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History Matching Field Results from a SAGD / Light Hydrocarbon Process (SAGD+^{TM})

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Abstract

Connacher Oil & Gas Limited is presently operating two SAGD projects at its Pod One and Algar sites, about 80 km southwest of Fort McMurray, Alberta, Canada. The total approved steam injection capacity is 57,000 barrels per day. Connacher is committed to enhance the performance of its current projects and future expansion sites by developing drilling, lifting and recovery technologies. Amongst these, SAGD with light hydrocarbon co-injection (SAGD+^{TM}) is one of the most promising methods.

In July 2011, Connacher initiated the first field trial at two Algar well pairs. Shortly after the light hydrocarbon (or solvent) co-injection, increases in bitumen production and solvent recovery were observed. In mid-November, the solvent injection was suspended and the well pairs reverted to the normal SAGD operating mode. The residual effects of solvent injection was monitored until February 2012.

This paper describes the selection of the well pairs, the modifications to the injection and production facilities and the design of the monitoring program. It also describes how the geological, wellbore and production information was used in a thermal simulation model to simulate the recovery behavior. By matching the production history, Connacher gained significant insights into the reservoir recovery and well flow mechanisms. Furthermore, Connacher was able to identify areas of improvement and applied them in the subsequent SAGD+^{TM} field trials.

Introduction

Connacher operates two SAGD plants in the Great Divide Area of Alberta. The older of these two plants, Pod One, has been producing bitumen since 2007. The Algar plant, which is 6 km from Pod One, came on stream in 2010 (Figure 1). Both plants use a steam assisted gravity drainage (SAGD) process [1] to produce bitumen from horizontal well pairs 500 to 800 m long and drilled in an oil sands zone that is up to 25 m thick. The average thickness of the bitumen bearing sand at Pod One is approximately 21 m and the average at Algar 20 m. Successful bitumen production from this resource requires the application of the very latest SAGD technology. Conventional SAGD requires two horizontal wells drilled along the base of the bitumen pay with the upper well, the injector, placed approximately 5m above the producing well. Production is initiated by circulating steam in both wells. Once communication is established between the wells, steam is injected at relatively high rates into the injector to form a steam chamber and the bitumen is produced by gravity drainage along the edges of the chamber and into the lower producer. Various techniques have already been advanced at the Pod One facility to enhance the basic SAGD process including the use of high temperature downhole pumps and pressure balancing under a gas cap [2].

Algar presented different geological challenges than Pod One. While there was no gas cap present, the average reservoir quality was slightly lower and the geology more complex. In order to improve production rates and reduce steam/oil ratios, enhancements to the basic SAGD process were considered. The processes evaluated were infill wells, steam with a surfactant additive and steam with a solvent additive. Infill wells will be tested in the near future in Pod One and field tests of a steam and surfactant additive commenced December 2011, also in Pod One. Algar was a better candidate for SAGD+^{TM}, a steam/light hydrocarbon (or solvent) co-injection process, as the reservoir was early in the development life and had few thief zones (e.g. a gas cap, a high water saturated zone) that could contribute to the loss of the injected solvent.

Background

Algar Facilities, Wells and Project History

Currently there are 17 well pairs producing at Algar (Figure 1). With the exception of one pair, all horizontal well pairs commenced steam injection in May 2010 and first production was in the following month. At the end of April 2012, the Algar project had produced 604,018 m^3 of bitumen and injected 2,856,251 m^3 of steam (cold water equivalent) for a thermal efficiency based on a steam/oil ratio of 4.46. Producing well peak bitumen rates were approximately 80 m^3/day and ranged between 49 and 120 m^3/day. The average bitumen production rate as of April 2012 was 57.3 m^3/day/well and the average steam injection rate was 274.5 m^3/day/well (Figure 2).

The bitumen at this facility is produced predominately as a bitumen-in-water emulsion with bitumen content of 15% to 25%. The product sold from the facility is “dilbit”, a mixture of bitumen and light hydrocarbon (diluent).

Reasons for the SAGD+™

The main reason for injecting solvent together with the steam is to deliver solvent to the edges of the SAGD steam chamber. At these cooler chamber edges the steam and light hydrocarbon condense; steam delivers its latent heat to the bitumen and the solvent dissolves and diffuses into the bitumen. Both mechanisms reduced bitumen viscosity.

Prior to this reported field test, Connacher carried out simulations (not reported here) of the steam / light hydrocarbon process with a typical light hydrocarbon (hexane) at concentrations of up to 15% by volume and at reservoir pressures between 2,000 and 4500 kPa. These simulations indicated that additional productivity, incremental recovery and improved thermal efficiency would result from the addition of simple solvents.

Reduction of bitumen viscosity using solvents has been reported in the literature and used in the field a number of times, though not necessarily in association with the SAGD process. Many laboratory-based experiments using steam and solvents to recover bitumen from the oil sands have been reported. The work of Redford and McKay [3] made it quite clear that in the laboratory the addition of most solvents to steam under a number of different conditions always improved oil recovery. The Redford and McKay work and a subsequent patent [4] showed that heavier solvents are generally better. When considering the practicalities of handling the solvent prior to and downstream of the wells, heavier solvents have a distinct advantage.

Based on PVT data, heavier solvents can also reduce reservoir losses. An important requirement of the SAGD+ ™ process is to recover as much of the injected solvent as possible and recycle it or include it with the sales oil, or dilbit (at Algar this is a mixture of bitumen ~75% and diluent ~25%). Minimal solvent losses are a critical aspect of the project economics as the injected solvent is more expensive than the produced bitumen.

While many technical papers and patents discuss the use of more specific (pure) hydrocarbons, practical reasons make their use uneconomic in the Athabasca Oil Sands, especially when solvent losses into the reservoir are taken into account.

A critical part of the treating process at the Algar plant, and nearly all other SAGD operations, is the addition of a diluent in the 680 to 730 kg/m^3 density range. This diluent is added to the produced emulsion together with other chemicals to reduce viscosity and promote separation of the bitumen from the water. Injecting a solvent that is compatible with the diluent used in the treating system makes operational sense.

Field Trial

Connacher's first SAGD+™ field trial was initiated to determine if previous simulation and laboratory work [3] could be duplicated in a practical manner in the field. The field trial was also intended to provide real-world data that could be used in a reservoir simulation model.

A commercially available solvent was co-injected with the steam starting in July 2011 at initial rates of 10% by volume and increased to 15% by volume in October 2011. The solvent injection was terminated in mid-November 2011.
The two well pairs selected for the SAGD+™ trial reported in this paper were 203-02 and 203-03 (Figure 1). Details of the trial are discussed below.

Compared to an April 2011 baseline, daily average bitumen production volumes during the months of August 2011 and September 2011 increased 23 percent. This was also accompanied by an average SOR decrease of 15 percent (Figure 12 & 13). The SOR decrease was limited by the necessity to maintain high steam injection rates so that downhole pressures were high enough for the successful operation of the gas lift system used in the producing wells. This requirement will not be necessary in the future when the company installs downhole pumps and transitions its Algar operations to low pressure SAGD.

Geological Description

The McMurray Formation in the area of the Algar SAGD project consists of a complex clastic assemblage of fine to medium sands with generally increasing muddy interbeds that are highly bioturbated toward the top of the reservoir which is capped with a mudstone. This facies sequence is defined by shale volume (Vsh). It often includes massive cross bedded sands (Z1) overlain by IHS, a laterally accretive, interbedded sands and shales (Z2-4) capped by laminated mudstones (Z5). These tight mudstones are considered a barrier to fluid flow and act as a local caprock. Whereas, intermittently, there is a brecciated facies (Z6) with various size clasts that are interpreted to be storm slump deposits and considered a baffle to fluid flow (Figure 3). The basal sediments of the reservoir are incised valley sediments deposited in a high-energy, sand-dominated environment. The upper parts were generated in estuarine to marginal marine environments, resulting in a fining upward sequence of sands and muds. The tight mudstones capping the reservoir are mudflat/swamp deposits.

Within the reservoir, there is presence of a bottom water interval. A typical McMurray water wet zone in this area has a petrophysical induction response of approximately 6-10 ohm*m (Figure 4).

Geostatistical models were generated to help understand the facies, grade and connectivity relationships within the complex McMurray reservoir in Algar. The model was generated with petrophysical log and core data from all vertical delineation wells and lateral well pairs drilled to date. Using high resolution petrophysical logs and cores, an accurate correlation of facies were determined for all vertical wells. In addition, petrophysical analysis was performed to calculate Vsh, porosity, effective permeability [5], grade (weight percent bitumen) and oil, gas, and water saturations (Figure 5). Regional geology, core sedimentary structure analysis and seismic were also used to help map sand body geometries. Stochastic realizations using variograms were then computed and validated (Figure 6). Validation was done by intentionally creating the model without certain key wells and observing the predictive capacity of the model. Further validation was done with new wells drilled this past winter.

Field Trial Design

Wells and Injection Facilities

The 203-02 and 203-03 well pairs were chosen because of their relatively simple and similar geology, and the fact that both wells had reached peak production and entered into a stable operational phase.

The downhole completions for the two well pairs are shown in Figures 7 (203-03 injector) and Figure 8 (203-03 producer). Each well was completed with a slotted liner and two tubing strings. The wellhead and tubing arrangements were designed such that a well shut-in was not required between the circulation and SAGD phases. The same well designs were also used at well pair 203-02.

Solvent and steam were injected into the long and short steam lines just prior to the injector wellheads (Figure 9). There is a flow control for steam and solvent on each string. Solvent was added downstream of the steam flow control to attain the required solvent concentrations. During the test period, steam rates were varied as required to maintain bottom hole pressure.

Fluid production from the long and short strings in the producing wells was controlled by gas lift rates and surface chokes. Generally, the wells were operated with a relatively low subcool of between 0^0C and 5^0C. The definition of subcool is the value by how much the steam saturation temperature, (corresponding to well buttonhole pressure) exceeds the temperature of the produced water. The water balance for the well pairs (i.e. the water produced / steam injected) was also used as a guide for production control.

Solvent Composition and Rate

There were five requirements for selecting the solvent used at Algar:

1. The solvent should be heavy enough so that a significant fraction will condense with the steam and be produced with the bitumen-water emulsion.
2. The solvent must be compatible with the bitumen and not cause adverse reaction such as the precipitation of asphaltene.
3. The solvent must be compatible with the diluted bitumen (dilbit) that is shipped from the facility to heavy oil upgraders.
4. The solvent must be commercially available in substantial quantities and at a price that will make it cost effective in reducing bitumen viscosity in spite of the reservoir losses.
5. The solvent should be easy to handle with normal oil field facilities and so a solvent that is a liquid at standard temperatures and pressures is preferred.

The solvent selected by Connacher which meets many of the above requirements was a commercially available condensate with C4-C8 components and a density between 675 and 695 kg/m^3. The solvent injection volume of 10% to 15% of the steam volume (cold water equivalent) was selected for the first trial based on findings from Connacher's initial simulation studies. This volume ratio is also a practical range. Firstly, the solvent concentration is a small portion of the injection stream and it should not significantly change the carrier steam temperature. The resulting low partial pressure of the solvent vapour should be able to keep even the heavier solvent molecules in their vapour form. Secondly, the solvent recovered with the bitumen should approximately equate to the amount of diluent required for blending the bitumen into dilbit.

Solvent Recovery Facilities

At the injector bottomhole, the solvent vapors rise into the steam chamber, contact the bitumen, condense and drain to the producer along with bitumen and water. The wellhead fluids at the producer bottom-hole are produced through the long and short strings with the aid of gas lift. The produced fluids are then directed either to the test or the group separators (Figure 10). The solvent, which was mainly in a vapour phase, was produced to the central processing facility where it was recovered and recycled (Figure 11).

A small amount of solvent is produced along with bitumen in the produced emulsion which is processed along with additional diluent in the CPF treaters to separate the bitumen and water. The solvent in the vapours coming from the well group headers (Figure 11) is condensed along with steam and recycled to the treaters. Solvent that is not condensed enters the fuel gas system and is burnt in the boilers. The diluted bitumen from the treaters is cooled and shipped as dilbit.

Measurement of Recovered Solvent

It was very important that adequate measurements be obtained to quantify the production increase, SOR improvement, and the solvent recovery to demonstrate the effectiveness of the SAGD+™ process. The solvent balance for the test was based on the fact that the solvent was composed primarily of C4-C8 components and there was little overlap with the bitumen produced or with the lift gas used to produce the bitumen. All produced C4-C8 components were attributable to the injected solvent. Measurements were done through a combination of flow meters and sampling to obtain the solvent fraction through simulated distillations and density.

The calculation of solvent recovered in the process required measurement of solvent in both the emulsion and gas streams. This was done by sampling those streams and analyzing the composition and density of the emulsion and the composition of the vapour.

Individual Wells

The solvent balance for individual wells was obtained by directing the production through the test separator as shown in the production system schematic (Figure 10).

For each well pair:

Solvent Injected = FTI201+FTI203 (Figure 9)
(FT# refers to the volume meters on the plant drawings in Figures 9 to 11)

Solvent Produced = Solvent in Vapour + Solvent in Liquid

Solvent Produced = S1 * FT14912 + S2 * FT14919*(1-W) (Figure 10)

S1 (Solvent Fraction) **wa**s determined by sampling the vapours off the test separator and determining the solvent components. S2 (Solvent Fraction in liquid Phase) was determined by separating the oil and water (W = Water Cut) and analyzing the oil for solvent components.

Battery

A solvent balance for the whole Algar production facility (battery) was also calculated so that errors could be proportionally allocated to the individual wells. The accuracy of fluid measurement at Algar was generally within 10%. This battery balance was calculated from the meters shown in Figure 10. The treating facilities operate at a temperature of approximately 125^{o}C.

For the Battery:

Total Solvent Injected = FT10401

Solvent Produced = Solvent in Vapour + Solvent in Liquid

Solvent Produced in Vapours
= Solvent Recovered in Vapours + Solvent Losses to Fuel Gas
= S5*FT11216 + S4*FT11213.

Solvent Produced
= S5*FT11216 + S4*FT11213 + S3*FT1311*(1-W)

Where, S3 is the solvent in the bitumen emulsion measured at the test separator. S4 is the solvent measured in the gases directed steam boilers. S5 is the condensed solvent recovered from the inlet vapour separator. The solvent measured at S5 (only components less than C9 are included) is returned to central processing plant FWKO/separator and aids in the treating process.

The amount of solvent in the bitumen produced is calculated from:
Solvent in Bitumen
= S4*FT11213 + S3*FT1311*(1-W)

Reservoir Losses = Solvent Injected – Solvent Produced

Field Results

Bitumen Production Prior to Solvent Injection

Bitumen production and steam injection for the two well pairs since the start of steam injection in May 2010, is shown in Figure 12. In the months prior to solvent injection (July 2011), the two test well pairs, 203-02 and 203-03 had produced 25,687 and 20,044 m^3 of bitumen respectively. This volume is approximately 12% of the original volume of bitumen in the well-pair drainage areas. During the same period, the well pairs had injected 95,084 m^3 and 84,647 m^3 of steam (cold water equivalent). Monthly peak bitumen rates prior to the trial were approximately 100 m^3/day for well pair 203-02 and 70 m^3/day for 203-03. Total bitumen production rates for the two wells averaged 79 m^3/day/well in April 2012, and average steam injection rates were 282 m^3/day/well. There was a plant turnaround in May 2012 so April is used as a pre-trial reference for production changes.

Measured Steam, Bitumen and Solvent Volumes during the Trial

The combined performance for the two well pairss during the SAGD+™ trial is shown in Figure 13. This graph also shows the injection, recovery and losses of solvent from the two well pairs.

Connacher's steam and solvent technology, SAGD+™, demonstrated favourable results during the 2011 field trial. Increases in production and lower steam / oil ratios were measured and a solvent recovery rate was achieved that is high enough to be economic in full scale project. Compared to April 2011 (baseline), the daily average bitumen production volumes during the months of August 2011 and September 2011 increased by 23 percent. This was also accompanied by an average SOR decrease of 15 percent during the same period (Figures 12 & 13). The SOR decrease was limited by the necessity to maintain high steam injection rates so that downhole pressures were high enough for the successful operation of the gas lift system used in the producing wells. This requirement will not be necessary in the future when the company installs downhole pumps and transitions its Algar operations to low pressure SAGD.

During the solvent injection trial, most of the solvent was recovered from the vapour separator (V-112, see Figure 11). The sampling results showed that significant amounts of solvent were also recovered through the emulsion and produced gas streams. The total solvent recovery was estimated to be over 85%. The current method of measuring solvent recovery has some inherent inaccuracies but we estimated that the results are within +/- 10%.

Further testing is required and as of May 2012, Connacher commenced a second test on one other well pair in the same Pad 203 at Algar. A number of refinements have been incorporated into the second trial including a more efficient solvent recovery scheme.

Numerical Simulation

Approach

A history match study of the SAGD+™ trial was started soon after the initiation of solvent co-injection at the 203-02 and 203-03 injectors. Geological information used in the model was an upscaled SAGD grid based on a 3-D geostastical model that had been created in a commercial software package. This model used well pairs 203-02, 203-03 and an adjoining well pair, 203-04. The geostastical model creates a number of realizations of the geology but for simulation purposes the most likely realization was selected.

The SAGD grid model was imported into a dynamic reservoir simulator and the model was downsized from three well pairs to one well pair for test runs (i.e. 203-04, to simulate SAGD only). Through several initial runs, the model thickness, facies descriptions, petrophysical properties, grid sizes, relative perm abilities, fluid properties, thermal properties, wellbore parameters and numerical parameters were examined to ensure that they were in the practical ranges. When satisfactory SAGD match results were obtained from 203-04, the model was expanded laterally into a dual well pair model to include one of the SAGD+™ well pair - 203-03.

Reasonable matches were obtained and with the experience gained, the geology and wellbore sections were modified to set up a new model for well pairs 203-02 and 203-03. The simulation process was repeated.

Without significant changes, good history matches were obtained for the 203-03 and the 203-02 well pairs. The repeatability indicates that the model parameters were valid. Subsequently, the history match run was updated periodically with new production data to further verify its validity. For the purpose of the current paper only the 203-02/03 model results up to mid-May 2012 are presented.

Input

The model has a length of 800 m and a width of 200 m. It has a range of thicknesses from 35m to 40m (McMurray C to the Devonian). This thickness was chosen such that adjacent secondary and/or lean zones were included. Although these zones were of low quality and were not expected to contribute significantly to the bitumen production, they were important for simulating any "thief-zone" effects. Table 1 shows a summary of the model parameters.

Grid dimensions of 2m (width) by 1m (thick) by 50m (length) were selected based on a comparison study conducted during the early runs.

Three sets of input data were used to describe the specific reservoir and operational settings: geological parameters, wellbore configurations and well constraints.

To obtain a realistic geological description, Connacher used advanced geomodelling software to provide 3D descriptions of the reservoir. As discussed in the Geological Description section, the model takes into account all geological features observed in the vertical delineation and horizontal SAGD wells and applies a statistical technique to populate the model with facies and petrophysical information.

To simulate the wellbore effects, a coupled reservoir simulator was used that was capable of simulating the wellbore dynamics. The casings, liners, long and short injection tubings and long and short gas lift tubings were described based on the actual wellbore trajectories and configurations. It was decided that only the horizontal portions of the SAGD wells would be modeled because the incorporation of vertical/slant sections would slow down the runs and introduce other simulation uncertainties.

The following are the daily operational constraints specified at the injectors and producers:

During Steam Circulation:

- Long tubing steam rate
- Heel annulus pressure

During SAGD and SAGD+™:

- Injector short tubing steam/solvent rate
- Injector long tubing steam/solvent rate
- Producer heel annulus pressure
- Producer heel tubing pressure (estimated from the annulus pressure by assuming a tubing pressure drop)

These were the key parameters that were controlled either directly or indirectly by field operators on an on-going basis. While the steam rates were directly controlled, the producer wellbore pressures were indirectly controlled through the lift gas rate and choke back pressure.

During the early runs, an investigation was performed to compare two input methods: daily data and 5-day averaged data. The daily data case was found to provide more meaningful predictions and numerically more efficient than the 5-day averaged case. The daily method was therefore adopted.

Objective of the History Match

The objective of this simulation was to tune the reservoir properties and process parameters so that the model was capable of predicting field performance. At Algar, the closely monitored field performance parameters were:

Bitumen/water production volumes

In this study, the production rates, trends and cumulative volumes are considered to be equally important. A higher priority has been given to the bitumen production because (i) bitumen prediction is the primary concern, and (ii) the bitumen volumes are more accurately measured than the other flow volumes.

Injector Bottom-hole Pressure

At Algar, the injector heel pressures are determined from the injector blanket gas pressures. This is one the most routinely monitored well pressure parameter. It is an indication of the steam chamber pressure.

Solvent Recovery Volume

The target solvent recovery for the history match was 85% based on field data.

Key Process Variables

A large number of sensitivities were conducted by varying the following reservoir and process parameters:

- Horizontal permeability
- Vertical permeability
- Initial oil and water saturation
- Critical water saturation
- Residual oil saturation to gas
- Residual oil saturation to water
- Relative permeability to water
- Relative permeability to gas
- Thermal capacity rock
- Thermal conductivity of rock
- Solvent k value
- Solvent viscosity
- Steam quality

Table 2 provides a brief summary of the observed sensitivities of each variable.

Simulation Results

Figure 16 and 17 show the rate and pressure matches for well pair 203-02. As of May 13, 2012, the predicted cumulative bitumen and water volumes are 55,828 and 178,751 m^3, respectively. These are equivalent to 103% and 97% of the measured field production volumes, respectively. With no solvent injection, the model predicted that the bitumen production would be reduced by 4,565 m^3. Thus, the model predicted that the incremental bitumen production from SAGD+^{TM} would be 5.9 m^3 of bitumen for each cubic metre of unrecovered solvent (18% as discussed below).

Figure 18 and 19 show the rate and pressure matches for well pair 203-03. As of May 13, 2012, the predicted cumulative bitumen and water volumes are 52,217 and 169,565 m^3, respectively. These are equivalent to 112% and 95% of the measured field production volumes, respectively. With no solvent injection the model predicted that the bitumen production would be reduced by 5,055 m^3. Thus, the model predicted that the incremental bitumen production from SAGD+^{TM} would be 6.1 m^3 of bitumen for each cubic metre of unrecovered solvent (20% as discussed below).

Figures 20 and 21 show the solvent injection and recovery rate comparisons. The model predicted 50 to 70% of solvent recovery during the injection period and an additional recovery of about 25% after the termination of solvent injection. The predicted cumulative recoveries from the 203-02 and 203-03 well pairs are 82% and 80%, respectively. These are slightly lower than the field estimate of 85%.

The above results are also summarized in Tables 3 and 4.

Discussion

The results presented in this paper represent the first field trial of Connacher's SAGD+^{TM} process. The satisfactory volume and pressure matches indicate that the model is capable of simulating the recovery mechanisms. It also verifies that a relatively small amount of solvent can improve the performance of a conventional SAGD process.

The hydrocarbon solvent vapour is carried in the steam chamber at very low concentrations, and is greatly concentrated at the chamber edges where steam condenses (Figure 22). As the mole fractions of different hydrocarbon components increase, their corresponding partial pressures also increase. When the partial pressure of a hydrocarbon component reaches that of its saturation pressure, it starts to condense. The reduction in concentration of this component in turn causes the remaining molecules to reach their saturation pressures and thus trigger a chain of mole fraction changes in the vapour system. Eventually, all condensable molecules are condensed by cooling at the steam chamber edges. A comparison of the vapour solvent mole distributions in Figure 22 and the liquid solvent mole distributions in Figure 23 indicates that all solvent condensations occur within a short distance of the chamber edges.

Among the reservoir variables considered in this study, the relative permeability end points (see Table 5) and the thermal properties (see Table 6) are the most sensitive. They appear to be highly interdependent of each other and suggest that the mechanisms are very complex. In this study, relatively low water and gas end point relative permeability curves have been used. Low relative permeability values of water and gas are often seen in laboratory tests of heavy oil and oil sands cores.

The liquid phase viscosity of solvent shows a strong effect on the bitumen productivity. This is an area that needs further laboratory testing.

The history match model was used to provide predictions for subsequent SAGD+^{TM} trials. It was also modified into a simpler semi-homogeneous model for an optimization study of the process.

Conclusion

1. The first trial of Connacher's SAGD+™ project was successfully completed and favourable field results, including increased production and improved steam / oil ratios, were obtained from both well pairs. The results were sufficient to justify another trial and commercial evaluation.
2. A 3D geostatistics model was developed to provide valuable information for the assessment and visualization of the Algar reservoir.
3. A reservoir simulation model coupled with the wellbore was developed from the geomodel. A history match study was conducted to assess the SAGD+™ process. Satisfactory results were obtained.

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Table 1: 3D Model Parameters

Parameter	Values
Top of McMurray C (m)	480 - 485
Top of Oil sand (m)	485 - 495
Bottom of Oil sand (m)	510 - 520
Average Porosity of Oil sand Pay	30%
Average Oil Saturation of Oil sand Pay	80%
Top Gas (m)	0
Bottom Water (m)	1 - 3
Average Horizontal Permeability (mD)	2361
Average Vertical Permeability (mD)	454
Initial Reservoir Pressure (kPa)	2500
Initial Resevoir Temperature (^oC)	14
Initial Solution Gas-Oil Ratio (m^3/m^3)	4.9

Table 2: Summary of Variable Sensitivities

Mode of Operation	Key Sensitive Variables	Comments
Steam Circulation	Critical water saturation	This parameter determines the amount of mobile water in the reservoir and thus affects the water leak off rate during steam circulation.
	Thermal properties	This set of properties affect how fast the injector and producer communicates during steam circulation.
	Steam quality	During the circulation period, steam delivered at the heels have lower qualities than during SAGD due to the heat transfers between injection and production tubings. The steam quality has a strong influence on how much of the reservoir is heated.
	Vertical permeability	The vertical transmissibility was varied to match the fluid communication timing between the injector and producer. It also affects the injection pressure during ramp up.
	Critical water saturation	This parameter has a strong effect on the amount of water produced.
	Residual oil saturation to gas	This parameter determines the residual oil saturation in the steam chamber.

	Residual oil saturation to water	This parameter, together with relative permeability end point, affects the bitumen rate and production stability.
	Relative permeability to water	This parameter has a strong influence on the bitumen rate and production stability.
	Relative permeability to gas	This parameter also has a strong influence on the bitumen rate and production stability.
	Thermal properties	The thermal properties have a strong influence on the heat distribution and thus are significant in obtaining the steam-oil ratio match.
	Steam quality	Steam is generated at 100% at the generators. Certain losses are anticipated. The steam quality is another variable used to match the steam-oil ratio.
Solvent	Solvent k value	The k value appears to have an inverse relationship with the solvent return. For the type of solvent studied, there is little influence on the incremental bitumen production.
	Solvent viscosity	This parameter contributes significantly to the incremental bitumen recovery.

Table 3: Measured Versus History Match Volume

	Parameter	Field Measure-ment	Model Prediction	Prediction Percentage
203-02	Cumulative Bitumen Volume (m3)	53991	55828	103.4%
	Cumulative Water Volume (m3)	185002	178751	96.6%
	Cumulative Solvent Injection (m3)	4299	-	-
	Cumulative Solvent Recovery (m3)	3654 +/- 10%	3526	82.0%
203-03	Cumulative Bitumen Volume (m3)	46569	52217	112.1%
	Cumulative Water Volume (m3)	178751	169565	94.9%
	Cumulative Solvent Injection (m3)	4268	-	-
	Cumulative Solvent Recovery (m3)	3628 +/- 10%	3433	80.4%

Table 4: Simulation Estimates of Incremental Bitumen

	203-02	203-03
History Match Case Cumulative Bitumen Volume (m3)	55828	52217
Steam Only Case Cumulative Bitumen Volume (m3)	51263	47162
Incremental Bitumen due to Solvent Co-Injection (m3)	4565	5055
Solvent Loss in History Match Case (m3)	773	835
Incremental Bitumen to Solvent Loss Ratio (m3/m3)	5.9	6.1

Table 5: Summary of History Match Variables

Variable	Values
Horizontal permeability (mD)	2361
Vertical permeability (mD)	1136
Thermal capacity of rock (J/m^3-C)	1.70E+06
Thermal conductivity of rock (J/m-day-C)	7.56E+05
Thermal conductivity of oil (J/m-day-C)	1.30E+04
Thermal conductivity of water (J/m-day-C)	5.44E+04
Thermal conductivity of gas (J/m-day-C)	2892
Steam quality during circulation	50%
Steam quality during SAGD/Solvent	90%

Table 6: Summary of End Points

Facies	Critical water sat.	Residual oil sat. to gas	Residual oil sat. to water	Water relative perm.	Gas relative perm.
Clean Sand	10.0%	12.5%	12.5%	0.01	0.04
Sandy IHS	15.0%	20.0%	20.0%	0.01	0.04
IHS	25.0%	30.0%	30.0%	0.01	0.04
Muddy IHS	30.0%	40.0%	40.0%	0.01	0.04
Breccia	10.0%	15.0%	15.0%	0.01	0.04

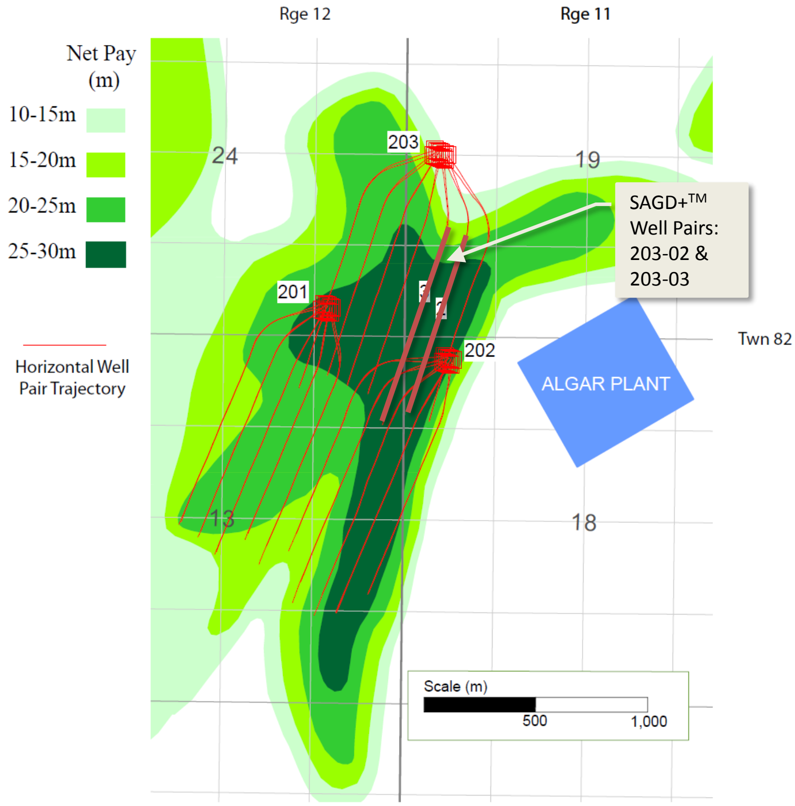

Figure 1: Algar Horizontal Well pair Trajectory

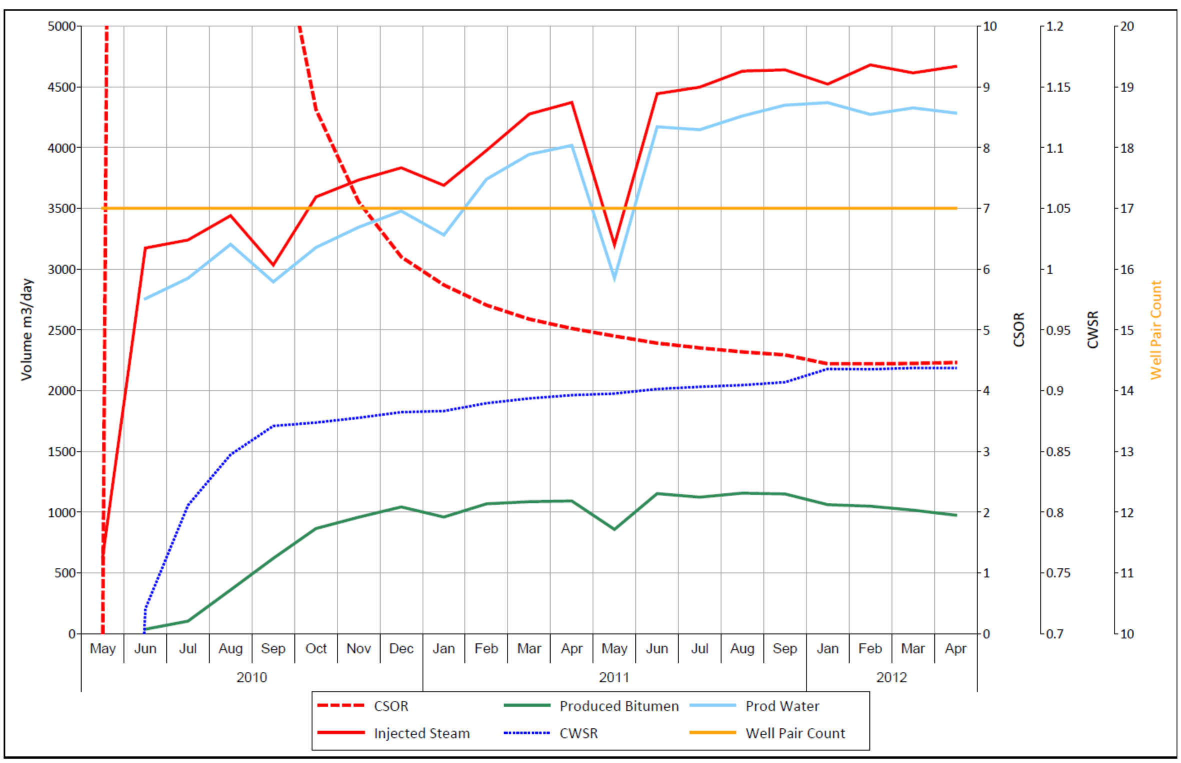

Figure 2: Algar Project Injection & Production

Zones
Defined by VSh

Cut-Offs
Z1 (Sand): 0-10% fines
Z2 (Sandy IHS): 10-20% fines
Z3 (IHS): 20-50% fines
Z4 (Muddy IHS): 50-80% fines
Z5 (Mud): 80-100% fines
Z6 (Breccia): >10% clasts

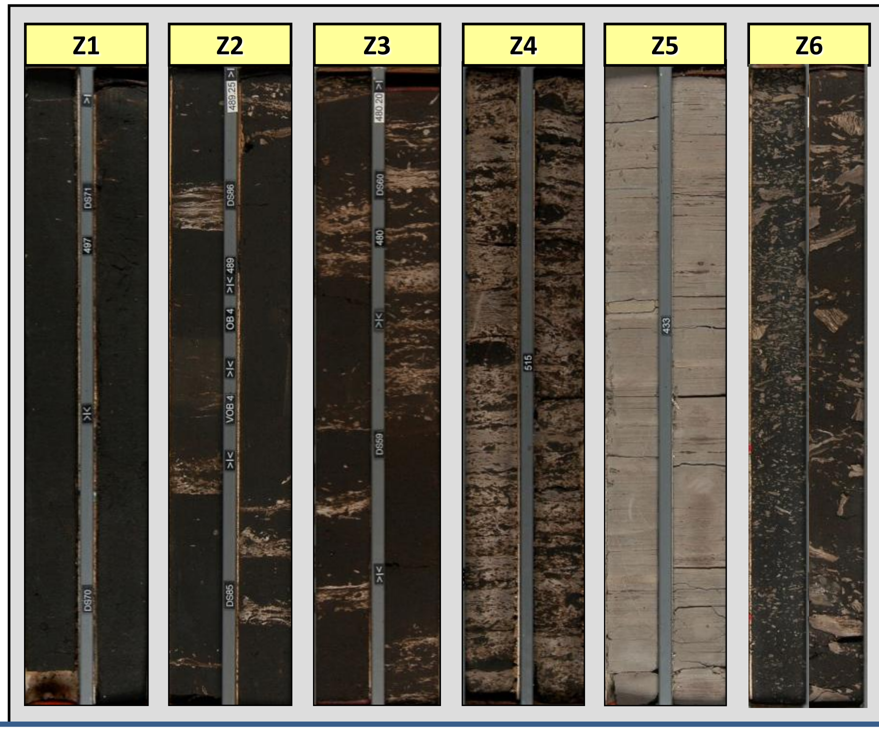

Figure 3: Connacher McMurrayFacies Definition

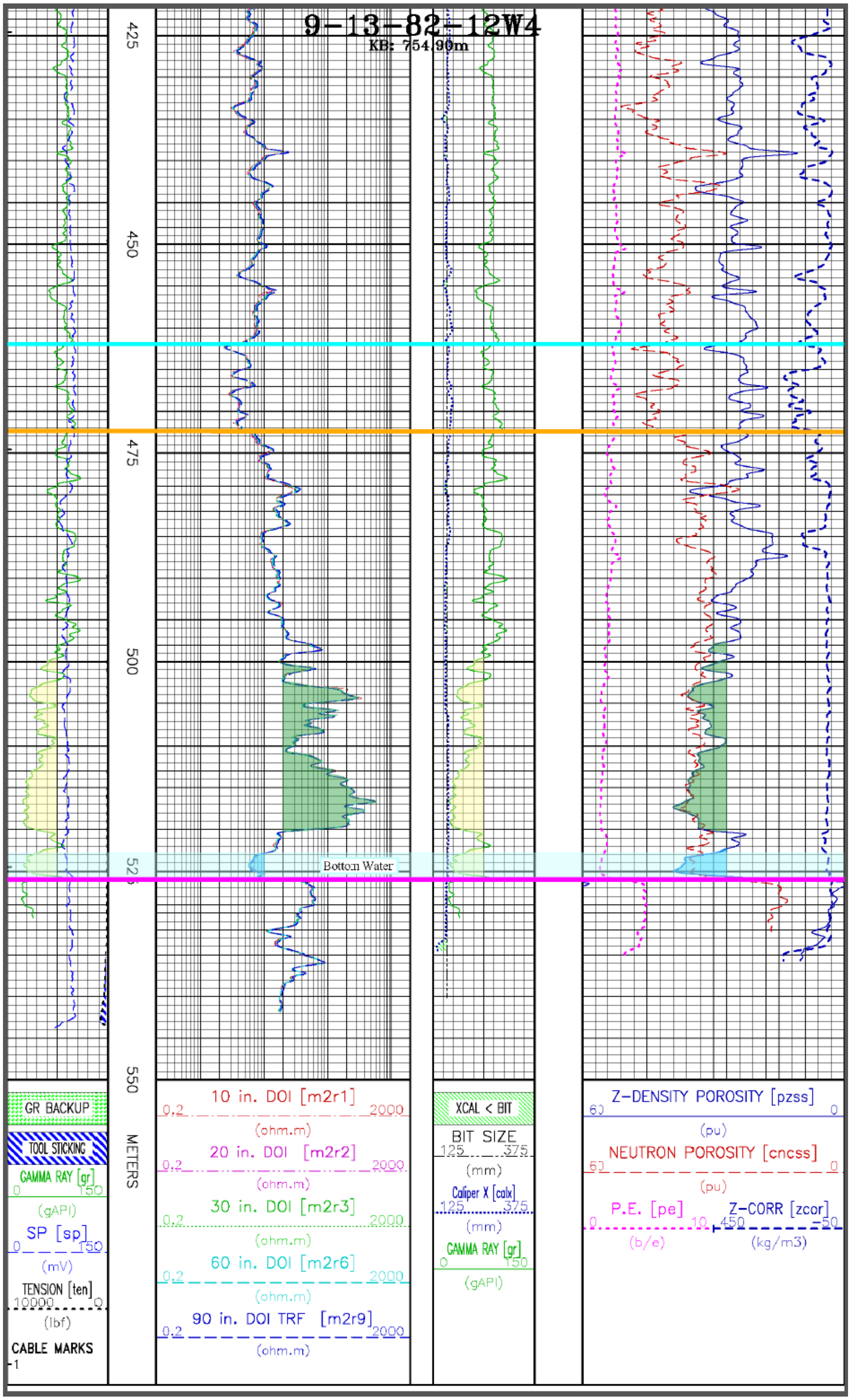

Figure 4: Algar Type Log Showing Bottom Water

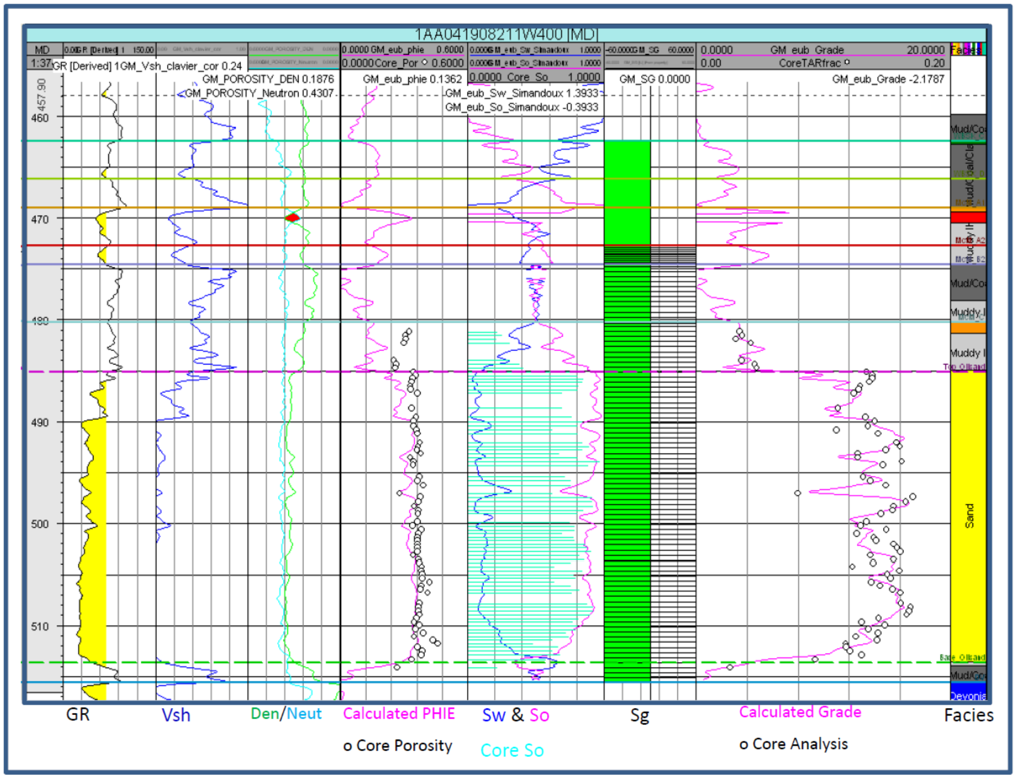

Figure 5: Petrophysical Analysis of Key Algar Well

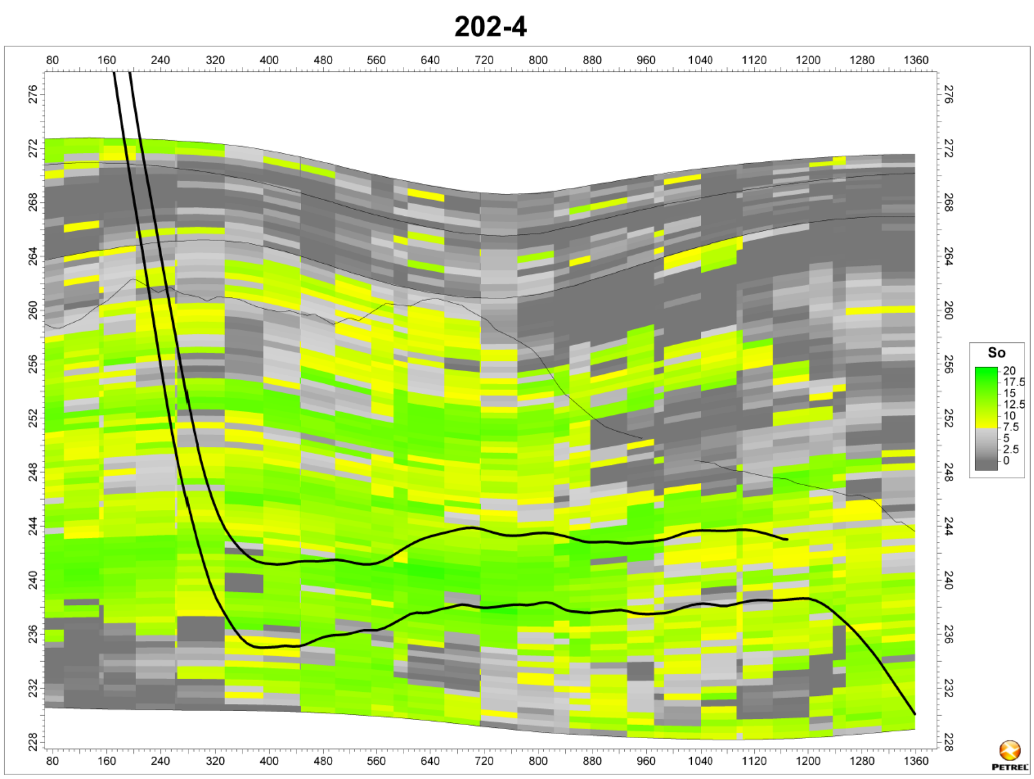

Figure 6: Geomodel Sections Showing Grade

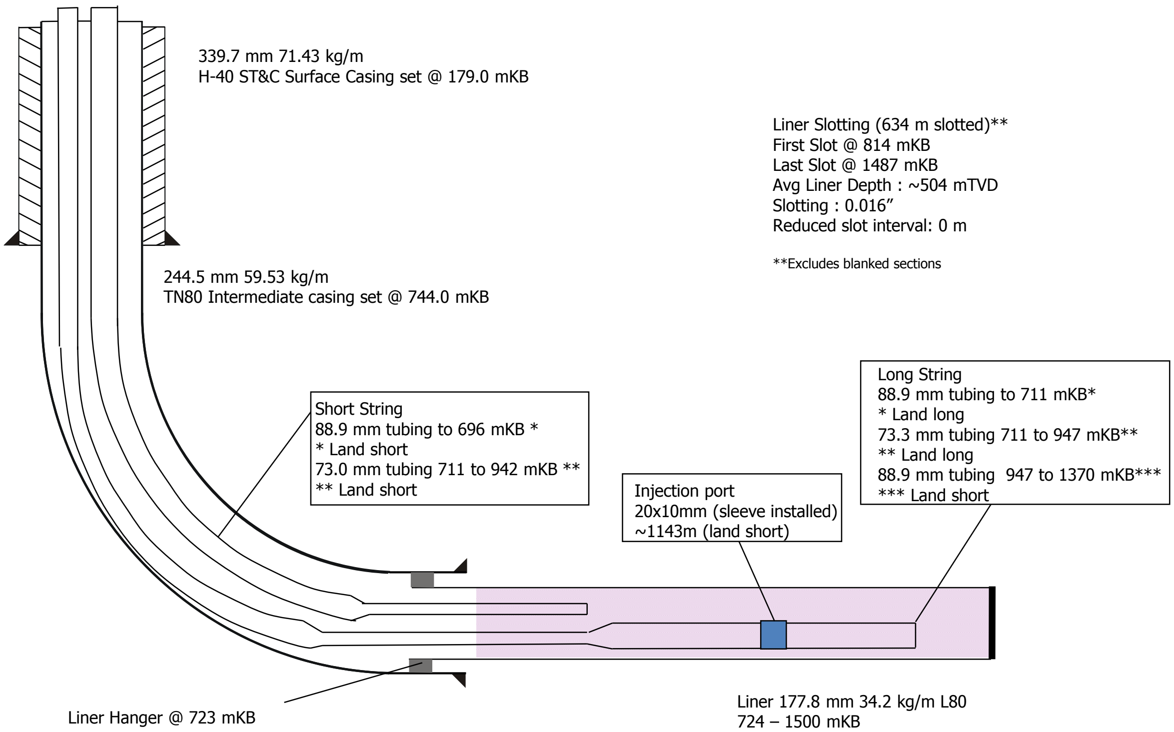

Figure 7: 203-03 Injector Configuration

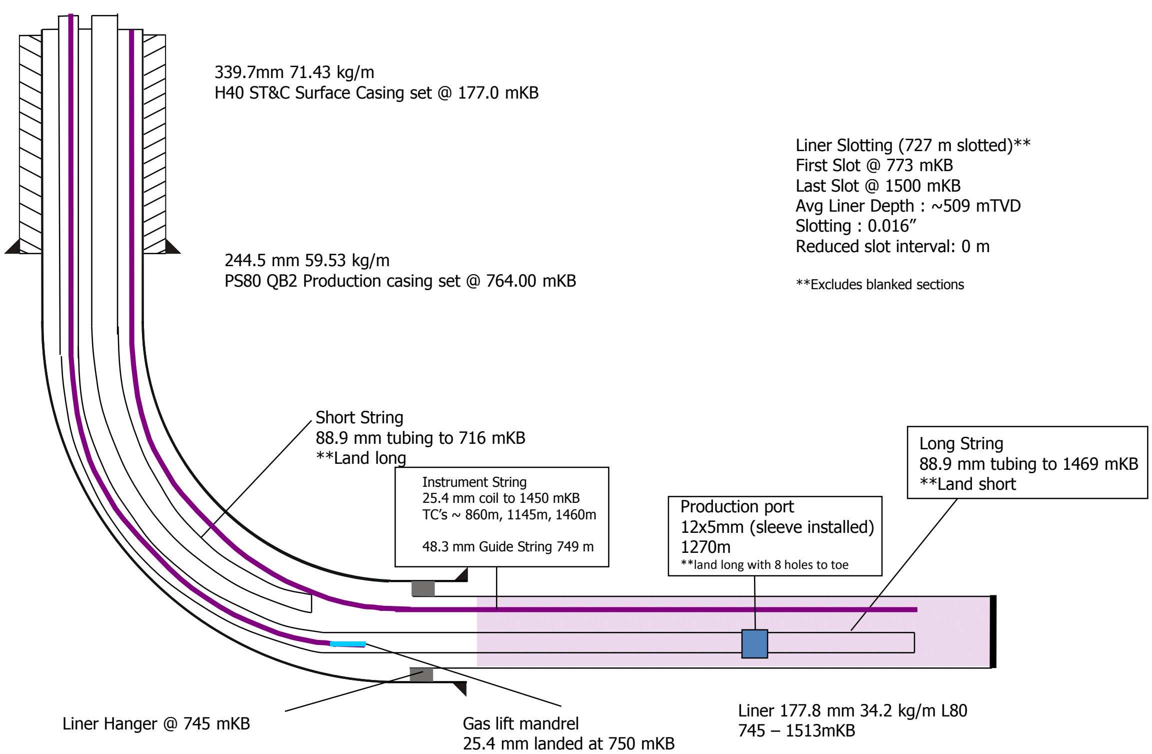

Figure 8: 203-03 Producer Configuration

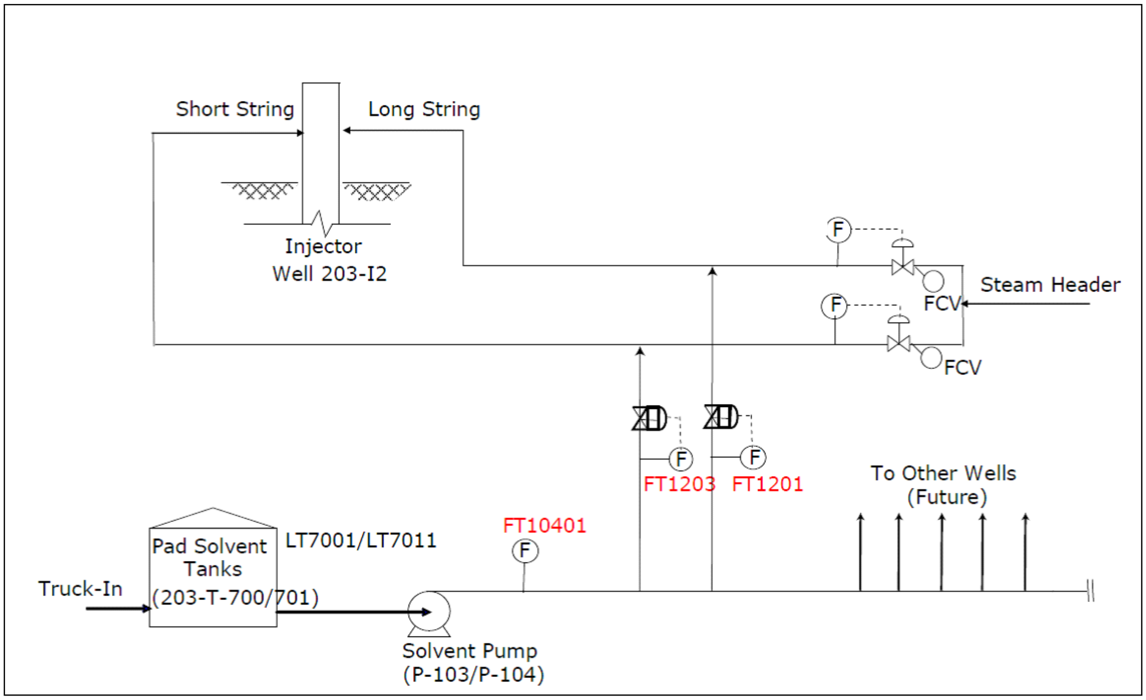

Figure 9: Algar Solvent Injection System

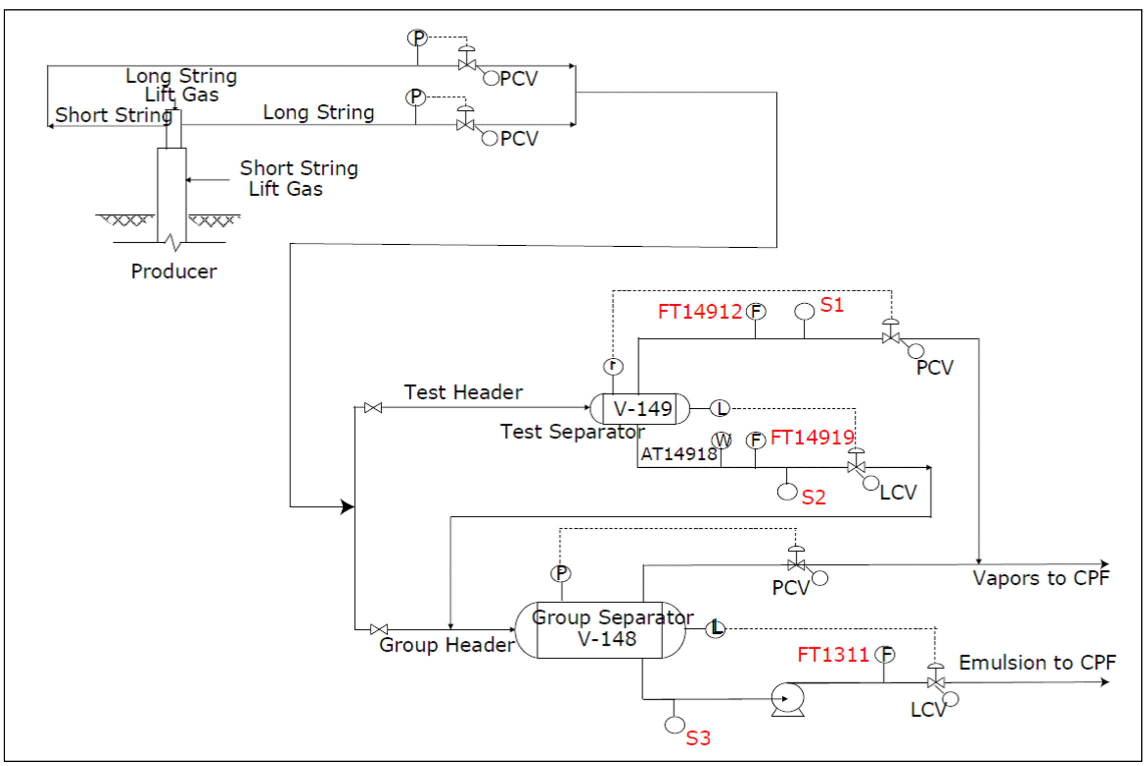

Figure 10: Algar Well Pad Production System

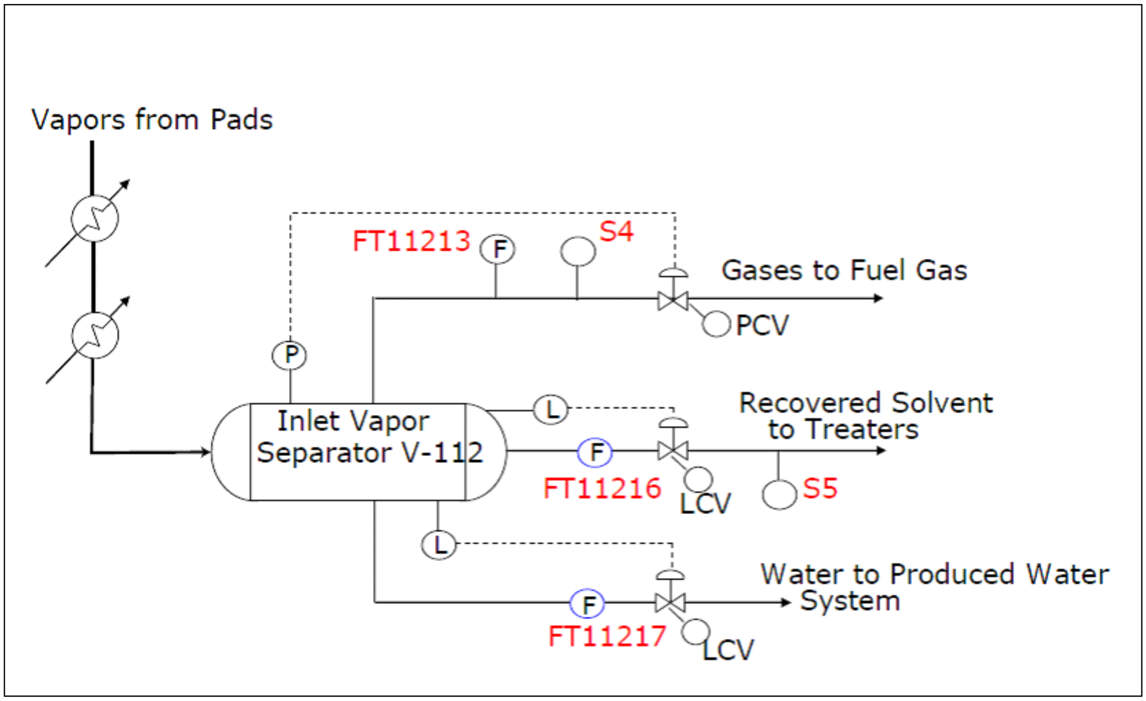

Figure 11: Algar Solvent Recovery System

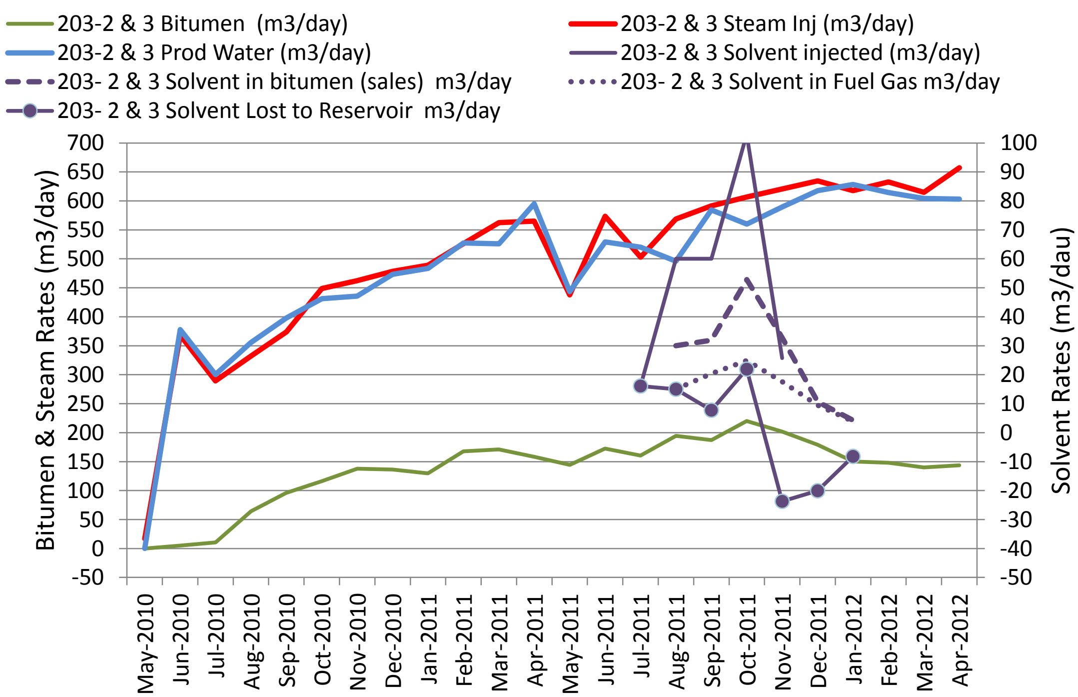

Figure 12: Performance Results of SAGD+™ Well Pairs

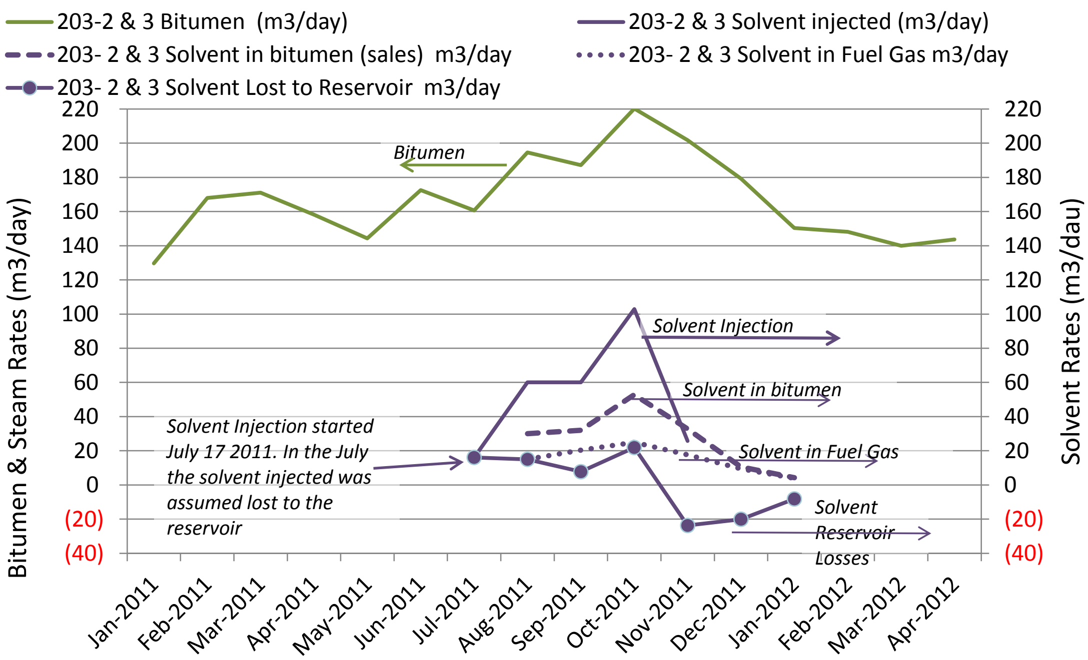

Figure 13: Solvent Injection & Recovery Results

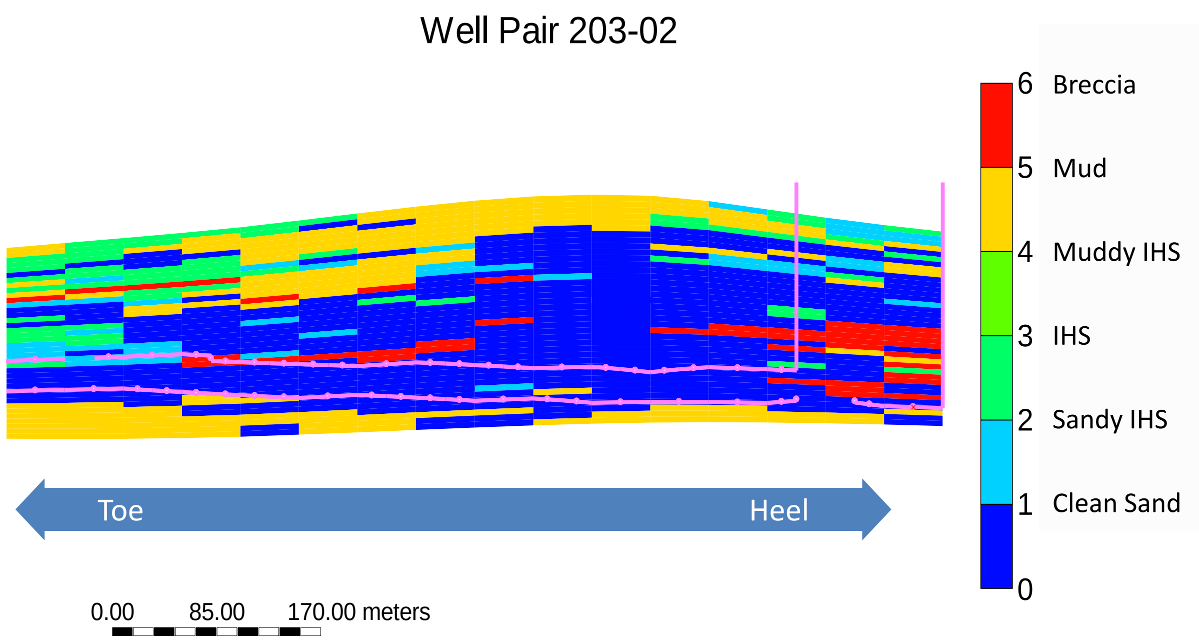

Figure 14: Cross Section of Model Along 203-02 Well Pair

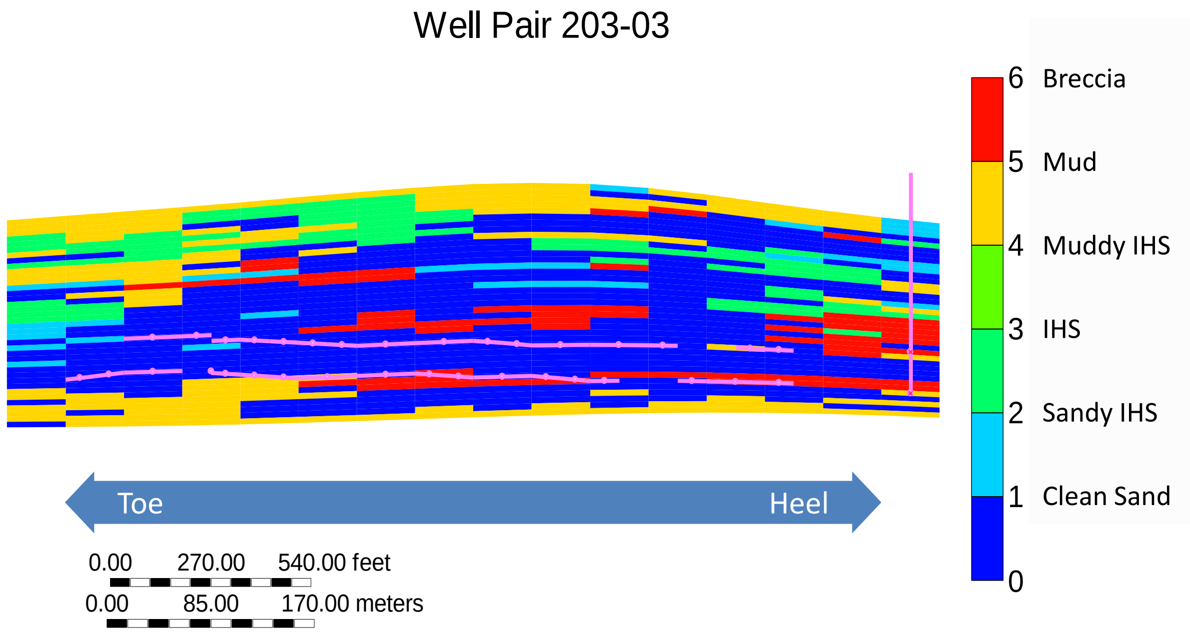

Figure 15: Cross Section of Model Along 203-03 Well Pair

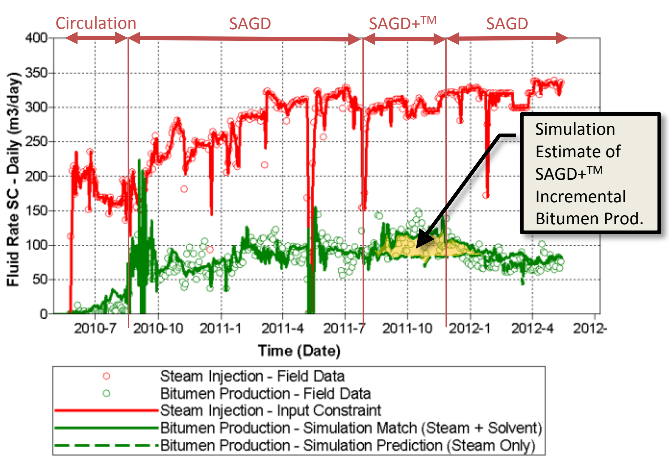

Figure 16: Well Pair 203-02 Rate Comparisons

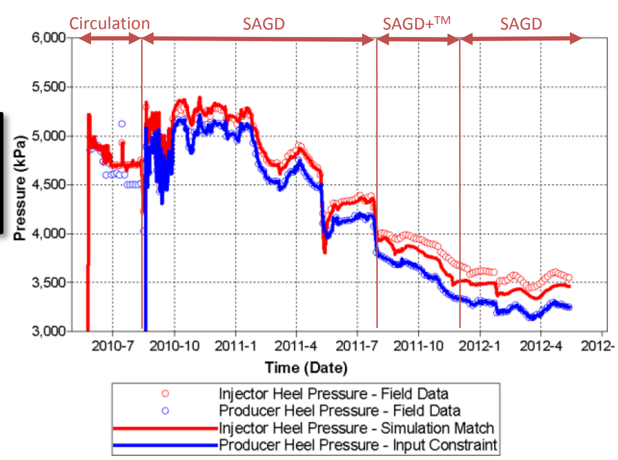

Figure 17: Well Pair 203-02 Pressure Comparisons

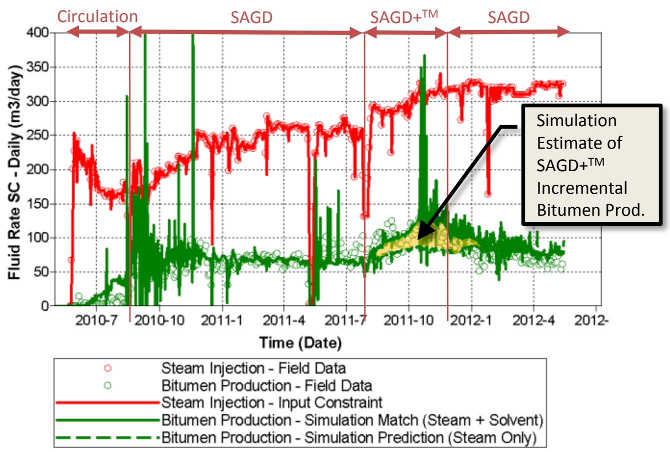

Figure 18: Well Pair 203-03 Rate Comparisons

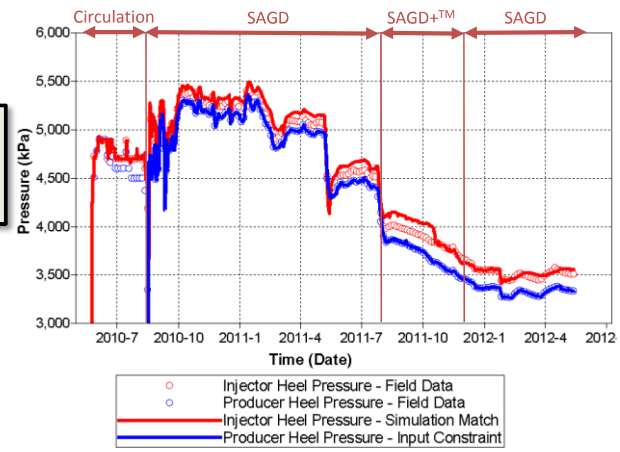

Figure 19: Well Pair 203-03 Pressure Comparisons

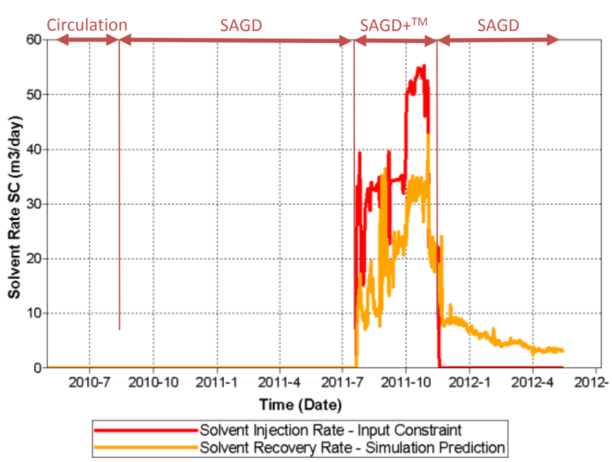

Figure 20: Well Pair 203-02 Solvent Rates

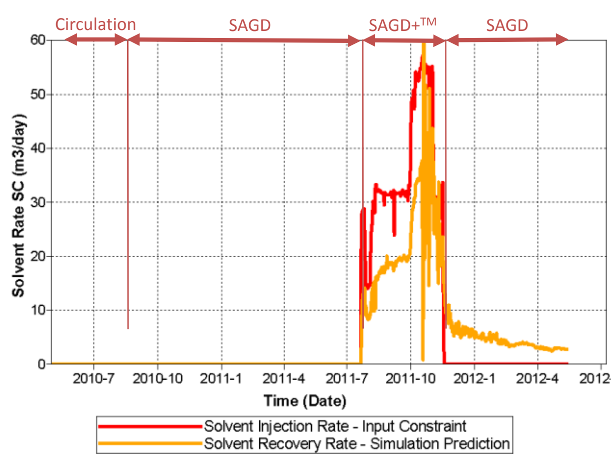

Figure 21: Well Pair 203-03 Solvent Rates

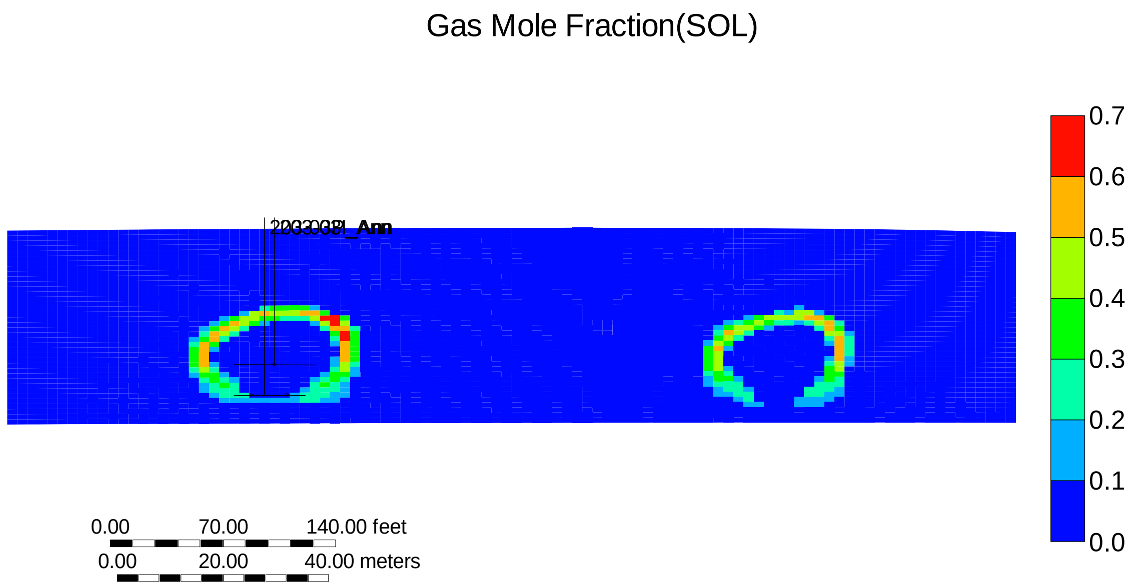

Figure 22: Model Cross-Section Showing the Mole Fraction Distribution of Vapour Solvent

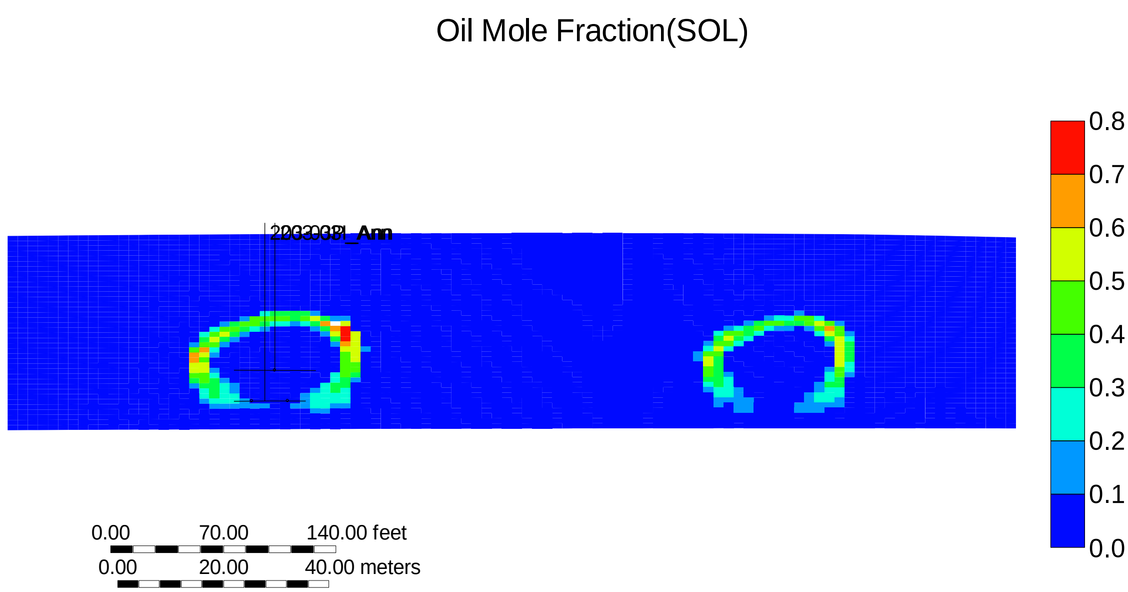

Figure 23: Model Cross-Section Showing the Mole Fraction Distribution of Liquid Solvent