The following article summarizes one component of a thermal project completed for the 2003/2004 Fourth Year Petroleum Design Project Course (ENPE 511/531) offered by the Department of Chemical and Petroleum Engineering at the University of Calgary.

Conoco Surmont Pilot Project

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An evaluation of Steam-Assisted Gravity Drainage (SAGD) at the Conoco Surmont field, located 75 km southeast of Fort McMurray, Alberta, was conducted by using the thermal reservoir simulator, CMG STARS. The Surmont SAGD three well-pair pilot was studied. Two of these well pairs contain a 400 m long slotted liner while the third well contains a 700 m long slotted liner. Field history was obtained from the three well pairs that are currently producing. Relevant information included drilling records, true vertical depths of the well pairs along with fluid production and injection data. As of June 30, 2003 the cumulative values of interest were as follows:

Cumulative Steam to Oil Ratio (SOR) = 2.60
Cumulative Oil Production = 209, 000 m^3
Cumulative Water Production = 630, 000 m^3
Cumulative Steam Injection (Cold Water Equivalent) = 544, 000 m^3

The reservoir description was derived from geological data gained from core and log data. From this analysis, five main intervals of interest were included in the model: top gas zone, top water, Upper McMurray, Middle McMurray and Lower McMurray. A non-orthogonal corner point grid model was prepared by CMG GridBuilder. This type of grid was selected to ensure that sub models of the individual well pairs could be extracted along their wellbores, while at the same time all three pairs could be run in the larger base case. For the course, well pair 2 was selected for a detailed history match because BHP data was available from the injection well and temperature data marking the rise rate of the steam chamber was available from the OBS 22 observation well located near the toe of the injector. Using GridBuilder, a two-dimensional, sub model of well pair 2 was extracted from the model. To accomplish the history match of the well pair 2 pilot data, the sub-model grid was refined to capture layers of reduced permeability as indicated by log and rise rate data. The grid and vertical permeability distribution is displayed in Figure 1. The blue streaks represent streaks of reduced permeability.

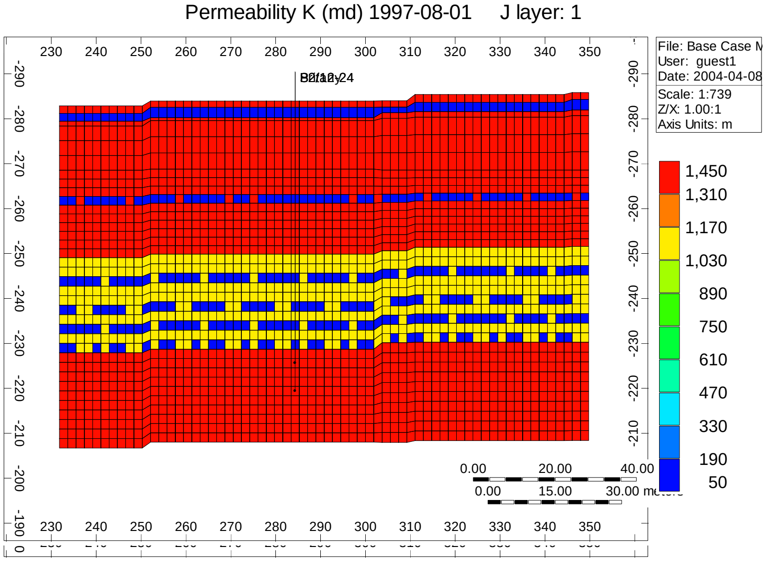

Figure 1: Vertical permeability in the well pair 2 sub-model.

For the history match, the steam injection and oil production rates in the sub-model were constrained to the field values. The matched (compared) variables included bottom hole pressure (BHP) of the injection well, water production, steam chamber rise rate, and steam chamber temperature. Geological and other reservoir properties were altered in order to achieve a close match between the simulation and the field data. The reservoir properties that were determined are as follows:

- Porosity = 0.30
- Initial reservoir pressure in bitumen zone = 1230 kPa
- Oil saturation in bitumen zone = 0.85
- Solution gas oil ratio = 1.8 m^3/m^3
- Horizontal permeability = 5000 mD
- Vertical permeability of Upper McMurray = 1450 mD
- Vertical permeability of Middle McMurray = 1150 mD
- Vertical permeability of Lower McMurray = 1450 mD

Figure 2 compares the field and simulated bottom hole pressure. This is a reasonable match given that the proper volumes of injected steam and oil produced were enforced.

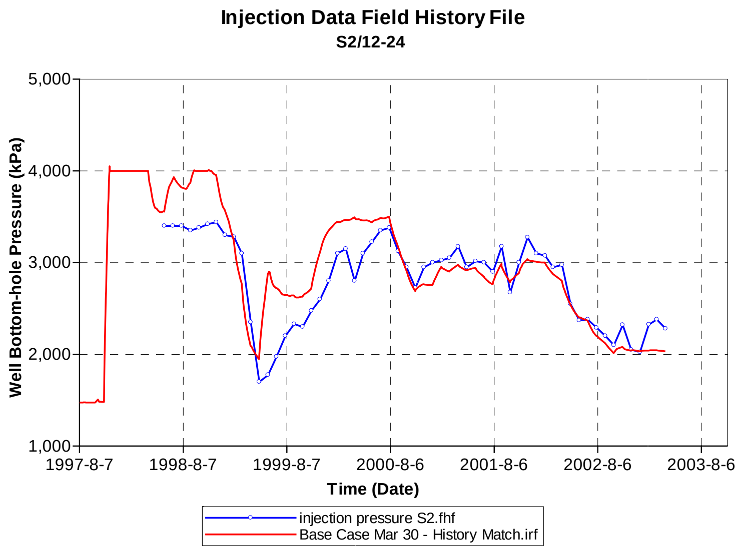

Figure 2: Field and simulated bottom hole pressure.

In addition to the reasonable match made on the BHP of the injection well, the rise rate observed from the simulator was extremely close to the temperature data from OBS 22, as shown in Figure 3. A reasonable match is obtained except for the late time when the simulation does not accurately represent the steam chamber level decrease past 2002-01.

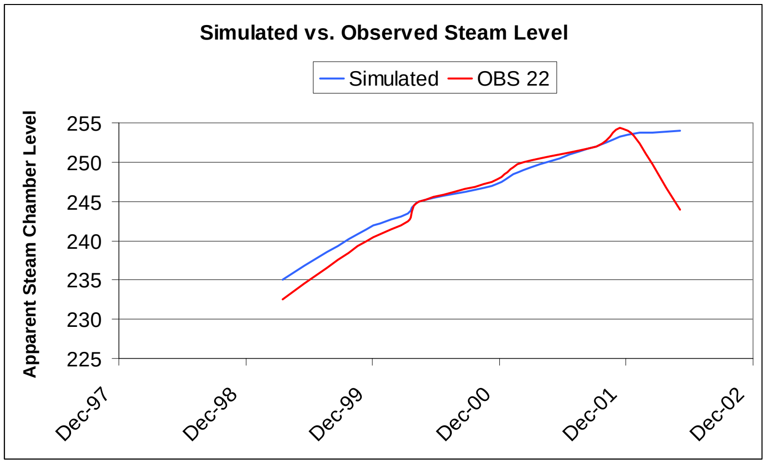

Figure 3: Field (determined from OBS 22 thermocouple data) and simulated top of steam chamber location.

The reason for the contraction of the steam chamber reflected by the field data at the beginning of 2002 is not completely clear but could be due to gas effects, chamber interactions, or operational changes.

The reservoir description obtained from the history match was used to forecast production for commercial expansion. Using different operating constraints, a forecast was achieved for both gas lift and ESP operations. Gas lift requires a BHP of approximately 2600 kPa while submersible pumps can operate with a BHP as low as 1000 kPa.

Figure 4 compares the oil production obtained from ESP versus gas lift operations. In late 2008, the oil rates in the gas lift case decline significantly. At this point, the steam chamber in the gas lift case comes into contact with the top water zone. The lower pressure water layer behaves like a thief zone and quickly dissipates the higher steam chamber pressure. As a result, oil production experiences a significant decrease. Meanwhile, the ESP steam chamber does not encroach upon the water for the entire 10 year run life. The most significant difference between the two cases is the shape of the steam chamber and therefore the rise rate observed. The Gas Lift temperature distribution in 2009-01-01 is shown in Figure 5. In contrast, the temperature distribution of the ESP (at the same point in time) can be seen in Figure 6.

Figure 4: Oil production from ESP and gas lift operations.

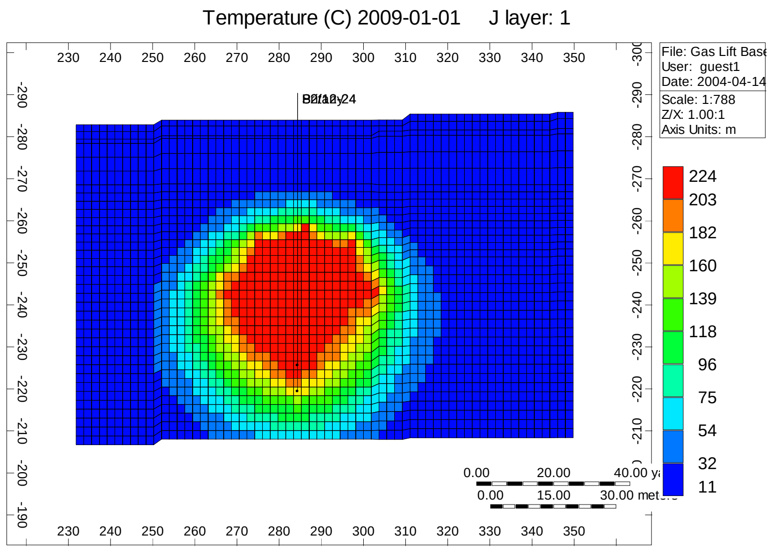

Figure 5: Temperature distribution of steam chamber with Gas Lift operation at 2009-01-01.

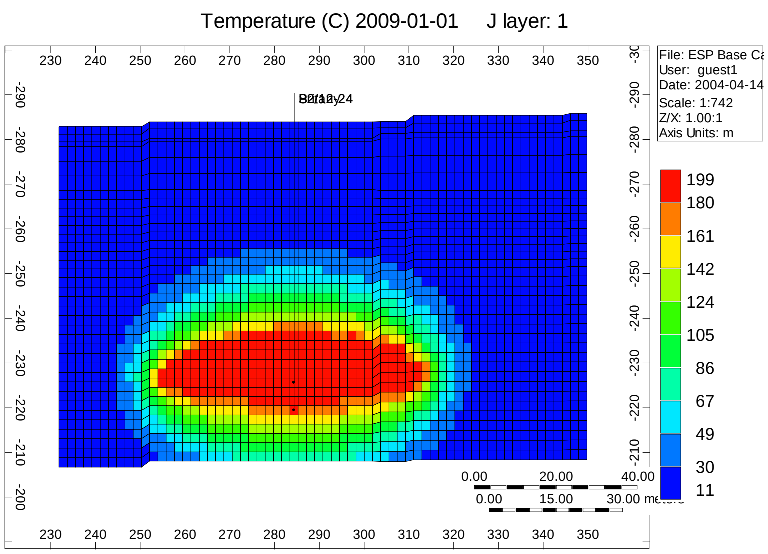

Figure 6: Temperature distribution of steam chamber with ESP operation at 2009-01-01.

The difference between the two steam chambers that results from a change in operating conditions is quite significant. Since the ESP case is constrained to a lower minimum production pressure, the steam injection pressure is slightly lower. As a result, the steam temperature corresponding to saturated conditions is lower in the ESP case. At lower temperatures, there is less heat transfer and subsequently higher viscosities. Figure 7 shows the viscosity difference (i.e. the oil viscosity of the ESP case is subtracted from the oil viscosity in the gas lift case) at 2009-01-01. Figure 7 reveals that the steam chamber in the gas lift case expands primarily in the vertical direction whereas the steam chamber in the ESP case grows horizontally. This may partially explain the reason for the slower vertical rise rate of the ESP case in comparison to the gas lift case. The gas lift case operates at higher pressure and temperature. This implies lower oil viscosity, faster rise rate, and so the steam chamber reaches the top water zone in the gas lift case sooner than that in the ESP one. It is important to note that the geology is exactly the same for each of the cases. In this particular situation, since this reservoir contains top thief zones, the impact of a fast steam chamber rise rate is ultimately detrimental to oil production.

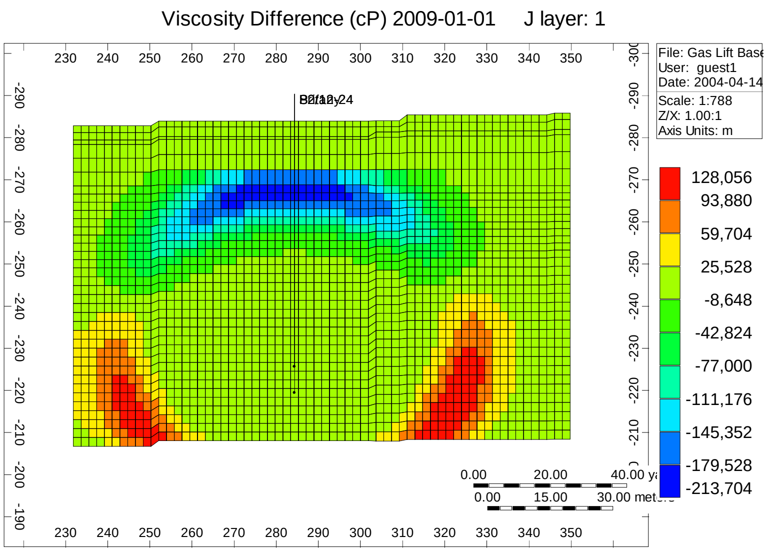

Figure 7: Oil viscosity difference (Gas Lift – ESP) at 2009-01-01.

For more information on this project, please contact Professor Ian Gates (ian.gates@ucalgary.ca) in the Department of Chemical and Petroleum Engineering at the University of Calgary.