MODELLING HEAVY OIL ARTIFICIAL LIFT METHODS

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ABSTRACT

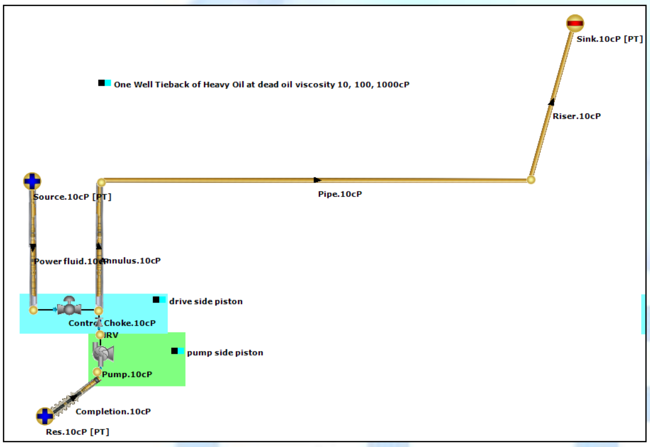
When the natural reservoir pressure is insufficient to push production fluids up the well to the surface, artificial lift can be used to increase production. Insufficient pressure can arise due to low reservoir pressure or occur due to production fluid properties. Heavy oils are more dense and viscous and, therefore, have a greater resistance to flow compared with light oils. This puts a larger backpressure on a reservoir due to pressure losses in the well and gathering network.

A series of one well tiebacks have been modelled using Maximus, for various oil viscosities and methods of artificial lift. The effect of the different methods of artificial lift on the produced oil flow rate has thus been studied.

The System

The system simulated is a simple one well tieback with a reservoir depth of 1800 m, a horizontal 1000 m flow line and a 1000 m riser. This system is modelled with three dead oil viscosities; 10cP, 100cP and 1000cP at reservoir conditions. The types of artificial lift studied in this work are the Hydraulic submersible pump (HSP), Electrical submersible pump (ESP) and Gas lift (GL). Figure 1 shows the system using HSP modelled in Maximus.

Figure 1 HSP method GUI screenshot



Hydraulic Submersible Pump

Hydraulic pumping uses energy in the form of a pressurised fluid to perform useful work driving a downhole pump. The hydraulic fluid used in this system is water, which is pumped down the tubing at high pressure. The power fluid performs work on the drive side of the pump, which is transferred mechanically to the production side of the pump. Modelling as an open system, the power fluid and production fluid mix at the outlet of the pump and travel through the annulus between the tubing and casing of the well.

Electrical Submersible pump

Electrical pumping uses a cable electrical power supply to drive a downhole centrifugal pump. Production fluid is pumped through the tubing to the wellhead.

Gas Lift

Gas is separated from the produced fluid, re-pressurised and injected into the tubing at the bottom hole to reduce the density of the column of fluid within the tubing, which reduces backpressure allowing the increase in reservoir production.

METHOD

The aim of this case study was to find the effects on the production oil flow rate when changing the type and amount of artificial lift provided for each of the three viscosity-defined wells. For each of the ESP and GL cases, a snapshot of the system for a range of sensitivity parameters was taken. The HSP cases were run in Life of Field mode.

HSP Simulation

The HSP model is a LoF model where each one day time step corresponds to a single sensitivity analysis case. Events are used to set the sensitivity parameter according to a lookup table (in a table model). The amount of power provided by the power fluid flowing through the system is calculated using model variables and power input to the pump is set using events.

The calculation (using model variables) is shown below. Calculated power is a function of hydraulic fluid flow rate and pressure drop between its downhole pressure and the pump outlet pressure, shown in Equation (1).

$$\text{drive power}_{\text{power fluid}}(\text{kW}) = \text{flow rate}_{\text{power fluid}}\left(\frac{\text{m}^3}{\text{s}}\right)\times\text{pressure drop}_{\text{power fluid}}\,(\text{bara})\times\text{driveside pump efficiency} \quad (1)$$

An event sets the power input of the pump object equal to the calculated drive power variable. A convergence criterion, as given in Equation (2), is used so that Maximus performs multiple iterations of the event until the criterion is met;

$$\text{abs(lastiteration(Pump.10cP.Power\_Input)-drive\_power\_kW.10cP)} \leq 0.1 \quad (2)$$

This criterion makes sure that the power input is equal to the calculated drive power before moving onto the next time step. Similar criteria are used with the 100cP and 1000cP systems.

ESP Simulation

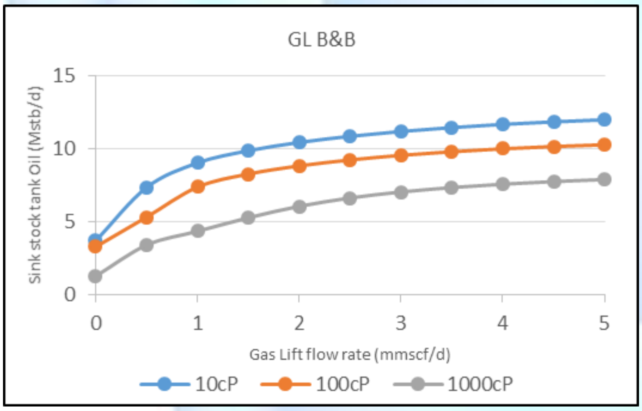
A snapshot simulation of the system is run within Maximus, using the Sensitivity Analysis mode to model a range of cases by changing certain variables. Pump power input is the sensitivity parameter varied, with a range of 0 to 500 kW of shaft power.

GL Simulation

Gas Lift simulation cases are run in snapshot mode using Sensitivity Analysis within Maximus to run a range of cases. Injected gas flow rate is the sensitivity variable, which ranges from 0 to 5 mmscf/d.

RESULTS

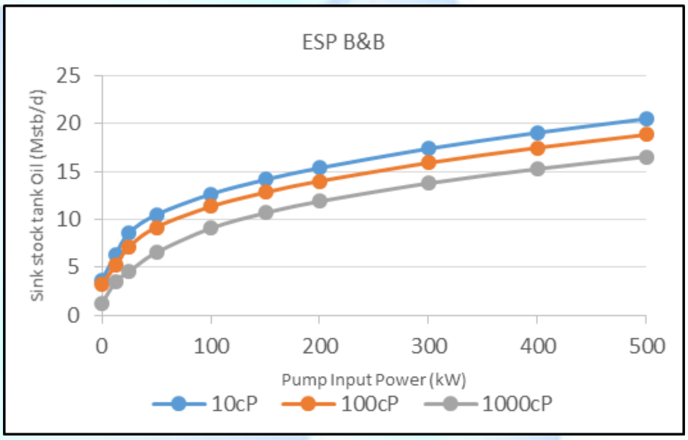
Figure 2 Effect of Gas Lift



In Figure 2, the effect of increasing gas lift is reasonably uniform over the viscosity range, where the increase in oil production for a given increase in gas rate is comparable for each viscosity oil. Effects are strongest below 3 mmscf/d; only marginal improvement is gained with gas rates above 3 mmscf/d. At higher gas injection rates, the increased frictional pressure losses through the system counteract the benefits of a reduced mean fluid density in the well tubing.

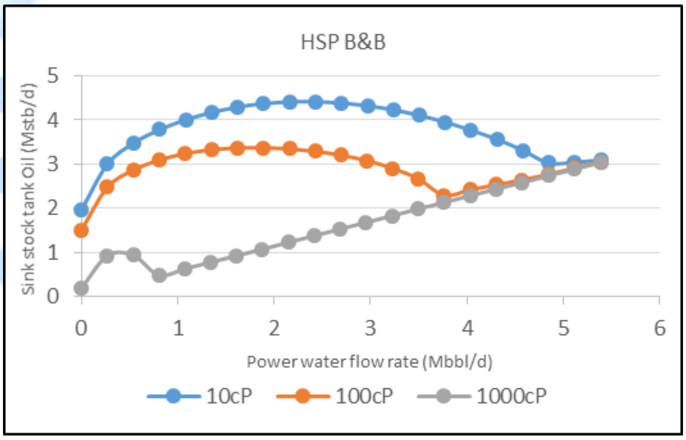
The effect of an electrical submersible pump, as shown in Figure 3, is similar for all viscosities, but as each fluid has different resistance to flow, they show increasing oil flow rates as viscosity decreases. The greatest effect of the pump occurs at low input power, where flow rates are low (this is due to the shape of a typical centrifugal pump head versus flow curve). Increasing frictional pressure drop and decreasing Δ-head across the pump, at higher flow rates means that the ESP becomes less effective as its input power is increased.

Figure 3 Effect of Electrical Submersible Pump



The HSP is an open system, as the power fluid mixes with produced fluid at the outlet of the pump. As the outlet pressure of the pump increases due to an increased input power, the pressure drop experienced by the power fluid on the power side of the pump decreases. This corresponds to lower power produced from the constant pressure supply of power fluid. As there is a relationship between the power supplied to the pump and the outlet pressure of the pump, pressure produced by the pump has a maximum value where increasing the power fluid flow rate will no longer increase the outlet pressure of the pump.

Figure 4 Effect of Hydraulic Submersible Pump



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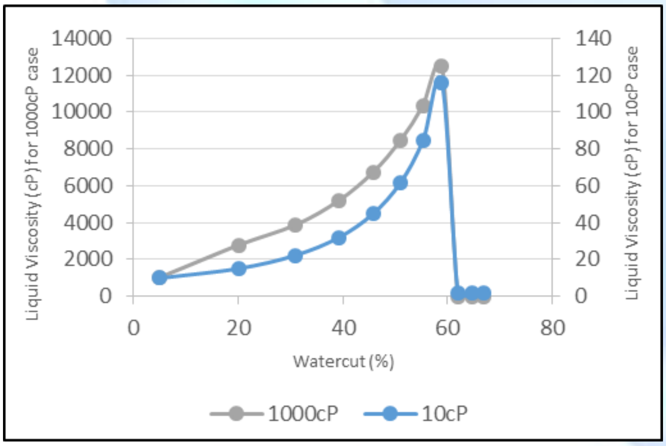
In the 1000cP case, the straight line in the right of Figure 4 is from the 60%+ watercut region, where liquid viscosity does not change drastically. In the 10cP case most of the graph is in the 0-60% watercut region, where liquid viscosity changes with watercut due to the formation of an emulsion. The curves in Figure 4 show that the same oil production rate is achieved at a low power as at a high power. At high power water flow rate, input power to the pump is greater; however more fluid must be pumped through the network, which, along with a higher viscosity caused by the higher watercut, causes a production oil flow rate equal to that achievable with a lower power fluid flow rate.

Viscosity vs Watercut

Figure 5 shows the relationship between viscosity of the produced oil/gas/water mixture and its watercut for the 10cP and 1000cP systems. These emulsions exhibit non-Newtonian behaviour and, as such, have much higher liquid viscosities than the oil or water alone. The emulsion inversion point setting is an input parameter within Maximus, which was set at the default value of 60%. The effect of this can be seen on the figure at 60% watercut; at this point there is a sharp drop in viscosity, where the water in oil emulsion becomes an oil in water emulsion, which has a viscosity close to that of water.

Figure 5 Viscosity of Oil/Water production fluid



HSP vs ESP vs GL

As extra water is pumped through the gathering network using HSP, more energy is required compared with pumping the production fluid alone (i.e. as is the case for ESP). However, when the watercut at the outlet of the pump rises above the emulsion inversion point, the benefits of a much reduced liquid viscosity are realised, but this has the potential drawback of reaching processing constraints at the reception facility. The actual behaviour of the specific water / oil emulsion would have to be studied (in the lab) for each case to which the application of HSPs are considered.

Work overs can be required when downhole pumps are used, which reduces the uptime of a well and restricts production. Gas Lift is inherently more reliable compared with downhole pumping due to the simplicity of its design.

Neither type of downhole pump is particularly tolerant to solids such as sand, due to tight clearances in centrifugal pumps and valves in the reciprocating piston design of a HSP.

The maximum production achieved in this study was given using ESP, where high power input is used. A HSP, or gas lift system, would normally have a greater restriction on their power fluid or gas flow rate compared to any restriction in electrical power supply for an ESP.

CONCLUSIONS

Comparison of the three methods of artificial lift is difficult due to the differences of each type. With the data produced from Maximus an appreciation of the benefits and drawbacks of each system are identified. Economic analysis could be carried out for each artificial lift scenario on an actual project to provide an economic optimisation of the system.

This study shows that conceptual studies using Maximus can offer an efficient way of simulating a variety of development concepts regarding heavy oil and artificial lift methods.