Introduction

The main objective of this project was to determine optimum spacing of wells and to compare the performance of cyclic steam stimulation (CSS) to steam assisted gravity drainage (SAGD) in shallow bitumen reservoirs.

CSS and SAGD are enhanced oil recovery methods in which steam is injected into heavy oil reservoirs to reduce oil viscosity and increase production. In CSS, steam is injected, then the well is shut in for a period of time called soaking period (to allow the heat from steam propagate through the reservoir), then the well is reopened for production. In SAGD, a pair of horizontal wells is drilled into the reservoir, one about 10 meters above the other. Steam is continuously injected into the upper wellbore to heat the oil and reduce its viscosity, causing the heated oil to drain into the lower wellbore.

A shallow bitumen reservoir (~90 meters deep and 20 meters thick), connected to an aquifer at the bottom, was modelled (in CMG) and analyzed. The reservoir consists of two wells (initially operated as SAGD, but converted to CSS) 600 meters apart and about 400 meters long. New CSS and SAGD wells were drilled between the existing wells to compare CSS oil recovery to SAGD recovery, taking into account steam requirements for each method.

Reservoir Model

- Initial reservoir temperature: 8°C
- Initial reservoir pressure: 440 kPa
- Relative permeability variation with temperature:
  - At 8°C, Sro = 0.1, Srw = 0.4, Sgr = 0.45
  - At 250°C, Sro = 0.056, Srw = 0.2, Sgr = 0.05
- Steam injection constraints:
  - 15 atm. injection pressure
  - 200°C steam temperature
  - 200 centigrade maximum injection rate
- Production pressure is about 150 kPa
- History matched oil and water production data from 2013 – 2015 to determine porosity, permeability and heat loss/transfer parameters

Reservoir Model – History Match Results

- Oil Zone Porosity: 0.36
- Oil Zone Permeability: 1322 mD
- Water Zone Porosity: 0.13
- Water Zone Permeability: 588 mD
- Overburden Thermal Conductivity: 9.7 x 10⁴ J/(m²·day·°C)
- Underburden Thermal Conductivity: 9.7 x 10⁴ J/(m²·day·°C)
- Overburden Heat Capacity: 2.44 x 10⁴ J/(m³·°C)
- Underburden Heat Capacity: 9.32 x 10⁴ J/(m³·°C)
- Water Thermal Conductivity: 1.13 x 10⁴ J/(m³·°C)
- Oil Thermal Conductivity: 4.21 x 10³ J/(m³·°C)
- Gas Thermal Conductivity: 4.36 J/(m³·°C)
- Rock Thermal Conductivity: 2 x 10³ J/(m³·°C)

Temperature Propagation

- Temperature propagation radius between wells is about 120 meters after 25 years, which suggests a 240 meter well spacing is required.

Effect on Oil Viscosity

- Temperature propagation causes the heated oil to drain into the lower wellbore.

Figure 1: Schematic of reservoir

Well 15018/15019

Well 15018 (bottom well) was shut in after well 15019 was converted to a CSS well.

Well 15037/15038

Well 15038 (bottom well) was shut in after well 15037 was converted to a CSS well.

Well 15019/15018

Well 15018 (bottom well) was shut in after well 15019 was converted to a CSS well.

Well 15037/15038

Well 15038 (bottom well) was shut in after well 15037 was converted to a CSS well.

Figure 2: CMO model of 15037/15038 well pair

Figure 3: CMO model of 15037/15038 well pair

Figure 4: CMO model of 15037/15038 well pair

Reservoir Model

- Oil Thermal Conductivity: 2 x 10⁴ J/(m³·°C)
- Overburden Heat Capacity: 1.13 x 10⁴ J/(m³·°C)
- Water Thermal Conductivity: 1.13 x 10⁴ J/(m³·°C)
- Oil Zone Porosity: 0.36
- Oil Zone Permeability: 1322 mD
- Water Zone Porosity: 0.13
- Water Zone Permeability: 588 mD
- Overburden Thermal Conductivity: 9.7 x 10⁴ J/(m²·day·°C)
- Underburden Thermal Conductivity: 9.7 x 10⁴ J/(m²·day·°C)
- Overburden Heat Capacity: 2.44 x 10⁴ J/(m³·°C)
- Underburden Heat Capacity: 9.32 x 10⁴ J/(m³·°C)
- Water Thermal Conductivity: 4.21 x 10³ J/(m³·°C)
- Oil Thermal Conductivity: 4.36 J/(m³·°C)
- Gas Thermal Conductivity: 0.2 x 10³ J/(m³·°C)
- Rock Thermal Conductivity: 2 x 10³ J/(m³·°C)

Figure 7: Cumulative oil history match

Figure 8: Temperature field at 2040 (after 25 years)

Figure 9: Viscosity field at 2040 (after 25 years)

SAGD vs. CSS Performance

- Case 1: Simulation is run to 2400 with no new wells added; 15019 and 15037 are operated as CSS wells with cycle timing of 200 days of injection, 40 days of soaking and 120 days of production. In 15019, the cycle timing is 200 days of injection, 40 days of soaking and 120 days of production.
- Case 2: Two new CSS wells are added between wells 15019 and 15037 at 10 meters above the aquifer, with cycle timing of 200 days of injection, 40 days of soaking and 120 days of production.
- Case 3: Two new SAGD wells are added between wells 15019 and 15037; producer is about 2 meters above the aquifer, and the injector is about 5 meters above the producer.
- Case 4: Two new SAGD wells are added between wells 15019 and 15037; producer is about 10 meters above the aquifer, and the injector is about 5 meters above the producer.
- Case 5: Two new SAGD wells are added between wells 15019 and 15037; producer is about 10 meters above the aquifer, and the injector is about 10 meters above the producer.

SAGD vs. CSS Performance

- Recommended well spacing is 240 meters.
- Although SAGD (case 5) slightly outperforms CSS (14.8% vs. 14.3% recovery), CSS is recommended for new wells because the amount of steam required for SAGD is almost double the amount of steam required for CSS.

Acknowledgements

The authors would like to acknowledge Daneshy Consultants International for support of this project.

The authors would like to acknowledge Daneshy Consultants International for support of this project.