Light Well Intervention Using Conventional Slickline and Electric Line off the East Coast of Canada

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Abstract

Well intervention is a critical aspect of managing brownfield assets as operators seek to optimize hydrocarbon recovery and perform maintenance work to ensure wellbore integrity. The costs of traditional workover methods and technologies, specifically in an offshore environment, can create economic barriers to the number and types of interventions that are completed in a declining field. Light well intervention technology is considered a cost effective alternative to performing rig interventions on aging subsea wells.

Operators and service providers continually seek to develop technologies and procedures that mitigate economic risk when working on these mature production wellbores. One revolution that has been in development for the past few decades involves using conventional slickline and electric line to perform light well interventions without the requirement of an offshore drilling or workover rig. This process uses a light well intervention vessel (LWIV) complete with a moonpool located mid-deck for open-sea access, a riserless pressure control package typically involving remotely operated vehicles (ROVs), and a combination of conventional slickline and electric line intervention packages. Interventions using this technology adaptation were primarily developed for the North Sea and Gulf of Mexico regions and have been widely used in those regions. However, after several years of planning, the technology has now been used for the first time to rework several wells for an operator off the east coast of Canada.

Light, riserless, well intervention technologies have been deployed in three individual wellbores offshore Canada. Multiple services were required in each of these three wellbores. Conventional slickline operations were run to prepare each of wellbores, with the retrieval of crown plugs and conventional drift runs. Operations then switched to electric line services to perform diagnostic runs followed by remedial intervention services. Once the electric line services were completed, slickline services were used for safety valve isolations and gas lift remedial work and then returning the newly configured wells back to production mode. The use of the LWIV provided the operator with an efficient intervention technique to evaluate and potentially improve well performance.

Introduction

Subsea completions have been used in various oil and gas fields throughout the world over the past few decades with increasing growth since 2007. Moving the wellheads and conventional surface infrastructure
to the ocean floor has reduced the capital requirements of building expensive surface structures to handle offshore hydrocarbon production. Subsea completion technologies have also provided the ability to explore, complete, and develop fields in increasingly difficult water conditions and depths. However, as these wellbores age and production declines, performing well interventions or workovers on these wells typically proves costly and requires many months or years of planning.

Conventional methods of completing well diagnostics and performing remedial intervention services require a mobile offshore drilling unit (MODU). A large-diameter pipe or riser package is installed from the subsea wellhead tree to the MODU positioned above at the surface of the ocean. Various tools and conveyance types are then deployed from the MODU through the riser and into the wellbore to complete the well intervention. Conveyance of tools through the riser may include, but are not limited to, various sizes of slickline, electric line, coiled tubing, conventional tubing, or drillpipe. The riser permits a contained path by which these conveyance types may easily pass through the ocean water and into the wellbore undisturbed by currents and ocean conditions. While this type of scenario can be relatively straightforward with respect to conveyance through the riser and into the wellbore, it can also be very difficult to deploy the riser itself and may prove cost prohibitive in certain subsea situations.

The emergence of deploying slickline and/or electric line services in a riserless environment over the past 10 years is providing well operators with an alternative option when light well interventions are required. Workovers are typically considered light well interventions when the diagnostics and remediation can be completed without the use of heavy tubing or pipe. There are many scenarios in which a light well intervention will be sufficient to complete intervention objectives. One of the most common involves aging wellbores that access several different formations and are experiencing rapid depletion. This is the scenario that existed for an operator in Canada, where a light well intervention vessel (LWIV) vessel was deployed recently for the first time.

**Technology Summary**

A light well intervention vessel (LWIV), shown in Fig. 1, is a self-propelled marine vessel capable of maneuvering to and from various offshore well locations as well as maintaining a fixed position, usually with the assistance of a global positioning system (GPS), when required to deploy intervention technology. There is typically a moonpool located mid-deck through which the intervention technology is lowered with an onboard crane, although in some scenarios, the equipment could be deployed over the side of the vessel with special equipment. In most cases, the vessel or the deployment package is equipped with a compensator to overcome changes in the sea level while deploying subsurface technology.

![Figure 1—Advanced light well intervention vessel (LWIV). (Courtesy of Helix Energy Solutions)](image-url)
The riserless package, the subsea intervention lubricator (SIL), is the equipment that is lowered to the subsea tree and contains the intervention tools and provides a conduit for the conveyance method (Fig. 2). The SIL ties in directly to the subsea tree and is the method by which the wellbore fluids and gases are safely contained at all times, while the tools are deployed into the well. There are multiple elements that seal well pressure around the slickline or electric line being deployed. The SIL also contains sealing and shearing equipment that may be engaged in the event of an undesired event. In addition to the intervention equipment, one or more remotely operated vehicles (ROV) are deployed to the seafloor near the subsea tree. The ROVs are used for guiding the equipment into place, manipulating valves on the intervention package and subsea tree, and sending pictures or video to surface to confirm the status at any point in time. A typical riserless intervention configuration is represented in Fig. 3.
Conventional slickline is a single-strand metal wire, capable of providing mechanical services or conveying memory tools only. There are many sizes of diameters and varieties of metal alloys, each with a specific purpose or condition to be used in. The slickline not only provides the means of conveying the mechanical tools, but is also used to manipulate the string either upwards or downwards in a jarring motion to complete various mechanical tasks. All information collected from a slickline system is done from surface measurements. Line tension, wire depth, and well pressure are measured at surface and interpreted by the slickline supervisor to infer what is occurring downhole; movements in the wire are subsequently adjusted accordingly.

Electric line services involve the use of a multistrand braided cable that contains an insulated center conductor cable. Electrical power can be sent through the conductor of the cable to the tools while simultaneously providing a means of real-time two-way communication. Some services provided using electric line are downhole measurement based or require communication to activate devices while downhole. Most light well interventions require a combination of slickline and electric line runs with the riserless package and the vessel to complete to objective. The well examples recently completed in Atlantic Canada utilize all these services to complete the intervention programs.

**Well Intervention A**

The light well intervention vessel (LWIV), riserless package, slickline, and electric line units were deployed in June 2014 to the first of three wells after 2 years of planning and design. This well was located in approximately 312 ft [95 m] of water. The primary objective of the first light well intervention was to perform a production log across all existing perforations. Then, based on the results of this log, either a water shutoff or a reperforation of existing formation would be performed to improve overall well performance. Water production can impact the amount of hydrocarbon being produced from other zones in the wellbore.

Once the equipment was in place on the first wellbore, an ROV was deployed to remove the tree cap from the top of the subsea tree to provide access for the intervention services. Initially, slickline was required to remove the internal barriers to provide access to the wellbore for subsequent runs. The slickline unit was rigged up with the riserless pressure control package and deployed subsea. The first run required slickline to retrieve the tree cap crown plug (TCCP). After activating a memory hydraulic-
powered pulling tool, the TCCP was pulled free and raised into the subsea intervention lubricator (SIL). After each run the SIL maintains pressure control, while the conveyance string and downhole tools are retrieved to the surface, to the deck of the vessel, to change out tools and prepare for the next run into the well. On the second run, the memory hydraulic-powered pulling tool was deployed via slickline to retrieve the tubing hanger crown plug (THCP). With the THCP successfully removed, the intervention crew had access to the wellbore; however, prior to deploying the electric line services, a protector sleeve was installed using slickline to ensure that the profiles for the TCCP and THCP were not compromised in subsequent trips into the wellbore. The final run required for the slickline unit was to run a gauge ring to the bottom of the wellbore to ensure the tubing and casing were clear of debris or obstructions prior switching to electric line services.

With the wellbore prepared and the tubing verified clear of restrictions, operations switched to electric line services. The first run with electric line required the collection of downhole production data to determine which formation was producing the majority of the water. The well design included four perforated intervals comingled downhole and producing through the tubing to surface. The production logging tool configuration used to determine the inflow characteristics included a gamma ray detector and collar locator for depth correlation purposes, a 3.5-in. collapsible full-bore flowmeter for determining bulk fluid velocity changes, a caliper measurement for checking the consistency of the inner tubing diameter across the logging interval, a gradiomanometer for measuring the bulk density of the produced fluid mixture, distributed electric probes for resolving the water-holdup of the produced fluids, and distributed optical probes for gas-holdup measurements. The logging program included multiple shut-in passes followed by several flowing passes performed at two separate rates. The shut-in passes are used for calibration and baseline measurements while also confirming whether there is crossflow occurring downhole from one perforated interval with a higher pressure into a lower pressure interval. Reservoir parameters can be calculated by performing the flowing passes at two or more separate and stable flow rates. Completing multiple passes at each separate flow rate will confirm the stabilization of well during logging and reduce the overall statistics of the interpretation calculations. While logging the first rate, it was determined from the real-time downhole pressure data that the flow conditions had not completely stabilized; therefore, the rate-1 passes had to be recompleted. Following the completion of the flowing passes, the well was shut in and the tools retrieved to surface. A portion of the raw logging data is represented in Fig. 4.
The analyzed production logging data indicated a high water cut from the lowest perforated interval (zone 4). The decision was made to isolate the lowest zone from production. The electric line operations conveyed and set a bridge plug into casing using an explosive setting tool. The setting tools were recovered to surface, and the electric line unit was rigged down.

Slickline was then rigged up to return the wellbore and subsea tree back into the production configuration. The first requirement was to remove the protector sleeve from across the crown plug profiles. The protector sleeve was removed successfully after several jarring attempts. The next step was to reinstall the THCP. The THCP was installed and successfully pressure tested from above to 5,000 psi [34 475 kPa]. The tools were retrieved to surface and prepared to run the TCCP. The first two attempts to set the TCCP were unsuccessful. Within the standard procedure of setting crown plugs of this type, pressure applied from above is used to assist the setting mechanism. It was determined the pump rate was not high enough to overcome the restriction of pumping through the ¼-in. (6.35-mm) tree cap injection (TCI) line that went back to surface onto a reel pack containing 5,577 ft [1700 m] of line. The decision was made to bypass the 5,577 ft [1700 m] reel. The third attempt to set the TCCP valve was successful; the plug was pressure tested to 5,000 psi [34 475 kPa] and the TCI valve was closed. The tools and SIL were removed from the seafloor and the tree cap reinstalled. The intervention vessel was subsequently moved to the next well located nearby.

**Well Intervention B**

The second well intervention planned, well B, presented nearly the same conditions as well A, with the exception of one additional sets of perforations, and involved the same program objectives, but with one extra step planned. Upon completion of the water shutoff, operations would be required to change an ineffective gas lift orifice valve. Gas lift is used to assist in downhole fluid and hydrocarbon recovery to
surface. Gas is typically injected from seabed down the tubing-casing annulus and enters the tubing through a mandrel and at a pressure controlled by the annular choke valve (Fig. 5). In some gas lift designs, such as the case in well B, the valves can be removed and valves with different pressure settings reinstalled using slickline services.

Initially, the intervention on well B followed the same steps as that in well A with the ROV removing the tree cap and providing access for slickline to remove the crown plugs. Slickline successfully deployed the memory hydraulic pulling tool to remove the tree cap crown plug (TCCP). The next run to remove the tubing hanger crown plug (THCP) was unsuccessful as a result of a tool failure. The fail-safe shear system was activated, and the memory hydraulic pulling tool was retrieved to surface. The second attempt to pull the lower plug was successful and the THCP was retrieved to surface. The slickline crew again placed the protector sleeve in the well similar to the process followed previously. The final well preparation run made by slickline was a gauge ring to tag the bottom of the wellbore ensuring the tubing was clear. Slickline was rigged down and moved aside.

Electric line services were deployed to perform a production log and potentially a water shutoff, similar to well A. The production logging toolstring was configured similar to that used in well A, with a minor modification to the flowmeter. Replacing the 3.5-in. full-bore flowmeter was an array-type flowmeter containing five 1.0-in. mini-spinners arranged on the tool to cover the internal circumference of the casing. Flowmeters of this arrangement are typically used when there are two or three phases of hydrocarbon-water mixtures being produced in a deviated or horizontal wellbore. After successfully completing a logging program identical to that of well A, a high water cut was identified from zones 3, 4 and 5. The bridge plug was successfully set on subsequent run, isolating these zones from production.

The next process in the intervention required slickline to be used to remove an ineffective gas lift valve and replace it with a new valve. Slickline was rigged onto the subsea tree after the electric line was moved off to the side of the vessel. The first attempts at removing the gas lift valve were unsuccessful due to the inability to latch onto to the top of the valve. It was decided to retrieve the kickover tool to surface and attempt to run a brush into the wellbore to clean the side pocket mandrel containing the ineffective valve. After several passes across the gas lift mandrel with the brush, the tools were removed from the well and the kickover tool was placed back on the line. The second attempt to remove the gas lift valve was again unsuccessful in latching the top of the valve. The tool was retrieved to surface and inspected without finding evidence of malfunction. Several options were discussed on the direction to proceed; it was decided to return the well to the production configuration and move to the third well. Slickline operations were deployed to pull the protector sleeve. After several unsuccessful attempts at retrieving the sleeve, the consensus was that hydrates had formed in the subsea tree when performing the production log. The tree cap injection (TCI) vent line was opened and methanol treatment initiated from the vessel. Slickline was deployed with the modified GS type pulling tool; after multiple hits with a power jar tool, the protector sleeve appeared to come free. The slickline mandrel was dropped below the subsea intervention lubricator (SIL) in a controlled manner and using the onboard camera of the remotely operated vehicle (ROV), the toolstring was inspected to determine if the protector sleeve was present. The image of the protector sleeve, shown in Fig. 6, indicated that the protector sleeve had separated in half. Once the sleeve was on the surface deck of the vessel, it was determined that the sleeve had unthreaded; a representation of the
lower half that was left in the well is shown in Fig. 7. An internal grab fishing tool would be required to pull the lower half of the protector sleeve. While sourcing this specialty tool, slickline services deployed a memory camera to determine the condition of the subsea tree and the potential fish (stuck object). The results indicated the fish was still present in the wellhead profile that it was set in originally. A brush was run on slickline in an attempt to recover the sleeve, no-go ring and/or remove any potential debris causing the sleeve to remain stuck in the tree. The first attempt with the brush retrieved the no-go ring to surface. A second memory camera run was attempted, but it was unsuccessful following the brush run due to the cloudy de-icing mixture. It was then decided to switch operations back to electric line to run the camera in real-time mode. The camera was deployed a third time, and while viewing the protector sleeve and internal profiles of the wellhead, it was determined that a specialty fishing tool would have to be constructed. Therefore the decision was made to set one of the crown plugs and move to the third well while this tool was being designed and manufactured. Slickline was able to successfully set the TCCP without issue, and the vessel was rigged off.

![Figure 6—Upper half of protector sleeve inspected from the ROV.](image-url)
Upon completion of the well intervention on well C, the vessel and equipment returned to complete the fishing operations. Slickline deployed the memory hydraulic pulling tool to the crown plug, once again gaining access to the wellbore. Following the crown plug removal, the next run with slickline was attempted using the new specialty fishing tool. After 10 jarring attempts, the lower half of the protector sleeve was removed from the wellhead and retrieved to surface. The slickline crew then attached a second type of kickover tool to the line and descended in the wellbore to attempt to remove the gas lift valve that was unable to be latched previously. Several passes were made across the gas lift mandrel, but each attempt failed to engage the gas lift valve. The team decided to leave the ineffective gas lift valve in place and return the well to the production configuration. The THCP and TCCP were set in the subsea tree on successive runs, each being pressure tested to 5,000 psi [34 475 kPa]. The equipment and vessel were rigged off the wellsite and demobilized.

**Well Intervention C**

The objective of the third and final light well intervention required mechanical slickline services only. During the planning phase this well was moved to a top priority well due to a control line leak to the downhole safety valve upper (DHSU) that required the well to be shut in, resulting in lost production. The requirement was to install an isolation sleeve into the DHSU and return the well to production. An additional requirement was to replace the downhole gas lift orifice valve to improve the recovery of formation hydrocarbons. Well C was located in approximately 344 ft [105 m] of water and presented similar operating condition to that in both well A and well B. The tree cap was removed using the remotely operated vehicle (ROV), and slickline was rigged up on the light intervention vessel (LIV). The memory hydraulic pulling tool was deployed to pull the tree cap crown plug (TCCP); two consecutive trips into the subsea tree were made. However, in both attempts, the memory hydraulic pulling tool was unable to retrieve the TCCP. Many crowns plugs are equipped with a backup mechanical method of retrieval that requires the deployment of conventional slickline pulling tools. In this instance, the crown plugs were equipped with two potential latching points or fishing necks. The first step in this mechanical retrieval system recommends the slickline team to run a 4-in. GR type pulling tool through the top of the plug and latching an external fishing neck manufactured at the bottom of the crown plug. This is to ensure there is not any debris or obstructions prior to deploying the 5-in. GS type pulling tool that will engage the...

![Figure 7—Lower half of the protector sleeve temporarily left in the subsea tree.](image-url)
internal upper fishing neck of the retrieval system. The GR type pulling tool was deployed to the subsea tree and successfully passed through the upper fishing profile and latched the lower 4-in. profile. The crew activated the jarring tool several times without success; they were instructed to shear off this lower fishing neck and retrieve the tools to surface. Then they switched tools to a 5-in. GS type pulling tool to engage the upper fishing neck and retrieve the TCCP. After several attempts at retrieving the TCCP, using the GS type pulling tool and power jars, the crown plug came free and was brought to surface. The entire sequence was repeated for the tubing hanger crown plug (THCP), once again requiring the 5-in. GS type pulling tool and power jars to be deployed.

Once the subsea tree had the barriers removed, slickline was used to deploy a protector sleeve simultaneously with the other slickline tools to protect the TCCP and THCP profiles. The protector sleeve was run above the slickline toolstring containing the gauge ring. The sleeve was left in the wellhead profiles while the toolstring continued into wellbore. The bottom of the well was successfully tagged and then the tools were removed from the wellbore. The sleeve was retrieved at the wellhead with the gauge ring toolstring. The crew then prepared to retrieve the ineffective gas lift valve. Due to the lack of success on the previous well with the original kickover tool used, an alternate style of kickover tool was deployed. This kickover tool was rigged up to the slickline and deployed with the protector sleeve. The sleeve was left in the wellhead profile while the kickover toolstring was lowered into the well. The gas lift mandrel was located and the valve fishing neck was engaged with the kickover tool. After initiating the jars several times, the tools pulled free and were retrieved to surface. The crew inspected the kickover pulling tools and observed that the emergency release pins had been sheared causing the tool to release and disengage from the gas lift valve. The kickover tool was repinned and redeployed into the wellbore for a second attempt. Once again, the mandrel was located and the gas lift valve engaged; the crew used the mechanical jars to attempt to remove the gas lift valve. After approximately 100 initiations of the jars, the crew was notified the annular pressure had increased indicating the valve was removed from the mandrel. Once at surface, the gas lift valve was successfully retrieved and present in the catcher of the kickover tool. A new gas lift valve was inserted into the kickover tool, and the slickline team proceeded to install this new valve into the existing mandrel.

The major requirement for this well was to install an isolation sleeve into the DHSU due to an ineffective control line and return this well to production. The isolation sleeve was successfully installed by jarring down on the tools and seating the sleeve into the DHSU seating profile. The sleeve running tools were retrieved to surface and switched over to the crown plug running tools. The THCP was successfully set into the hanger profile and pressure tested to 5,000 psi [34 475 kPa]. The TCCP (upper crown plug) was prepared and deployed to the subsea tree. It was noticed while attempting to set the TCCP that the tree cap injection (TCI) vent line was blocked. The TCCP was set; however, it failed the pressure test to 5,000 psi [34 475 kPa]. The TCCP was eventually retrieved to surface. The decision was made to install the THCP, suspend operations on the well, rig-off the intervention vessel and return at a later date to install a high-pressure tree cap. The high-pressure tree cap has since been installed and well returned to production.

**Conclusion**

Performing work in a subsea wellbore, using openwater light well intervention methods does present several important challenges. This is particularly true when planning and working offshore in eastern Canada where some of the harshest environments exist for offshore operations worldwide. The technologies and processes developed in the North Sea and Gulf of Mexico, as well as choosing the right time of the year (May–September), contributed to successful completion of operations for a operator off the east coast of Canada. These three subsea workovers demonstrate some of the capabilities of completing light well interventions without the requirement to mobilize offshore drilling units.
Slickline services were deployed in all three scenarios to remove the wellhead barriers and ensure the tubing was clear of restrictions. In wells A and B, electric line was used to diagnose the inflow profile, and then, upon interpretation of the data, perform remedial action to improve hydrocarbon production. Slickline services were then used to return the wellbores to production modes, specifically installing the wellhead barriers. The secondary objective in well B, and the primary objective in well C, was to perform a gas lift valve replacement. Although unsuccessful at engaging the gas lift valve in well B, well C was completed as planned. The workovers were completed within the planned timeframe despite encountering some difficult operating conditions where adjustments to the workover programs were necessary. However, the variety of services available using slickline and electric line services and the ability to quickly switch between services when conditions change contribute significantly in the success of light well intervention applications. Lessons learned from the first light well intervention campaign off the east coast of Canada will improve future riserless campaigns not only for this operator, but all those planning work using this method of remedial workovers.

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