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Flue Gas Injection Into a Mature SAGD Steam Chamber at the Dover Project (Formerly UTF)

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Abstract

The Dover Project (formerly the Underground Test Facility) is the world's first field pilot of the Steam Assisted Gravity Drainage (SAGD) process using dual horizontal well pairs to recover bitumen. There have been four phases of SAGD piloting at the Dover site thus far. The Phase B pilot, which consists of three 500 m long horizontal well pairs spaced 70 m laterally apart, has been in continuous operation since early 1993. Phase B reached the peak production rate of 300 m³/d or 100 m³/d per well pair on average in the middle of 1994. After sustaining the peak rate for about two years, the production has been in decline with a steady increase in steam-oil ratio. Research carried out in the past few years suggested that the addition of a suitable amount of non-condensable gases (NCG) would be an effective method to wind-down the steam chamber. It provides an economic means to continue bitumen production by utilizing the large amount of heat stored in the SAGD chamber. Beginning in April 1998, a small amount of natural gas was added continuously to the steam injection. The concentration of NCG has increased steadily in the past 3.5 years. The resulting performance has been better than initially expected. Based on the success of this NCG-steam wind-down strategy, a four-month flue gas injection test was conducted in 2001 to investigate the possibility of using the more cost-effective flue gas, rather than natural gas as an injectant.

This paper summarizes the rationale for selecting the NCG-steam wind-down strategy, the field implementation of the flue gas injection test, and the resulting pilot performance. The successful implementation of this technology will have a profound impact on the overall process economics.

Introduction

The Dover Project is an in situ bitumen recovery facility on the Oil Sands Lease Number 328 located 70 km northwest of the City of Fort McMurray. It was initiated by Alberta Oil Sands Technology and Research Authority (AOSTRA) in 1984 and was later joined by industry participants to pilot the SAGD process using dual horizontal wells. The Dover Project Area is located in eight sections of land at the extreme eastern edge of the lease, as shown in Figure 1. To the immediate east of Dover is Petro-Canada's MacKay River Project, which is expected to produce 30,000 BOPD using the SAGD process in 2003.

Several papers(1-3) have been published to describe, in detail, the Dover Project from the beginning until mid-1997. The following is a brief summary.

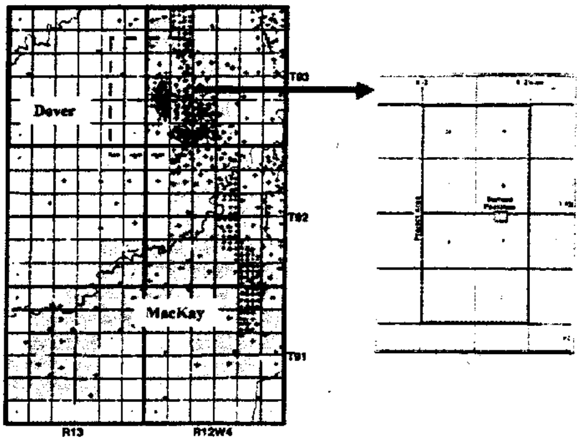

FIGURE 1: Dover project area.

The first phase of testing, Phase A, involved the drilling of horizontal wells from a limestone tunnel network located about 20 m below the oil sand formation. These well pairs had a horizontal length of about 60 m and were spaced 25 m apart, as shown in Figure 2. They were operated from 1987 to 1991. Encouraged by the results from Phase A, the Project proceeded to the second phase of piloting in late 1991. In Phase B, the well pair length and lateral spacing were increased to 500 m and 70 m, respectively. The wells were drilled from the extended underground tunnels and their objective was to test SAGD using commercial size wells. Phase B started in 1993 and it is still in operation.

While the underground wells have successfully demonstrated the viability of the SAGD process and the associated production methodology, studies conducted by AOSTRA have shown that the supply cost of the SAGD technology can be further reduced by as much as $1.50/barrel by utilizing horizontal wells drilled from the surface. In late 1995, the Project approved a new pilot, Phase D, which consists of two surface drilled well pairs having a planned well length of 750 m and a lateral spacing of 90 m. Only one well pair achieved the target length and the other larger diameter well pair was completed shorter than the anticipated length due to problems encountered during liner installation. The main objective of Phase D was to develop surface horizontal drilling technology in shallow depths (160 m TVD) and the production methods associated with such technology. Phase D started in April 1996 and it is still in operation.

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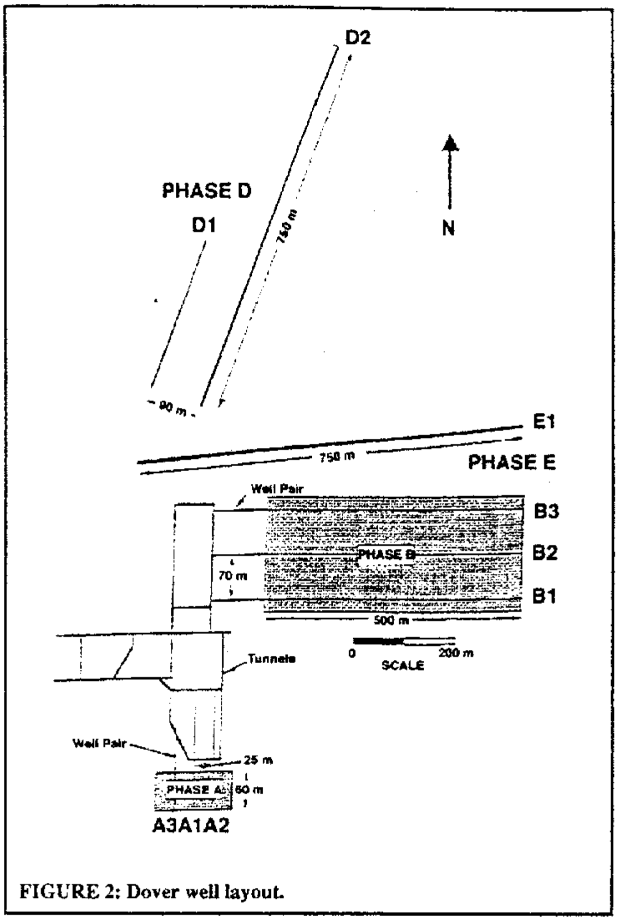


FIGURE 2: Dover well layout.

In May 1997, E well pair was drilled from the surface north of the Phase B pattern. The objective was to place and operate a new surface-drilled SAGD well pair adjacent to the mature Phase B chamber. The E well pair was started-up in June 1999 and it is still in operation.

Geology

Detailed descriptions of the Dover Project Area have been published previously[4,5]. A simplified version is presented below.

A north-south tidal channel sand deposit has been delineated from the large amount of wells drilled inside the Project Area. It is about 3,000 m long and 800 m wide. The target reservoir is the McMurray Formation. The reservoir is divided into three major flow units: trough cross-bedded sands near the base, a transition zone in the middle, and inclined heterolithic stratification (IHS) near the top. Table 1 shows the average reservoir properties of the Dover reservoir.

The best part of the reservoir is in the cross-bedded sands near the base with oil saturations more than 80% and porosity in the mid-thirties. Temperature observations have indicated that the steam rise rate (SRR) could be as much as 8 cm/day in the cross-bedded sands. If there are shales or mudstones present in the good sands that are not areally continuous, steam will eventually go through or wrap around them and continue its upward rise. SRR is less in the IHS because of the reduction in vertical permeability.

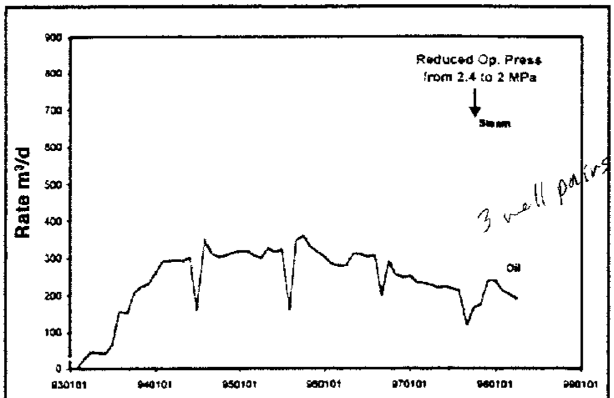
Phase B Operations

The Phase B wells were placed on steam circulation operations from December 1991 to May 1992. Because of boiler limitations, only two well pairs could be steamed at any given time. The injector and producer communication was achieved within one to two months. Encouraged by the results from the circulation phase, the wells were subsequently shut in to allow the construction of the surface facilities that lasted until early 1993. After a brief period of steam circulation, the wells were successfully converted to normal SAGD operation in the middle of 1993.

Once the wells were placed on SAGD operation, the steam injectors were under wellhead pressure control. As shown in Figure 3, the steam rates continued to increase as the steam chamber developed. The steam chamber was operated at about 2.4 MPa* until July 1997, with some minor pressure fluctuations from time to time due to steam availability and other operational constraints. The bitumen production increased in step with the steam injection and reached a peak production of 300 m³/d within a year of the commencement of the SAGD process. The peak rate was sustained for about two years and production started to decline at the end of 1996. Coinciding with the drop in production, the instantaneous steam-oil ratio (SOR) climbed from the low twos to higher than three, as shown in Figure 4. The steam chamber

TABLE 1: Dover average reservoir characteristics.

Depth to reservoir top, m	130
Net pay, m	15 – 24
Porosity	0.32 – 0.35
S_{oi}	0.75 – 0.85
K_h, D	3 – 5
Initial reservoir pressure, kPa	550
Initial reservoir temp T_r, °C	7
Dead bitumen viscosity@T_r, cp	3,000,000
API, degree	8



3 well pairs

FIGURE 3: Phase B performance to April 1998 before gas addition to steam.

100 m³/d/well pair

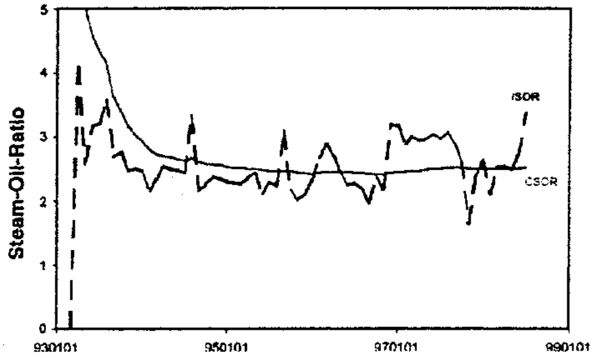


FIGURE 4: Phase B SOR to April 1998 before addition of gas to steam.

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* All pressures are reported in absolute units.

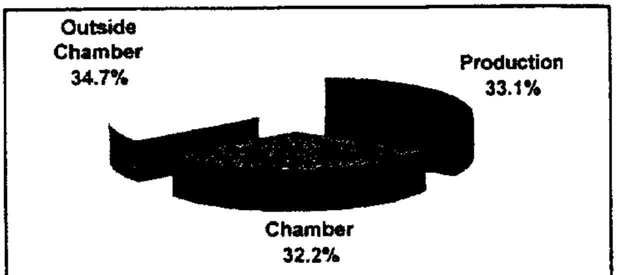

FIGURE 5: Injected heat distributions after five years.

pressure was decreased from 2.4 MPa to 2 MPa in September 1997 due to steam limitations and water disposal problems. The SOR dropped temporarily but soon climbed back to above three once the operation was stabilized.

Wind-Down Considerations

Internal studies suggested that a wind-down operation should be implemented when the instantaneous SOR was higher than three for Dover-type operations. At the same time, the startup of the E well pair was expected to exceed the steam and produced water disposal capacities. Hence, a study was conducted to devise an optimum wind-down strategy for Phase B.

Figure 5 shows the cumulative distribution of the injected heat into Phase B at the beginning of 1998 after about five years of SAGD operation. About one third of the injected heat returned as sensible heat within the bitumen and water produced. Another one third of heat remained in the steam chamber. The remaining one third dissipated into the reservoir surrounding the steam chamber. Hence, there was a large amount of injected heat remaining in the reservoir after a prolonged period of steaming. The effective recovery of this stored energy is important to the overall process economics.

When steam injection is reduced or discontinued, the pressure of the chamber falls as the system cools. The sensible heat stored in the rocks, particularly within the core of the chamber where temperature is the highest, is recovered and transferred to water in the pores, and further steam is produced. The in situ generated steam flows to chamber boundaries where it heats the bitumen and continues the recovery operation. There are two problems with this method of heat scavenging operation:

- Most SAGD operations to date do not have downhole pumps and they rely on natural steam or gas lift for product lifting. The decline in pressure as the chamber cools limits the bitumen recovery.
- The decline in chamber pressure encourages fluid inflow from surrounding areas, e.g., steam from adjacent chambers and water from connected aquifers.

Several options were considered to effectively wind-down the SAGD operation. The most promising one that optimizes recovery efficiency appears to be the injection of a non-condensable gas (NCG) to replace the condensed steam. The NCG maintains the chamber pressure to facilitate product lifting and minimizes intrusions from the surroundings.

The Phase B pilot is particularly well suited for conducting the wind-down experiment because of the long production history and its large array (28 in total) of observation wells. The primary observations will be the temperature and pressure distribution in the chamber and the well performance. The knowledge gathered from the wind-down operation will undoubtedly have a significant impact on the future commercialization of the SAGD process.

Gas/Steam Wind-Down

Butler(6) proposed modifications to the SAGD process, called Steam-and-Gas-Push (SAGP), to improve thermal efficiency. The initial thought was that it was not necessary for the entire steam chamber to be heated to a uniform high temperature. Only the lowest part, where the coning tendency for steam is greatest, needs to be at the highest temperature. By introducing NCG's with steam in an injector located a few metres directly above the producer, the region between the injector and the top of reservoir will be at lower temperatures due to gas accumulation at the top. The region between the injector and producer will be kept hot due to the continued purging of the gas with production. It was anticipated that the reduction in the oil drainage rate due to the overall lower temperature would be more than compensated by the decrease in the steam-oil ratio. In the ensuing experiments(7), it was found that the concept might be even more effective than was originally anticipated. The reason for this appears to be that the introduction of gas with steam brings about a new mechanism as the gas flows counter-current to the falling liquids. This mechanism involves the creation of a large surface area for mass and heat transfer. A bigger volume is draining at a much lower temperature resulting in significant improvements in the steam-oil ratio.

Although all the SAGP experiments involved the addition of gas to the steam injection at the beginning of the recovery process, it is speculated that a similar benefit can be realized by adding gas to the steam at the mature stage of a SAGD process, such as Phase B. In addition to maintaining the chamber pressure, the NCG reduces the temperature at the top of chamber, thus resulting in lower heat loss to the overburden. The reduction in the oil drainage rate due to an overall lower chamber temperature can be more than compensated by the improvement in the steam-oil ratio.

Difficulties were encountered in simulating the gas-steam co-injection scheme using commercially available numerical simulators such as STARS (Computer Modelling Group). The simulation predicts that when gas is injected with steam, the vapour[**] chamber size is considerably smaller. The core of the chamber is at steam temperature and outside the core, the temperature drops due to the build-up of gas. This reduces the temperature at the edge of the chamber, resulting in a significant decrease in heat and mass transfer and a pessimistic prediction for the process performance. Such a phenomenon has also been reported by others(8). In the experimental results presented by Butler(7) et al. where gas was added to steam, there was a gradient of temperature in the vapour chamber. In their experiment, it was found that the top of the chamber was considerably cooler than that of a comparable SAGD experiment. Yet at the sides of the chamber, the reduction in temperature was relatively small. Another phenomenon found in the SAGP experiment was that the vapour chamber tended to be bigger than a SAGD chamber at comparable times, due to the penetration of gas fingers ahead of the steam condensation front in the rising period of the process. This is the reason why the production rate was not significantly affected even though the overall chamber temperature was lower.

Field evidence also suggests that the reduction in SAGD performance may not be as severe as predicted by the simulator. For example, in the North Tangleflags field operated by Sceptre Resources (now CNRL), the high initial GOR of 11 sm^3/m^3 (as compared to 1 – 3 sm^3/m^3 for most Athabasca reservoirs) does not seem to have a negative impact on the SAGD process.

Because of the conflicting results from laboratory experiments and computer simulations, an experimental program was designed for Phase B to pilot the gas-steam co-injection as a wind-down strategy.

Numerical Simulation

An internal study(9) was carried out to match the historical performance of Phase B by using a relatively simple simulation model. In addition to matching the injection and production history, it was also important to match the temperature data gathered from the large array of observation wells located within the Phase

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[**] Vapour refers to a mixture of NCG and steam.

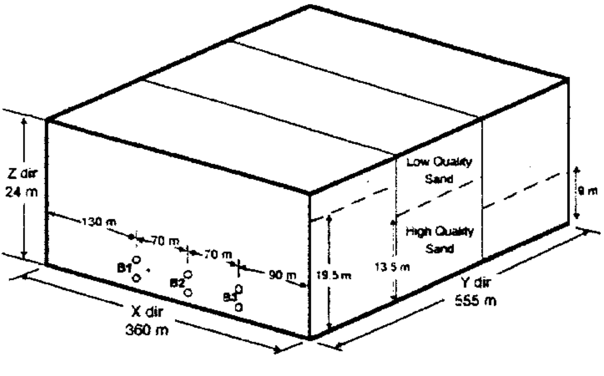

FIGURE 6: Schematic of simulation model (not to scale).

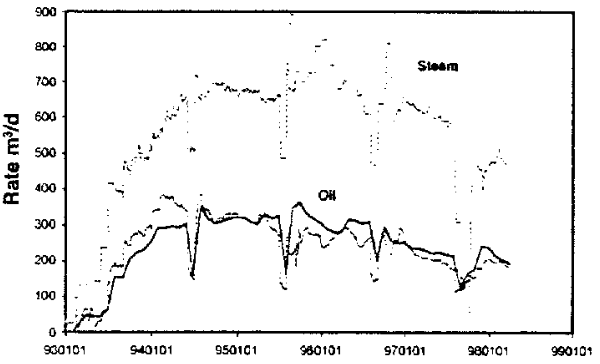

FIGURE 7: Phase B simulation history match. Heavier lines are actual.

B area. The calibrated model was then used to study various scenarios to optimize the wind-down operations.

The simulation study utilized the thermal reservoir simulator STARS from the Computer Modelling Group. The grid system used for the Phase B history match is shown in Figure 6. The model's dimensions are 24 m along the vertical, 360 m perpendicular to the SAGD wells, and 555 m parallel to the SAGD wells. This model area was chosen to include the entire Phase B pattern and allows the study of multiple well effects. Temperature data indicate that the chamber has developed more extensively near the B1 well pair, as compared to B2 or B3. Hence, a larger spacing between the model boundary and the B1 well pair was allowed. The block sizes in the X and Z directions*** are 2 m and 1.5 m, respectively. Grid sensitivity studies showed that these are the largest grid sizes that can be used without incurring substantial numerical errors. This finding is consistent with a previous study(10). The model was divided into three equal blocks in the axial direction, of the wells. Each block was sub-divided into two layers to reflect the change in reservoir quality in the vertical direction as was discussed in the geology section. The petrophysical properties for these two layers are shown in Table 2.

The combined length of the model wells is 555 m; 11% longer than the actual well length to account for the contribution coming from the ends. Since the block sizes in the Y direction are large, they are not intended to simulate the axial propagation of the steam chamber and pressure losses in the wellbore but rather to accommodate changes in reservoir quality between heel and toe.

The bitumen viscosity was the same as the one published in the previous study(10).

The comparison of field performance vs. simulation is shown in Figure 7. As mentioned previously, an extra 11% well length was added to the simulator to approximate the drainage coming from the ends of the well. Since the end effects become larger as the steam chamber grows, adding a fixed length to the well will over-estimate the production in the early part of the well life and under-predict the performance when the actual drainage is larger than the assigned length. This early over-prediction by the simulator was observed in the first year of operation. The simulation model also captured the rapid chamber rise in the highly permeable cross-bedded sands and the subsequent slow down in the advancement rate when the chamber encountered the IHS layer. Overall, the match was satisfactory.

TABLE 2: Simulation parameters.

	Lower Layer	Upper Layer
K_h, D	5	1
K_v, D	2.5	0.1
ϕ	0.35	0.32
S_{oi}	0.8	0.75

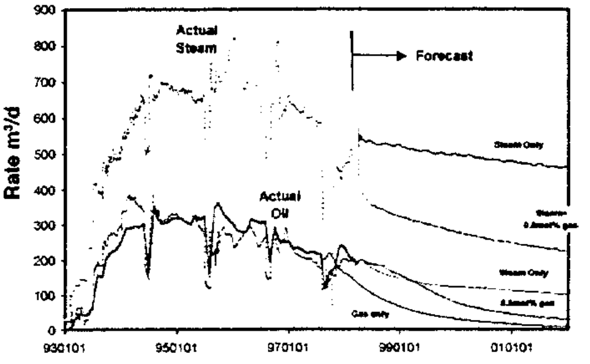

FIGURE 8: Simulation forecast of various wind-down strategies.

After the model was calibrated to match the historical performance from the start of production until the beginning of 1998, it was then used to predict the performance for various gas/steam wind-down scenarios that cover the full range of possibilities, i.e., from all steam to all NCG injection.

Three different operating strategies are shown in Figure 8:

- All NCG injection—The simulation model predicted that the bitumen rates would drop from the 200 m³/d level to less than 50 m³/d in about 1.5 years if steam injection was replaced by only NCG at the beginning of 1998. A substantial amount of bitumen was left in the reservoir.
- Continue steam injection—This case gave the most bitumen produced but also consumed the most steam.
- Steam with 0.8 mole% of NCG—The simulation model predicted that a small amount of NCG added to steam gave the best balance between recovery and thermal efficiency.

Natural Gas/Steam Wind-Down (1998-04 to 2001-04)

Because of the potential problems in the simulator for predicting SAGD performance in the presence of NCG as discussed above, it is not prudent to formulate wind-down strategies based on simulation results alone. Laboratory experiments and field observations continue to play an important role in optimizing the wind-down process. Based on the results from the SAGP experiments and the simulation prediction, the initial injected gas concentration could be less than 1 mole%. Since there was already a sizable steam chamber in Phase B before the addition of NCG, it was expected that the injected gas concentration would increase with time depending on field observations.

*** X and Y refer to the two horizontal directions. Y coincides with the axial direction of the wells. Z is the vertical direction.

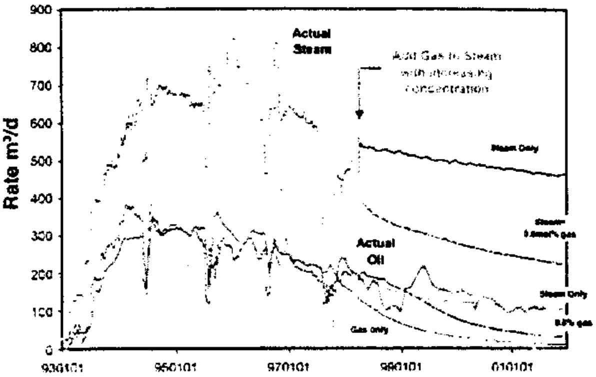

FIGURE 9: Comparison of wind-down performance with forecast.

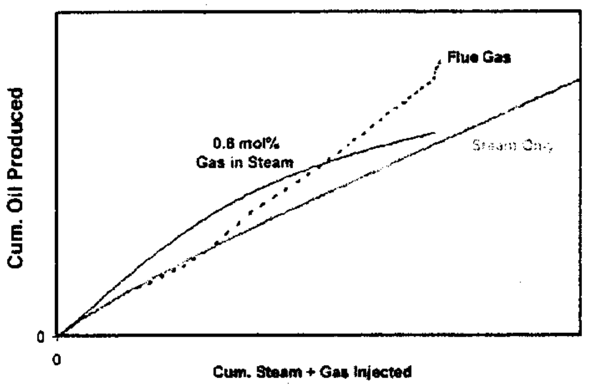

FIGURE 11: Phase B performance since 980401. Assumed flue gas was used.

Natural gas, which consists of mostly methane, was used as a NCG to supplement steam injection in April 1998. The concentration of natural gas in steam started at less than 1 mole% and increased steadily to higher concentration levels by April 2001. The chamber pressure was kept constant at about 2,000 kPa with some minor fluctuations due to operating constraints. The actual performance is shown in Figure 9, along with the simulation cases for fixed NCG concentrations of 0.0, 0.8, and 100 mole%. There was a significant drop in the bitumen rate from July to December 1998 due to plant operating problems. Once the problems were resolved, Phase B was placed on full production resulting in the spike appearing in the first half of 1999. By the second half of 1999, Phase B was in steady state operations. Since the natural gas concentration increased steadily with time, the actual performance can not be directly compared with the simulation predictions. However, it is reasonable to expect that the actual performance should fall into the range predicted by the 0.8 and 100 mole% gas injection cases. However, the actual performance was substantially higher than the simulation prediction. In fact, the bitumen rates were even better than those predicted for the continued steaming case (i.e., no gas/steam wind-down).

To fully appreciate the effect of adding gas to steam injection, it is more instructive to look at the cumulative injection and production profiles since the start of the wind-down operations in April 1998. Since the injected gas carries cash value, it is important to factor it into the evaluation. For the current situation, it is assumed that the injected gas is hypothetically converted to steam, based on the amount of steam that the gas would generate for injection. There can be other means to account for the gas injection depending on the operating conditions. Figure 10 shows that the equivalent cumulative steam-oil ratio (after converting the injected gas into equivalent steam) observed in the field was indeed better than the simulation prediction.

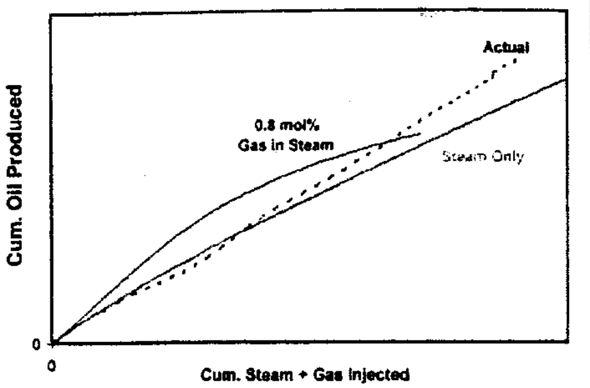

FIGURE 10: Phase B performance since 980401. Gas injection is converted to steam equivalent.

Flue Gas Injection (2001-05 to 2001-09)

The major cost of the gas/steam wind-down process is the cost of the NCG. Several options were considered to reduce the cost. They ranged from air, to enriched nitrogen, to flue gas. For example, if the natural gas being injected into Phase B were replaced by flue gas, then the cost would have been much lower. Figure 11 shows the equivalent cumulative steam-oil ratio using flue gas instead of natural gas. In May 2001, an experimental program was put in place to test the concept of flue gas injection into Phase B.

Simulation studies show that the wind-down operation is insensitive to the type of NCG used. Similar observations were also derived from some of the SAGP experiments(11). The main problem with flue gas injection is that the injectant is corrosive to surface piping and subsurface tubulars. When the unburned oxygen comes in contact with water, it will corrode unprotected carbon steel pipes in a very short time. Several design criteria were put in place to minimize the potential of corrosion:

- Reduce the oxygen content to a minimum by conducting the combustion in a fuel-rich environment.
- Eliminate the possibility of vapour condensation by ensuring that the flue gas is always above its dew point.

Other potential corrosive components in the flue gas are carbon dioxide and carbon monoxide. Again, it was thought that if the flue gas was above the dew point, then the potential for corrosion would be reduced.

Ideally, the source of the flue gas will come from the steam generator exhaust gas. This will provide a source of low cost gas and the opportunity to sequester some of the flue gas. However, the uncertainty about whether the corrosion problem can be brought under control discourages the large investment required to modify existing equipment for the test. Instead, an Exhaust Gas Processor (EGP) used for underbalanced drilling was leased from Northland Energy Corporation. A schematic drawing of the EGP is shown in Figure 12. It is a self-contained unit that generates and compresses the required amount of flue gas to the desired injection pressure. It has two internal combustion engines that power two separate compressors. Natural gas was used as fuel for the IC engines in this test, although propane could also be used. The exhaust gas is first compressed by a blower to raise the pressure to slightly above atmospheric pressure. The moisture in the flue gas is then reduced by going through an aerial cooler. The first rotary vane compressor raises the pressure to about 240 kPa. The second reciprocating compressor has four stages with inter-stage coolers to progressively increase the gas pressure and to remove the moisture content in the flue gas. Figure 13 shows the moisture content in the flue gas at the outlet of each inter-stage cooler for a gas temperature of 32° C, which corresponds to an ambient temperature of about 16° C. The water vapour fraction leaving the EGP is reduced to 0.0013 (or 30 kg per MMCF).

Normally, the gas is ready for injection when the moisture content is reduced to such a low level. The complication in this situation is that there is a long (830 m) pipeline from the outlet of the

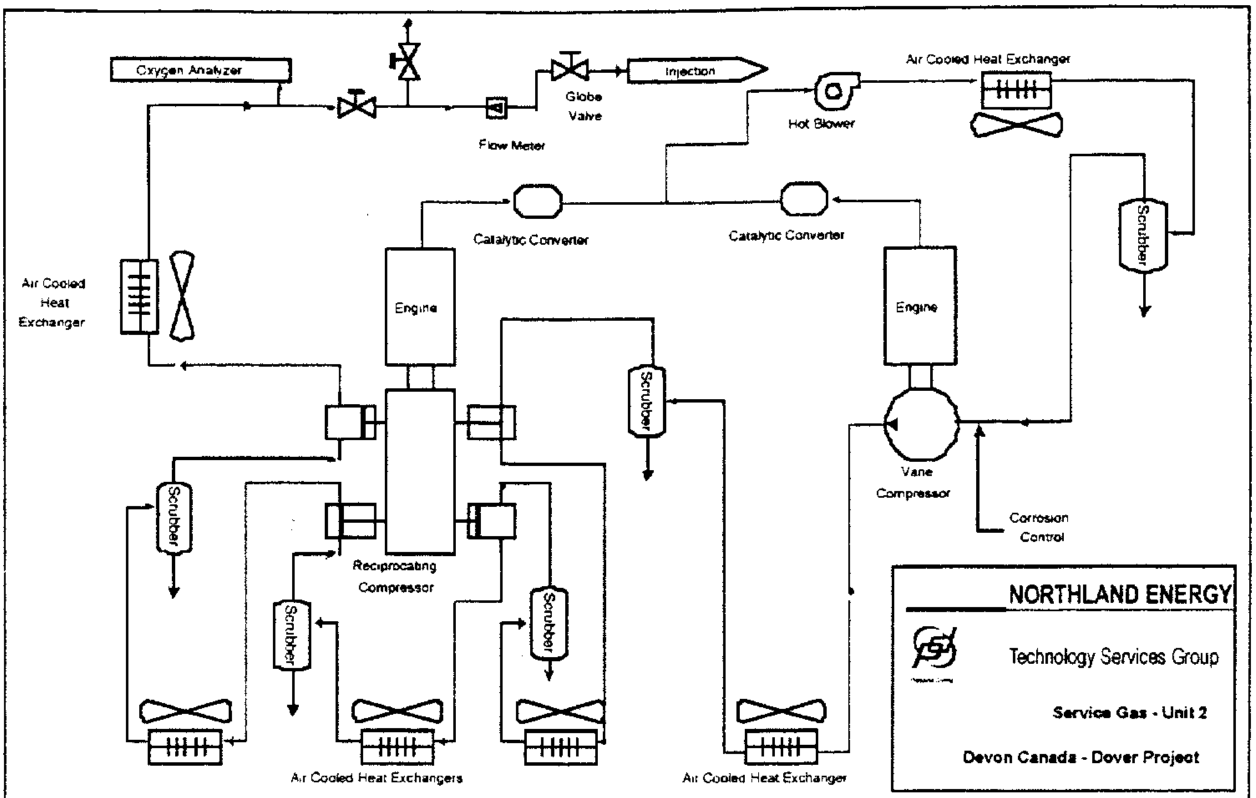

FIGURE 12: Schematic of exhaust gas processor.

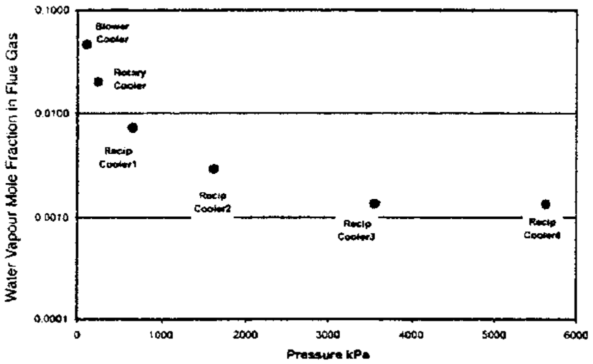

FIGURE 13: Water content in flue gas at 32° C.

TABLE 3: Flue gas compositions (mole percent).

Comp	May 16, 2001	June 4, 2001
H_2	1.34	0.12
O_2	<0.01	0.004
N_2	81.57	83.71
CO	0.71	1.05
CO_2	16.15	15.06
C_1	0.23	0.06

EGP at the surface to the underground wellhead. The flue gas temperature drops as it travels from the surface to the wellhead. To avoid condensation in the line, the flue gas is re-heated to a higher temperature at the outlet of the EGP.

Flue Gas Injection Results

Table 3 shows the flue gas compositions at the outlet of EGP during the test period.

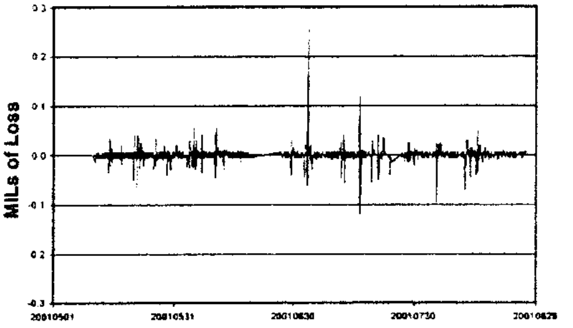

FIGURE 14: Metal loss on resistant probe.

The flue gas oxygen content was successfully controlled to below 100 ppm. However, the concentration of CO_2 was higher than expected.

A number of corrosion coupons and resistant probes were strategically placed in the steam injection line and the fluid production line to monitor the potential for corrosion. After 4 months of operation, none of the corrosion devices showed any signs for concern. Figure 14 shows the readings of a resistance probe for metal loss, placed near the wellhead of the injection well where corrosion was most likely to occur. No detectable losses were recorded.

Discussion

Valuable lessons have been learned from the gas/steam wind-down experiment at Phase B. Some of the major ones are discussed below.

IHS Depletion

As discussed earlier, the steam rise rate into the low reservoir quality IHS layer has been observed to be substantially lower. A

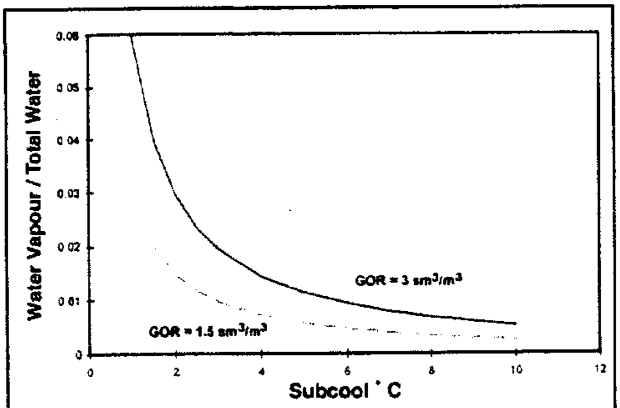

FIGURE 15: Associated water vapour production with gas production, pressure = 2,500 kPa, oil cut = 32%.

series of cased-hole neutron logs were run in some of the vertical observation wells at Phase B as part of the program to understand gas distributions in the reservoir. Results show that a significant amount of gas travels ahead of the apparent top of the "steam" chamber. Although such a phenomenon was predicted by calculations, it was measured for the first time in a SAGD field situation. It means that the depletion rate in the IHS layer had been higher than previously calculated based on the rate of saturated steam temperature movement corresponding to the operating pressure.

Gas Dissolution

Phase B has been operated at pressures that are higher than the initial pressure (2,000 vs. 550 kPa). When the injection pressure of a mixture of steam and gas is higher than the initial reservoir pressure, some of the gas may dissolve into bitumen under some circumstances as discussed by Butler(12) et al. The dissolution of gas reduces the tendency of gas accumulation at the chamber interface. This provides a means to accelerate heat transfer into colder regions of the reservoir, which may offset the gas insulation effect as predicted by numerical simulation.

Subcool Adjustments

As the gas concentration builds in the chamber due to gas being added to steam, the tendency to produce more gas increases with time. The operating policy should be adjusted to avoid excessive gas production since the produced gas is saturated with steam. Figure 15 shows the amount of vapour production as a function of producing gas-oil ratios (GOR) and subcool settings. For example, the subcool needs to increase from 3° C to 6° C in order to maintain 1% of vapour production when the producing GOR changes from 1.5 sm³/m³ to 3 sm³/m³.

Flue Gas Compositions

The EGP used for the test carries out the combustion in the IC engine in a fuel-rich environment to minimize the oxygen concentration in the exhaust gas. On the other hand, the combustion in typical oil field once-through steam generators is done in an air-rich condition. Hence, it is expected that the oxygen content will be higher if boiler exhaust gas is used for injection. Further work is required to qualify the impact.

Conclusions

- The addition of NCG to steam injection has proved to be a technically viable method to effectively wind-down a mature SAGD chamber.
- The gas/steam wind-down process has performed better than expected. It has achieved good oil rates and steam-oil ratios.
- The heat transfer rates into the colder regions of this reservoir are not affected significantly by the presence of NCG. This is different from the results predicted by numerical simulation.
- NCG travels ahead of the apparent "steam" front, which gives higher depletion levels than previously thought.
- Flue gas has been used successfully to replace natural gas in the wind-down operation. The injection system was designed and operated to ensure the flue gas temperature is always above the dew point of the gas so condensation will not occur. This technology has the potential to reduce the cost of injection substantially and to provide a means to sequester some of the exhaust gas from steam generation.

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NOMENCLATURE

K_h = Horizontal permeability
K_v = Vertical permeability
S_{oi} = Initial oil saturation
ϕ = Porosity

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