Managing retrieval of triple-zone intelligent completions in offshore extended-reach well

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AN INDEPENDENT operator offshore California has successfully achieved triple-zone intelligent well completions in an extended-reach drilling (ERD) campaign in its Rocky Point field. To date, two workover interventions have been performed in five deployments in the field, of which three are currently fully operational.

The Rocky Point reservoir is a highly fractured carbonate and can rapidly initiate water production. Achieving zonal isolation in the wellbore and at the reservoir level is critical. During the production stage, it was recognized that two of the wells did not achieve the required zonal isolation evident by increasing water cut. The operator decided to retrieve these completions to conduct liner cement repairs.

These triple-zone completions are controlled by 3½-in. tubing-retrievable flow-control valves, open/close and multiple-position, that work with dedicated gauges for monitoring of pressure and temperature. Each of the productive zones was isolated by three multiple-port retrievable production packers.

The main challenges in retrieving these completions were:

- Conveyance of the cutting tools to depth (due to ERD profile).
- Accurate location of the cutting targets (+/- 6 in. at 18,000 ft MD).
- Severing all control/electric lines and pulling all three packers in the same trip.
- Re-dressing and re-running the completions within two weeks of retrieval.

This paper describes the feasibility of deploying explosive jet cutters by pumping wireline conveyed assemblies to locator profiles above each packer, which allowed for simple, cost-effective intervention, avoiding costly mobilization of tractors or coiled tubing. Lessons learned are shown on how completions components were affected by the cutting operation and the extent of their refurbishment before re-completion. The paper also identifies modifications to intelligent completion design parameters (e.g., minimum distance of control valves from packers) that will be implemented in future installations.

**Introduction**

Even though the intelligent completion industry is maturing (500-plus installations), there is limited experience with the managed retrieval of these complex systems. This paper highlights the methodology, procedures and lessons learned associated with the retrieval of intelligent completions installed in ERD wells.

<table>
<thead>
<tr>
<th><strong>Items to be replaced</strong></th>
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<tbody>
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<td>Multiport isolation packer, 7 in. x 3.5 in.</td>
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<td>3 ½-in. swivel</td>
<td>Uneconomic to refurb this item.</td>
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<td>Hydraulic control lines</td>
<td>Due to the uncertainty of the condition of the control lines and the inability to perform suitable integrity tests, it is recommended to replace all the control lines.</td>
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<tr>
<td>Electric cable splice</td>
<td>Cable splice will be required to have connectivity between the gauges. Removal and redress of the blocks is not economical.</td>
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<tr>
<td>Tubing electric cable</td>
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<td>Tubing retrievable subsurface safety valve</td>
<td>Requires replacement of all elastomers, full FAT and re-certification.</td>
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<tr>
<td>Gas lift mandrel system</td>
<td>Thread inspection, pocket inspection. Valves removal and inspection, redress seals, valve set-up, valve loading and function test.</td>
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<tr>
<td>3 ½-in. tubing retrievable flow control valves – open/close and variable</td>
<td>Replacement of all elastomers, function test and FAT.</td>
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<tr>
<td>Monitoring system – gauges and mandrels</td>
<td>Thread inspection. Function test and cable head redress, re-calibration.</td>
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<td>Pipe accessories</td>
<td>Thread inspection and hydro-test.</td>
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ERD wells complicate retrieval due to the fact that the applied forces downhole are drastically reduced, and thus reduces the potential to the successful retrieval of pull-to-release devices.

The Rocky Point Field is located six miles northwest of Point Conception, offshore California. Geologically, it consists of a series of complexly faulted anticlines, which trend northwest-southeast. The reservoir is normally pressurized with oil-bearing, highly fractured intervals. These formations are complex lithologically with calcareous-siliceous and clayey-siliceous lenses.

Permeability is largely derived from natural fractures, with little effective contribution from the matrix rock. The reservoir is underlain by a large infinite acting aquifer providing sustained pressure support; water/oil contact varies between fault blocks.

The development plan for Rocky Point included drilling eight deviated wells from the Hidalgo, Harvest and Hermosa platforms (Gary P. Hertfelder et al, 2007).

The main objectives of installing “intelligent completions” ("IC") in these deviated wells were to minimize intervention whilst maintaining the ability to control water production and maximize the production from each of up to four zones. Other well objectives were:

- Provide economic commingled production from up to four oil zones driven by strong water drive allied to the constraints of topside infrastructure in highly fractured sandstone.
- Maintain simplicity of installation and operation.
- Reliable design to afford required longevity and minimize total life of well costs.
- Maximize recovery from highly fractured strong water drive reservoir.
- Maximize early production.
- Minimize potential for early water breakthrough.
- Selectively control water breakthrough per zone either by shut-off or, if drawdown dependent, by zonal pressure control.
- Maximize PI in $8^{1/2}$-in. hole.
- Minimize intervention.
- Maintain an adequate means for isolation between producing zones.
- Minimize risk exposure associated with completion technology new to the Point Arguello asset.

The initial completion was installed as a triple-zone intelligent completion in the operator’s Hidalgo C-13 oil producer well. Zonal isolation was achieved using two $3^{1/2}$-in. open/close flow control valves and one $3^{1/2}$-in. variable flow control valve with annular isolation by using 7-in. feed through, multi-port packers with cut-to-release mechanisms. Monitoring of the respective zones was achieved in the upper two zones with two dual gauge carriers with one quartz gauge reading annular conditions, and, in the lower zone, a single gauge carrier with a single quartz annular gauge.

Wells were cased with $9^{5/8}$-in. 43.5-lb casing to an approximate depth of 19,422 ft MD. The 7-in. liner was hung off with a liner top packer.

A tapered 4 $1/2$-in. to 3 $1/2$-in. production tubing string was run to maintain strength of completion whilst allowing for optimal gas lift efficiency. 4 $1/2$-in. tubing was run to the 9 $5/8$-in. above the liner with 3 $1/2$-in. below.

**WORKOVER SCOPE**

The objectives of the workover were:

1. Pulling the existing completion.
2. Surveying the wellbore to determine the source of the water production.
3. Implementing a plan to address and achieve zonal isolation between production zones.
4. Re-completing as required.

To understand completely the impact of any engineering and workover planning, a separate production analysis was conducted to collect and analyze data to determine the potential source of the water influx.

This data may deliver an alternate solution to pulling the existing completion or assist in planning likely scenario of re-completion equipment configurations. Possible solutions could involve pumping treatments, which would be evaluated in terms of cost and risk compared with pulling the completion. The study would also gather sufficient data to make an informed decision about the likely success of any water shut-off treatments and costs associated with re-installation of a suitable completion.

The scope of work focuses on two activities to be carried out in parallel and to be led and coordinated under a project management strategy (PMI 2000).

Preliminary work scope covered:

- g) The workover program preparation scope to provide the following services and deliverables:
  - Decision tree/flow chart and risk analysis (DRA) for the workover operation (completion retrieval options and risks).
  - Preparation of workover procedures (retrieval and completion re-run, including fishing operation contingencies).
  - Identify and locate/source third-party retrieval service equipment.
  - Determine potential re-usability of equipment to be retrieved and establish equipment requirements for each re-completion scenario.
  - Plan for equipment redress logistics.
  - Prepare schedules for equipment sourcing, reworking, redressing.
  - To assist in the re-completion design and in the secondary work scope (production analysis), a review of well construction data required (includes directional survey, open hole logs, drilling tour sheets, casing tallies, casing auxiliary equipment list, cement bond logs, cement volume logs, cement job reports).

b) The production analysis scope to generate:

- Analysis of available production data from C13.
- Compare C13 production data pred- and post-acid stimulation.
- Prepare diagnostic plots and perform a diagnostic analysis.
- Evaluate intervention options to shut-off water production (through-tubing or confirm the necessity for a workover).
- Perform DRA on success and potential costs of treatment vs re-completion.

**REFURBISHMENT / REPLACEMENT PLANNING**

Each completion component was evaluated for either refurbishment or replacement. In some cases, refurbishment costs exceeded replacement costs or vice versa. The table on Page 132 lists the completion components to be replaced and components that could be refurbished.
WORKOVER OBJECTIVE

The objective was to release three production/isolation multiport packers deployed in the Hidalgo intelligent completion wells by cutting each packer mandrel with an explosive jet cutter run on wireline.

Above each packer, the completion design included 2.813-in. nipple profiles to efficiently locate and cut each target. Each packer has, from the locator to the target window, an exact known distance. In order to minimize running time for the cutting of each packer, an equivalent target was defined to comply with the cutting objective for all three packers, allowing a common tool deployment configuration.

The target window to perform the cut was 19.6 in. Radioactive pip-tags were part of each of the locators at the bottom of each nipple sub and in the top gauge ring of each packer in order to accurately correlate the exact location of each profile and packer by using a gamma-ray tool, run as part of the explosive jet cutter bottomhole assembly (BHA).

As a reference, the packers and locator profiles were installed at the following depths:

- Lower packer top at 19,243 ft MD - isolation packer.
- Middle packer top at 19,073 ft MD - isolation packer.
- Upper packer top at 18,658 ft MD - production packer.

Locator profiles top were 22.7-22.9 ft from the packer target. Locator profiles bottom were 19.8-20.0 ft from packer target. The packers were located on inclinations of approximately 80°.

SAFETY PRECAUTIONS

To achieve a successful retrieval of the intelligent completion, safe operating and personnel practices were put in place and acknowledged across all involved parties. This was the first intelligent completion workover for the operator on the project.

RETRIEVAL METHOD OPTIONS

The retrieval of the intelligent completion wells installed in the Hidalgo Platform were dependent on the successful release of each of the three multiport cut-to-release packers. The selection of a cutting method limits the choice of conveyance method, so each had to be carefully evaluated.

CUTTING METHODS

Explosive jet cutting

Explosive jet cutting (EJC) uses a circular-shaped charge to create a radial jet to cut through a tubing wall. Temperature limits are determined by the lifetime at temperature of the detonators and explosives.

The EJC method requires live explosives handling. Safety issues must be addressed in transport and use. If EJC cutting is planned, explosives specialists must be on hand or directly available to the job site.

Abrasive jet cutting

This method cuts by directing a rotating high-pressure, high-velocity jet of sand suspended in gel against the tubing wall. It requires the availability of coiled tubing for conveyance.

Mechanical milling

Mechanical cutting is a service performed by reputable fishing tool companies to release cut-to-release packers. This method uses sharp-edged tools rotating against the target walls to sever the target.

Chemical-cutting

Metallurgy and well chemistry can limit the effectiveness of attempts to chemical-cutting. The maximum temperature for a chemical-cutting operation is 300°F. The solid bromine trifluoride will detonate at 310-320°F. Centralization is important, and should the cut fail, the second cut must not be made in the same area because chemical contamination will prevent the second reaction. For these reasons, chemical-cutting is discouraged as a cut-to-release method for cut-to-release packers.

CONVEYANCE METHODS

Several conveyance methods are available, and each was taken into consideration for intervening with the cutters in Well C-13.

Slickline

Slickline is very compatible with explosive jet cutters. Its use is limited in highly deviated wells similar to wireline. Slickline is the preferred conveyance method for non-deviated wells.

Wireline (E-line)

Wireline works well with explosive and chemical methods. Again, high deviations are difficult and require wireline tractors or other TLC (tough-logging-conditions) equipment to motivate the cutting string into position. One concern in using wireline is accurate positioning, providing a path for the wireline to reach the firing mechanism after passing through the wireline head and locating mandrel.

Coiled tubing

Coiled tubing (CT) is compatible with abrasive jet cutters and mechanical cutters. It is capable of conveying a cutting string into highly deviated wells and can be used with standard slickline equipment (1 11/16-in. to 2 7/8-in. slickline tool diameters). The preferred landing provision for use with CT is a no-go restriction. CT requires provisions allowing for the flow of returns generated by the cutting process in smaller tubing diameters to avoid deadheading into the reservoir formation.

Jointed tubing

Straight jointed tubing can conduct and operate mechanical and abrasive jet cutters into low-deviation wells. Jointed tubing has good control in up-hole and down-hole directions and allows the rotation and torque transmission from surface. There are similar concerns with return flows as with coil tubing in smaller production tubing sizes. Jointed tubing may be the preferred conveyance method in large-diameter tubulars and for landing on top of seal-bore latches.

RETRIEVAL METHOD

All retrieval options were investigated and selected using a decision tree analysis tool. The decision tree resulted in the recommendation to use EJC, which are placed across the packer cutting target with the assistance of a locator device that’s engaged in a locator sub above each packer.

The primary conveyance method for the locator tool and cutter assembly was chosen to be wireline. The wireline choice required pumping the BHA in order to carry it through the S-shaped profile of the well, with a maximum inclination of 82°. A contingency 1 ¾-in. CT reel and unit were mobilized in case the pumping down of wireline was unsuccessful in conveying the cutter BHA to the depth of the deepest XMP packer.
The cut-to-release locating profile and target.

The selection of the conveyance method for the ERD Well C-13 was made based on computer simulations, equipment availability and comparative costs.

An initial computer simulation for CT and wireline showed that very little weight down was available through coiled tubing when trying to locate the lower-most packer. This did not favor the choice of coiled tubing because of the risk of not being able to determine if the BHA landed on a locator or if it simply stopped because of friction. The CT option would be feasible if some means of reducing CT-to-tubing wall friction could be achieved.

Wireline simulations showed that gravity alone was insufficient to convey the BHA across the long and highly deviated section of the wellbore (82°). The advantage of the wireline solution, however, was the possibility of using pump-down cups to help convey the BHA to TD. As an alternative, an e-line tractor could be used. Due to the faster and least expensive option of pumping the wireline BHA to depth, the tractor option was kept as a contingency option.

Another factor that precluded the tractor option from being the primary method was uncertainty about the reliability of the tractor system in conjunction with the electronic release disconnect device and the electronic firing head. The use of the electronic release disconnect device was dictated by the S-shaped wellbore and the amount of friction involved with pulling the wireline from TD, which would have exceeded the shearing force of a conventional mechanical emergency disconnect device.

Workover execution

The following equipment requirements were established for the workover execution and procured during onshore preparations:
- Tubing retrievable safety valve protective sleeve.
- Wireline unit equipped with min. 20,000-ft 7-46XS cable.
- 2.75-in. EJC 38 gr explosive cutter.
- Shock Sub, 2.00 OD for HPHT cutter.
- Centralizers.
- Spacers.
- Adapters.
- Trip selective locating tool (for nipple profiles).
- Electric firing head.
- Electronic release disconnect.
- Gamma-ray, PPL and casing collar locator logging tools.
- Pump-down mandrels.

Certain preparations were carried out offshore well in advance of the pulling operation (e.g., cycling of downhole control valve tools to required positions for pulling).

The variable downhole valve deployed in the lower-most zone was set in the fully open position to allow well control. Well parameters (temperature and bottom-hole pressure) were recorded as baseline for the operation.

Downhole pressure gauges were intended to be used to monitor wellbore conditions during packer cutting.

Well pressure and volume of each control line were verified and recorded prior to and after each packer was cut to ensure control line integrity.

The two upper open/close flow control valves were part of the contingency strategy when the wireline cutting tool was pumped down the well. Cycling the valves allowed achieving the required pump rates to deploy the tools at the required position.

In order to quantify specific pump-down rate to deploy the tools, the injectivity capacity of the reservoir and the limitations associated with the cups in the wireline cutting string had to be continuously monitored. A rate of 5 bbl/min was established as the ideal rate to ensure the tools would not affect the reservoir by inducing fractures and efficiently allow the displacement of the tools through the highly deviated zones in the ERD well profile.

Operational summary

The cutting operation was performed as per procedures.

An initial dummy run was performed to verify the effectiveness of the pump-down operation. During this run, a combination of GR-CCL and spinner tools were run with the nipple profile locator tool, spacers and a dummy jet cutter.

One risk associated with the pump-down procedure is excessive pump-down force, which may release the cutter BHA when the BHA passes from the 4 ½-in. tubing section to the 3 ½-in. section. By measuring the fluid pump-down rate at the BHA using the spinner, the wireline operator could verify the flow velocity drop-off delay at the BHA when the pumping was reduced to enter the 3 ½-in. tubing section.

Another objective of the dummy run was to verify that the locator profiles could be easily identified and that enough pump-down force was available to pass through and pick up into each profile, even with the ERD S-profile wellbore.

During the dummy run, the BHA was left free-falling down to 3,600 ft. At this depth, pumping was initiated to carry the BHA. Pump rates inside the 4 ½-in. tubing section were taken up to 4 BPM, observing 300-psi injection pressure.

Logging was performed to observe the drop-off of the fluid rate at the tool before reaching the tubing crossover to 3 ½-in. at 15,283 ft. The BHA was picked up to 15,100 ft, and pump rates were reduced from 3 to 2 to 0 BPM. The BHA was then pumped through the crossover at 1 BPM. This rate was maintained up to 17,000-ft depth. At this point, pumping was stopped, and the tool was lowered by free-fall.

The BHA was lowered to 18,290 ft, past the lower packer and locating profile. It was then picked up through the packer and profile. The packer radioactive pip-tag was observed while picking up. The
Choke mandrel damage was observed.

locator tool pin sheared, and the BHA was picked up at 17,900 ft. The BHA was run in hole again and landed on the locating profile at 18,228 ft.

The dummy BHA was then picked up through the other upper packers and profiles, and each time it was landed in each of the two other profiles, one at 17,691 ft and the last one at 17,248 ft.

During this run, the radioactive pip-tags in the packers and locator subs were identified with the GR tool and when landing down on each profile, and the wireline was flagged at surface to mark the position of each pip-tag. Subsequent runs were performed with the actual 2.75-in. explosive jet cutters to the following targets:

- **Lower packer top at 18,219.92 ft MD:**
  - Locator profile top is 22.8 ft from packer target.
  - Locator profile bottom is 20.2 ft from packer target.
- **Middle packer top at 17,682.41 ft MD:**
  - Locator profile top is 21.7 ft from packer target.
  - Locator profile bottom is 20.2 ft from packer target.
- **Lower packer top at 17,238.12 ft MD:**
  - Locator profile top is 22.8 ft from packer target.
  - Locator profile bottom is 20.2 ft from packer target.

When running in hole the first jet cutter, the pump rate in the 4 ½-in. tubing section was taken up to 5 BPM with 370 psi of surface injection pressure, then lowered to 2 BPM while in the 3 ½-in. tubing, down to 17,000 ft.

After the first cutter detonation, gauge data from the lower gauge was lost, indicating that the explosive had cut the packer mandrel target and the TEC line through the packer by-passes at the same time.

During the second cutter run, the BHA would not free-fall through the upper packer, and 1.5-BPM pumping had to be used to get the BHA past the top packer and down to the middle packer. After detonation of the cutter, no hydraulic line pressure was lost and the gauge data from the middle gauge was still visible. This was an indication that neither the TEC line nor the CLs had been cut.

When the BHA was retrieved at surface, it was observed that the jet cutter had not fired. The problem was identified in a faulty primer cord connection between the detonator and the jet cutter. The detonator was run and successfully fired.

The middle packer run was repeated with a new detonator, primer cord and jet cutter assembly. This time, both the gauge data and the CL (common-off line) hydraulic pressure were lost, indicating that the cutter had fired and severed the TEC line and one of the control lines.

The upper packer run was flawless, and, immediately after firing, all gauge data were lost, indicating that the TEC line had been severed again during the cutter detonation.

The entire wireline operation (total of one dummy run and four cutter runs) took 29 hrs.

After all three packer cuts had been performed, the wireline equipment was rig-dow n, the wellhead was removed and the rig BOPs installed.

Once the tubing hanger was connected to the rig elevators, the hook weight observed was 48,000 lbs. The completion started pulling out of the hole with 230,000 lbs overpull, and the entire completion was retrieved over 4 ½ days. The POOH operation was interrupted twice due to well kicking, and approximately 17 hrs were spent killing the well in order to resume the retrieval operation.

All completion sub-assemblies were laid down and loaded in baskets for transportation to shore for equipment conditions assessment.

**REFURBISHMENT, ASSESSMENT OF RETRIEVED EQUIPMENT**

**Flow control valves assessment**

Lower zone, variable flow control valve. This on/off-type flow control valve was backed off from the pup joint below it and the swivel connector above it.

The valve itself was observed to have 6 ea choke inserts missing from the choke mandrel at the time that the valve...
There was evidence of fluid invasion between the filler and the insulator as indicated by a change of color.

surfaced the rotary table. Several other choke inserts were partially unseated from the choke mandrel, and some had to be pushed in in order to disassemble the valve.

The entire valve was disassembled, and the following parts were found damaged:

- Choke mandrel.
- Primary and secondary seats.
- Metal seal gland.
- Ring seals.
- Indexing pin.
- Indexer mandrel.

These were replaced with new parts, with the exception of the indexer mandrel, which could be re-worked and made good.

All elastomers within the valve were also changed out as per the valve’s redress kit.

The valve was put through a series of function tests as per the valve’s FAT procedure. This was done at the manufacturer’s test facility.

Once the valve successfully passed the FAT, it was made up and torqued up to the other components of sub-assembly #1, and the entire sub-assembly was hydro-tested and drifted. The valve was then wrapped in protective material for transportation inside the 50-ft basket back to location.

An investigation on the valve damage was performed, and the results were documented by the manufacturer’s flow management engineering department.

From this analysis, it was concluded that there was considerable evidence attributing the failure of the inserts within the 3 ¼-in. flow control valve to the presence of a pressure wave resulting from the use of an explosive packer cutter 30 ft above the valve. The explosion directed a pressure spike through the valve, causing the upper inserts to be removed.

Based on the investigation, it was recommended that the following actions be taken to prevent future problems:

- The use of explosive cutters may not be suitable for completions where sensitive equipment is deployed. Pressure sensors, flow control valves and the likes may not be re-usable if they are not protected from the pressure wave originating from the EJC.
- Concepts for attenuating the pressure wave or alternative cutting methods should be looked at, if damage to other parts of the completion is a concern.

**Middle zone, open/close flow control valve.** This valve was backed off from the pup joint above and below, and the entire valve was stripped down and inspected for damage. No damage to any of the valve components was detected.

The valve was re-dressed by changing out all critical components and was subjected to a FAT as per the valve QA/QC manufacturing requirements.

After the valve successfully passed the FAT, it was made up and torqued up to the rest of its sub-assembly components. The sub-assembly was then hydro-tested and drifted prior to wrapping the packers with protective material for transportation inside the 50-ft basket back to location.

**Upper zone, open/close flow control valve.** This valve was backed off from the pup joint above and below, and the entire valve was stripped down and inspected for damage. No damage to any of the valve components was detected.

The valve was re-dressed by changing out all critical components and was subjected to a FAT as per the valve QA/QC manufacturing requirements.

After the valve successfully passed the FAT, it was made up and torqued up to the rest of its sub-assembly components. The sub-assembly was then hydro-tested and drifted prior to wrapping the packers with protective material for transportation inside the 50-ft basket back to location.

**Monitoring assemblies assessment**

**Lower zone.** The single gauge mandrel was shipped to the manufacturer’s product center with the gauge still installed in the mandrel. Once at the product center, the single gauge and a TEC pig-tail attached to it were removed and sent for recalibration of the gauge.

The mandrel itself was sent to a third-party contractor for cleaning and sand blasting. A phosphate coating was also applied to prevent corrosion once cleaned.

The single gauge mandrel was hydro-tested and drifted prior to wrapping in protective material for transportation inside the 50-ft basket back to location.

The gauge itself did not pass the calibration procedure and had to be substituted with a new gauge that was sent straight to location from the operations support district.

After the calibration, a more detailed evaluation was carried out on the gauge to identify the failure. Under the evaluation, fluid invasion in the TEC line was identified. Once the line was cut closer to the connector, fluid drops could be seen coming out of the line between the armor and the filler.

The section that was cut was also examined, and there was evidence of fluid invasion between the filler and the insulator as indicated by a change of color.

**Middle zone.** The dual gauge mandrel was shipped to the manufacturer’s product center with the gauge and Y-block still installed in the mandrel. Once at the product center, the single gauge, Y-block and a TEC pig-tail attached to the Y-block were removed and sent for recalibration of the gauge.

The mandrel itself was sent to a third-party contractor for cleaning and sand blasting. A phosphate coating was applied to prevent corrosion.

The dual gauge mandrel was hydro-tested and drifted prior to wrapping in protective material for transportation inside the 50-ft basket back to location.

This gauge passed the calibration procedure and was packaged with the Y-block.
Drilling contractor Completion and its TEC line pig-tail. It was sent to location ready for installation during the re-completion operation.

An additional test was performed with the retrieved gauge and the other two to see if all gauges were working properly. All gauges performed as expected, but to the evidence of fluid invasion in the lower-most gauge. It was agreed with PXP to completely change the gauge system and individually evaluate the gauges. The objective was to minimize any future risk of gauge failure with any potential moisture in the TEC line.

**Upper zone.** The dual gauge mandrel was shipped to the manufacturer’s product center with the gauge and Y-block still installed in the mandrel. Once at the product center, the single gauge, Y-block and a TEC pig-tail attached to the Y-block were removed and sent for recalibration of the gauge.

The mandrel itself was sent to a third-party contractor for cleaning and sand blasting. A phosphate coating was applied to prevent corrosion.

The dual gauge mandrel was hydro-tested and drifted prior to wrapping in protective material for transportation inside the 50-ft basket back to location.

This gauge passed the calibration procedure and was packaged with the Y-block and its TEC line pig-tail. It was sent to location, ready for installation during the re-completion operation.

**Packer assemblies assessment**

The radioactive pip-tags in the packer upper gauge mandrel and the locator profile were removed at the rig-site by a wireline operator prior to off-loading the sub-assembly from the rig.

The packer sub-assemblies were un-torqued and disassembled. The released multi-port packers were substituted with 7-in. x 3 ½-in. 26-29 ppf multi-port packers. These new packers were shear-to-release type, and the shear setting for each was set at 140,000 lbs. This was the maximum recommended shear setting for 7-in. L80 casing (above this shear setting value, the packer slips would never release from the casing walls).

Each of the multi-port packers were converted from 32-35 ppf packers to 26-29 ppf that were made available from another location. This was necessary due to the extensive lead time required for the manufacturing of new multi-port packers (five to six months). Additionally, these particular packers’ mandrels and upper and lower housings had to be substituted in order to comply with NACE materials regulations for sour gas service as per the Hidalgo C-13 well conditions. Crossovers from 3 ½-in. Vam Top to the packers’ 3 ½-in. New Vam connections were installed to make up the packers to the existing 3 ½-in. Vam Top pup joints equipment.

These sub-assemblies were made up with the multi-port packer and the crossovers above and below the packer, and the sub-assemblies were hydro-tested and drifted prior to wrapping the packers with protective material for transportation inside the 50-ft basket back to location.
The DCIN was backed off from the two pup joints above and below it. The DCIN mandrel by itself was then transported to the manufacturer’s facility in Houston, where it was completely redressed and FAT’ed. The DCIN was then sent to a third-party facility for making up to its pup joints above and below and for the connections to be hydro-tested and drifted.

One of the pup joints retrieved from the well was found damaged, probably by rig tongs while breaking off the sub-assembly from the tubing string. The damaged 4-ft pup joint was replaced with a new one.

The sub-assembly was wrapped in protective material and loaded into the 35-ft basket for transportation to the well site.

Gas lift assemblies assessment
The gas lift mandrel sub-assemblies were inspected for damage and were found to have some significant pitting due to sour gas corrosion in one of the pup joints. The pitted pup joint was backed off and replaced with a new one.

Experts from the manufacturer’s metallurgy department inspected the corrosion on all gas lift mandrel sub-assemblies and issued a recommendation for further metallurgical testing to determine possible corrosion inhibitor solutions, as it was determined that the gas lift mandrels were undergoing considerable corrosion, and the life expectancy of the completion was compromised if subjected to the same environment on the next completion.

The gas lift mandrel sub-assemblies were then loaded in the 35-ft basket for transportation to the well site. One of the gas lift mandrel sub-assemblies was inspected and found to have significant pitting due to sour gas corrosion in one of the pup joints. The pitted pup-joint was backed off and replaced with a new one.

Subsurface safety valve assembly assessment
The safety valve was backed off from its flow couplings and pup joints above and below it, and the valve itself was transported to the manufacturer’s facility in Houston, where it was completely redressed, FAT’ed and re-certified.

The valve was then returned to the product center, where it was made up and torqued up to the flow couplings and pup joints again. The entire sub-assembly was then hydro-tested and drifted while the flapper valve was held open with hydraulic line pressure. The valve was then wrapped with protective material and loaded in the 35-ft basket for transportation to location.

Hydraulic and electric lines assessment
Hydraulic control lines. All control lines (flat packs and single encapsulated lines), as well as the TEC line and chemical injection line, were spooled back onto their reels during retrieval. However, new lines were procured for re-installation of the completion.

None of the lines was recommended to be used again due to potential deformation each time they are spooled into the well and out of the well, and the higher risk of failure if the line is subjected to this spooling cycle more than once.
Many of the encapsulations were found to contain wellbore fluids, including gas. For this reason, they required cleaning, straigtening and pressure-testing by a qualified third-party company. In theory, if this is done and the lines pass the pressure testing, they may be used for re-installation in another completion. The actual feasibility and cost of this refurbishment would have to be verified with proficient third-party services should the need arise to make use of the retrieved control lines.

A third-party company was approached for the re-spool of the lines as single(s), clean up jacket, and for NAS Class certification.

The effect of moisture invasion of the TEC line is also a likely potential risk that may influence premature failure of the TEC cable should it be run back into a well.

**Protective clamps assessment**

All protector clamps retrieved from C-13 were shipped back to the manufacturer. Some clamps have been damaged beyond repair, but the majority were found to be in good condition and would require sand-blasting and refurbishment of the compression indents and possibly some hinges.

A new set of clamps was procured to be used for the re-completion of C-13. An additional set of splice protectors was designed and built to accommodate the four additional splices in the C-13 re-completions that connect the gauge Y-block pig-tails to the main TEC line.

**Lessons Learned, Conclusions**

1. Cut-to-retrieve multiport packers are an effective choice when stacking isolation packers for ICs. Retrieval of the entire IC completion in one trip is facilitated by the nature of the cut-to-release design, and explosive jet cutters can effectively sever control lines and electric lines to facilitate the retrieval.

2. Intervention to cut the packer targets can be effectively performed using wireline as a conveying string, and the pump-down method is a cost-effective alternative to e-line tractors, even in ERD well trajectories.

3. The use of explosive jet cutters is very efficient in cutting the packer targets, but the shock from the explosive charge can affect the integrity of gauges and/or flow control valves that are placed in proximity of the packers. It is recommended that a minimum distance of 20 ft be kept between a cut-to-release packer and a flow control valve or gauge if explosive jet cutters are planned to be used during the retrieval operation.

4. The compatibility of wireline tractors, electronic release disconnect and explosive firing system has not been tested before, and therefore precluded the tractor option to be selected as one of the back-up contingency methods. Further stack-up testing of these components could facilitate alternative options in future IC completions work-over or intervention operations.

**References**


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