

SAGD Process in the East Senlac Field: From Reservoir Characterization to Field Application

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Abstract

In 1995, CS Resources Limited initiated the first heavy-oil field application of the twin-well Steam Assisted Gravity Drainage (SAGD) technology at East Senlac, Saskatchewan, Canada. Three 500 metre long horizontal well pairs have been drilled from the surface to the relatively thin Cummings/Dina channel sand at a depth of 750 m. Following several operational problems with these initial well pairs, a new infill well pair was drilled and so far has been operating successfully.

This paper presents the various phases of the project including the reservoir description and characterization using 3D seismic inversion, reservoir process, water supply and disposal, steam generation and production treatment facilities, drilling and completion of the wells, integrated modeling of artificial lift, twin-well pair start up and well monitoring. The early operating experience and performance of the well pairs are reviewed.

Introduction

The East Senlac field, located on Sections 11, 12 & 13-40-26 W3M and Sections 7 & 18-40-25 W3M near Senlac, Saskatchewan, Canada, has been operated by CS Resources Limited since 1994. In July 1997, PanCanadian Petroleum Limited purchased CS Resources Limited.

The reserves of East Senlac were established with the drilling of 11 vertical wells. However, the complex nature of the reservoir, which is characterized by significant bottom or edge water and varying thickness of massive sand and interbedded transition zone within the reservoir, makes it difficult to perform reliable production forecasts under primary production. CS Resources and Institut Français du Pétrole (IFP) initiated a joint geological and geophysical re-evaluation of the East Senlac pool. Using 3D-seismic, an impedance cube was generated which demonstrated a relationship between the existing geology and seismic that was not evident from seismic amplitude data used previously. This

enabled CS Resources to create a series of maps that were used to make an economic assessment of the production potential. The resulting pay-thickness maps were used to develop production simulations that confirmed that the pool could support significant thermal in-situ exploitation using the Steam Assisted Gravity Drainage (SAGD) process. While primary recovery had produced approximately 22,260 m³ (140,000 bbls) of oil from three horizontal wells, the SAGD process has the potential to produce more than 3,2 million m³ (20 million bbls) of crude oil over a 12-15 year period. Approximately 127,000 m³ of oil (800,000 bbls) has been produced during the first 22 months of operation of the East Senlac Thermal Project.

Some of the major aspects of the SAGD application in the East Senlac field since the start of the project are discussed in this paper.

Reservoir Description and Characterization

Up to 1992, 11 vertical wells were drilled in the Dina/Cummings reservoir that is the primary zone for heavy oil accumulation in the Senlac area. In 1992, an extensive mapping and three-dimensional seismic program was completed that enabled the exploitation team to outline the configuration and variable nature of the reservoir rocks of the Dina channel.

In 1993, the East Senlac pool received a thorough seismic inversion analysis, using the Interwell 3D software developed by IFP. This analysis has resulted in the development of a new analytical mapping technique which allowed CS Resources to create a qualitative model to complement the more traditional quantitative model. Lithological information as well as the productive characteristics of this complex reservoir have been defined from the seismic data. **Fig. 1** presents the seismic facies map derived from the inversion-processed 3-D seismic study¹. During the Summer and Fall of 1993, after the study was completed, two stratigraphic wells and three horizontal wells were drilled that confirmed the accuracy of the new proposed approach. Two of the horizontal wells initially produced approximately 31,8 m³/day (200 bbl/d) on primary production. **Figs. 2** and **3** show the good fit between the

expected and observed impedances especially through the Dina/Cummings formation in the two newly drilled wells. These figures also illustrate typical well logs in the Senlac pool.

The Dina formation in East Senlac is primarily a channel sand directly overlying the Paleozoic Unconformity. The depositional environment is interpreted to be either a valley fill system or an estuary deposit. The Dina is composed of a basal massive sand which generally fines upwards with the upper portion of the channel deposit having increasing shale content and being often comprised of sand and shale interbeds ("transition zone"). The Dina channel is laterally offset by the Regional Dina Facies which are composed of interbedded argillaceous sands and shales not considered to be prospective. An isopach map of the oil pay is shown in **Fig. 4**. Key reservoir parameters are summarized in **Table 1**.

Within the area of the five section project, 860 ha, the original oil in place is estimated at 17,6 million m³ (110 million bbls). In the area of the thermal project, the reserves are estimated at 4,8 million m³ (30 million bbls) OOIP. Of this, numerical studies have indicated that approximately 65% are recoverable by SAGD. It should be noted that the massive sand body in this area ranges from 8 to 12 m and represents an extremely thin sand body for application of the SAGD process.

SAGD Recovery Process

Steam assisted gravity drainage (SAGD) combined with horizontal well technology is certainly one of the most famous concepts developed in reservoir engineering in the last two decades. Gravity drainage in itself is not new. However, its use to unlock heavy oil and bitumen reserves to profitable recovery was not so obvious. The concept of SAGD was first suggested and studied by Butler² as a special form of steamflooding. Butler proposed to use steam to assist the movement of oil to a production well by means of gravitational forces. The geometry of SAGD, in its general form, is quite simple. Steam is injected through a horizontal well low in the reservoir to form a steam chamber. As steam is introduced, it flows through the sand to the interface with cold oil where it condenses. The liberated energy heats the oil near the interface and allows it to drain by gravity to a second horizontal well placed below the first one. Butler developed the gravity drainage theory that predicts the rate at which the process will occur and confirmed the viability of the concept by lab experiments. The unique features of SAGD³ are:

- Use of gravity as the primary motive force for moving oil.
- Large production rates obtainable with gravity using horizontal wells.
- Flow of the heated oil directly to the production well without having to displace uncontacted oil.
- Almost immediate oil production response (especially in a heavy oil reservoir).
- High recovery efficiency (up to 70-75% in certain cases).

- Low Cumulative Steam Oil Ratio due to the large potential injection/production rates limiting the heat losses (can be lower than 2.0 m³/m³ of Cold Water Equivalent steam at 80% quality).
- Low sensitivity to heterogeneities like limited shale intervals and interbedding.

Project Development

There are several different well configurations that have been used for SAGD. The process implemented in Senlac consists of horizontal well pairs of 500 m length, 3 to 7 m apart, with a 135 m spacing between the well pairs (**Fig. 5**). The first drilling phase of the project consisted of three well pairs (named A1, A2 and A3). Well lengths and spacings were optimized by means of reservoir simulation. Production from the first phase was expected to be around 600 m³/day (3,800 bbl/day) with peak rates of 800 m³/day (5,000 bbl/day) reached during steaming of the second phase while production from the first phase continued without further steam injection. At the end of 1997, a fourth well pair (A4) was added between the pairs A2 and A3 due to completion problems in the first three well pairs.

The development planning of the thermal project as defined at the end of the project design (first quarter of 1995) as well as the considerable engineering done prior to that date have been described in a previous paper⁴. The final implementation schedule of the project at the start of the first steam injection in the wells, in March 1996, is shown in **Fig. 6**.

Following receipt of required regulatory approvals, field work on the main facilities began in October 1995 with startup in March 1996. With an initial capital budget of approximately Cdn\$ 30 million (**Table 2**), the project is expected to have a life of fifteen years⁵.

Construction has been simplified as most of the facilities have been built in module and moved to the site for installation. Modular design (or skid design) has reduced overall construction costs, kept most of the capital investment portable and made it easier for site reclamation.

Facilities

Fig. 7 shows a schematic view of the Surface Facilities from water and gas supply to water disposal and oil sale. As indicated in this figure, heat exchangers are used to substantially reduce heat consumption in various parts of the process. Energy savings was a special focus since the economical profitability of a thermal project is highly dependant of its energy consumption. Up to 25% of the energy required for steam generation is recovered by the use of five heat exchangers.

Water supply for steam generation is taken from the Lower Judith River Aquifer at the project site. The water requirement for the project is 2,000 m³/d (12,580 bbl/d). Six water source wells have been drilled to supply the required volume of ground water. Prior to entering the steam generators, the water is softened and preheated by a number of waste heat streams

(produced oil and water, and the steam generator blowdown water streams), thus reducing fuel costs to a significant extent.

Three 50 MMBtu/hr steam generators are used to produce up to 1,950 cold water equivalent m³/d (12,250 bbl/d) of steam at 80% quality. The liquid phase (blowdown) is separated from the vapor phase at the output of the steam generators and is injected in a deep disposal well after some heat exchange with the boiler feed water. It is a better practice to inject high quality steam in a SAGD well pair since the high pH liquid fraction could cause extensive silica dissolution between the two horizontal wells. A second reason is that the liquid fraction would have no beneficial effect on the SAGD process and it is more efficient to recover heat from it at surface.

Natural gas is used as the fuel in the steam generators. Gas is provided through a tie-in to a regional gas distribution line approximately six kilometres west of the project site.

Production treatment facilities consist of a three phase gravity separator and a flash treater. The produced water from the gravity separator is cooled through a heat exchanger and further cleaned in skim tanks prior to injection in a deep well disposal. The oil is cleaned in a flash evaporator and sent to the sales pipeline. The separated gas, coming mainly from the injected gas to lift the heavy oil and water emulsion, is sent to a mix drum where it is mixed with the gas used for steam generation.

Deep disposal wells have been drilled in the Duperow formation (limestone) immediately underlying the Dina sands. These wells are used to dispose of up to 1500 m³/d (9420 bbls) of produced water, along with 400 m³/d (2500 bbl/d) of boiler blowdown water and 200 m³/d (1250 bbl/d) of softener regeneration water.

Well Design, Drilling and Completion

Drilling two wells in close proximity creates complexities which do not normally exist in conventional horizontal drilling. The production wells have been placed near the base of the oil pay. The injectors have been drilled "relative" to their producer using a guidance system and technique developed by Sperry-Sun⁶. A maximum build rate of 9°/30 m has been specified for all the wells to minimize pipe bending during installation and allow for accurate well surveys. No major problems have been experienced during drilling of the four well pairs.

Both injection and production wells have been completed with 178 mm (7") liners. A1, A2 and A3 pairs have wire wrapped screens for sand control in both the injectors and the producers. A 140 mm (5 1/2") production tubing was installed initially in the production wells at a depth of approximately 740 m.

The production is artificially lifted through the injection of gas down the producer annulus. At high production temperatures, the produced water flashes to steam as the pressure declines while coming up the tubing. This results in a reduction of the amount of lift gas required.

This gas lift system, which is critical to the success of the project, was designed with the Gensim numerical model⁷. This

in-house model allows full coupling of a transient wellbore model to the reservoir model. Geysering effects can be reproduced⁸. This feature is a key point, as geysering has to be controlled in the production string since it has a direct impact on the reservoir and production processes.

Twin Well Pairs Start Up and Monitoring

The start up consists of pre-heating the interval between the two horizontal wells to a temperature large enough to allow the oil to flow towards the producer just by gravity. This period is the most critical stage of a well pair production life cycle. Once this "communication" is established, the well pair can be produced in a pure SAGD mode: permanent steam injection in the upper well and permanent production from the lower well.

The start up of a well pair in a heavy oil reservoir like East Senlac is significantly different from the process of initiating a steam chamber along a horizontal well pair drilled in a bitumen sand.

When the crude oil is not mobile at initial reservoir conditions, the steam injectivity is minimal. To establish communication between the two wells in that case, steam is circulated in both the producer and the injector until pressure communication is observed. An injection string is landed at the toe of each well for this phase. This type of start up is mostly governed by heat conductivity and can be as long as 2 to 4 months and is highly dependent of the distance between the two horizontal wells (as well as average permeability, porosity and well diameter).

At East Senlac, the relatively low oil viscosity (5,000 mPa.s at reservoir condition) enables the steam stimulation of a well pair at high rates without circulating the steam condensate back to surface. It is feasible to start up a well pair by simply injecting steam into the reservoir. Start ups were achieved in less than two months. Only one steam cycle was used to pre-heat the interval between the horizontal wells for the A2 and A3 well pairs. However, the maximum injection pressure was reached sooner than expected on the A1 well pair due to a lower initial injectivity. Additional steam slugs were injected to achieve a successful start up. The start up procedures were developed from numerical simulations.

Once the start up is completed, the steam injection rate is controlled in each well to maintain a constant pressure. The injection pressure is monitored by injecting a small amount of gas down the tubing-casing annulus.

The producer downhole temperature is monitored through a thermocouple strapped to the production tubing. The surface emulsion choke is controlled to maintain a constant downhole temperature reading. The operating temperature is usually set at a temperature 30 to 50 °C lower than the steam temperature at the operating bottom hole pressure to avoid any steam breakthrough along the horizontal well. The production can also be controlled by the total fluid production rate during restart phases. Finally the downhole producer flowing pressure is monitored through the gas lift injection pressure.

Early Operating Experience and Performance of the First 3 Well Pairs

The A1 well pair performed as expected until December 1996 with oil rates peaking over 200 m³/day (1,300 bbl/day). The oil rate started to decline abnormally (**Fig. 8**) and leveled at 80 m³/d (500 bbl/day) due to the reduced effective producer well length caused by sand production. The A1 oil rate had been predicted to remain almost constant in the 160 m³/d range (1,000 bbl/day). Once the sand production was controlled by January 1997 after changing the operating conditions, the oil rate decline was arrested. The A1 Cumulative Steam Oil Ratio (CSOR) was approximately 3,25 m³/m³ by mid February 1998 which is higher than the planned CSOR of 2,5 m³/m³ due to the reduced effective producer well length.

The A2 well pair start up was executed as planned with no delay and peak oil rate exceeding 200 m³/day (1,300 bbl/day). However, the injector sanded in June 1996 (see production plot **Fig. 9**). Injection was restarted in November 1996 after a work over to clean out the injector. The production well continued to have sand problems that were even more severe than in the A1 well pair. It dramatically impacted the oil production which was reduced to approximately 30 m³/d (190 bbl/day). A scab liner was installed in July 1997 in the producer. Since the installation of this inner liner, sand production has been controlled and oil rate has peaked at 100 m³/d (630 bbl/day).

The A3 well pair start up was impaired by sand production problems from the very beginning (see production plot **Fig. 10**). Sand cleanouts and additional steam stimulations of the well pair were conducted; however, the sand production problems continued. A scab liner was installed in June 1997 to avoid any further significant sand production. Following this work over similar to A2, oil rate peaked at 100 m³/d (630 bbl/day).

The main operating problem for the initial Phase A well pair operations was sand production. It is believed that the sand problems occurred because of failure of the wire wrapped screens which were provided for sand control in all three well pairs. However, the SAGD process viability was demonstrated with the high oil production rates and low steam-oil ratios that were achieved.

New Infill Well Pair Performance

Because of the lower than anticipated production rates from A1, A2 and A3 and the lower steam usage at the plant, a decision was taken in mid-1997 to drill and complete an infill well pair between the A2 and A3 pairs (135 m apart from each other - **Fig. 5**). Another important reason to drill this infill well pair was to test a new sand control device. From reservoir simulations, it was determined that the planned infill well pair trajectory would not approach within 25 metres of the A2 and A3 steam chambers and no steam communication would be seen between the infill location and those steam chambers.

Drilling of the A4 pair commenced in August, 1997. As in the other pairs, the injector was drilled "relative" to the producer using the guidance system developed by Sperry-Sun⁶. No major problems were encountered during the drilling

of this 450 m long well pair. The well pair was started up (steam stimulation phase) in mid-September of 1997, followed by initiation of continuous production in early November 1997. Both A4 injection and production wells have been completed with 178 mm (7") slotted liners. A 114 mm (4 1/2") tubing was installed in the production and injection wells.

Because sand control had been the main problem for the first three well pairs at Senlac, the main objective for the operation of the A4 pair was to ensure that *a*) the downhole sand control device (*i.e.* the slotted liners) acted satisfactorily during the course of the operating life of A4, and *b*) the well pair operational process itself was gentle and smooth so that significant and rapid fluctuations in bottomhole temperature, pressure and rate could be avoided at all times. As **Fig. 11** shows, the startup of the A4 pair occurred very satisfactorily.

Normal production operations commenced on November 4 1997 and within a few weeks, peak oil production reached 230 m³/d (1,400 bbl/day). After the first 110 days of production operations, the average production to date is 150 m³/d (950 bbl/day), steam rate is 335 m³/d (2,100 bbl/day) and the CSOR is 2,52 m³/m³. No sand problems have been encountered in the A4 well pair to date.

Forecasted Development

With the knowledge that the A4 operations have so far been more successful in terms of sand control and production performance, a decision to proceed with a second phase of three well pairs has been made. They will be located in a different segment of the same channel of the Dina Sand. These three well pairs ("Phase B") will be drilled in the Summer of 1998 and should be in full operation by early Fall, 1998. The design of these wells, in terms of downhole production and surface equipment will be almost identical to those for the A4 pair. At present time, we expect the wells to be 500 m in length, 5 to 7 metres apart and with a 130 metre spacing between the well pairs.

The start of production from Phase B will coincide with the pressure maintenance stage (blowdown) of operations for the Phase A wells. It is anticipated that following the start of blowdown, more than 40,000 m³ of oil (250,000 bbls) will be recovered from the Phase A producers while injecting only natural gas for pressure maintenance purposes. It is also expected that prior to blowdown from Phase B, a total of 318,000 m³ of oil (2 MM bbls) will be recovered from the Phase B wells. This corresponds to a 56% recovery factor prior to blowdown. The ultimate recovery factor is expected to be 65%. The peak oil production from Phase B alone is expected to be 635 m³/d (4,000 bbl/day) and the CSOR approximately 3,0 m³/m³.

Conclusions

The integration of geophysical and geological studies for characterization of the East Senlac heavy oil reservoir has been a success. Surface facilities have been designed to respond to the particular specifications of SAGD operations, with a special focus on energy and cost savings.

The beginning of the first phase (Phase A) of the SAGD operations at East Senlac posed several technical challenges, with sand control being the most vital among them. However, once sand production was identified as a major problem, new completion and operating strategies were developed to achieve adequate sand control. This knowledge base, developed in the early part of Phase A operations, contributed significantly to the operation of the infill well pair (A4). Early performance from this pair shows that sand control and production performance have improved considerably, as shown by the increased production rate, low SOR and no measurable sand production. Therefore, Phase A operations were successful in two regards: *a)* the SAGD process has been proven at East Senlac as a technically viable method for recovering heavy oil at high production rates and low steam oil ratios, and *b)* development of new completion and operating strategies for sand control.

It is felt that the next phase of well pairs will perform according to expectations in terms of oil production rates and steam-oil ratios following the considerable operational knowledge gained from the Phase A activities.

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TABLE 1 – Reservoir Properties

Depth to base of reservoir	750 m
Initial reservoir temperature	29°C
Initial reservoir pressure	5200 kPa
Total oil pay thickness	8-15 m
Bottom water thickness	0-15 m
Permeability	5-10 D
Porosity	33%
Oil gravity	13°API
Density	980 kg/m ³
Oil Viscosity (@ Reservoir Condition)	5000 mPa-s
Oil saturation	85%

Table 2 - East Senlac Thermal Project – Capital Budget.

	Cdn \$m	% of Total	% Due to Steam
Horizontal Wells (3 Pairs)	5,100	17	0
Water Treating & Steam Generation	5,700	19	100
Production Treating, Tankage	4,500	15	50
Utilities, HEX, Misc. Piping, Offsites	10,200	33	75
Engineering	3,700	12	61
Saskatchewan E&H Tax	1,250	4	61
Total	30,450	100	61

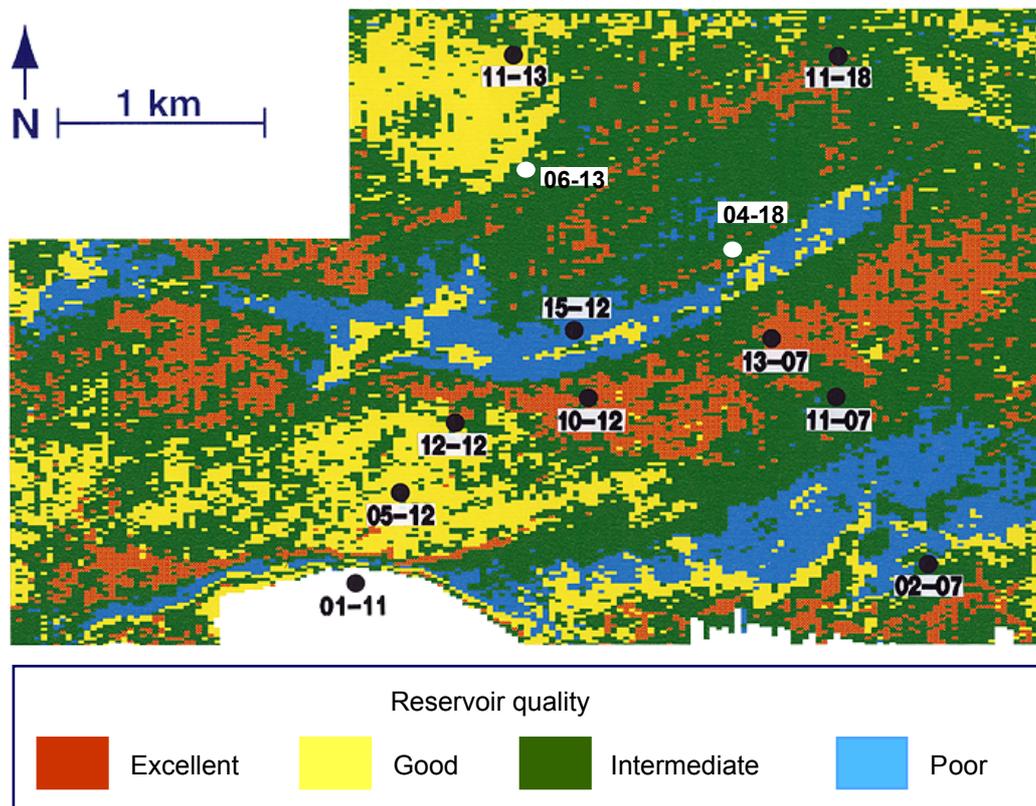


Fig. 1 – East Senlac field. 3D Seismic facies map.
 (Wells 04-18 and 06-13 not drilled at the time of the 3D seismic inversion analysis)

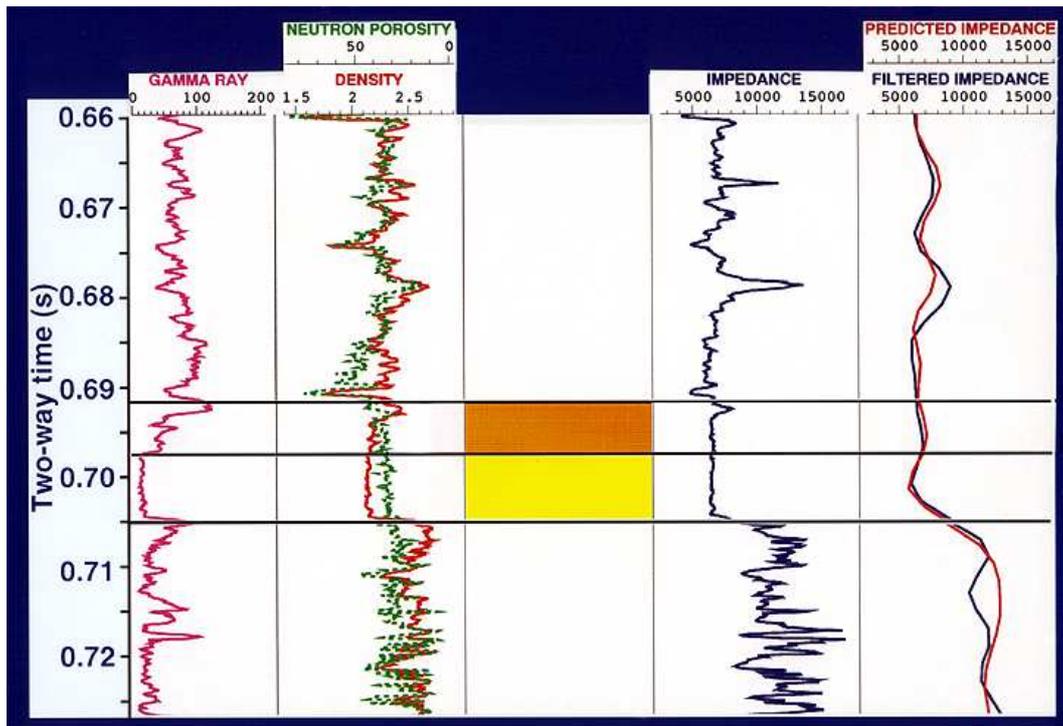


Fig. 2 – Logs of the 04-18 well drilled after the analysis of the 3D seismic inversion.

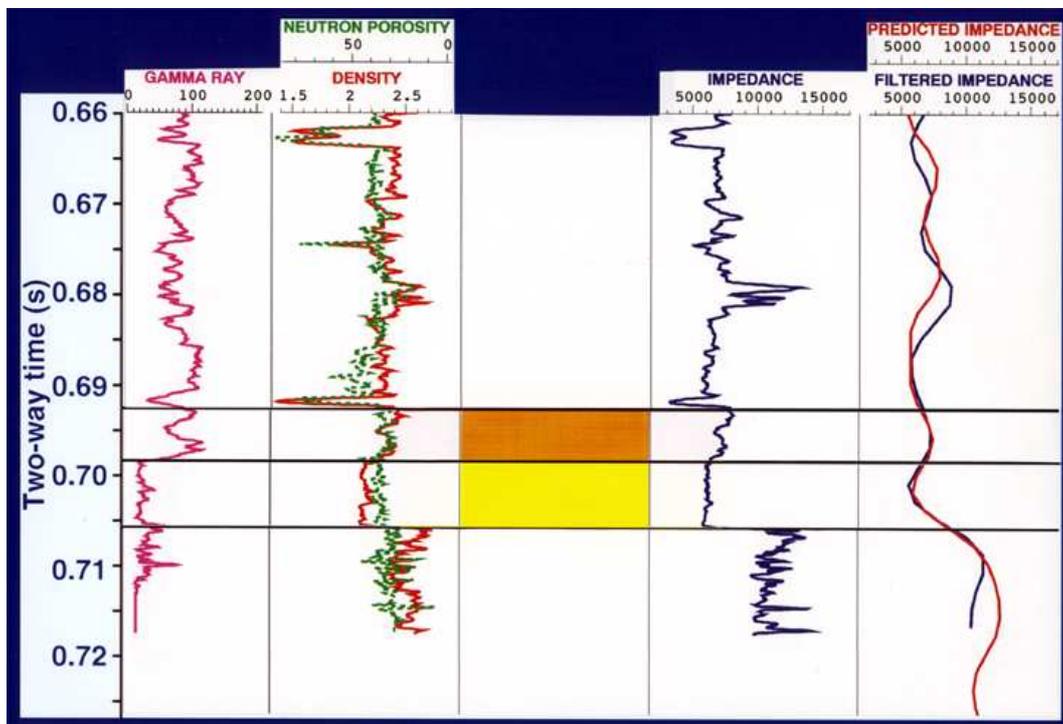


Fig. 3 – Logs of the 06-13 well drilled after the analysis of the 3D seismic inversion.

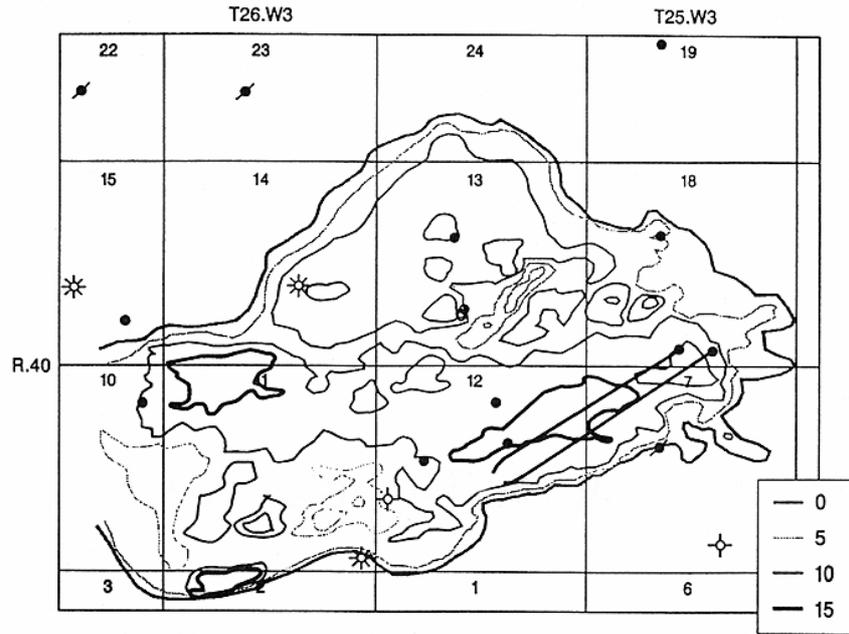


Fig. 4 – East Senlac field. Total Dina Pay Isopach (metre).

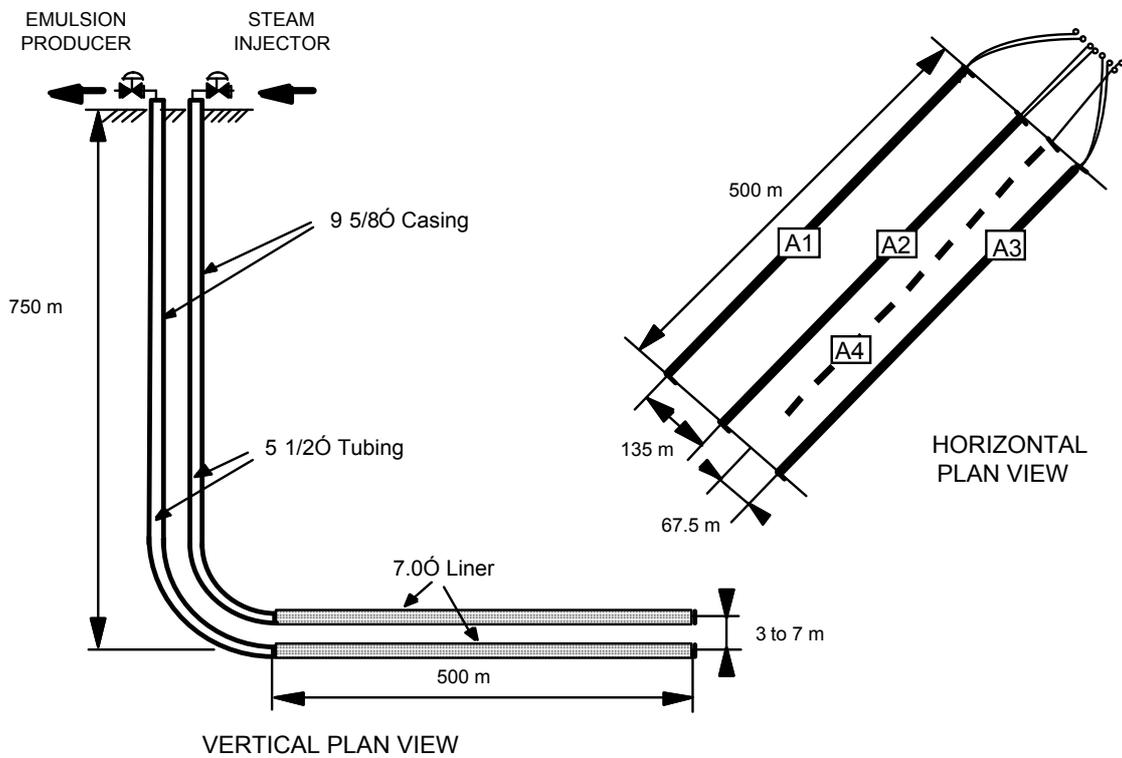


Fig. 5 – East Senlac SAGD well pairs configuration.

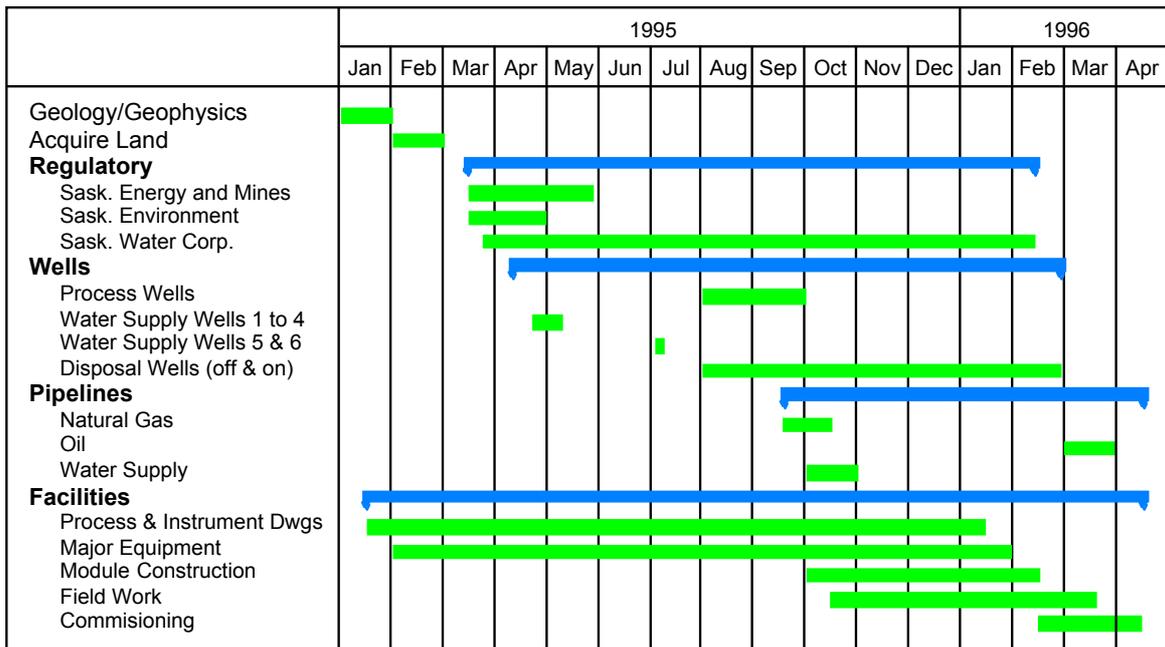


Fig. 6 - East Senlac thermal project. Project Planning.

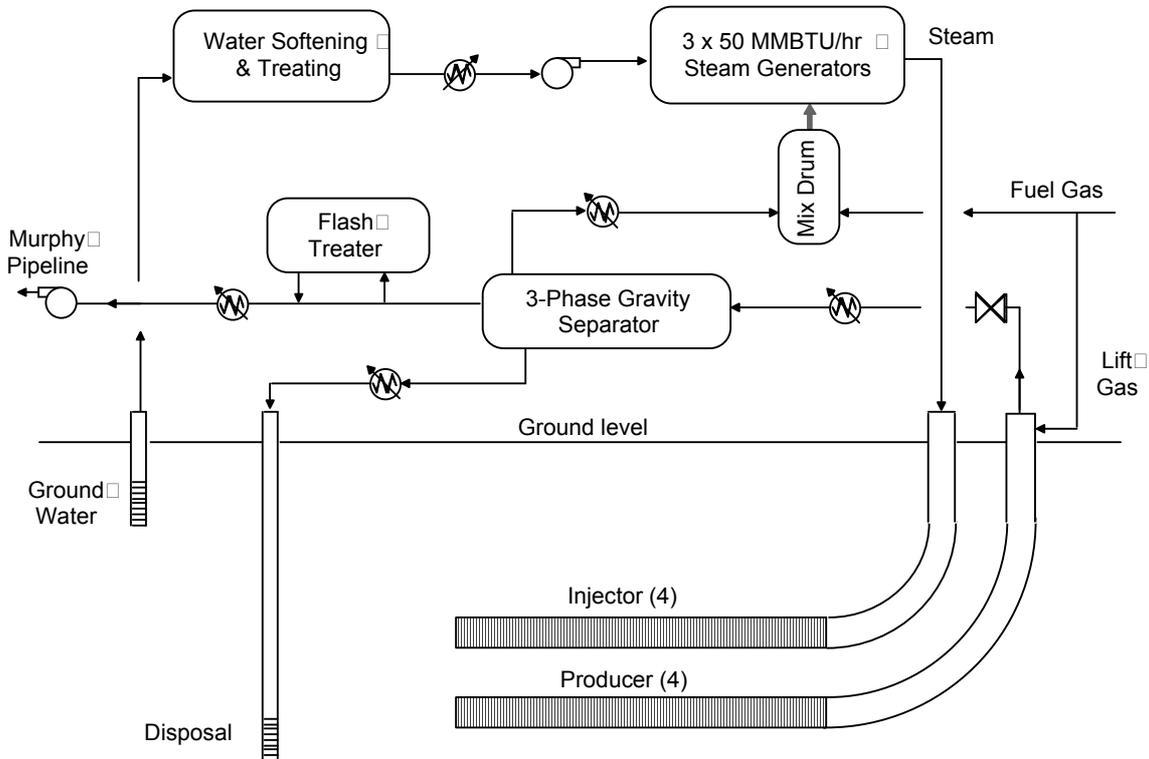


Fig. 7- East Senlac thermal project. Schematic of Process Facilities.

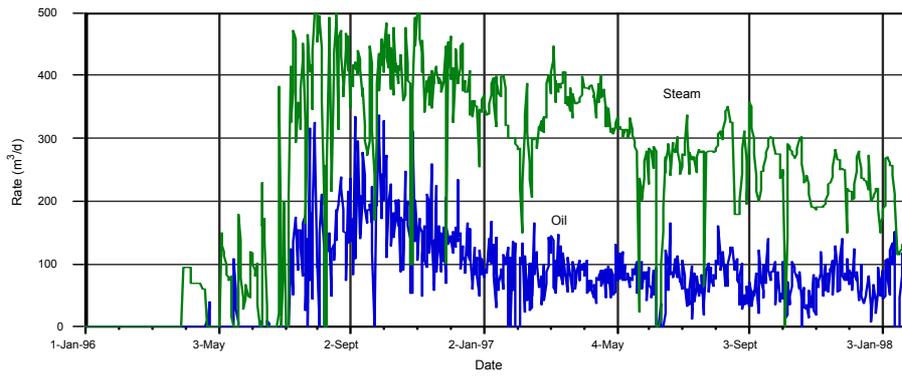


Fig. 8 – East Senlac field. Performance of the SAGD A1 well pair.

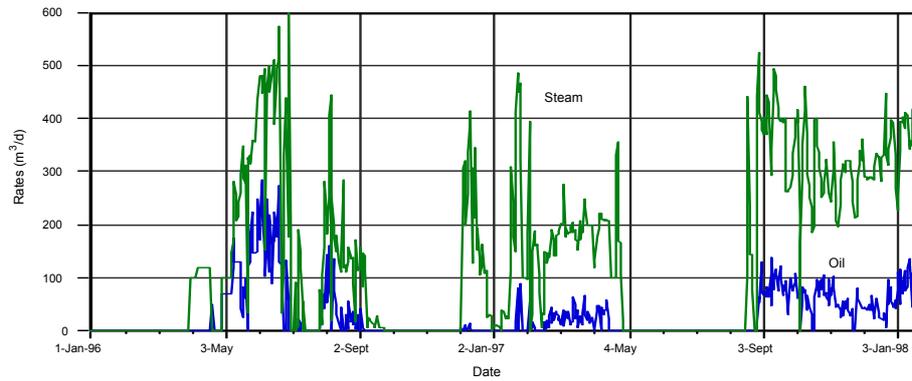


Fig. 9 – East Senlac field. Performance of the SAGD A2 well pair.

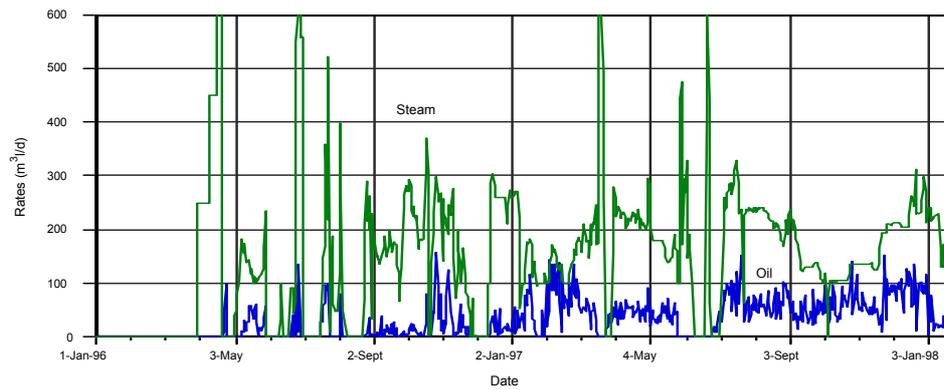


Fig. 10 – East Senlac field. Performance of the SAGD A3 well pair.

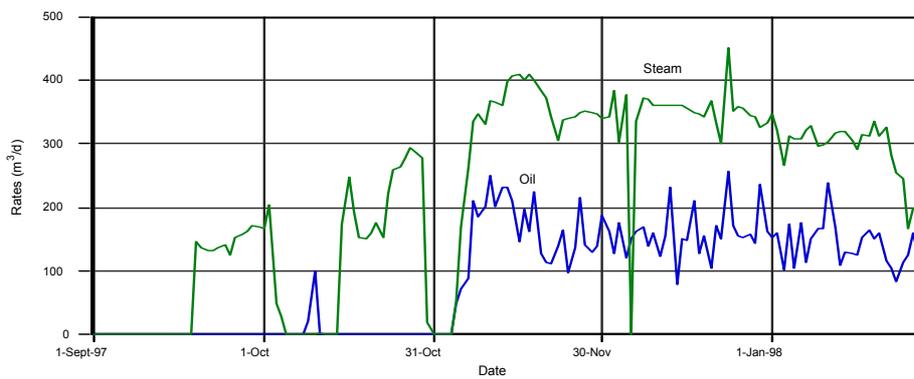


Fig. 11 – East Senlac field. Performance of the SAGD A4 well pair.