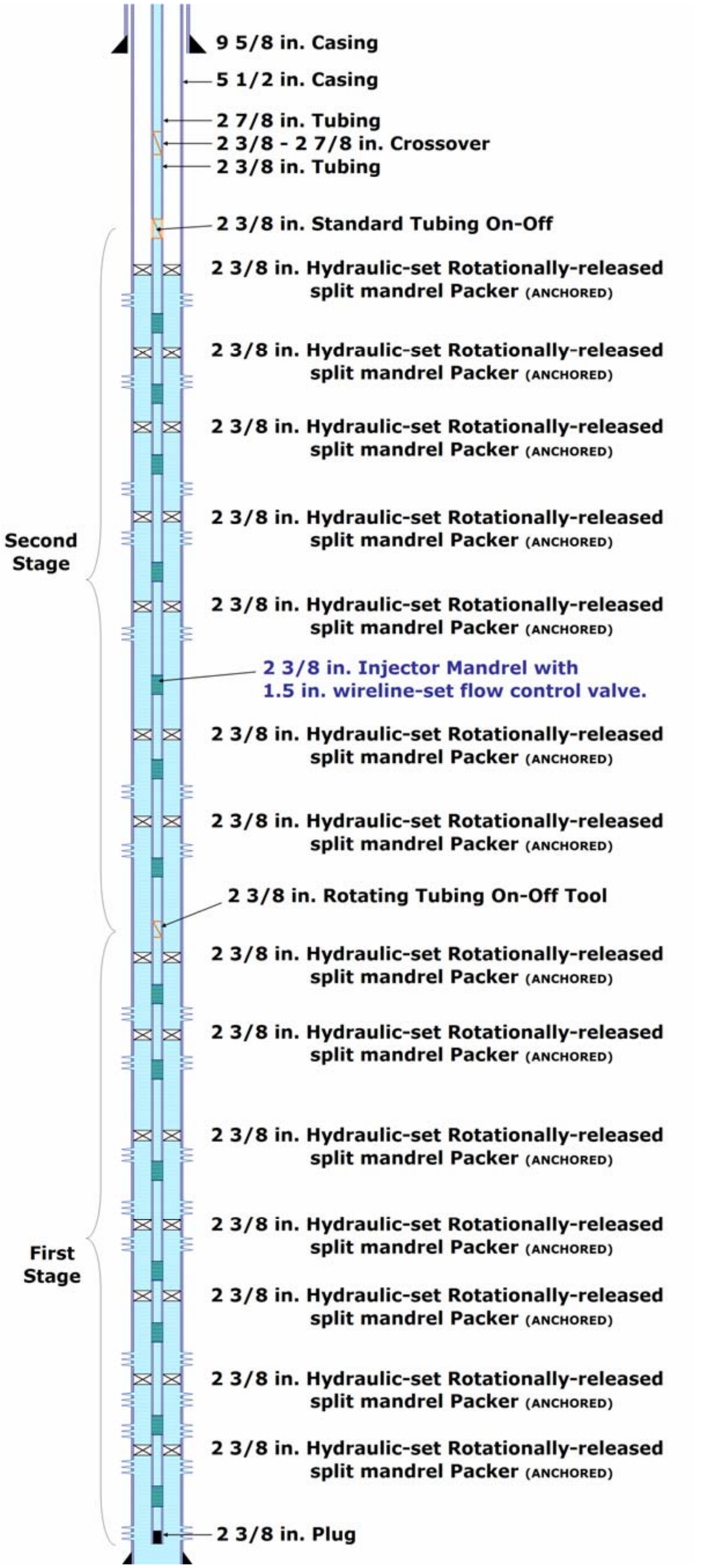

Fig. 10 – Hydraulic-set rotationally-released completion with split mandrel packers

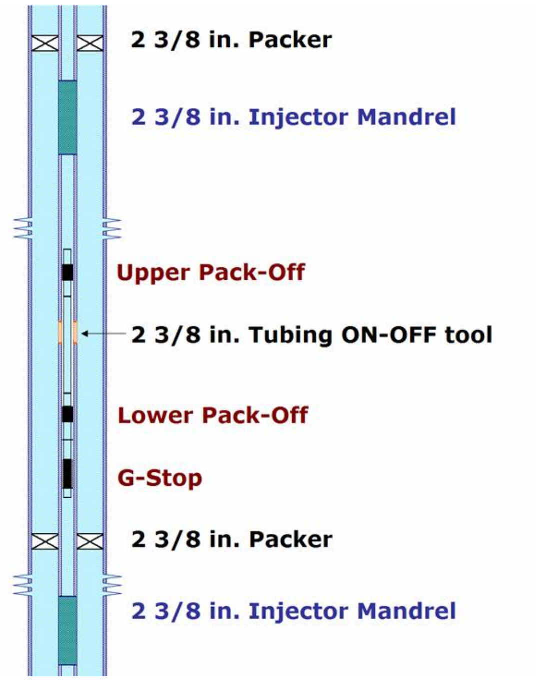

Fig. 11 –Patching of an on-off tool leakage.

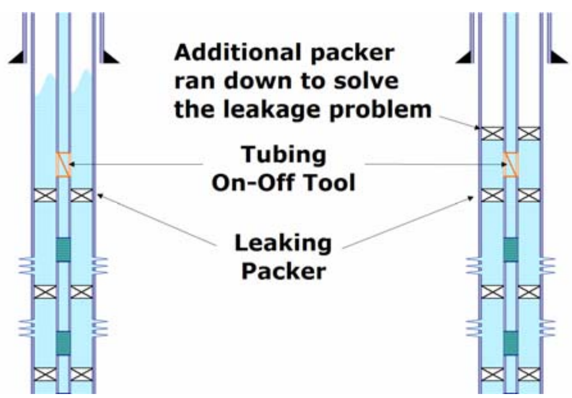

Fig. 12 –.Advantage of having an on-off tool above the selective installation