ENHANCED GRAVITY DRAINAGE INSTRUMENTATION

AI 2458

Public Final Report

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EXECUTIVE SUMMARY

In this project, Imperial tested the deployment of advanced down-hole instrumentation to enhance the bottom-hole surveillance of Gravity Drainage processes (e.g. Steam Assisted Gravity Drainage (SAGD)). The advanced down-hole instrumentation included digital temperature sensor (DTS) by fiber optics and high pressure-high temperature pressure and temperature sensors. These instruments were installed in the horizontal producer well of one of the Cold Lake Pad T13 well-pairs.

The enhanced surveillance was expected to enable estimation of liquid level above the well and result in prevention of un-used steam bypass from injector well to producer well. Thus, it has the potential to lead to reduction in steam to oil ratio (SOR) and the associated GHG emissions and water use per barrel of the produced bitumen. In addition, it may provide an alternative to use of seismic surveys to map the extent of steam chamber resulting in reduction in land use and disturbance.

The project is now completed. The advanced down-hole instrumentation were procured and delivered to Imperial and were successfully deployed and installed in one of the production wells of Pad T13. The surface data acquisition systems for the set of the instrumentation were also installed and commissioned. Following a number of remedial actions, the high quality data was collected and analyzed to evaluate the surveillance workflows.

In this field trial, it was shown that the deployed ERD™ sensors can provide reliable pressure measurements in high pressure and high temperature operating conditions of SAGD for surveillance of injection and production wells. However, due to multiple factors of uncertainties, the workflow to estimate liquid level along the horizontal well using pressure measurements was found not viable for field application. The assessment of the Pressure Transient Analysis (PTA) workflow on the extended shut-in data collected in this project is inconclusive. The results of this project and the subsequent recommendations can be used to design a conclusive trial of PTA workflow for distributed chamber volumes estimation in future.

1. INTRODUCTION

1.1 Sector Introduction

The petroleum industry is one of the major contributors to the economic activity in Alberta and Canada. The upstream petroleum industry activities in Alberta are focused on hydrocarbon recovery from oilsands deposits either at surface by mining or from in-situ reservoirs. SAGD and other gravity drainage thermal recovery processes are proven technologies to access the in-situ deposits and mobilize and produce bitumen. The upstream petroleum industry in Alberta is thrived by continuing innovation to reduce GHG emissions, water usage and land footprints associated by their activities.

1.2 Technology Gaps

The efficient operation of injector and producer wells in a gravity drainage thermal recovery process (i.e. SAGD, SA-SAGD) will result in maximizing bitumen production rate and reduction of the steam use per barrel of the produced bitumen. It strongly depends on the extent of the steam chamber conformance along the injector and the magnitude of the condensed steam and bitumen build up above the production well. A uniform and well developed steam chamber along the injector well ensures the greatest well utilization and resource access. The optimum liquid build up along the horizontal well will ensure minimum steam by-pass from the injector to the producer well while not impairing the bitumen production rate. The technology gaps in the area are identified as below:

1.2.1 Liquid Level Estimation and Control

Currently, there is no direct method to measure and respond to changes in liquid level in order to mitigate the negative impacts of and the risks associated with the steam by-pass. The current industry best-practice is to minimize direct steam production by measurement and control of the production temperature (subcool). Several methodologies were developed to relate the subcool to an average liquid level above producer well and to optimize its value. The latter studies recommend subcool values in the range of 3-40 °C with the evidence of the requirement of specific optimal subcool for any given well varying over time. Low subcool, or alternatively low liquid level, can result in potential direct steam production with a significantly higher velocity through the completion than water or bitumen leading to tubing erosion, sand production, and failure of the pump and production facilities. Additionally, the bypassed steam from the injector to the producer is not available to assist in reduction of the bitumen viscosity resulting in lower efficiency and higher steam to oil ratios (SORs). The current state of the industry requires development of workflow to measure the liquid level above the producer along the

horizontal well in real-time. This will give the operator the opportunity to utilize operation strategies to manage and control the liquid level to optimize well performance.

1.2.2 Steam Chamber Conformance

Current industry methodology to assess the steam chamber conformance is by the analysis of periodic 4D seismic survey data. These surveys are costly, require substantial land disturbance and have significant turn-around time from acquisition to analysis and conclusion. The industry is yet to develop a real-time low-cost method to determine the steam chamber volume and conformance. Development of the real-time method will enable rapid adjustment of steam strategies, targeting SOR optimization assisting in maximizing oil production. In addition, the real-time method can potentially decrease the number of 4D seismic survey executions reducing land use and disturbance associated with such surveys.

2. PROJECT DESCRIPTION

2.1 Technology Description

This project intends to capitalize on the capabilities of commercially available enhanced down-hole instrumentations in order to develop robust operation optimization workflows and control solutions. The proposed instruments include distributed temperature sensing fiber optic (DTS) with addition of distributed pressure/temperature sensors. The latter enables the potential to optimize bitumen production through efficient reservoir monitoring and innovative workflows for direct liquid level measurement and control. This field trial will determine if distributed chamber volume determination and direct liquid level control workflows are feasible for use in a commercial application. The description of the studied workflows are as follows:

2.1.1 Liquid Level Estimation and Control

The detailed description of the studied workflow for Liquid Level Estimation and Control is provided in Canadian patent 3020827 with the title of “SYSTEMS AND METHODS FOR ESTIMATING AND CONTROLLING LIQUID LEVEL USING PERIODIC SHUT-INS”.

In general, the developed workflow is based on the pressure and temperature measurements collected during shut-in and flowing periods of the producer well. The liquid level above the producer at any given point during the shut-in is related to the pressure difference between shut-in pressure at that point and the chamber pressure utilizing the following equation:

$$LL_{test} := \frac{\left(P_{prod\_test} - P_{inj\_test}\right)}{\rho_L \cdot g}$$

2.1.2 Steam Chamber Conformance

The detailed description of the studied workflow for Steam Chamber Conformance is provided in Canadian patent 3038186 with the title of "SYSTEM TO ESTIMATE CHAMBER CONFORMANCE IN A THERMAL GRAVITY DRAINAGE PROCESS USING PRESSURE TRANSIENT ANALYSIS". The theoretical basis of the Pressure Transient Analysis (PTA) for steam chamber conformance monitoring was also discussed by Zamani at al. (SPE 165489).

In this project, Pressure Transient Analysis (PTA) is used to evaluate the steam chamber conformance and its fractional volume distribution along the horizontal well using the distributed pressure measurement data collected by the deployed downhole gauges. The PTA analysis relates the pressure decline characteristics at any given measurement point to the extent and size of the connected steam chamber. The results of the PTA analysis is validated against the result of a 4D seismic survey conducted on the studied SAGD pad at a similar time as the trial.

2.2 Performance Metrics

The project performance metrics and objectives are defined as:

1) demonstrate estimation of liquid level above the producer well within the reservoir using improved downhole instrumentation during shut-in and flowing conditions;
2) demonstrate estimation of distributed steam chamber volume using improved downhole instrumentation;
3) demonstrate the ability to deliberately vary liquid level along horizontal well with operation feedbacks;
4) demonstrate the feasibility to relate and predict the steam coning event to measured liquid level.

3. METHODOLOGY

In this project, a new instrumentation package including 10 pressure transducers and one fiber optic DTS string was deployed in horizontal producer well T13-01 of the pad T13 of Imperial's Cold Lake operations, Figure 1. The instrumentation package was deployed

utilizing a 1.5” coiled tube string. This installation required the removal of the existing instrumentation string and the replacement by the new instrumentation. Table 1 list the scope and the detail of the instrumentation package. The data collected from these tools included pressure and temperature data by ERD^{TM} sensors and distributed temperature by DTS. Table 2 list the nominal deployment depth of the ERD^{TM} sensors in the well. ERD_3 and ERD_4 are located at around the nominal depth of the pump and heel of the well, respectively. ERD_10 is the closest pressure measurement location to the toe.

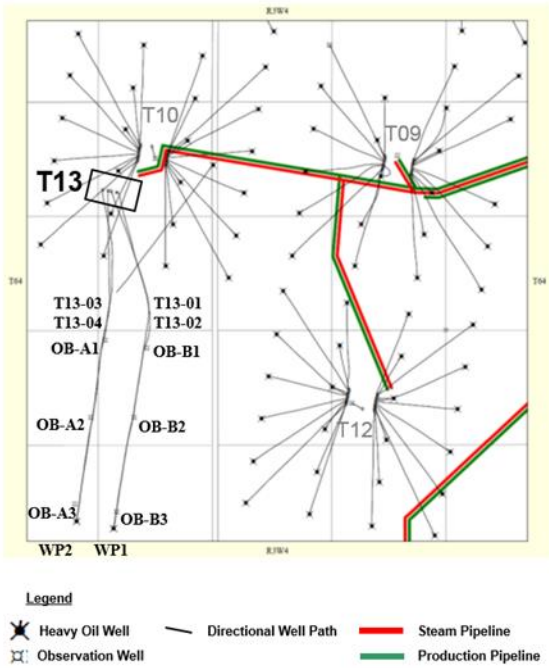

Figure 1: T13 Pad Location in Cold Lake Operations.

Table 1: Scope and Detail of the Enhanced Instrumentation Package.

Existing Instrumentation	Enhanced Instrumentation
3 bubble tubes	10 Promore ERD^{TM} Sensors-Temperature and Pressure
20 thermocouples	Distributed Temperature Sensing (DTS) fiber

Table 2: Nominal deployment depth of the Pressure Sensors in the Well.

Pressure Sensor	Nominal Depth-MD (mKB)
ERD_1	486
ERD_2	593
ERD_3	684

ERD_4	831
ERD_5	941
ERD_6	1051
ERD_7	1161
ERD_8	1271
ERD_9	1381
ERD_10	1489

A number of shut-in trials were planned and executed during this project to collect the required data for the analysis and the assessment of the workflows. In addition, a 3D seismic survey was conducted during the project period to provide the reference chamber volume distribution for comparison with the PTA analysis outcomes. The cost, schedule, and the detailed results of the seismic survey were out of the scope of this project.

4. PROJECT RESULTS

The project progress and results according to the project milestone tasks specifications are as follows:

4.1 Task 1–4; Procure Equipment, Execute Workover, Surface Tie-Ins

The procurement of the equipment and instrumentation was completed by Q3 of 2018 following the receipt of funding and execution of the AI agreement in Q1 of 2018. Promore was contracted to fabricate a 1.5” instrumentation coiled tube string to include 10 pressure and temperature transducers and one capillary tube to host fiber optic string. Baker Hughes supplied the fiber optic string capable of supporting both a DTS and a DAS interrogators.

The workover was successfully executed in December 2018 to land the instrumentation coiled tubing (CT) at the final design landing depth of 1489 mD KB. Consequently, the optical fiber was successfully pumped through the capillary tube within the CT in January 2019 enabling the distributed temperature sensing (DTS) capabilities.

Instrumentation and controls engineering work was completed by issuance of IFC drawings for the instrumentation surface tie-ins. In January 2019, the surface DTS interrogator was installed and connected to the optical fiber. The pressure surface instrumentation data acquisition and DTS interrogator were connected to the computer on the pad enabling real-time data collection and transfer to Imperial’s central data management system. The integrity readings of the sensors confirmed their functionality.

4.2 Task 5–6; Data Collection and Performance Monitoring

The post-installation system checks confirmed the installed instruments provide repeatable, unique and distinct measurement values during shut-in and production periods and the data integrity is preserved during the transfer to and storage on the data management system.

4.2.1 Calibration of ERD Sensors

During task 5, the reliability of the pressure measurements by pressure sensors were found uncertain due to observed non-physical trends. In addition, a noticeable mismatch between temperature measurements by ERD sensors and the DTS fiber measurements at the corresponding depth were flagged for further examination. Several working meetings were held with the technical experts of the instrumentation vendors to investigate the sources of the uncertainties. The common uncertainties in the CT built depths and the well directional survey, and the temperature-pressure calibration dependencies were found as the sources of the uncertainties in ERD pressure measurements beyond the nominal accuracy of the measurements (<5 kPa) at the calibration conditions.

The accuracy of the installed ERD measurements were deemed to be within ±25 kPa of the actual values by the ERD vendor. The shallowest ERD sensor was deemed faulty. This magnitude of the uncertainty on the pressure measurements (±25 kPa) results in up to ~ ±2.5 m uncertainty on the estimate liquid level values. Given the 5 metre vertical distance between the injector and producer wells, the magnitude of these uncertainties are beyond the acceptable ranges for the feasibility of the Liquid Level workflow. The acceptable range of the uncertainties in pressure measurements for the liquid level workflow is ±5 kPa resulting in ~ ±0.5 m uncertainty on the estimated liquid level above the well. As a remedial action, a methodology was developed to correct ERD pressure data to account for the uncertainties in well direction survey, ERD placement, and ERD accuracy. The proposed adjustment does not affect the implementation of the distributed chamber volume estimation workflow by PTA analysis. However, it limits the application of the Liquid Level estimation workflow to a relative basis with respect to a hypothetical reference depth of the heel. Hence, the estimated liquid level along the horizontal well is not measured from the actual trajectory of the well.

4.2.2 Remedial Actions

The initial analysis of the collected shut-in data indicated the potential negative effects of the severe scale buildup in and around the completions of the production well on the data quality. It was noted the time to pressure build-up post shut-in is in the order of days which limited the opportunity to collect the early time pressure response data. In addition, the

significant pressure difference between flowing BHP and the chamber pressure caused noticeable after-flow and potential cross-flows due to skin on producer well. The post shut-in flow in general limited the viability of the liquid level workflow to correctly estimate the liquid level along the well with respect to a hypothetical reference depth of the heel.

As a remedial action, an acid stimulation was planned, scheduled and successfully executed in Q4 of 2019. The early observations indicated considerable removal of the scale build-up and reduction of the skin around the well. Hence, the differential pressure between the bottom hole of the production well and the steam chamber was considerably lower than the period before the acid stimulation. In addition, the time required to pressure built-up after production well shut-in was in the order of few hours. All these positive changes due to the remedial action resulted in the much higher quality of the shut-in pressure data collected by the enhanced instrumentation for both Liquid Level and PTA workflows.

Following the acid stimulation, the production rates were maximized to produce off the built up liquid in the reservoir in and around the wellbore due to poor productivity of the well prior to the acid stimulation. The experienced low production temperature and high water cut post acid stimulation for a prolonged period of time were indicative of the built-up liquid removal. Hence, the trial of the workflow and collection of shut-in data were suspended to ensure the built up liquid does not affect the learnings from the trial. Based on deteriorating performance data, the decision was made to execute a pump change on this well in Feb 2020. The latter resulted in satisfactory recovery of the production temperature.

4.2.3 Shut-in Trials and Data Collection

Upon satisfactory recovery of the production temperature, a short (8 hour) simultaneous production and injection shut-in was planned and executed on April 7 on wellpair 1 of T13 pad. The short shut-in was intended to provide the opportunity for data collection for Liquid Level workflow. The following data analysis showed the duration of the shut-in was not sufficient to eliminate the after-flow effects. Hence, another shut-in was planned for execution on April 19, 2020. The duration of this shut-in was selected as minimum of 24 hrs to ensure the collected data by the enhanced instrumentation is suitable for both Liquid Level and PTA analysis workflows. The subsequent analysis confirmed the approach; therefore, all the following shut-in trials were conducted for a minimum of 24 hrs as listed in Table 3. Total of 5 shut-in trials were executed in this project post acid stimulation, and the data collected in 4 of them were used for Liquid Level and PTA analysis workflow validation. The shut-in trials were planned and executed over a 4 month period to evaluate if the operation strategy of maximum pump rate is affecting the

estimated liquid level above the well. The highest level of execution excellence was maintained in these shut-in trials to ensure:

1) steady state operation of both injection well and production well with minimum interruption and change in advance of the shut-in trial to limit superposition effects;
2) simultaneous shut-in of both injection and production wells.

For each shut-in trial, the injector well was purged immediately after shut-in and after 8 and 24 hrs to ensure the measured wellhead injector casing pressure is not affected by condensate build up.

Table 3: List of Shut-in Trials Executed in T13 after Acid Stimulation.

Date	Duration	Pressure Build-up	Data Used for Validation
April 7, 2021	8 hrs	50 kPa	No
April 19, 2021	24 hrs	50 kPa	Yes
May 19, 2021	24 hrs	200 kPa	Yes
June 7, 2021	24 hrs	350 kPa	Yes
July 6, 2021	24 hrs	600 kPa	Yes

4.3 Task 7–8; Post Steam 3D Seismic Survey and Processing

Post steam 3D seismic survey was shot on January 20, 2020. The field preparation was conducted in Q4 of 2019. The exact timing of the survey was planned to ensure the chamber pressure is at target pressure of 3.5 MPa following multiple months of pressure ramp up. This assured the data is collected at the highest possible quality and is comparable to the prior surveys in T13 pad for time-lapse analysis and 4D survey interpretation.

The processing of 2020 3D seismic survey raw data was conducted by a third party service provider. To ensure the consistency with the base line, the 2008 pre-steam 3D seismic survey raw data were also reprocessed by the same vendor. Imperial's subject matter experts oversaw the processing activities, reviewed the progress and provided feedback to ensure the results meet the corporate best practices.

The processed 3D seismic survey results were interpreted by Imperial's own petro-physicists and geoscientists to create 4D time-lapse seismic image of the developed steam chamber and the depletion footprints. All auxiliary data such as observation temperature logs and the results of RST logging in 4 out of 6 observation wells collected in March 2020 were utilized to assist in the interpretation of the results.

Post Steam 3D seismic survey is the reference pad-level surveillance activity to map the extent of the steam chamber development, depletion patterns and the conformance along the well. The result of this survey, interpretation and the time-lapse analysis is utilized as the reference for PTA workflow validation. Figure 2 demonstrates the 3D view of the chamber volume along the horizontal wells of pad T13. Post Steam 3D seismic survey data confirm the complete chamber development along the well with a close-to-uniform chamber volume distribution.

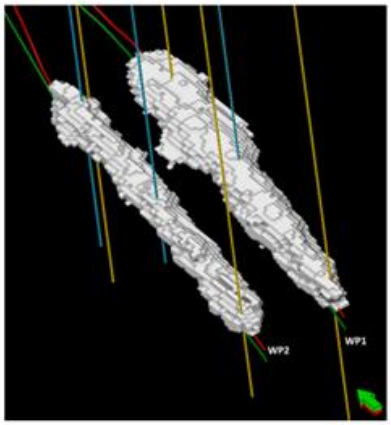

Figure 2: Seismic Geo-bodies Demonstrating the Potential Affected Area by the SAGD Process

4.4 Task 9; PTA Tuning and Validation

The results of the 4D time-lapse seismic interpretation were used to extract the 3D geo-bodies of areas affected by the process. In principal, the shape, size and extent of these geo-bodies represent the effect of the steam injection on the surrounding area and is directly related to vapor saturation, temperature and pressure. The geo-bodies show the extent of vapor/steam chamber, depletion patterns and the conformance along the well. Figure 3 shows the distributed chamber volume fraction along the well based on the seismic data. Each color in the footprint map indicates the volume corresponding to each ERD sensor location. The promise of the PTA analysis workflow is to provide the same level of information without need to acquire the 3D seismic survey.

The PTA analysis workflow were applied on the data collected by the enhanced instrumentation during 4 shut-ins as listed in Table 3. The results were used to create the projected steam/vapor chamber volume distribution along the well. The volume distributions were normalized over the total steam chamber volume and were compared to each to evaluate the repeatability of the PTA analysis results. They also evaluated against volumes distribution from 4D time-lapse seismic geo-bodies for validation.

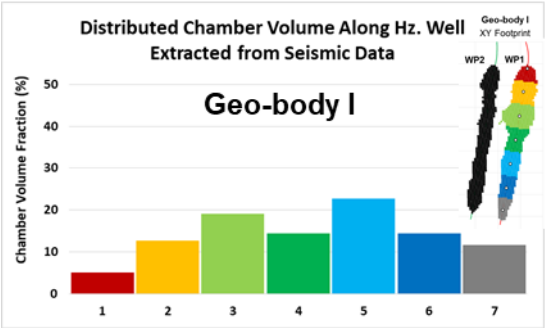

Figure 3: Chamber Volume Distribution along the Well from Seismic Geo-bodies Interpretation.

Figure 4 demonstrates the results of the PTA analysis on the post-acid stimulation shut-in data to estimate the disturbed chamber volume along the horizontal well. For comparison, the estimated chamber volume by 4D seismic survey interpretation is included in the plots as well. PTA results from April and May 2020 indicates insignificant variation in chamber volume along the well. The PTA analysis on June and July shut-in data indicates characteristic chamber volume distribution along the horizontal well. However, the volume distribution is not consistent in these two trials. This variation in the estimated chamber volume distribution in the latter two trials is potentially due to the inherent levels of the uncertainty in this analysis. Overall, none of the estimated chamber volume distributions with PTA analysis is in general agreement with the estimated chamber volume by 4D seismic survey interpretation as shown in Figure 4.

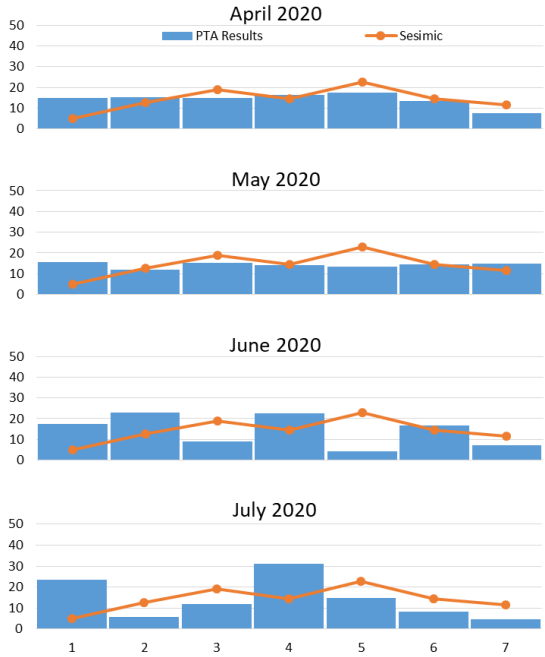

Figure 4: Distribution of Chamber Vol. along Hz. Well by PTA Analysis on Post-Acid Stimulation Shut-in Data.

Figure 5 compares the average estimated chamber volume distribution by PTA analysis from 4 shut-in trials. Each estimated average chamber volume is shown with uncertainty bars indicating the standard deviation in chamber volume fraction at given location along the well. By comparison, the average chamber volume distribution from PTA analysis is in general agreement (within the uncertainty bars) with the estimated chamber volume by 4D seismic survey interpretation as the reference. The only exception is at the heel. However, one can deduce the agreement between the distributed chamber volumes by seismic and PTA analyses is not significantly better than the assumption of the uniform chamber development along the well and the seismic results.

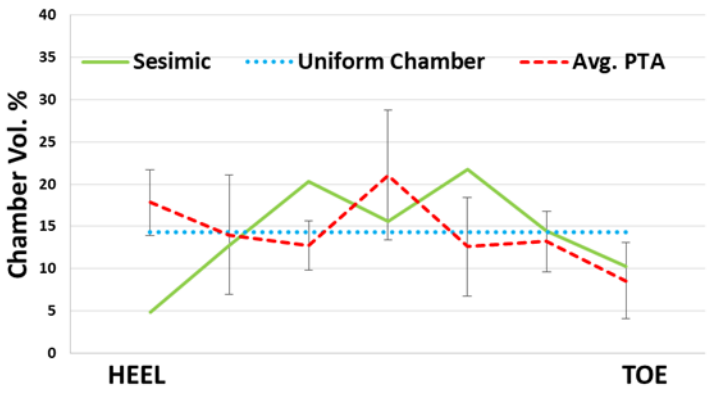

Figure 5: Average Chamber Volume Distribution by PTA Analysis in Comparison to Seismic and Uniform Chamber Assumption.

Given the close to 100% chamber conformance along the trial well by the seismic data, the results of trial of distributed chamber volume by PTA workflow in T13 is deemed inconclusive.

4.5 Task 10; Liquid Level Validation

The Liquid-Level Estimation workflow were applied on the data collected by the enhanced instrumentation during 4 shut-ins as in Table 3. The output of the workflow is the distribution of the liquid level along and above the well and inside the reservoir. This information may help to indicate the high and low productivity zones and the potential for steam coning. In this task, the effect of operating strategies on the liquid level distribution were also evaluated based on the established trends over the 4 month period covering 4 shut-in trials.

Figure 6 demonstrates the estimated apparent liquid level along the horizontal well based on 4 post-acid stimulation shut-in trials with respect to hypothetical reference hydrostatic depth of the heel. The pressure data after 12hrs of shut-in time is used for the analysis as described in the previous section. As shown in Figure 6, the apparent estimated liquid level with respect to hypothetical reference hydrostatic depth of the heel is monastically

decreasing from Toe to Heel. This observation is in agreement with the expected direction of flow and the dynamic pressure gradient along the well from Toe to Heel. However, it does not provide any valuable insight on how the fluid level is potentially distributed with respect to the well trajectory. The liquid level with respect to the official well trajectory indicates insignificant variation along the well with a local minimum around ERD_8 as shown on Figure 7. Both demonstrations show considerable decrease of the liquid level along the well from April to July shut-ins is in agreement with the overall expectation of the well operation strategy.

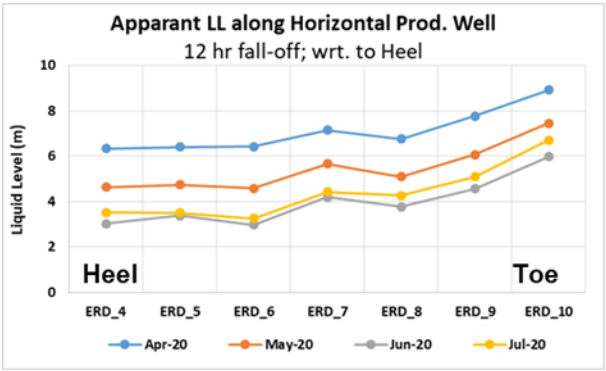

Figure 6: Estimated Liquid Level with respect to Hypothetical Reference Hydrostatic Depth of Heel.

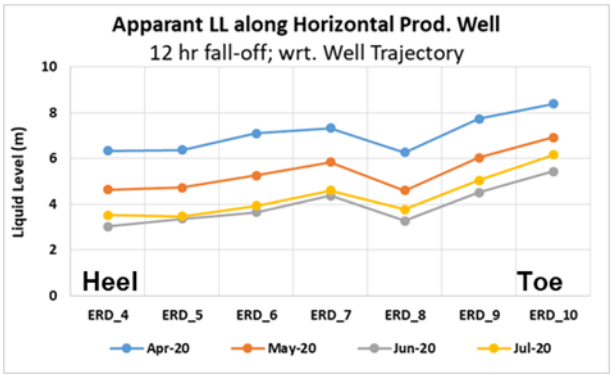

Figure 7: Estimated Liquid Level with respect to Official Well Trajectory.

It must be noted that the uncertainty on the estimated liquid levels with respect to the well trajectory can be as high as 2.5 m due to uncertainties in sensor accuracy and well-trajectory. Hence, the variation in the liquid level along the well (~2m) is comparable to the uncertainties of the measurement.

5. KEY LEARNINGS

The following is a list and description of several major learnings obtained during this project with implications for one or both of the studied workflows.

5.1 Uncertainties in Well Directional Survey and Sensor Placement

Uncertainties on the horizontal well directional survey are in the order ~1 metre. It is generally believed that the absolute well surveys of the horizontal wells are good to within a few metres of the reports; however, the relative positioning of the injector and producer well has lower uncertainties. In addition, the troubleshooting of ERD sensors measurements also led in the revelation of the uncertainties in the final landing depth of the instrumentation coil tubing and the relative placement of the ERD sensor on the CT.

The uncertainties in the absolute directional survey of the well, and the TVD placement of the ERD sensors coupled with inherent uncertainties of the pressure measurements may result in non-physical pressure distribution along the well after extended shut-in periods. Hence, the correction factors must be applied to provide uniform pressure distribution along the horizontal well after extended shut-in periods (~1 month) providing that all ERD sensors were in hydrostatic pressure equilibrium in with respect to a hypothetical reference depth. This limits the practicality of the Liquid Level estimation workflow to provide liquid levels in a relative basis with respect to the hypothetical reference depth. The magnitude of the actual liquid level above and along the horizontal well depends on the absolute trajectory of the well with respect to the hypothetical reference depth. Hence, the uncertainties of the liquid level estimations based on the pressure measurements will be always greater or equal to the uncertainties on the reported directional survey of the horizontal producer well.

5.2 Uncertainties in Chamber Pressure Estimation

Chamber absolute pressure is one of the main inputs to the Liquid Level estimation workflow during the shut-in periods. The studied well and pad in this project was not instrumented for the direct measurement of the chamber pressure. Hence, several indirect measurement methods were studied to estimate chamber pressure. These measurement methods include;

1) injector casing wellhead pressure measurement,
2) estimated pressure based on the injector bottom-hole temperature, and
3) estimated pressure based on the observation well temperature.

As methods 1 and 2 measure pressure inside the liner, the shut-in pressures are only representative of the chamber pressure for short period of time before the condensate accumulation. Hence, a nitrogen purge is required to remove the condensate build up. Method 3 estimates the chamber pressure on a continuous basis inside the reservoir. However, methods 2 and 3 are generally susceptible to the accuracy of the thermocouples. Both methods 2 and 3 require corrections to match the immediate shut-

in pressures by the casing WHP. The corrected pressure by method 3 may potentially underestimate the chamber pressure due to partial pressure effects exerted by non-condensable solution gas components in the chamber.

In this project, the uncertainties of the chamber pressure estimation was narrowed down to +-10 kPa based on the flowing and immediate shut-in casing WHP measurements. Consequently, the uncertainty on the absolute estimated Liquid Level immediately after shut-in is +-1.1 m. Hence, in conjunction with the uncertainties on the well trajectory and ERD sensor accuracy, the applicability of the Liquid Level estimation workflow is limited to the collected data during a specific shut-in at any given time on a relative basis.

The analysis of the acquired shut-in trial data post-acid stimulation confirms the evaluations on the importance of the above-mentioned uncertainties on the Liquid Level results. Figure 8 shows how the values of the estimated liquid level along the well is strongly dependent on the method used to estimate the chamber pressure. The trend of the change of the estimated liquid level over time is also affected.

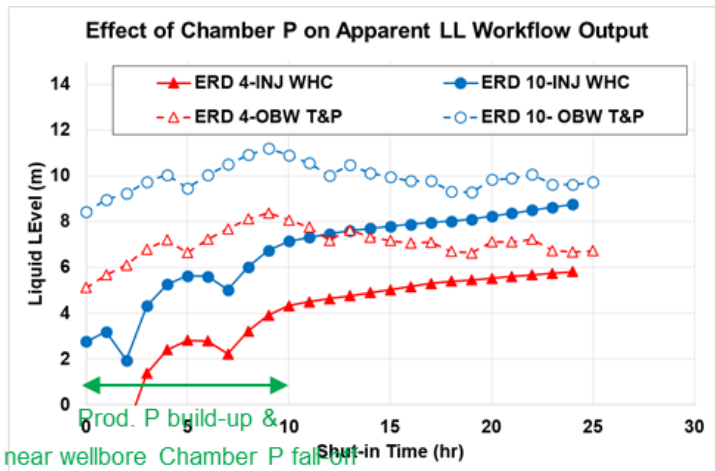

Figure 8: Estimated Liquid Level Variation with Time by Input Chamber Pressure Reference.

Overall, the estimation of the liquid level in early shut-in time is not practical due to the pressure build up in the producer well after shut-in. In addition, the injector casing wellhead pressure is strongly affected by the near well-bore chamber pressure fall-off post-steam shut-in. PTA analysis provides the time scale for early to mid-time pressure fall-off response to be less than 12 hrs. Hence, the injector casing wellhead pressure is used as the input to the Liquid Level estimation workflow using the shut-in data after 12hrs on a consistent basis. Nevertheless, this does not alleviate the impracticality of the workflow to provide the liquid level estimation on an absolute basis.

5.3 Data Quality — Skin and Scale Build-up Effects

The design of production well completion affects the skin and the flowing pressure drop from the chamber to well bottom-hole conditions. In addition, the scale build-up due to the mineral deposition around and inside the production well completion increases the apparent skin on the production well. Following the deployment of the instrumentations, the scale-build up in T13 wells was found quite considerable resulting in significant flowing pressure difference between the producer BHP measurements and the chamber pressure.

The analysis of the shut-in data collected before the acid-stimulation for both Liquid Level estimation and PTA workflows were cumbersome due to significant skin on the producer well. The skin resulted in extended periods of the after-flow and crossflow within the producer well. The former caused a transient behavior after well shut-in at the surface condition as the well continued to flow to balance BHP with chamber pressure. This effect leads in loss of early time data for PTA analysis concealing the actual detection onset of distributed chamber volumes along the horizontal well. The crossflows generally tend to mask the hydrostatic pressure differences along the horizontal well resulting in underestimation and overestimation of liquid levels at areas with relatively higher and lower liquid levels, respectively. Hence, they add to the uncertainty of the Liquid Level estimations. In general, the presence of significant skin due to the production well design and/or scale build-up limits the applicability of both workflows.

The remedial action of Acid Stimulation was found quite effective in reducing the scale build-up and the flowing pressure difference between the producer BHP and the chamber. As shown in Figure 9 for shut-in trial executed in April 2020, the flowing pressure difference between the producer BHP and chamber was as low as 50 kPa. In addition, pressure build up and fall-off response was quite fast (~12 hr) in comparison to significantly delayed responses in the trials before acid stimulation (~4 days).

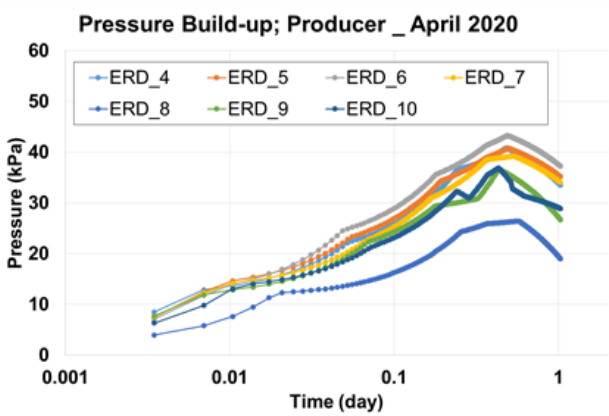

Figure 9: Fast Pressure Build-up during April 2020 Shut-in Trial; Post Acid Stimulation.

This reduction in the response time directly improves the quality of the data for both Liquid Level and PTA analysis workflow. The lower after-flow enables estimation of liquid level in a shorter period of time after shut-in that potentially reduces the hydrostatic equilibration due to the cross-flows. It also improves the data quality for the PTA analysis. As shown in Figure 10, the lost-time data due to skin and superposition effects were considerable and were in the order of few days in pre-acid stimulation trials. In addition, the derivate plot was heavy scattered due to after-flow, liquid level adjustments and phase re-distribution by cross-flow. In comparison, the lost-time data during short period of pressure build-up is less than few hours in post-acid stimulation trials as shown in Figure 11. This enables to collect the early pressure fall-off trends and to detect distinguishable time to pseudo-steady state (tpss) values for different sections of the well. The chatter on the derivative plots are also much subtler; however, visible liquid level adjustments and phase re-distribution effects are still visible.

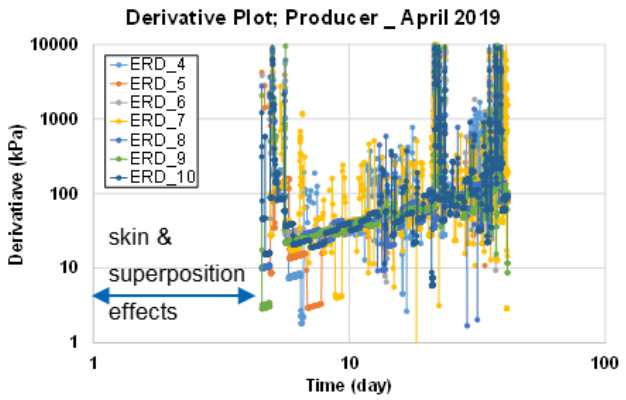

Figure 10: Lost Time Data and Considerable Scatter on Derivative Plot in Pre-Acid Stimulation Shut-in Trial.

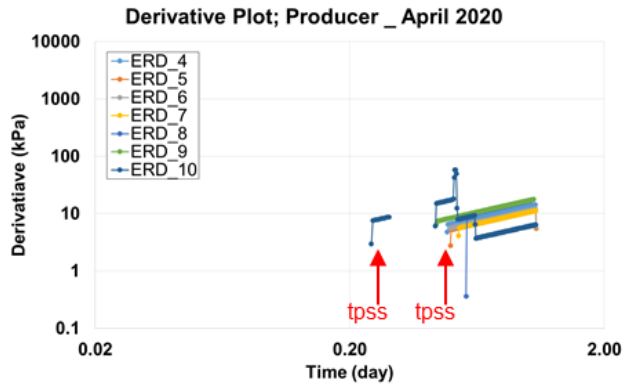

Figure 11: Minimum Lost Time Data and in Pre-Acid Stimulation Shut-in Trial.

5.4 PTA Analysis in Production Well

The PTA analysis on shut-in pressure data of the producer well to estimate the distributed chamber volume was found to be cumbersome. The pressure derivative plots were found to be challenging to interpret due to the scatter by after-flow, liquid level adjustments and phase re-distribution. The early time data were susceptible to loss due to delay in pressure fall-off response caused by skin. In addition, the data can be potentially affected by superposition and out-sync injection and production shut-ins.

Our evaluation from the trial of distributed chamber volume workflow in T13 is inconclusive. The level of variation of PTA analysis results between several shut-in trials is beyond the expected ranges due to:

1) Potential random errors in data collection masking the true tpss for each measurement location; and/or
2) Potential systematic errors due to inability of the deployed measurement sensors (sensor, deployment, well conditions) to independently and accurately measure the pressure fall-off within the chamber.

In addition, the close to uniform chamber distribution along the horizontal well in T13 limited our ability to conclusively rule-out the incapability of the PTA analysis for this application. Overall, the positive assessment of the applicability of this workflow requires a reference chamber volume distribution by the seismic survey which considerably varies along the well. Hence, the reference chamber volume distribution must be statistically different from uniform distribution with potentially non-conformance intervals. This will provide the opportunity to evaluate the PTA analysis workflow beyond its potential inherent shortcomings in principal i.e. the probable pressure communication along the wellbore between deployed pressure measurement sensors.

5.5 Value of Information by Liquid Level Estimation Workflow

The liquid level profiles in Figure 6 and Figure 7 indicated insignificant variation along the well which was reducing over time as the well was pumped off post acid stimulation. The increasing trend of flowing production temperature data with time, as shown in Figure 12, provides the same information on the considerable decrease of the liquid level along the well from April to July shut-ins. In addition, the temperature fall-off analysis can also provide valuable information on the liquid level distribution along the well with respect to the well trajectory. Based on this analysis, one can conclude that interval between ERD_7 to ERD_9 is highly productive and potentially have lower liquid level. In addition, the interval encompassing ERD_9 to ERD_10 is not productive and may have relatively lower liquid level/distance to chamber. The interval from ERD_4 to ERD_7 is the most

challenging for interpretation as the temperature fall-off may indicate either less productivity, or higher liquid level, or both. These observations from temperature fall-off is in overall agreement with the cross section of vapor chamber from the seismic survey. However, they are not in agreement with liquid level estimation workflow output as shown in Figure 6 and Figure 7.

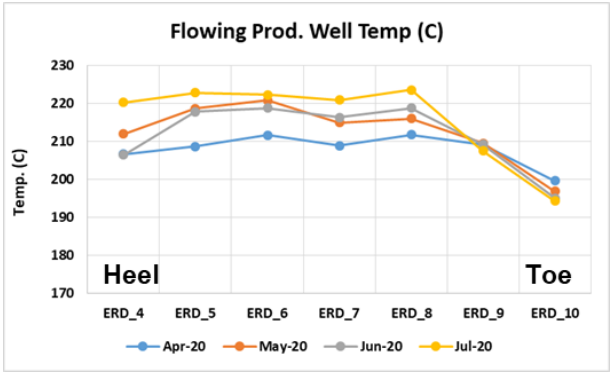

Figure 12: Increase in Flowing Production Temperature with Time

Due to close to flat profile of the liquid level estimation by the workflow as shown in Figure 6 and Figure 7, one may conclude the true liquid level profile is masked by the cross-flow effects from high liquid level to low liquid level interval via the well. Nevertheless, the analysis and validation of this workflow in this project demonstrated its limited viability in field applications due to:

1) unavailability of high accuracy chamber P measurements,
2) uncertainty on P measurement accuracy and directional survey of production well limiting the applicability of the workflow to LL estimation above the hypothetical hydrostatic level (vs. actual wellbore).

The value of the information by this workflow is not significantly superior to the temperature fall-off analysis.

6. OUTCOMES AND IMPACTS

6.1 Project Outcomes and Impacts

In this project, a new instrumentation package including 10 pressure transducers and one fiber optic DTS string is deployed in a horizontal producer well in SAGD operation utilizing a 1.5" coiled tube string. It is shown that the deployed ERD^{TM} sensors can provide reliable pressure measurements at temperatures higher than 200°C on a continuous basis. The accuracy of the hydrostatic pressure measurements is determined as ± 25 kPa given the uncertainty of the well-trajectory. This successful trial of the sensors unlocks the

opportunity to their deployment in high pressure and high temperature operating conditions of SAGD for surveillance of injection and production wells.

The deployed instrumentation package provided the data to evaluate the viability of the enhanced instrumentation and the associated proposed workflows. The project success metrics and objectives were defined as to:

1) demonstrate estimation of liquid level above the producer well within the reservoir using improved downhole instrumentation during shut-in and flowing conditions;
2) demonstrate estimation of distributed steam chamber volume using improved downhole instrumentation;
3) demonstrate the ability to deliberately vary liquid level along horizontal well with operation feedbacks;
4) demonstrate the feasibility to relate and predict the steam coning event to measured liquid level.

In this project, it is demonstrated that the enhanced instrumentation can provide data to estimate a profile of liquid level on a relative basis at any given time (Metrics #1). However, due to the uncertainties in the sensor accuracy and placement, directional survey of the well and the chamber pressure, the estimated liquid level is not absolute, and is measured with respect to the hypothetical reference depth instead of the well trajectory. This is a deviation of the project success metrics which limits the accuracy in the liquid level estimation to the accuracy of the well survey at best. In addition, it is shown that the estimated liquid level profile along the well is potentially flattened due to the cross-flow post shut-in and is not the actual liquid level profile. In the conclusion of this project, the workflow to estimate liquid level along the horizontal well using pressure measurements is found not viable for field application.

The implementation of the PTA workflow on the extended shut-in data collected in this project is inconclusive (Metrics #2). The application of the workflow on the shut-in trial data showed a considerable level of variations on the chamber volume distribution from one trial to other. In addition, none of the estimated chamber volume distribution profiles are in a general agreement with the estimated chamber shape by the reference seismic survey results. Nonetheless, all PTA analysis results indicated close to complete conformance along the well in agreement with the seismic survey observation. A conclusive trial of the workflow will be required to positively indicate the areas of non-conformance as well. The results of this project and the subsequent recommendations can be used to design a conclusive trial of PTA workflow for distributed chamber volumes estimation in future.

In this project, the operation strategy of maximum pump rate and post-acid stimulation resulted on the considerable increase in production temperature. This trend indirectly indicates a decrease in liquid level above the well trajectory, and is confirmed with the fall-off analysis as well. The same trend of decrease in liquid level was also implied by the liquid level workflow. (Metrics #3). However, neither of the workflows and analysis did detect a steam confining event (Metrics #4).

6.2 Clean Energy Metrics

The field trial of the instrumentation project is completed with total spending of $963K CAD funded by Alberta Innovates (AI) and Imperial. The funding is invested in the development of the clean technologies for bitumen production from in-situ resources using gravity drainage processes such as SAGD. The result of the field trial was to provide the basis to develop operational workflows in order to:

1) reduce GHG emissions linked with the bitumen production by 0.5-2 percent (i.e. 10-200 kton/yr depending on the size of deployment);

2) decrease the need for 3D seismic surveys and the associated land disturbance.

A total of ~2 full-time equivalent HQSP supported the project. The results of this trial will be potentially presented in a conference within the confidentiality period after the project completion date.

The liquid level workflow was found not viable for field deployment to prevent and detect steam coning and bypass conditions. Hence no direct reduction in GHG emissions associated with bitumen production is expected to occur due to the deployment of the evaluated workflows in this project. A conclusive trial of PTA workflow in future can decrease the need for 3D seismic surveys and the associated land disturbance. Given the results of the project, no direct future investment in the new instrumentations is anticipated in the commercial projects in the near future. If a future trial of PTA workflow analysis conclusively demonstrates its field viability, a potential $30-210 million investment in deployment of enhanced instrumentation is foreseen.

6.3 Program Specific Metrics

The enhanced gravity drainage instrumentation project is listed under Clean Hydrocarbon Production Program with the specific program metrics of: 1) 0.01-0.04 GJ energy intensity reduction, and 2) 0.07-0.13 $ netback cost intensity reduction, both measured per barrel of produced bitumen.

The results of this project do not provide the evidence on the viability of the instruments and the workflows for commercial deployment. The remedial actions in this project including acid stimulation of the producer well improved the data quality and enhanced the ability to analyze the data per the requirements for each workflow. The evaluation of the chamber distribution by PTA analysis workflow was inconclusive and it may warrant another trial with the conditions set below in the forthcoming sections. Based on the results of this project, the commercial deployment of the enhanced instrumentation and workflows are not expected. Hence, no direct reduction in energy intensity and unit production cost reduction will result.

7. BENEFITS

7.1 Economic

It was anticipated that the positive results of the enhanced gravity drainage instrumentation project and potential deployment in the commercial projects would enable 0.07-0.13 $ netback cost intensity reduction per barrel of produced bitumen. The potential reduction in netback cost intensity would be realized by reductions in the costs associated with the surveillance by 3D seismic, energy and operational maintenance, and the revenue loss due to the downtime.

Given the results of this field trial as described in the prior sections, no immediate reduction in the netback cost intensity is expected to occur due to the deployment of the evaluated workflows in this project.

7.2 Environmental

It was anticipated that the positive results of the enhanced gravity drainage instrumentation project and potential deployment in the commercial projects would enable 0.01-0.04 GJ energy intensity reduction per barrel of produced bitumen. This is equivalent to 0.5-2 percent saving in thermal energy use in SAGD operation. The potential reduction in energy intensity and GHG emissions would be realized by the effective prevention of steam by-pass in SAGD wellpairs, and effective use of thermal energy to create and utilize the steam. In addition, the distributed chamber volume by PTA analysis can reduce the need for repeated 3D seismic surveys and the associated land disturbance. Hence, it would enable faster natural restoration of seismic cut lines.

Given the results of this field trial as described in the prior sections, no immediate reduction in the energy and GHG emission intensity is expected to occur due to the deployment of the evaluated workflows in this project. If a future trial of PTA workflow

analysis conclusively demonstrates its field viability, it potentially can potentially reduce the need for 3D seismic surveys and the associated land disturbance.

8. RECOMMENDATIONS AND NEXT STEPS

In this project, the liquid level workflow was found not viable for field application. The commercial deployment of the advanced instrumentations for the sole purpose of use with the liquid level workflow is not anticipated due to:

1) limited viability of the workflow for field applications;
2) inferior value of information in comparison to distributed temperature sensors such as DTS.

The commercial deployment of the advanced instrumentations for the purpose of use in PTA analysis will require a conclusive trial of the workflow. Based on the learnings acquired during this project, a conclusive trial of the workflow must include the following conditions:

1) a considerable variation of the vapor/steam chamber distributed volume along the well is confirmed and demonstrated by 3D seismic survey and 4D time-lapse analysis.
2) a poor conformance along the injection and production well is identified by the seismic survey or other surveillance means. The length of the non-conformance intervals must be comparable to the distance between the pressure sensors.
3) The distributed chamber volume by PTA analysis provide evidence in agreement with the information listed in 1 and 2.

Given the inherent challenges of pressure measurement in the production well, the deployment of the distributed pressure sensors in the injection well poses a better alternative to gather pressure data for the distributed chamber volume by PTA analysis. In addition, the deployment of the sensors behind the liner will further improve the data quality by reducing the potential effects of the pressure communication via the well on the results of the analysis.

9. KNOWLEDGE DISSEMINATION

The results of the trial will be potentially presented in a heavy oil conference within the confidentiality period after the project completion date.

10. CONCLUSIONS

This project intended to capitalize on the capabilities of commercially available enhanced down-hole instrumentations in order to develop robust operation optimization workflows and control solutions for the gravity drainage processes such as SAGD. It aimed to enable the potential to optimize bitumen production through efficient reservoir monitoring and innovative workflows for direct liquid level measurement and control. This field trial also evaluated the feasibility of use of PTA analysis for estimation of the distributed chamber volume for use in a commercial application. The results of the field trial was to provide the basis to develop operational workflows in order to:

1) reduce GHG emissions linked with the bitumen production by 0.5-2 percent (i.e. 10-200 kton/yr depending on the size of deployment);

2) decrease the need for 3D seismic surveys and the associated land disturbance.

In this field trial, it was shown that the deployed ERD™ sensors can provide reliable pressure measurements at temperatures higher than 200°C on a continuous basis unlocking the opportunity to their deployment in high pressure and high temperature operating conditions of SAGD for surveillance of injection and production wells. However, due to the uncertainties in the sensor accuracy and placement, directional survey of the well and the chamber pressure, the workflow to estimate liquid level along the horizontal well using pressure measurements is found not viable for field application. The assessment of the PTA workflow on the extended shut-in data collected in this project is inconclusive. A future conclusive trial of the workflow will require to positively indicate the areas of non-conformance. The results of this project and the subsequent recommendations can be used to design a conclusive trial of PTA workflow for distributed chamber volumes estimation in future.