Solvent Enhanced Steam Drive: Experiences from the First Field Pilot in Canada

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Abstract

In recent years, the addition of a hydrocarbon condensate (C4 to C20) to steam operations (such as CSS and SAGD) in heavy oil and bitumen reservoirs has emerged as potential technology to improve not only oil recovery and but also energy efficiency. Shell has extended the idea of solvent addition to a steam drive process, applied it for the first time in the Peace River area in Canada, and obtained evidence of oil uplift in the patterns where solvent was injected. However, piloting this new technology in a brown field had many challenges, especially when evaluating its main economic factors: production increase and solvent recovery.

To overcome these challenges, emphasis was put on experimental design, data acquisition and quality, and production surveillance. The pilot conditions were designed to increase the probability of success on the two economic factors aforementioned within a short period of time. The assessment of the pilot required that all production streams (emulsion and casing vent gas) were metered and frequently sampled to measure their respective compositions. Cross calibration of metered and sampled water cuts was essential in obtaining conclusive production uplift data. Automatic proportional samplers were success- fully deployed under these challenging conditions to obtain representative samples. Due to the overlap of solvent and bitumen components, special attention was taken to allocate hydrocarbon production into bitumen and solvent. New in-house developed algorithms were tested to accurately calculate this split.

The addition of a 4 month concentrated slug of solvent in two steam drive patterns resulted in a significant production uplift when compared to two adjacent patterns with steam-only injection. Solvent recovery is still ongoing and exceeds original expectations. Frequent sampling allowed the detection of several trends, including bitumen composition changes during solvent injection and solvent fractionation in the reservoir.

Introduction

Vertical well steam drive is the selected process to recover bitumen from the Peace River Bluesky formation [1,2]. Solvent co-injection has been identified as an economical method to improve the efficiency of this process. The details of the solvent co-injection process have been described previously in literature [3–5]. In an early phase of the steam drive, a slug of hydrocarbon condensate (diluent) is

co-injected with the steam. The solvent condenses at the cold steam/bitumen interface to form a solvent bank. This bank has the potential to accelerate the bitumen production by viscosity reduction and also to improve ultimate recovery. During the development stage of this technology, an early derisking opportunity arose in a small brown field infill development. Although this infill pattern flood is different in several aspects from the commercial development, valuable information on the application of solvent co-injection could be obtained.

The efficiency of the diluent co-injection in a steam drive process is expected to be lower than that of LASER [6]; however the solvent recovery factors are expected to be much higher. The solvent recovery is therefore a key factor in the economic viability of the process. The main objectives of the pilot were to obtain a positive response in bitumen production and accurate quantification of the diluent recovery. An accurate assessment of the bitumen production increase was not expected due to the small size of the pilot and lack of control patterns; hence, the design of the injection slug size and concentration was designed to obtain a significant and measurable bitumen response.

A simulation study concluded that a four-month slug of 15 wt% diluent would be able to meet the pilot objectives in a reasonably short time frame. The results of the pilot will also be used to validate simulation models which will then be applied to optimize a potential commercial development.

Pilot Design

The Peace River lease in Alberta has been subject to many well and recovery technology trials for the last 30 years. One of the technologies tried is cyclic steam stimulation (CSS) with multilateral horizontal wells. Pad 19 has been developed with so-called ″soak radial wells″; four horizontal laterals in a cross pattern (Figure 1). Over a nine-year timeframe, bitumen has been produced in 7−8 CSS cycles. With a recovery of less than 20% from the initial design, a part of the pad has been converted to a pattern steam drive to increase recovery to more than 50%. Vertical injectors and producers are drilled to complete the inverted 5-acre 5-spot patterns. Currently four patterns are operational as shown in Figure 2. Vertical producers are perforated over almost the complete interval, while steam injectors have been completed with five limited entry perforations to evenly distribute the steam over the entire reservoir interval.
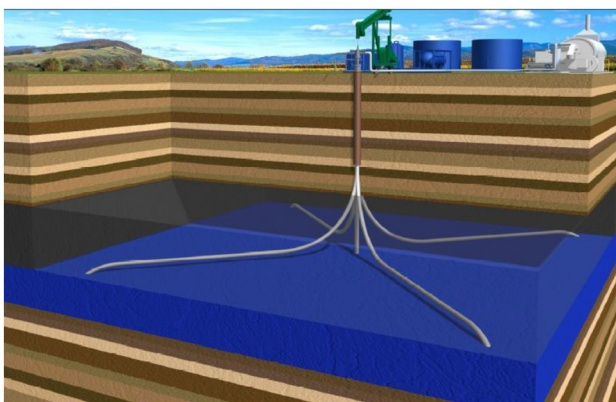

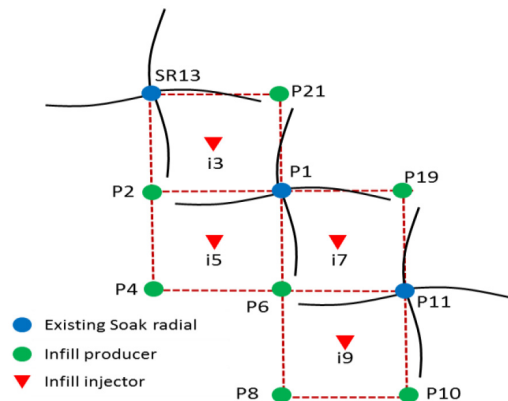Figure 1—Arrangement of a multilateral soak radial well

Figure 2—Layout of the infill steam drive area in Pad 19

Based on the field development plan, the newly drilled vertical infill producers were subjected to two CSS cycles to create communication between injectors and producers. Infill injectors were not subjected to cyclic steam. After that, the pad was intended to be switched to a Vertical Well Steam Drive (VSD) with continuous steam injection of 100 m³/day (CWE). The rate was to be subsequently tapered down to 50 m³/day over the life span of the steam flood.

The solvent injection strategy that determined in which injectors solvent would be co-injected, for which period of time and at what concentration[1], was designed in a two-stage process. In the first stage, a simplified element of symmetry model (Figure 3) was used to screen a wide range of options with respect to solvent concentration, and start and duration of solvent co-injection. It was found that, based on the development scheme, bitumen rates in VSD would be low for a few months before mobilized bitumen would reach the producer, at which point the rates would show a strong increase followed by a gradual decline. Solvent addition increases bitumen mobilization and leads to a higher desaturation of the steam chamber due to the formation of a solvent bank [4]. This leads to a more pronounced increase in bitumen rates once the mobilized bitumen reaches the producer. Solvent co-injection after steam breakthrough is not effective, since most of the solvent is directly produced back without any benefit. In combination with the fact that a higher solvent concentration leads to a faster formation of a solvent bank and, hence, has a stronger impact on the increase of early bitumen rates, a short slug with a high solvent concentration was found to be optimal in VSD.
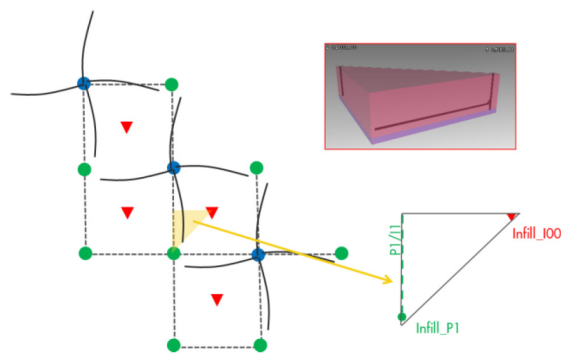

Figure 3—Element of symmetry model

The impact of different solvent concentrations of the early bitumen rates and hence the bitumen uplift signal is shown in Figure 4. After this period, injection conformance in the LEP injectors would have

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[1] All solvent concentrations are stated in weight % of total injection stream (steam+solvent)

stabilized so solvent would be injected over the full height of the pay zone. To obtain a strong bitumen uplift signal in wells adjacent to multiple injectors, and to be able to compare production performance in patterns with solvent injection against patterns without solvent, two injectors were selected for solvent injection (i7 and i9) while two would only inject steam. The pilot injection strategy was set to co-inject 15 wt% of solvent for four months starting two months after the beginning of VSD.
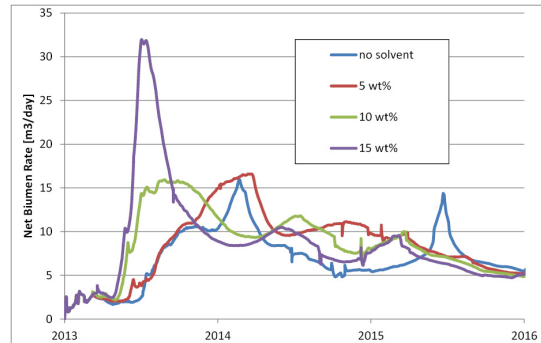

Figure 4—Net Bitumen rates in VSD as function of solvent concentration predicted by the element of symmetry model

In Stage 2, this solvent injection strategy was tested in a full field model that had been history matched to the historic CSS cycles on a well-by-well basis. In addition, the temperature data gathered from logging the infill wells had been used to scale the effectiveness of each leg of the multilateral wells. Bitumen and solvent rates for an infill producer, as well as for a multilateral well, are shown in Figure 5 as well as simulated bitumen rates without solvent injection. Both wells show an increase in bitumen production together with solvent breakthrough. Unfortunately, a big signature such as was seen in Figure 4 is absent. This is due to a change in the startup strategy (prior to VSD); in the original design, infill injectors would only receive steam at the start of VSD while infill produces would undergo two CSS cycles. This would cause a short period of low production at the beginning of VSD in which communication between injectors and producers would be established (Figure 4 first three months), followed by the big bitumen uplift signature caused by solvent addition. After the original solvent injection design had been finalized, the decision was made to pre-steam the infill injectors, as well. That leads to earlier bitumen production, but also reduces the visibility of the uplift signature. However, both wells shown in Figure 5 display an significant increase in bitumen rates after start of solvent injection. To identify this signature of bitumen uplift caused by solvent injection is a key objective of the pilot.

Key performance indicators predicted by the full field model are shown in Table 1. It is clear that the economic success of a steam solvent application in VSD will rely heavily on the solvent utilization, determined by the bitumen uplift per solvent injected and on solvent recovery.
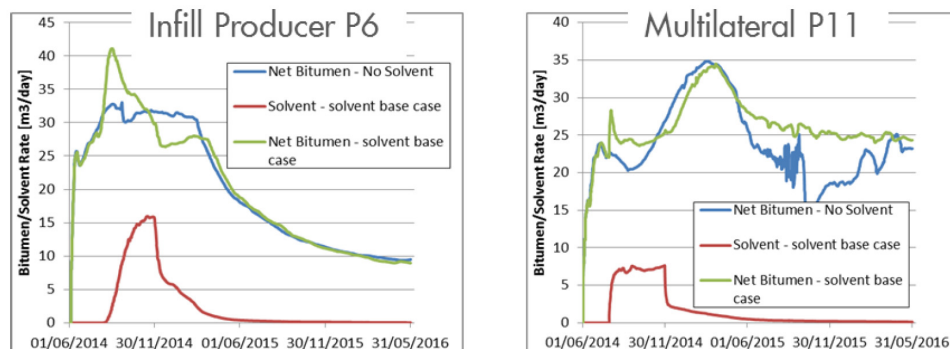

Figure 6— Bitumen and solvent rates for selected producers predicted with full field model

Table 1—Key Performance Indicators based on full field model (2 year pilot period)

Solvent Recovery Factor	85.6 %
Bitumen uplift per solvent injected	0.7 m^3/m^3
Bitumen uplift per solvent lost	4.9 m^3/m^3
Recovery improvement in VSD[2]	4.0 %
OSR improvement in solvent patterns	8.4 % (0.16 to 0.18)

Data acquisition

A comprehensive surveillance plan, part of the Wells, Facilities, and Reservoir Management (WRFM) plan, is necessary to evaluate the main objectives of the steam-solvent pilot, bitumen uplift and solvent recovery. The surveillance plan in turn requires intensive metering of the injection and production streams as well as sampling of the produced hydrocarbons, as described in the following sections.

Metering overview

Figure 7 shows a schematic representation of the production streams and metering located in Pad 19. Each well produces two streams, water/bitumen emulsion and casing vent gas (CVG), that are treated separately.
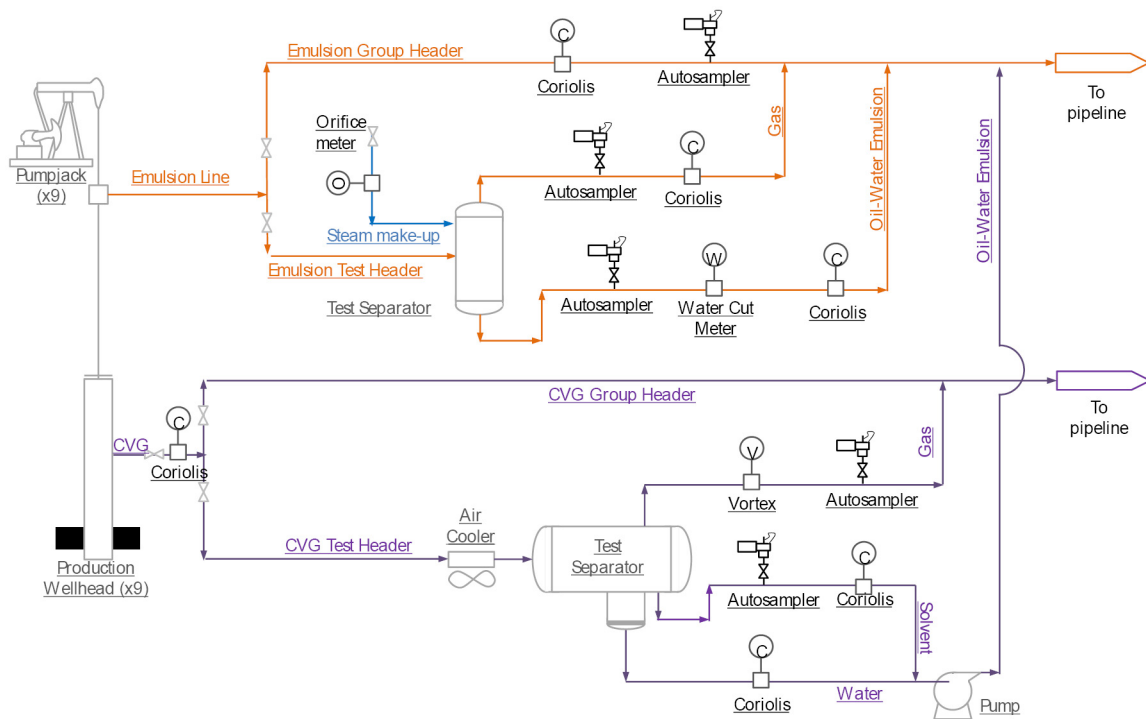
Figure 7—Schematic of Pad 19–3 production facilities for the steam-solvent pilot including main metering points (excluding pressure and temperature ports)

The CVG stream of each well has pressure and temperature transducers as well as a Coriolis mass flow rate meters; each of the CVG streams could go directly to the central processing facilities through the CVG group header or could be directed towards a cooler and three-phase separator unit. This unit was specifically designed to measure and recover solvent produced through the CVG system. CVG production

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[2] Relative to total production during VSD

from wells surrounding steam-solvent injectors are planned to be re-routed through the CVG separator. The water, liquid hydrocarbon, and gas flow rates are measured at the outlet of the separator. Moreover, the gas and hydrocarbon lines have proportional automated samplers (auto samplers).

The emulsion stream of each well also has pressure and temperature transducers; however, the flow rate and water/hydrocarbon split of these streams is measured during a well test. Each well is tested for 24 hours. The test separator is aimed at stripping the entrained gas off the emulsion and subsequently to measure the water cut and flow rate of the liquids. The gas outlet flow rate is also measured and auto samplers are located at both outlet streams of this separator. As can be seen in Figure 7, a high pressure steam inlet (make-up) is added and measured to the separator vessel to provide pressure support on the vessel and allow the fluids to flow back to the emulsion group header. The flow rate through the emulsion group header, containing the emulsion flow of all the wells except the one on test, is measured and can be sampled using an auto sampler.

In addition to the described metering for production, the performance of the pumps is also metered, that is, the current speed of the pump (strokes per minute, spm), the barrel fillage, and the overall daily uptime of the pump. As important, the injection pressure and flow rate of steam and solvent are measured for every injector well on the pad. The composition of the solvent is measured at its source on a monthly basis. Finally, a field operational log is kept on a daily basis to relate possible changes in operability of the pilot, calibration curves, measurement noise, and as a data back up in case of field power outage.

Sampling strategy

As shown in Figure 7, five auto samplers are located across the pad surface facilities to perform proportional sampling of the production streams. There are two main purposes for sampling in the pilot: 1) measure hydrocarbon composition to determine solvent production and recovery and possible changes in solvent and bitumen composition with time or area across the pad; and 2) as means of water cut verification and calibration on a frequent basis.

The type of fluids to be sampled can be categorized in gases, liquid hydrocarbons (for the solvent outlet of the CVG separator), and emulsions. These samples are gathered at temperature ranging from 40–200 °C, pressures between 300–1500 kPa, and with fluids that may contain solid particles, CO_2, and H_2S. The implementation of auto samplers under these conditions was new to the Peace River Complex and required a special design of the gathering systems as shown in Figure 8. Once the samples were collected, they were shipped on a regular basis (1–2 times per week) to a third party lab for analysis, which included gas chromatography (GC) up to 12 carbon number (GC12+) for gases, and up to 30 carbon number (GC30+) for liquids. The emulsion samples were also subject to accurate water cut measurement and density determination.
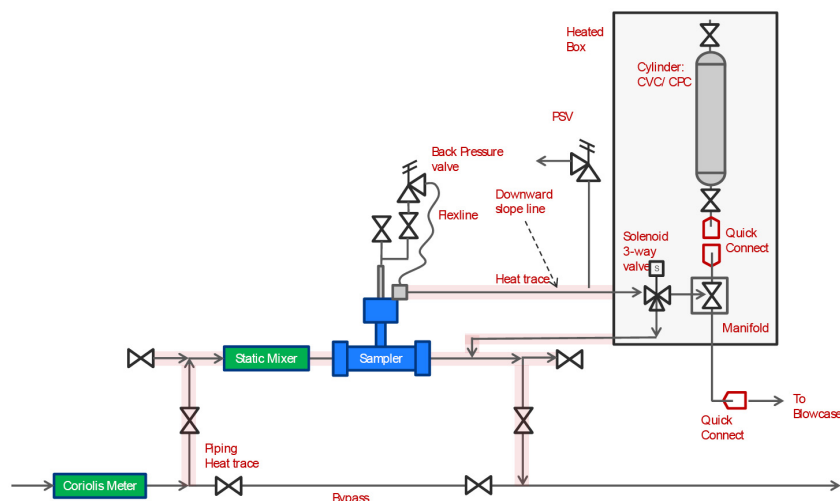

Figure 8— Schematics of liquid auto sampler design

The frequency of sampling is as important as the methodology to capture compositional trends that can happen over relatively short periods of time; moreover, large numbers of data for verification of water cut implies that random deviations in the data tend to disappear, leaving the systematic deviations which can be treated. In this case: 1) composite samples of four to six hours are taken daily from well testing with priority on wells surrounding the steam-solvent injector; 2) four to six hour composite samples are taken from the CVG separator three times per week; and 3) a five-day composite sample is taken from the emulsion group header once per week. The auto sampler control narrative allows sampling to occur roughly in the middle of the well test and proportional to the flow recorded in the pipeline, with sampling timing ranging from 2–4 hours.

Execution

The metering and sampling plan execution was monitored on a frequent basis and deviations from it were contained in accordance with the contingency plan developed as part of the WRFM. Initially, a thorough review of the metering, sampling, and overall plan strategy was executed. The main topics were:

- Meter connectivity, proper reading out and reporting into the centralized control system and into the online remote data display, and unit transformation and internal calculations. Although minor, errors within online data gathering can lead to significant uncertainty in the data
- The novel auto sampler system design and development was closely followed, including heat insulation and proper utility air supply, control narrative and operator display, shipping logistics, and an evaluation of the most adequate cylinder system given the type of samples, the conditions, and the frequency. As a conclusion of the latter topic, constant volume cylinders were utilized as supplied by the third party lab doing the sample analysis
- The solvent injection system and CVG separator were specifically tested for solvent handling and recovery. As a result of the test, the injection pump was deemed appropriate with minor revisions on the contingency control system while the CVG separator system, particularly the downstream centrifugal pump was deemed unfit to pump solvent back to the emulsion group header

After the initial commissioning of the metering and sampling system the pad facilities were ready to start injection of solvent and measurement of KPIs, except for the CVG separator which entered a re-design phase. To mitigate the loss of compositional data of the CVG production, a manual sampling plan was developed where the CVG composition of six wells was measured once every week directly at the wellhead. As a consequence, on the one hand, solvent being produced from the CVG was not recovered; on the other hand, a more accurate account of individual CVG composition for the wells was obtained which aimed at identifying solvent chromatographic separation and solvent recovery trends for individual wells.

The initial execution of the sampling plan resulted in a low sampling efficiency of 45%, particularly on the device sampling emulsion downstream the well test separator. An assessment of the auto sampler determined that some of the internal constituents originally made out of Teflon were damaged, likely due to abrasive action of solid particles and enhanced by high temperatures and H_2S. These parts were exchanged to PEEK polymer equivalents, improving the sampling efficiency to 90% over a period of more than 6 months.

Data quality assurance and control (QA/QC)

All data recorded is analyzed for consistency (sudden changes in trends are scrutinized), units, and accuracy. Several minor incidents are prone to occur in every field pilot, most of them unrelated to the pilot itself; all of these incidents were recorded on the daily log and repairs occurred within a week. Examples of these minor incidents are power outages and unit conversions. One of the most important tools for analyzing consistency of the data is mass balances; in this case, mass balance for gross

production across the pad is performed independently through a comparison between the summation of the well test result and the emulsion group header flow rate. Figure 9 shows the proration factor between group header gross flow rates and summation of well tests. The gross rate proration factor is defined as:

$$P_{Gross} = \frac{Q_{Gross,group\ header} + Q_{Gross,current\ well\ on\ test}}{\sum Q_{Gross,well\ tests}}$$
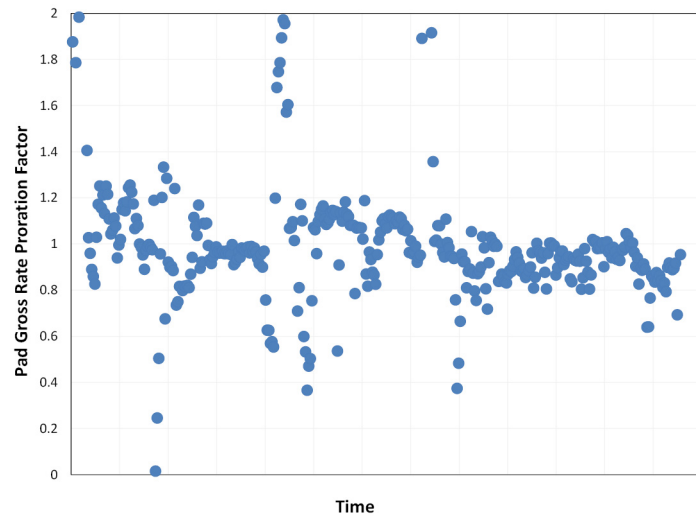

Figure 9 — Pad gross rate production curves during steam-solvent trial (compared for proration)

The average proration factor across the pad is 0.99, indicating an excellent agreement between well tests and overall gross flow rate. Figure 9 also shows some periods where the group header and well tests are not in agreement. These periods are mainly related to: 1) gas entrainment on the group header, which generates pikes in the readout of the Coriolis meter; such periods were recorded during flow back after a CSS cycle and sometimes during production when the casing vent gas of the well is cross-flown through the tubing. 2) Periods where there were repairs in the test separator and well testing values were extrapolated from their previous results; these periods occur infrequently, with separator or pad repairs occurring 10% of the time while gas entrainment occurring 5% of the time.

It is also important for accurate bitumen rates to validate the water cut values obtained from the meter (Figure 7). To do so, the values obtained from the meter are compared directly with those obtained from the sampling campaign. The accuracy and repeatability of the data obtained from the auto sampler was determined by comparing auto sampler data with manual samples from the same stabilized well test. The manual samples were taken with pressurized cylinders. Results from the auto sampler show a systematic but small average relative deviation of -2.0% and reproducibility better than 1.4%; providing confidence in the auto sampler data.

Figure 10a shows a cross plot of the water cut data for all wells collected from the auto sampler and the results of the inline meter. As can be seen, it shows significant scattering with all the data. Initially, the data was evaluated for validity with respect to the well testing, i.e. whether the test itself was carried over at steady state conditions (for representative water cut values) or whether the water cut trends were steady to within 5% of readout (for gas entrainment). In 25% of the well tests the metered values were considered invalid. Figure 10b shows a cross plot with the data filtered from invalid well testing and invalid calibration curve. As can be seen the scattering was reduced significantly; however, some scattering remains, especially at water cuts around 45–80%, most of which lies on a region where the

calibration curves can jump from oil-in-water to water-in-oil emulsions and can generate a systematic deviation on the metering data.
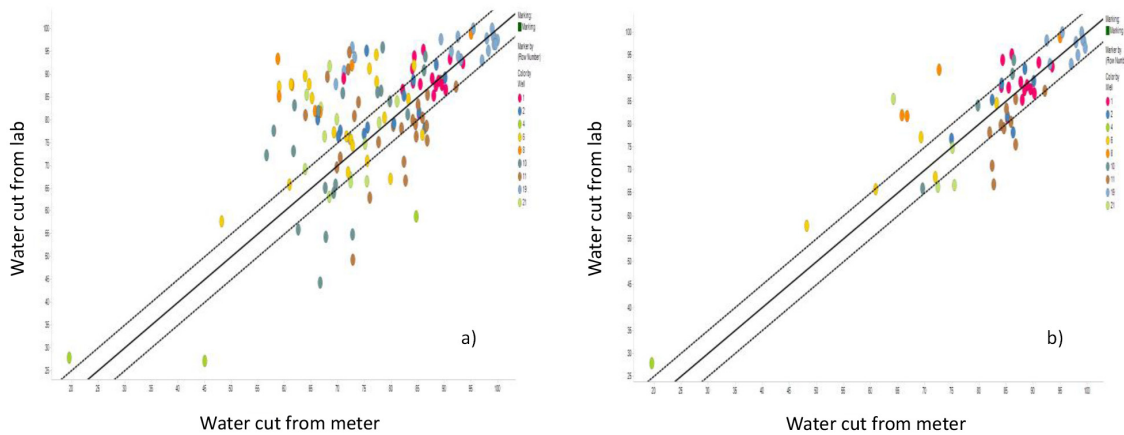

Figure 10—Comparison of water cut cross plots; a) all data, b) validated data

Finally, the data from the third party lab was QA/QC. Initially, the sampling analysis turnaround was tracked through the centralized data delivery system and compared with the original agreement with the third party lab. It was found that regular meetings with the vendor, weekly communications, and frequent sampling shipping from site (i.e. sampling shipping as frequent as possible to avoid building up) were required to keep the turnaround on track as close as possible; however, several issues are often unavoidable with contracts expanding for more than a year such as equipment maintenance, lab personnel availability, etc. The turnaround was kept to target to within 2 weeks. It is important to realize that sampling turnaround impacts the assessment of the pilot since possible trends in solvent recovery or bitumen uplift as well as possible issues regarding sampling (i.e., autosampler performance, line mixing, shipping, etc.) can only be spotted with 1–2 months delay; this time delay could potentially cause losses in data in the case there is a mishap on the sampling system that can be only corrected after a month's worth of data has been gathered.

In addition the hydrocarbon composition was assessed over time. Overall, the compositional data was consistent on more than 95% of the samples with few compositions out of trend. As an example, Figure 11a shows the hydrocarbon composition of one well with time with a particular outlier showing a solvent-type signal at a time where solvent was not injected, indicating contamination of the sample.
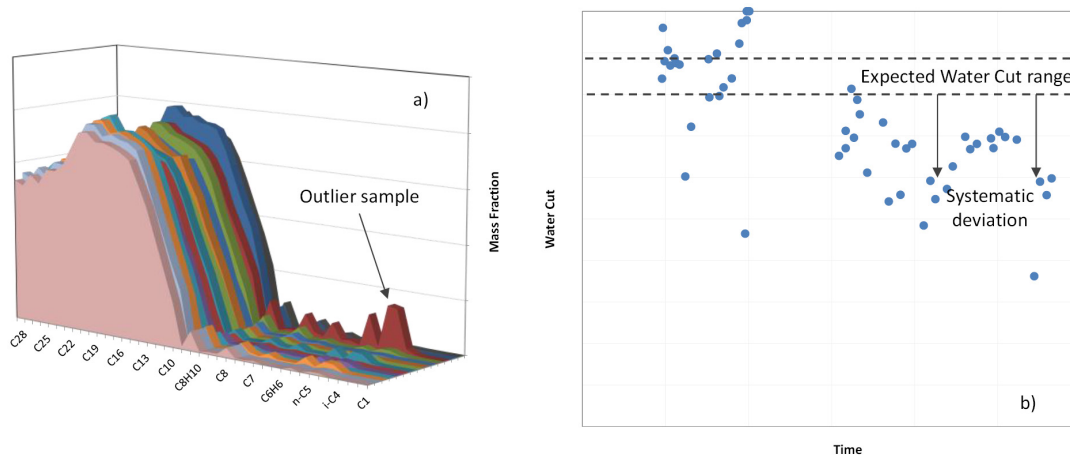

Figure 11— Possible errors on a) CG analysis and b) water cut meter for emulsion header

Finally, the water cut data from the emulsion group header was evaluated. Figure 11b shows a comparison of the water cut values obtained from the emulsion group header auto sampler and the expected water cut range from the summation of the well tests. As can be seen, there is a systematic deviation of the lab values towards low water cuts. After evaluating the auto sampler system the most likely explanation for this systematic error is the lack of homogenization of the fluid; the actual flow rates are lower than the static mixer design window.

Bitumen –Solvent allocation

One of the main challenges on evaluating solvent recovery and bitumen uplift from sampling data is that the composition of the used diluent and that of the bitumen have a significant overlap, as seen in Figure 12. Moreover, the composition of the bitumen and the solvent may change with time due to bitumen stripping (generating solvent components in-situ), solvent chromatographic separation and bitumen grading. Due to these conditions the amount of solvent in the produced hydrocarbon stream is hard to obtain. To overcome this problem a thorough allocation strategy has been implemented including the evaluation of different algorithms to split diluent from bitumen in the hydrocarbon streams.
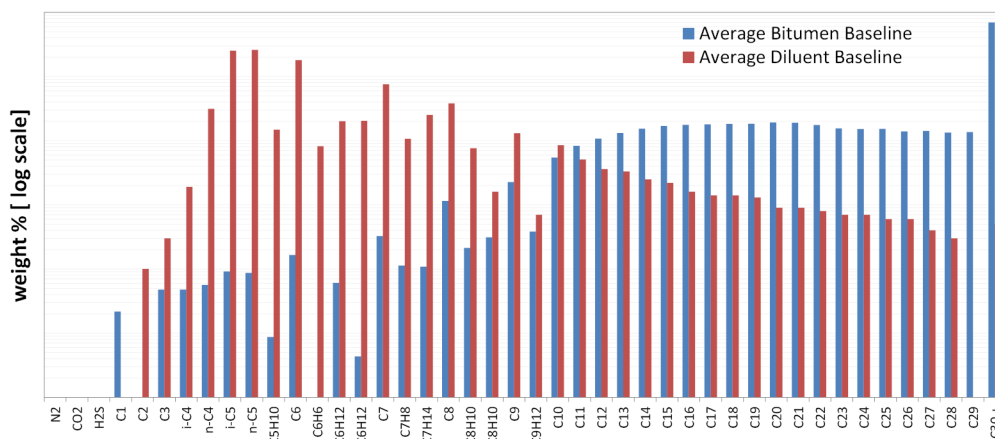

Figure 12— Solvent and Bitumen Composition (mass basis)

Allocation strategy

The allocation workflow is shown in Figure 13 and Figure 14. The plan consists on obtaining daily values for flow rate of the three different phases (water, hydrocarbon, and gas), for the two well streams (emulsion tubing and CVG), for each well. This strategy included:
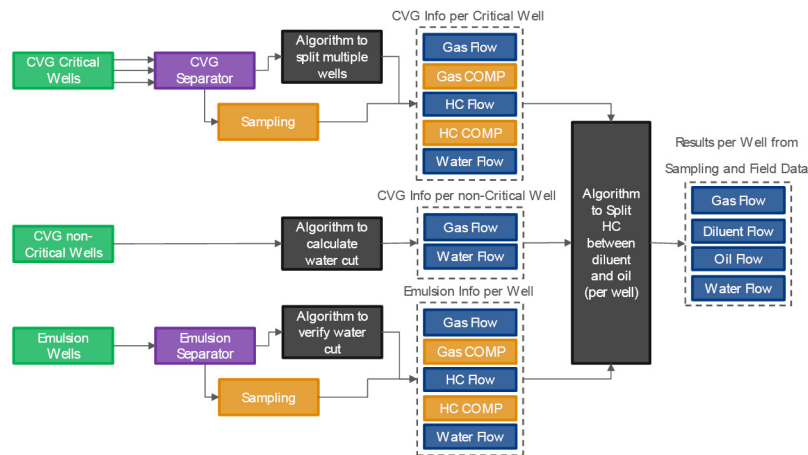
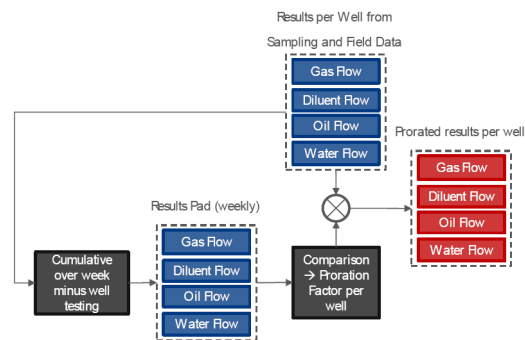**Figure 13—Allocation workflow for CVG and emulsion production**

Figure 14— Allocation workflow for pad production and proration

- Calculation of water content of gas streams based on thermodynamic equilibrium and measured molecular weight of the dry gas
- Verification of validity of well testing and water cut values using sampling information
- Determination of make-up steam values for well testing to correct water cut measurements for condensed make-up steam (Figure 7)
- Frequent measurement of hydrocarbon phase composition of different streams
- Frequent well testing. Well flow rates were assumed constant from well test to well test for the same well. In case information about composition was not available between tests, the composition was considered constant

The hydrocarbon flow rate information of all streams per well is combined and input to the diluent splitting algorithm (described below) to obtain the bitumen and diluent flow rate per well stream.

Diluent splitting algorithms

Three different evaluation methods are considered for diluent splitting comprising six different algorithms in total as shown in Table 2. A more detailed description of the different methods is given in Appendix A. The implementation of all six different methodologies will provide six different solvent production curves which will account for part of the solvent recovery uncertainty. Evaluation of the listed assumptions per method is critical to reduce the number of valid methods. This is only possible through sampling and hydrocarbon composition analysis.

Table 2—Description of diluent splitting algorithms

	IOL methods		Bitumen Baseline	Synthetic Assay methods		
	Regular	**Advanced**		**No Adjust**	**GC30 Adjust**	**Dilbit GC30+ Adjust**
Underlying principle	• Assumes all C10- corresponds to solvent and all C10+ corresponds to bitumen • Advanced method makes a correction on C10+ content of the diluent		• Ratios of C_N with C_{20}-C_{28} are constant in bitumen. The discrepancies in the analysis are fitted based on the diluent composition	• Solvent and bitumen composition remain the same and solvent concentration is regressed to fit actual composition • Adjust methods utilize the C_N/C_{30+} ratios to improve upon fitting considering changes in composition in the bitumen with time		
Input	GC analysis, water cut, mass rates					
GC baseline required?	No		Yes (Bitumen)	Yes (Solvent and Bitumen)		
Computational requirements	Analytical		Analytical	Numerical (minimization of regression error)		
Advantages	Simple to utilize		Simple to utilize	Correct errors in C_{30+} fractions		
Inherent uncertainties	• Large errors at low solvent content • Neglects C_{10-} fraction in bitumen • Neo-formed bitumen volatiles • Light end solvent reflux		• Large errors at low solvent content • Neo-formed bitumen volatiles • Light end solvent reflux	• Neo-formed bitumen volatiles • Light end solvent reflux • Bitumen and solvent baseline may change		
Assumptions	• C_{10-} content on bitumen negligible • C_{10-} content on diluent is neglected on regular and correlated on advanced method • C_{10+} correlation is not operation dependent		• C_{20+} content on solvent negligible • C_n/C_{20}-C_{28} ratio for bitumen remains constant	• No adjust: constant composition of bitumen • GC_{30} adjust: C_n/C_{30+} ratio of bitumen not constant and adjusted with solvent fraction • Dilbit GC_{30} adjust: C_n/C_{30+} ratio of dilbit not constant, C_{30+} ratio adjusted for dilbit		

Data analysis and uncertainty

As shown in previous sections, allocation of solvent and bitumen depends on measured flow rates, water, sampling and splitting algorithms and hence, uncertainty on these data will translate on uncertainty on evaluation of the key performance indicators. After an error propagation analysis, it was concluded that the largest source of error on the evaluation of bitumen uplift is the water cut accuracy, followed by mass rates, GC accuracy, and lastly, the splitting algorithm accuracy. The largest source of error on solvent recovery was the splitting allocation followed by GC accuracy (with almost no significant input from water cut and flow rate uncertainties). This conclusion comes from the fact that the majority of the diluent is produced through the CVG system where emulsion water cut has no effect, whereas the water cut will determine the amount of bitumen produced with relatively small amounts of diluent.

Figure 15 shows the emulsion group header hydrocarbon composition trend with time showing different features from which the different assumptions on the splitting algorithms can be evaluated. Before solvent injection, the composition of the produced bitumen steams was tracked with time to determine the bitumen baseline composition which, as can be seen, was very consistent. From this baseline it can be concluded that the C_{10-} fraction of the bitumen, albeit small, is not insignificant, especially if assessed on a cumulative basis. With this in mind, the premise from which the first two methods in Table 2 is based on was evaluated; results show that a significant error is made if the C_{10-} fraction of the bitumen is not accounted for; furthermore, the C_{10+} solvent fraction as a function of its C_{10-} fraction was tested with a PVT simulator at different conditions expected during the pilot showing that the

correlation is not constant but significantly varies with the bottom hole conditions. Therefore, the first two models were excluded from the allocation methodology.
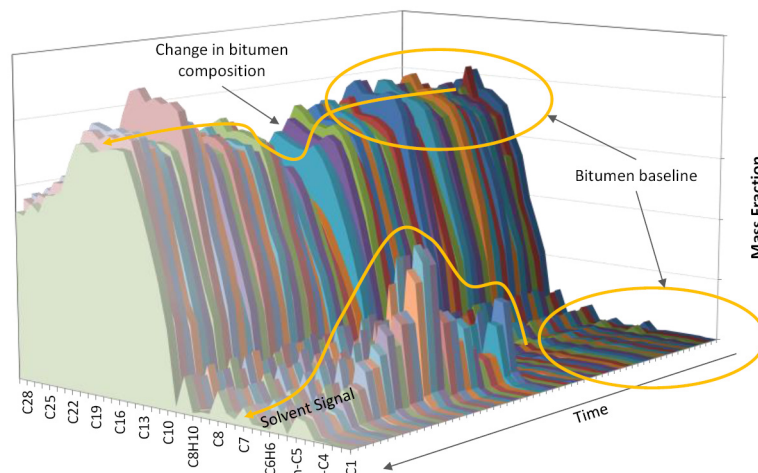

Figure 15— Overall pad compositional trend showing bitumen baseline composition, solvent signal with time, and bitumen compositional changes

Figure 15 also shows that, during the solvent production period, the bitumen composition had a significant change compared to the baseline. After evaluating this trend, it was determined that it was mainly changes in the C_{30+} fraction. These findings render the first and last of the synthetic assay methods listed in Table 2, leaving two valid methods for the solvent recovery uncertainty, ″Bitumen Baseline″ and ″GC30 adjust″ methods. With these two methods the uncertainty was reduced from approximately 50% to 15%. Further assessment confirmed that the C_{20}-C_{28} ratios within the bitumen are constant, providing sufficient means to discriminate bitumen from solvent in the ″Bitumen Baseline″ method.

Pilot Operations

Due to the limited time available for testing the steam-solvent technology in a brown field situation, the success of the pilot depended not only on the technology itself but also on the proper integration and objective alignment among the different teams (Research & Development, Surveillance and Operations) involved in the operation and monitoring of the Peace River Complex. A balance between maximizing production from the pad and obtaining the necessary data from the pilot constituted a key parameter in achieving the desired results from the pilot.

Considering this, Pad 19–3 was agreed to be operated with the philosophy of maximizing gross production (all producer wells in the four patterns were to be maintained at pumped off condition or maximum speed) trying to maintain a balanced operation across each of the patterns using factors as Total Fluid to Steam (TFSR) and the oil-steam ratio (OSR). Only in the case of a potential steam breakthrough (>10 ton/d of steam through the CVG or tubing head temperatures around 180°C-190°C) would slowing down the well be considered or alternatively, the CVG production would be choked. In the case of injectors, their flowrate target was established at 100 ton/d (based on initial injectivity tests carried out in June/July 2013) considering that the maximum operating tubing head pressure was 12.5 MPag.

Steam and Solvent Injection

After the second CSS cycle in the vertical infill producers, the downhole pumps were installed and the steam drive phase of the project started in June 2014. Injectors 3, 5 and 9 could be operated at the targeted injection rate of 100 ton/d, but injector 7 had a maximum injection rate of approximately 75 ton/d at a

tubing head pressure of 12.5 MPa. Due to the high pressure drop over the LEP perforations, the injectivity could not be increased by fracturing or dilating the reservoir, and it was decided to operate this injector at maximum THP (12.5 MPag). The continuous steam injection started June 7, 2014 and after approximately 8 weeks of steam injection, 15 wt% (cold) solvent was directly injected to the steam at the wellhead in Injectors 7 and 9. The injection was continued for 4 months, without major problems (see Figure 16 and Figure 17) achieving a total of steam and solvent injected of 19,600 tons of steam and 3,400 tons of diluent. As supported by PVT calculations, addition of the solvent did not lead to a reduction of the steam injection capacity in the LEP constrained wells. The volume increase by solvent vapour is compensated for by the condensation of steam to provide the vaporization energy. The injected diluent was obtained from the processing facilities storage and its composition was monitored on a monthly basis and found to be very consistent (Figure 18). Once the diluent was received in the pad, a single positive displacement pump provided the required head to overcome the high injection pressures in the steam lines of both Injectors 7 and 9. This system was regulated through a pressure control loop that recirculated solvent back to the pump suction in order to maintain a constant discharge pressure of 13.5 MPag. Flow control into each well was done manually by an operator using a 2″ globe valve and a Coriolis meter for reference. However, due to the differences and variability in tubing head pressure between both injectors, it was difficult and very time consuming for the operators to maintain a constant flowrate; thus, automatic flow rate control is recommended in case this technology is applied on a larger scale.
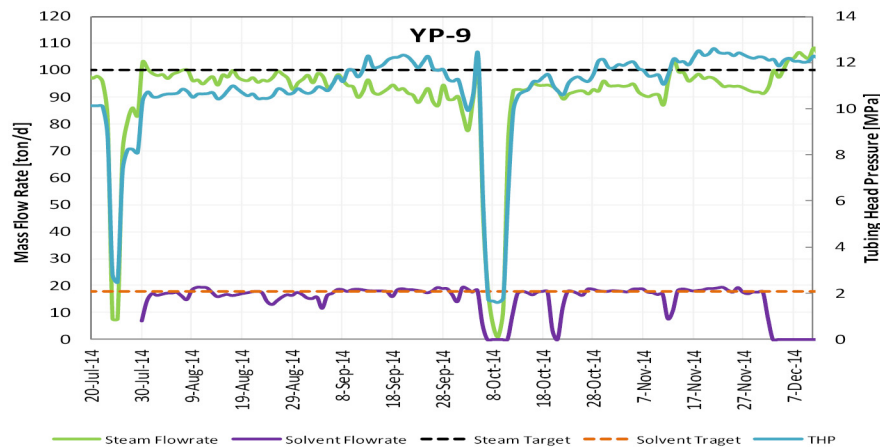

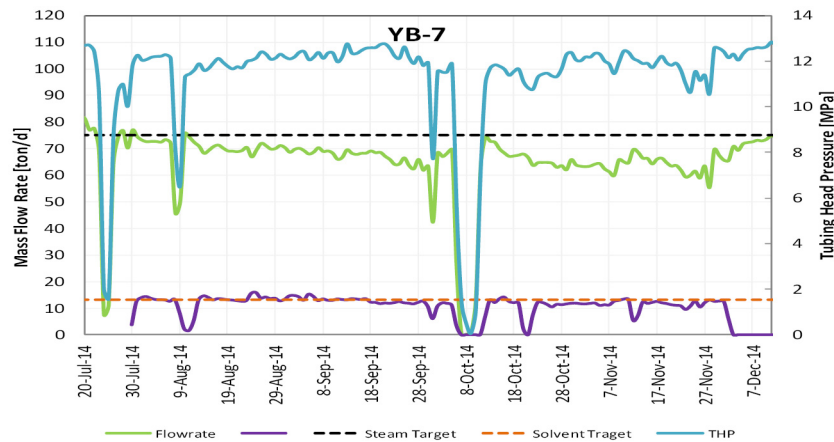Figure 16— Injection rates and pressures of Injector 9

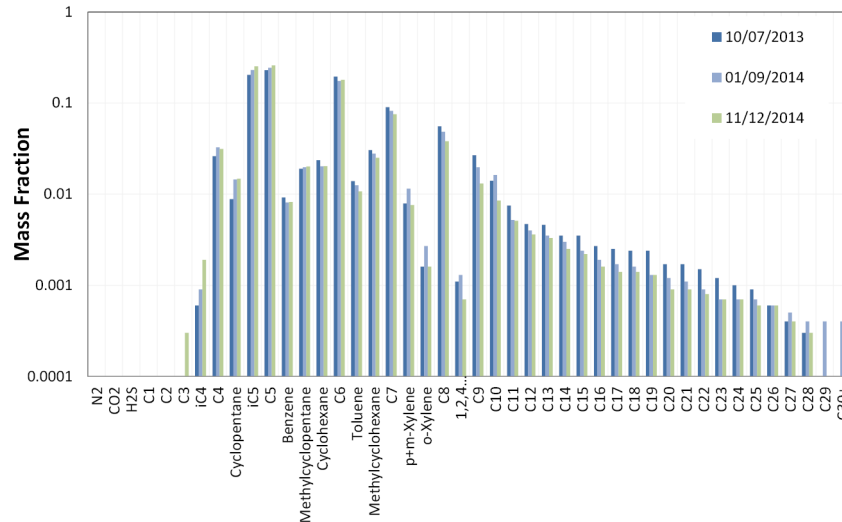Figure 17— Injection rates and pressures of Injector 7

Figure 18— Injection diluent composition measured monthly at the central processing facility

Production System

The artificial lift system applied in Pad 19–3 is rod pumping and, as was mentioned previously, the producer wells in the four patterns were maintained at pumped off condition when possible or at maximum operating speed. However, due to unplanned events such plant issues, pump failures (packing, worn barrel, low tubing head pressure, motor overload/underload, lack of inflow), and pad curtailments, it was difficult to maintain all of the wells running at the desired conditions during the four months of solvent injection. In particular, the uptime of the pad is largely affected by the lack of inflow showed by Wells 4 and 8 which, despite several attempts (adjusting the pumps and the application of well flux), could not be re-started. Considering this, it was decided to carry out a third CSS cycle in these two wells from September 4/2014 until December 5/2014. Figure 19 presents a graph of the average uptime of all the wells on the pad throughout the solvent injection period.
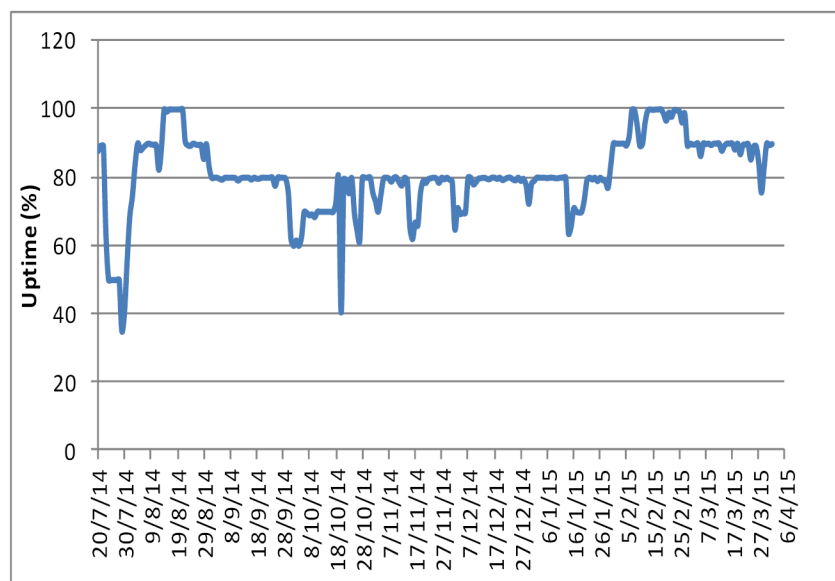

Figure 19— Total uptime of the producers wells during the solvent injection period

Bitumen Production

One of the objectives of the pilot is to demonstrate a significant bitumen production increase as a response to solvent injection. The solvent injection slug was designed to give a significant bitumen production increase in some wells surrounding the solvent injection. This was clearly observed in the multilateral well P11 which has a horizontal leg that is close to solvent injector I9. Figure 20 shows the bitumen production of this well and, after one month of injection, the production rate of this well more than doubled compared to the baseline production of the steam drive. After this initial peak, that coincided with solvent breakthrough, the rates declined but were sustained at a higher plateau for approximately six months. An accurate bitumen uplift in this well is hard to quantify because of the short and uncertain baseline production. Significant solvent production was also observed in Wells P19, P10 and P6; however, bitumen responses were less pronounced and affected by unstable operations. Surprisingly, P19 produced hardly any bitumen during the described period, indicating a possible short cut between injector I7 and P19. No solvent was detected in Wells P1 and P8, indicating that there are preferential paths between injectors and producers and uneven conformance.
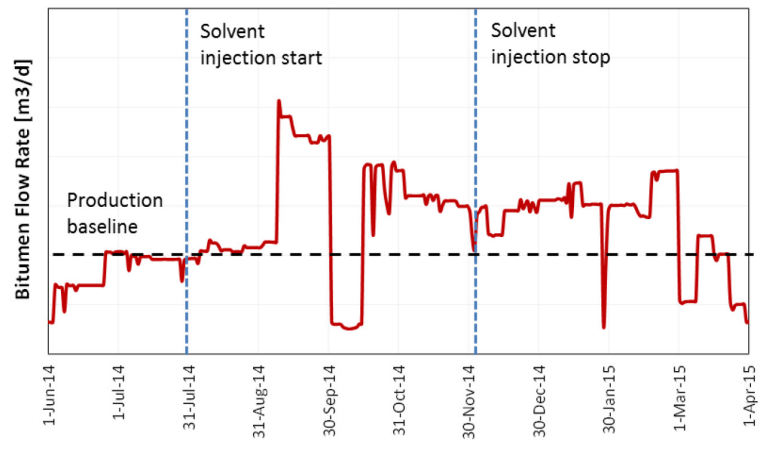

Figure 20—Bitumen production as measured in well P11 showing a significant response to the solvent injection

A more robust method to determine the bitumen uplift is to compare the OSR of solvent injection patterns with steam-only patterns to suppress some of the noise in the data. Note that there were four patterns in total, so the statistical base is small. The instantaneous OSR's of the steam-only patterns and the solvent injection patterns are shown in Figure 21. For the first couple of months both groups show similar OSR performance when they were injecting only steam in the solvent injection patterns. Approximately one month after the start of solvent injection in I7 and I9, the OSR of the solvent patterns increases and remains at a higher value for the duration of the solvent injection. This is very similar to what we observed in P11; however, now this also includes the uplift in the other wells (P6, P10, P19), and there is a much more reliable baseline from the steam-only patterns. While the steam patterns had a cumulative OSR over the pilot period of 0.22, in line with expectations, the OSR of the solvent patterns was increased to 0.32. The increase attributed to the solvent injection is therefore 0.1 over the first 10 months of the steam drive. This translates into a 3.9 e3m^3 incremental bitumen produced from the four wells in this short timeframe. This translates to a solvent effectiveness (incremental bitumen over solvent injected) of 0.76. This value is very similar to our expected increase based on our simulations prior to the pilot.
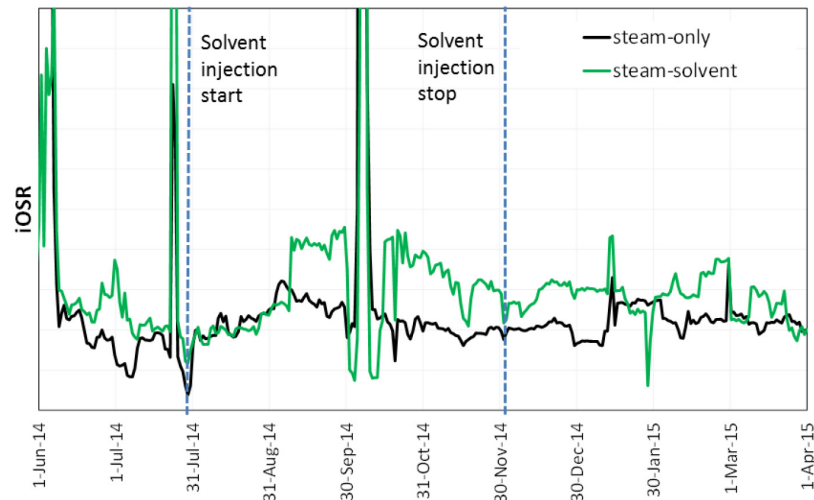
Figure 21— Comparison of instantaneous OSR between steam only and steam + solvent patterns

Solvent Recovery

Much attention was given to the accuracy of the diluent recovery in this pilot, as it is the a key economic factor in the solvent injection process. The fact that more than 75% of the recovered diluent was produced via the CVG system helped, as the measurement errors of the gas stream (rate, composition) are much smaller than those of the emulsion stream. The main uncertainty comes from the calculation method to allocate the hydrocarbons to bitumen and diluent. Figure 22 shows the cumulative diluent recovery over time using the two most reliable methods, the bitumen baseline and synthetic assay methods. At four months after stopping the solvent injection, the recoveries for both methods (51%-59%) exceed by far the expectations based on modelling (37%). Although this was an encouraging result, the fast diluent recovery might indicate bypassing or ineffective use of the solvent. A significant portion of the diluent is recovered from Well P19, while it does not show significant bitumen production. This seems a considerable drawback of the process; however, the diluent recovery in this bypass situation is also very high, which mitigates the downside.
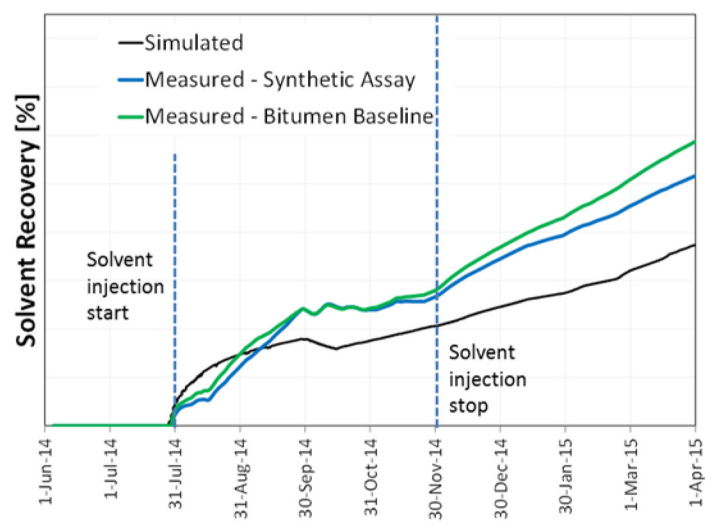

Figure 22— Cumulative solvent recovery curves with ″Bitumen Baseline″ and ″Synthetic Assay GC30 Adjust″ splitting algorithm methods

Based on the recovery so far and the current rates, it is expected to achieve or even exceed the predicted recovery factor of 86% after two years. At that mark, the incremental oil to lost solvent ratio will be 5.2, which is economically favourable and compares well against other solvent co-injection processes [8]. The pilot injection scheme was not designed for optimal economic performance; hence, there is room for improvement in case of a field implementation. Solvent recovery will be monitored continuously to obtain the complete solvent recovery curve.

Conclusions

- Conducting a recovery technology pilot in small brown field infill development is very challenging. It requires a robust design for expected signal and high frequency and redundant data acquisition to obtain quantifiable results.
- Well testing and water cut metering are a large source of error, and need to be thoroughly checked and validated with independent measurements.
- New allocation algorithms were developed and validated to be able to accurately allocate solvent and bitumen in a steam drive process.
- Bitumen uplift could be positively observed in a several wells; the OSR in the solvent patterns was on average 0.1 higher than the patterns without solvent (0.32 vs. 0.22) during the first 10 months of the pilot.
- Solvent recovery is faster than expected, more than 50% of the solvent recovered after four months of stopping solvent injection.

Nomenclature

CWE	= Cold water equivalent
VSD	= Vertical well steam drive
CSS	= Cyclic Steam Stimulation
LEP	= Limited Entry Perforation
CVG	= Casing Vent Gas
TFSR	= Total Fluid/Steam Ratio
OSR	= Oil/Steam Ratio

Acknowledgements

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Appendix A

Diluent accounting methods

LASER method

The first method was described by Khaledi et al. for the LASER pilot of Imperial Oil in Canada [7] whereas the remaining two were developed in-house exclusively for this steam-solvent pilot.

Bitumen baseline method

In this method, it is assumed that the diluents' hydrocarbon portion heavier than C20+ is negligible and that a reference component/pseudo-component native to bitumen exists. The reference compound belongs entirely to the bitumen and is identified using GC analysis of bitumen (Bitumen Baseline - BitBase), that is acquired prior the solvent co-injection, and composition of produced hydrocarbon fluids (Diluted Bitumen - DilBit) during and after solvent co-injection. Figure 23 illustrates the selection of the reference compound and diluent allocation. The rate of diluent components in the produced hydrocarbon mixture is calculated relatively to the content of the reference compound in the bitumen. It is assumed that the selection of the reference compound is not influenced by the measurement error in the component composition and does not change overtime. It is known that the GC determined weight fractions of heavier components are increasingly uncertain. Based on the initial assumption, the reference compound is heavier than C19 and lighter than C29. The C29 and C30 pseudo-compounds should be excluded from the selection range due to the large GC experimental errors for these fractions. It is preferred to use range C20-C28 as the reference as such treatment averages out fluctuations in component measurement errors.
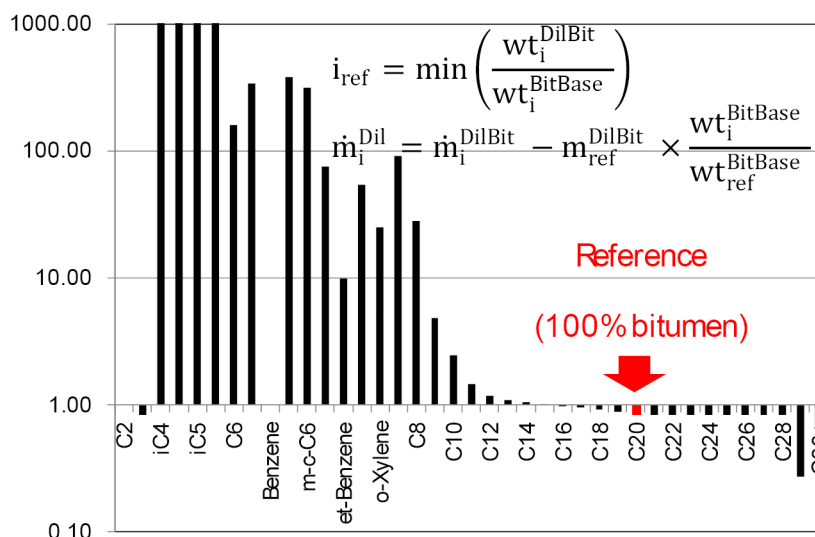

The equations shown in the figure:

$$i_{ref} = \min\left(\frac{wt_i^{DilBit}}{wt_i^{BitBase}}\right)$$

$$\dot{m}_i^{Dil} = \dot{m}_i^{DilBit} - \dot{m}_{ref}^{DilBit} \times \frac{wt_i^{BitBase}}{wt_{ref}^{BitBase}}$$

Reference

(100% bitumen)

Figure 23— Weight ratios of mass fractions of individual carbon numbers (i=C1 to C30+) measured individually for DilBit and bitumen baseline. Compound with minimum ratio is selected as a reference compound

Synthetic assay regression methods

Three in-house regression methods fluids were tested. The methods assume that the relative mass fractions of various solvent components in the produced hydrocarbon mixture (diluent+ bitumen) remain the same as in the injected solvent and that the bitumen composition does not change over time (prior and during diluent injection) and can be therefore regressed. The regressed composition is referred to as synthetic assay (SA). The following GC measurements are required:

1. Overall composition of the produced hydrocarbon fluids (Dilbit) is measured. The mass fractions of this recombined produced blend are wt_i^{DilBit} (i=C1 to C30+) and $\sum wt_i^{DilBit}=1$.
2. The composition of the injected diluent is measured. The mass fractions of the injected diluent are wt_i^{Dil} (i=C1 to C30+) and $\sum wt_i^{Dil}=1$.
3. The produced live bitumen composition (BitBase) has to be acquired prior to the steam-diluent co-injection. The mass fractions of the bitumen baseline are $wt_i^{BitBase}$ (i=C1 to C30+) and $\sum wt_i^{Bit}=1$.

Synthetic assay regression method 1 – no GC adjustment

Synthetic Assay (wt_i^{SA} (i=C1 to C30+) and $\sum wt_i^{SA}=1$) is constructed as follows:

$$wt_i^{SA} = f \times \left(wt_i^{Dil} - wt_i^{BitBase}\right) + wt_i^{BitBase},$$

where f is the mass fraction of solvent in the produced hydrocarbon blend.Synthetic assay regression method 2 – wtC30+ adjustment of bitumen baseline

This synthetic assay algorithm was designed with the objective to addresses possible inaccuracies in the bitumen baseline GC C30+ fraction measurement and bitumen composition variations within the reservoir. The regression method solves for two unknowns. The first unknown is the mass fraction f of solvent in the produced recombined blend. The second unknown is the "adjustable" bitumen baseline C30+ mass fraction ($wt_{30+Adjusted}^{BitBase}$)

The original averaged bitumen baseline with the mass fraction of $wt_i^{BitBase}$ (i=C1 to C30+) is scaled with respect to the adjusted $wt_{30+Adjusted}^{BitBase}$ as follows:

$$wt_i^{ScaledBitBase} = wt_i^{BitBase} \times \frac{(1 - wt_{C30+}^{BitBase})}{(1 - wt_{C30+Adjusted}^{BitBase})}$$

Consequently, the modified synthetic assay is constructed as follows:

$$wt_i^{SA} = f \times \left(wt_i^{Dil} - wt_i^{ScaledBitBase}\right) + wt_i^{BitBase}.$$

Synthetic assay regression method 3 – wtC30+ adjustment of recombined oil

In this variation of the method the regression method solves for two unknowns. The first unknown is the mass fraction f of solvent in the produced recombined blend. The second unknown is the "variable" wtC30+ mass fraction in the recombined oil i.e. $wt_{30+Adjusted}^{DilBit}$. The mass fraction composition of the recombined produced hydrocarbon blend i.e. wt_i^{DilBit} (i=C1 to C30+) is scaled with respect to the adjusted $wt_{30+Adjusted}^{DilBit}$ as the following:

$$wt_i^{ScaledDilBit} = wt_i^{DilBit} \times \frac{(1 - wt_{C30+}^{DilBit})}{(1 - wt_{C30+Adjusted}^{DilBit})}.$$

The modified synthetic assay (wt_i^{SA} (i=C1 to C30+) and $\sum wt_i^{SA} = 1$) is constructed as the following:

$$wt_i^{SA} = f \times \left(wt_i^{Dil} - wt_i^{BitBase}\right) + wt_i^{BitBase}.$$