Abstract

Liner failure is one of the key risks in operation of SAGD producers and is often associated with erosion as a result of steam production (Burke, L. et al. 2018). Among various intervention methods, tubing deployed inflow control devices (ICDs) have been used to remediate wells. In this paper, two field examples of using tubing ICDs are discussed, one inside a wire wrapped screen liner and the other inside a liner deployed ICD system.

Liner failures were diagnosed by analyzing the temperature data from fibre optics along with the performance indicators of the ESP pumps. Various remediation plans such as patching the failed intervals, using tubing ICDs or drilling a parallel lateral were considered. Using tubing deployed ICD systems along with blanked intervals was selected as the most practical solution to recover productivity from these wells. To size the ICDs and length of segments, a range of emulsion production volumes as well as estimated corresponding vapor and gas volumes were assumed. Furthermore, the risk of creating new hot points near the existing failed points or vapor producing intervals was considered.

The well workovers involved detailed planning of operations and services to effectively achieve cleanouts, maintain adequate inner wellbore diameter to run the swell packers and correlate DTS data with workover findings. The workover involved gauge runs, a jet-vac clean-out, a multi-finger caliper log and mud circulation of the wellbore for final solid removal to ensure successful installation of the new ICD systems.

The wells were put on production initially with low drawdown and slowly ramped up to let the packers set and sand to form bridges. After a few months of production, the wells were fully ramped up with production rate increasing 2 to 5 times the pre-workover rates. ESP pump performances is stable in both wells and the fibre optic temperature data show that failed liner intervals and hot points are well managed.

The intent of this paper is to share the processes and factors considered in using remedial ICDs and the learnings from the workover operations and startup of the wells.
Introduction

Lindbergh SAGD project is located in NE Alberta, 60 km south of the town of Bonnyville as shown in Fig. 1. Lindbergh is the southernmost SAGD project in Alberta. The producing formation in Lindbergh is the Lloydminster formation which is part of the Mannville group of formations with an average thickness of about 18m. The Lloydminster bitumen is lighter than typical McMurray bitumen with API gravity of about 10 and in situ viscosity ranging from 50,000 to 500,000 cP at reservoir conditions.

The project started as a two well pair pilot in 2012. Following the excellent performance of the pilot well pairs, the Phase 1 commercial project was sanctioned and started operating in 2015 with oil production peaking at about 16,500 bopd from 22 well pairs. Phase 1A followed in late 2018 to offset the decline and grow the production to 18,000 bopd with a steam to oil ratio of 2.90.

The standard completion in Lindbergh SAGD injectors has been slotted liners. For producers, wire wrapped screen on perforated joints has been historically used. However, a select number of wells in Phase 1A were completed using nozzle based liner deployed inflow control devices (ICD) based on experience in Lindbergh Phase 1 and the reported successes of ICDs in SAGD applications (Stalder, 2012, Becerra, et al. 2018). In this paper, we discuss using tubing deployed ICD systems to remediate two wells. Well A with an original liner deployed ICD completion (Fig. 2 schematic of well A completion) and well B with an original wire wrapped screen (WWS) completion (Fig. 3 schematic of well B completion). Both wells experienced liner failure within a few months after start-up.

Initial Diagnosis

Well A:
In well A’s original completion, a liner deployed ICD system was used as shown in Fig. 2. The basis of the design was to use tighter nozzles at the heel of the producer to mitigate steam short-circuiting from the heel of the injector to producer. Fig. 4 shows the first 240 days of operating well A. The initial completion
consisted of short and long tubing strings in both wells to circulate steam. Within a few days, 100 T/d of steam was injected into each long string and produced back via the short string at circulation pressure of 4,500 kPa (~1,500 kPa above the formation pressure) to encourage steam leak-off to the formation and enhance heat transfer. After about 60 days of circulation, the circulation pressure of the producer was slowly lowered by 200 kPa to encourage the communication between the injector and producer.

After about 90 days of circulation the producer was worked over to pull the long string and an electric submersible pump was run in hole. Upon inspection of the retrieved long string joints, a washed-out point corresponding to 1037 m MD was discovered (Fig. 4 inset) which was interpreted as a sign of liner failure at this depth. This depth also corresponded to a hot point in the temperature profile during and after completion of the circulation phase. Despite this issue, the pump was run, and the production stage commenced with hopes that reservoir sand may form a bridge at the potential failed interval, and as well, the downhole equipment required to fix the problem would not be available for several months. Upon starting up the pump, it was quickly understood that the liner failure was very serious and that even a small drawdown of the producer (shown in Fig. 4 as the pressure drop across the well pair) resulted in serious vapor production from the well. The drawdown on the well was limited due to inability of the pump to produce the vapour (note this in Fig. 4). The same can be said about the steam injection rate which was limited to the amount of liquid withdrawal from the producer. The temperature profiles (Fig. 5) in the well were also describing significant vapour influx at several points along the well, and combined with the operating conditions of the well, several zones of concern were noted. Fig. 5 illustrates temperature profiles of some key times during the operation of Well A: flowing profiles early after pump startup, after three days of pumping, and just prior to failure. It also shows the static temperature profile prior to remediation of the well.
The initial ESP that was installed following the circulation phase lasted approximately 70 days before mechanical failure due to what was assumed to be solids production at the time. It was decided to run a new ESP system without further intervention to maintain production. An ESP teardown inspection was conducted on the first ESP which confirmed multiple stages were washed out due to heavy solids production from the well. As demonstrated in Fig. 4, oil and steam rates were not ramping up as expected, and drawdown could not be established. Between this and the temperature profiles, we are confident this had caused points of excessive vapour production with high velocity sand to be produced through the ESP. To maintain any stability while pumping, the ESP could not be ramped up as expected to keep within operating metrics (i.e. amp fluctuation, gas locking and underload trips). Despite this after failure of the first ESP, a second pump
was available and installed which lasted approximately 40 days before a similar failure due to heavy solids production. At this point the decision was made to leave the well down and prepare for a remedial workover to address the failure of the liner.

**Well B:**
The well B completion is a liner with WWS and no flow control, as shown in Fig. 3. Steam circulation configuration was very similar to that of well A, except that the circulation pressure was done at 4,000 kPa (about 1,000 kPa above the formation pressure). Fig. 6 shows the first 18 months of well B operation. After about 90 days of circulation the producer was worked over to pull the long string and run an electric submersible pump. A scab liner was run with TD of about 80% into the lateral section with two perforated subs to provide even drawdown. No sign of wear was encountered in the tubulars. The initial ramp up of the injection and production was within the expected range.

![Figure 6—Rates and drawdown of well B prior to remediation](image)

After about four months of pumping, the well developed a hot point at the toe leading to an eventual pump failure at the 5th month of pumping operation. Fig. 7 illustrates temperature profiles of some key times during the operation of well B. Note in Fig. 7 that the hot point in the well while flowing is often at the end of the scab liner at 1616 m MD and during the fall off at 1590 m MD. Hence the likely point of vapor influx is somewhere between these two depths. It is common for the hot point to move due to static vs. flowing conditions, so both are always considered for evaluation of vapour influx. Also note that the scab liner has prevented the hot spot that would be likely at the heel (based on the post circulation fall off) but has resulted in a hot spot near the toe inlet.

During operation of the first ESP, approximately 4-5 months after install, two back-to-back coil cleanouts were conducted inside the ESP tubing string. This type of plugging and required workover was a first of its kind in the Lindbergh field. Both plugging events followed pump shut-down events which allowed suspended solids to settle in the tubing above the pump and solidify to a point of fully plugging the string. Coil tubing was required to break the sand plug free and circulate out what solids could be brought to surface to allow the ESP to restart successfully. It was at this point, combined with the temperature profiles that
we were able to diagnose the breakthrough at the toe of the well and assume likely all solids production was from this single failure point. Interestingly we were able to see the exact point of liner failure and sand volume travelling down the lateral section towards the pump from fiber optic temperature measurements. Shortly after the plugging events, the fiber optic coil tubing was breached at the toe. Once pulled from the well and confirmed, this also backed up the conclusion of a liner breach in that section of well at depth of about 1590m MD near the peak temperature on Fig. 7. Similar operating characteristics to that of well A after the breach were encountered. The inability to ramp-up the well due to high vapour production from the toe section meant the well pair was producing considerably less than typical offsets. For reasons similar to the previous well (amp fluctuation, gas locking and underload trips), the ESP was slowed down considerably to maintain some level of production while producing maximum vapour. The first ESP failure in this well was encountered approximately 200 days after the pump start-up and was deemed an electrical failure at the time. Upon inspection, it was also deemed very close to mechanically failed as stages were heavily washed out. A second ESP was run to once again maintain production at a very low speed, until the equipment required for remedial workover could be built and run. This ESP was able to run until proactively pulled on day 440 to install the partial ICD system.

**Figure 7—Temperature along the horizontal section of well B**

**Evaluating Repair Options & ICD Design**

**Well A:**

Well A was considered to have several points of likely failure in an existing ICD liner. Due to the widespread locations of the hotspots and the early point in the well life, a secondary full-length ICD string was installed to recover inflow, with several blank sections as shown in Fig. 8. These blank sections were determined based on the DTS information and intended to limit inflow from the four sections of the well where inflow of the steam was most apparent. As the well was already comprised of ICDs creating variable pressure drop in some portions of the lateral, a design was required that would find some balance of not adding significantly more pressure drop, while limiting steam and gas to an extent that prevented further failure points. Uncertainty related to the function of the remaining ICDs (Dragani et al. 2017) and the fact that the liner ICD design directed the flow radially into the liner, raised serious erosion concerns that was factored
into the design. In the end, the secondary tubing ICD string was designed to limit large amounts of steam, recognizing a balance between limiting overall ability to drawdown the well (two significant ICD pressure drops in the system), and the ability to restrict steam and prevent erosional jetting of the tubing. It was debated whether the original liner should be perforated to avoid excessive pressure drop, but the final decision was to keep the original liner as is to maintain the base level of sand control.

Once blanked sections were determined, a pressure drop design was developed considering overall rates from the well and expected gas inflow rates. This design was based on providing an additional 100 kPa of pressure drop on average, while utilizing overall mass rate expected per device as a proxy for providing risk-based backpressure to zones which were either adjacent to the failure point or significantly hotter than others during the producing history. This resulted in a design with four blank sections (as depicted by example in Fig. 8), 22 ICDs, and 24 swell packers. Further detail in device location and count is provided in Fig. 12. Packer spacing and device density were used as the primary method for driving more or less liquids through a device, and therefore limiting gas or steam content based on a planned drawdown pressure and assumed hydraulic pressure loss along the new 4.5" completion. Swell packers were used to create isolation between sections. Each ICD joint was also comprised of five meters of WWS to provide an additional layer of sand control in case the primary screen was compromised.

Well B:
The well B failure point was near the toe of the well near the end of the tail pipe which was determined based on the DTS profile. Three options were considered:

- Blanking a significant portion of the toe (50m on each side of the failure point)
- Running a partial ICD string to manage inflow at the toe section
- Running a complete ICD string to manage current failure and further hot spots likely to develop

As this well was not an ICD liner with limited drawdown expected to flow, the approach was to shut in the failure point but still permit inflow through the toe section of the well. Anecdotal industry results related to blanking well sections near hot spots or failure points raised concern that the hotspot would simply migrate over the blanked section, limiting the effectiveness of the first approach quickly. Considering the prior performance of the well it was decided that running a relatively unrestrictive ICD design would be of value to recover some fluids from the toe, limit the risk of further breakthrough, and reduce the cost and risk of running a full ICD string. A 275 m long ICD string was designed to cover the expected failure point with a blank section from 1570 m to 1610 m, with several sections of ICDs on either side as illustrated in Fig. 9. The ICDs were sized based on a liquids rate of 15 m³/day CWE, and a gas content of ~1500 m³/day per interval. This resulted in a design which required two 7 mm orifices per device, creating an estimated pressure drop of 45 kPa. The low pressure design points were selected based on the consideration that the
devices would have little effective pressure drop when flowing liquids, allowing some inflow from this zone despite a significant portion of the well not having any ICDs. Meanwhile if steam and gases were to enter the well the device would begin to restrict those zones and prevent further failure of the primary screen. Each of the ICDs in the remedial completion were designed with 5m of wire wrapped screen to ensure sand control in the case that the primary sand control was compromised.

Workover Operations

The historical operational information indicated that the ESP failures were direct result of liner failures. Hence, the focus of the workover operation was to clean out solids and prevent further influx. The workover operations had to be strategic and de-risked to effectively accomplish the cleanouts, maintain adequate inner diameter of the wellbore for the new swell packer installations, and correlate the DTS data with workover findings.

For well A, analysis of the intermediate casing section was done by running a casing scraper and multi-finger caliper (MFC) log to ensure integrity and confirm lateral section repair limits. After this, a concentric coil tubing with a "jet-vac" was run to clean out the solids, while monitoring under and over-balanced and hydrostatic wellbore conditions. This cleanout system had previously been deployed successfully in SAGD horizontal wells in Lindbergh and elsewhere and proved to be very efficient (Winkler et al., 2018). Next, the status of wellbore lateral inner diameter was determined which showed remaining sand accumulation and highlighted primary failure points of the liner ICD with a recorded MFC log (ran on the concentric coil). Afterwards, a gauge mill run was performed with a downhole mud motor (also ran on the concentric coil string) to confirm the MFC log findings and ensure drift to de-risk the ICD and swell packer installs. Full polymer mud system was circulated in the wellbore to ensure removal of solids, adequate hydrostatic to prevent influx, and a reduction of wellbore friction. These workover operations led to the successful installation of the new ICD system.

Our opinion is that using multi finger caliper (MFC) logs along with DTS temperature data and the original as-run completion profile was likely the most important step in diagnosis of liner failure. This learning was used to place the packers and blank sections. Some examples for interpretation of MFC log are described below and illustrated in Fig. 10. One can typically see caliper trend from collar responses. The location of the ICD nozzles in between the collars can also be detected. At certain intervals where
the temperature profile had indicated potential problems, the MFC traces appeared to show questionable abnormalities. Sand accumulations are easy to detect as they typically impact a group of arms on one side of the log. Stuck caliper arms can also be easily isolated.

Figure 10—Select Multi Finger Caliper (MFC) log examples from well A
For well B, analysis of the intermediate section was performed followed by running concentric coil tubing to clean out the solids. However, the MFC log was not run. Due to well B’s completion, it was necessary to remove the scab liner system. It was decided to perform three independent magnet runs to capture any downhole milling and damage debris, followed by the gauge mill run to ensure full drift. Once again, all runs were performed utilizing the same concentric coil rig. Afterwards, the wellbore was circulated with a full polymer mud system leading to successful installation of the new ICD system.

**Results**

Both wells have demonstrated a strong production enhancement following the described workovers. The pre and post workover oil production are presented in Fig. 11.

![Figure 11—Production before and after remediation of both wells with tubing deployed ICD completions](image)

**Well A:**

This well has successfully ramped up to 120 m³/day of oil with an SOR of 2.10. The steam injection and emulsion production were intentionally ramped up slowly to allow the packers to set and reservoir sand to bridge around the new flow paths. Despite the concerns that the added pressure drop would limit inflow, the well operation is excellent. The current drawdown is high (800-1000 kPa) but does not seem to be limiting rate or causing excessive water condensate flashing. Based on current temperature profiles, the well is producing live steam throughout, but this is not impacting pump performance.

The temperature profile in Fig. 12 shows that the three zones of concern from Fig. 5 have been tempered by the remedial completion, as they do not show peaks at these points. In fact, the falloff temperature information shows that the 4 zones that were eventually blanked, have lower overall temperatures than the nearby zones. This suggests the design rates were well estimated, and the packers are providing isolation. Also note the toe of the well has eventually heated, which was not the trend prior to remediation. This reassures the authors to believe the ICDs are functioning as intended, providing restriction to zones with higher vapour fractions. The added drawdown has helped steam chamber development at the toe, which was initially not flowing despite multiple steam cycles.
Well B:
This well has successfully ramped up to above 120 m3/day of oil with an SOR of about 2.20. The drawdown of the well is very reasonable (~150 kPa). The pre and post workover temperature profiles in Fig. 13 show that the failed liner point is successfully remediated. The recent temperature profiles show that the heel of the well is getting warmed up and it could eventually become the new limiting factor in the well operation. Looking back, it is realized that although a partial ICD system is cheaper and easier to run, it is more beneficial to run a complete ICD string with high pressure drop design to avoid the need for future workovers. Furthermore, the toe has cooled somewhat, and it is hard to say if inflow has been limited there. Recognizing this, the lesson learned is that we would look to installing a full ICD string in this well if the opportunity presents itself again, where further drawdown would be expected to improve productivity. That said the recompletion did successfully manage the high temperature influx at the toe and has allowed for inflow where a simple patch (blanked section) may have resulted in the problem migrating around the failure point and causing further issues.
Summary and Conclusions

In this article, the successful workover of two SAGD producers with tubing deployed ICD system were described. In well A, a new full-length ICD string was run inside a liner ICD system that had experienced failure. This is a risky operation as the presence of multiple packers and tubulars means there is only one chance of fixing the well. Furthermore, potential jetting from pre-existing ICDs was a concern.

Although the total pressure drop across two layers of ICDs is high, this has not caused any operational issues or excessive steam condensate flashing, i.e. as long as there is liquid to be produced, flashing is not a major concern.

The root cause of liner failure in well A is unknown, but overlaying the results of MFC log, fiber optics temperature data and the as-run tally, suggested that the main suspect is the weld between the ICD housing and the base pipe. Using the MFC log was very useful and is recommended for similar failure scenarios. Furthermore, using the "jet-vac" system to clean out the wellbore was deemed a success and is recommended in similar situations.

Before the workover, one of the outstanding questions was whether the nozzles of the original ICDs were plugged and if perforation of the base pipe was needed. After much deliberation and flow testing, it was deemed that the risk of perforating the original liner (i.e. losing the base line sand control even though it may have multiple failure interval) is much higher than that of potential plugging of nozzles. Post workover results proved that the decision was correct for this well.

Another learning was that a one-foot packers do provide sufficient isolation between the segments. That said, double packers were used around the failed intervals of the liner.

The workover of well B is also deemed successful. In hindsight, one major learning from pre and post workover temperature data was that it is preferred to run a full-length ICD system with a higher pressure drop design to ensure desired conformance for the life of the well. The additional cost of the downhole equipment is a fraction of the cost of a full workover program.

Overall, deploying tubing ICD systems to fix wellbores, in our opinion is a better option than drilling sidetrack laterals. The cost of sidetracking could be twice as much as deploying a tubing deployed ICD system.

In general, our ICD deployments have been successful, and through the remediation of these wells we recognize that there may be gaps in design that should be addressed for SAGD wells. For the remediation we chose devices designed specifically for SAGD applications, and although this was a unique challenge, the approach to design has been met with success so far.

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