Deep Heavy Oil Recovery by Steam Injection using Twin Horizontal Drainholes.

G A Cooper*, M Gondouin# and M S Zeyrek*

* Hearst Mining Building, University of California, Berkeley, CA 94720

S-Cal Research, 32, San Marino Drive, San Rafael, CA 94901

FG01-92CE15553

(Paper presented as SPE 24088 at the SPE 1992 Western Region Meeting, Bakersfield, California, 30 March - 1 April 1992, modified and edited for submission for publication, Sept 1992)

ABSTRACT

We propose a novel method for improving the efficiency of recovery of heavy oil. Two horizontal drainholes are made at the bottom of a vertical well so that one may be steamed while the other is in production. Downgoing steam and rising produced fluids are carried in the same vertical casing so that heat from the produced fluids reduces heat losses from the steam. This arrangement requires a downhole valve that will switch steam and produced fluids between the boreholes. We discuss the design of a suitable well and of the valves, and report results of tests to select suitable materials to function in the high temperature downhole environment.

1 INTRODUCTION

Much of the Western hemisphere's oil reserves are in the form of heavy oil, in deposits located in Alaska, western Canada, Venezuela and, particularly, California. Heavy oil is too viscous to flow to the well at a reasonable rate under ordinary conditions, and so it must be helped in some way. The most practical method developed so far is to inject steam into the reservoir, to raise the temperature and to reduce the oil's viscosity. This is often achieved by the so-called Huff-and-puff method, in which steam is injected for a period of days to months (Huff), allowed to soak, and then the well is pumped to produce the now hot and fluid oil (Puff). In a later stage, when the hot zone has grown sufficiently, steam may be injected into one well, and oil produced from an adjacent well (Steam drive). Both methods are limited by the heat losses to surrounding rocks that are incurred as the steam is sent down the injection well, and so for any particular reservoir and

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

price of oil, there is a maximum depth of reservoir that can be exploited economically.

To improve the economics of the process, and to access the large volumes of deeper oil that exist in California and elsewhere, some way must be found to limit the heat lost from the injected steam. It is therefore proposed to arrange a return flow of hot oil in the same well as that used to inject the steam. To do this, it is necessary to have the same well both injecting and producing simultaneously. This can be done conveniently by placing two tubings in a conventional well casing, one of which is insulated, and carries steam, while the other is uninsulated, and carries the produced hot oil. Alternatively, the produced fluids may be brought to the surface in the annular space between the steam tubing and the casing. At the bottom, two horizontal perforated liners are placed to run out on opposite sides of the main borehole. One of the horizontal liners is set to injecting steam while the other produces hot oil. After some time, the roles of the two horizontal liners are switched to achieve the desired Huff-and-puff effect. At a later stage, when the heated zone has grown sufficiently, a pair of such wells may be combined to form a steam drive. To do this, the two horizontal drainholes of the first well are routed parallel with and opposite to the drainholes of the second well. In this way, steam injected into the left hand drainhole of the first well can drive towards the left hand branch of the second well, and steam injected into the right hand branch of the second well can drive to the right hand branch of the first well. This arrangement preserves the essential feature of steam injection and simultaneous production in both casings.

Apart from the improvement in steam quality, the horizontal arrangement of the drainholes may have additional benefits. The first is that a horizontal well is expected to have a greater productivity than a vertical well in the same layer; Joshi (1), for example, estimates that in a 300 ft (90 m) layer, a horizontal section of 1100 ft (330 m) should have a productivity index about three times that of a corresponding vertical well. The second benefit is that the producing section of the well, and in particular the pump, can be placed at a lower position in the reservoir than in a vertical well. This will be of critical importance in depressurized reservoirs in which the oil lies below a gas cap whose pressure is close to atmospheric (a situation typical of many

Californian reservoirs). In such a case, the drawdown pressure available before causing the pump to cavitate may be up to twice that which could be obtained if the oil flowed through the perforations or open pay section in a vertical well to a pump located at the bottom. If maximum benefit were obtained from these two possibilities, we might hope for a six-fold increase in productivity per well. Finally, productivity will be further increased because no production time is lost while steaming, since the other drainhole will be producing at this time.

The switching of the injected steam and produced oil between the two horizontal tubings must be carried out by a down-hole valve or an equivalent flow control device. This is the only part of the system described above that is not commercially available. It is the purpose of the present paper to discuss a suitable design for this valve, and the materials from which it will be made.

One of the benefits of "huff and puff" operation of horizontal wells is to reduce the heat loss from the steam chamber to the overburden, because the heat front into the overburden recedes during the production cycle. A quantitative evaluation of the counter-current flow of steam and oil in this steam-assisted gravity drainage process is given by Butler (2).

2 WELL DESIGN

There are many possible designs of well and completion arrangement that could be used in a practical embodiment of the ideas sketched above. A major consideration is whether we are dealing with a new project or plan to re-work an existing vertical well that has already been in conventional production. In the former situation, we are free to design the casing string with a number of specialized fittings that will allow the kick off and completion of the two curved drainholes. In an existing well, on the other hand, we shall have to cut through the casing at some point and introduce the kick off hardware and subsequent completion equipment through an opening that corresponds with the minimum internal diameter of the existing casing. The other major factor is the pressure regime in the reservoir; as mentioned above, a low reservoir pressure will have a large influence on the location of the pump, and considerations of cavitation in the production tubings will determine whether we shall need a pump in each drainhole, or could use one pump in a sump placed in a lower section of the vertical casing, connected to the

drainholes via syphons that run up the casing to the kick off point and then down the ~~curved~~ sections to the perforated horizontal sections. For a full discussion of all the different possibilities, the reader is referred to two recent patents (3, 4); for the present, we shall describe one simple application of the idea to an existing cased well in which we drill the two drainholes from the bottom of the well. (Note that in the case where the existing well casing is of small diameter, the modifications to be suggested may not be possible because of space restrictions; in such a situation, other configurations are possible. The best way to save space is for the various components to be stacked vertically in the existing casing. In such a case, a satisfactory dual completion may be made in a casing as small as 7" (nominal OD)).

In the case of the pre-existing well with a large diameter casing, we start from a vertical well, drilled, cased and cemented by conventional techniques. Using a motor and bent sub, the casing shoe is drilled out and two short (about 50 ft or 15 m) smaller diameter holes are drilled from the bottom of the well (fig 1). These holes will have deviation angles of only a few degrees from vertical, and the separation between the holes will at most be a few feet at the bottom and a few inches at the top. Consequently, in some formations, it may be desirable to under-ream a single large diameter hole below the casing shoe, and start the deviated holes from the bottom of the larger hole. Two short "intermediate liners", about 60 ft (18 m) long, are now run into the two holes, and cemented into place. The cementing operation may be carried out in one step by running-in the assembly shown in fig 2. This consists of an inverted "Y" nipple, to each branch of which is attached a tail pipe for the injection of the cement. The tail pipes are connected to the "Y" by spherical seal ball joints (fig 3), that allow the tail pipes to pass down inside the vertical casing, and then to spread out under the influence of a spring so as to enter the two deviated holes. Each tailpipe carries its liner section via a liner releasing tool. Each also has a cup type packer at the lower end that prevents cement from rising inside the liner during cementing, but opens during reverse circulation of mud for cleaning after cement placement, and prior to the removal of the tail pipes after release of the liner latches. After cementing, the two liner sections are thus tied in and cemented to the vertical casing with an overlap of about ten feet. Entry to one of the liners is now closed by a temporary plug, and a directional drilling assembly is run into the

open liner. This then drills the curve and the horizontal extension as far as desired. A small diameter liner is now run in and cemented at least as far as the beginning of the horizontal section. Alternatively, the drilling assembly may be run on coiled tubing, and the bit and motor abandoned at the end of the hole before cementing the coiled tubing as the liner. The cemented liner is finally perforated, and the hole gravel packed or otherwise prepared for production. It is expected that the liner will be of small diameter, (2.5 inches or less), and that therefore coiled tubing would be a good choice. The tubing may be mechanically perforated by running through it a hydraulically-actuated perforating tool that punches slots in the tubing as it is drawn along inside the liner.

The temporary plug may now be transferred to the completed hole, and the second drainhole drilled and cemented in identical fashion to the first. Completion is achieved by make-up, run in and setting of the production tubing string assembly shown in fig 4. This consists of a tubing connected to a conventional hanger, below which is an inverted "Y" nipple, with each of its branches attached to a spherical seal union joint (see fig 3). To each of these is attached a connector tube equipped with a conventional packer that can be set hydraulically or by wireline. The tubing is oriented so that the tail end of each connector enters its respective cemented intermediate liner, helped by a spring that tends to spread the connector tubes apart. Each of the packers is set, and after leak testing, the hanger in the vertical casing is set and the well head nipped up. The liner string above the packer may of course contain conventional equipment intended for artificial lift if this is desired.

3 VALVE DESIGN

The well is now ready to receive the special down hole valves that will allow switching of the steam from one drainhole to the other while accepting the flow of produced oil from the other drainhole. These are the only pieces of equipment that do not already exist commercially, and so we have been at pains to develop a design that deviates as little as possible from what is available already. In essence, the job can be done by two three-way valves that are each (schematically) in the form of an inverted "Y", that switch the steam or produced oil between the two drainholes. A possible solution would be to modify two conventional Subsurface Safety Valves (SSV, also called Storm

Valves in offshore wells) and to connect their upper ends to the steam supply while their ~~lower~~ ends communicate with the drainholes. Opening one valve allows steam to pass into the selected drainhole while the other valve, if closed, will isolate the producing drainhole from the steam supply .

To complete the arrangement, we must allow oil to flow from whichever drainhole is producing, and this can be done if the action of closing the safety valve simultaneously opens a passage from below the safety valve into the space surrounding it (the annular space between the valves and the well casing - the "sump", from which the produced oil can flow or be pumped to surface in the annular space, or through a production tubing). A suitable arrangement could use a safety valve of the "flapper" type, (5) (fig 5) in which the sealing element blocking the flow into the tubing is a hinged metal flapper applied against a transverse metal seat in the tubing. The flapper pivots around an axis perpendicular to the tubing axis and may assume two positions: an open position, when it is tangent to the tubing wall, and a closed position when it is perpendicular to the tubing axis. The flapper hinge is tangent to the tubing wall and perpendicular to the tubing axis. In such a valve, the flapper opens downwards. To modify the valve, a side exit hole would be machined in the valve body immediately below the flapper, so that when the valve is closed to the normal axial flow (steam down shut off), the side exit is open (oil flows up and out to "sump"), but when the flapper is "open" (steam down), the flapper closes off the side exit and stops the steam from getting into the sump. Such a design would require machining one side exit in the valve body, and arranging a second sealing surface on the lower face of the flapper. We consider both modifications to be feasible, but flapper-type valves may be too sensitive to sand production to be used in many sandy heavy oil reservoirs.

Other types of valve exist, in which the sealing element is either a rolling ball or a sliding sleeve. Although the details vary, it is possible to modify each of these basic types to produce the desired three-way function (see figures 6 and 7). All three valve types may be actuated by a combination of hydraulic fluid with spring return, and we do not envisage that it will be necessary to modify these actuators. Some attention must, however, be given to the fact that the steam pressure will always be greater than the pressure of the

produced fluids, and the differential pressure over the valve will thus act in the opposite sense to that experienced when such valves are used in their normal "safety valve" function (in which it is expected that the reservoir pressure will be greater than the wellhead pressure). Again, we do not envisage that these considerations will require major modifications to the valves. Finally, all three types of SSV and the downhole valves derived from them may be installed by wireline using existing tools, and all of them maintain the original "straight through" configuration that will provide access into the drainholes for all the tools and coiled tubings normally used for maintenance and repair of the producing interval. A sketch of the completed valve arrangement is shown in fig 8, which shows the two modified valves in an arrangement where the steam is conveyed in an insulated "Thermocase" tubing, and the produced fluids rise in the annular space. Also shown is a down-going tubing for the power fluid to the pumps that are situated in each of the horizontal drainholes. An alternative completion could, for example, use two tubings, the one for the downgoing steam being insulated by a silicate foam, while the production stream is carried in a separate uninsulated tubing rather than in the annulus, which in this case is gas-filled. In such a case, a rod pump could be inserted through the production tubing.

4 MATERIALS SELECTION EXPERIMENTS

A major consideration in the development of the valves is to be sure that a design and suitable materials can be found to allow effective sealing and operation in the high temperature, high pressure environment that exists downhole. We expect that steam temperatures up to 300 C (572 F) may be required, corresponding with steam pressures over 1000 psi (6.9 MPa). Hydraulically actuated devices exist that allow operation at such temperatures; the actuators are built using all-metal construction, including the sealing arrangements. Since we do not expect the produced fluids (oil or formation water) to come into contact with the sealing parts of the actuator, we believe that we shall be able to adapt these parts of the design to our new valves "as is". On the other hand, we need to determine whether it is possible to develop a metal-to-metal seal that will function satisfactorily at high temperature and pressure in the presence of saline waters, and possibly of hydrogen sulfide. Accordingly, we have built an apparatus that simulates

the sealing surfaces of a metal-to-metal ball and seat valve, and have subjected the seal to high pressure, high temperature conditions in a variety of environments.

4a Experimental equipment

A test cell was designed and built to study corrosion effects of some downhole liquids (fresh water, salt water, drilling mud, etc.,) on typical ball and seat materials under high temperature, high pressure conditions. A schematic diagram of the cell is presented in Fig. 9. The main experimental unit consisted of two symmetric, small high pressure stainless steel cells each with a volume of 18 cc. At the open end of each cell was placed a commercially available ball-valve seat (7/8" ID, 13/8" OD, 1/2" thick). The cells were placed with their open ends facing each other so that a spherical stainless steel ball of 1-1/8" diameter (also commercially available, and matching the seats) could be sandwiched between them. The balls and seats were obtained from The Ball and Seat Specialty Company, P O Box 11236, Odessa, TX 79760. This company specializes in making seal components for oil field equipment, and represents the state of the art in this sector of the industry. In this way, two closed chambers were formed, sealed by the seating of the ball on each of the two seats. To prevent leakage, the two cells were pressed together against the ball by a small hydraulic press set in a loading frame surrounding the cells.

A complete schematic diagram of the down-hole steam valve experimental apparatus is shown in Fig. 10. The cell was surrounded by an insulated heating jacket, inside which were placed two thermocouples, one to measure the temperature of the cell, and the other to operate a temperature controller. Leading out of each of the high pressure cells were two 1/16" diameter stainless steel tubes. These were joined to allow pressure equilibration between the cells, and they also communicated with a pressure transducer so as to read the pressure inside the cells. For one series of experiments, both the ball and seats were made of type 440 stainless steel. In a second series, they were made of stellite, of composition (in weight percent) Co 39, Cr 32, W 18, Fe 3, Ni 2.5, C 2.5, Mn 1, Si 1, other 2.

To carry out an experiment, the cells were placed horizontally in the loading frame with the ball between them. Connectors in the two high pressure tubes were opened so that a quantity of water (or other corrosive agent) could be injected into each of the cells by means of a hypodermic syringe. The quantity of water was calculated so as to make each cell a little over half full. With the cells horizontal, this resulted in the sealing surface between the ball and either seat being partly submerged and partly in a steam-air mixture. Thus the sealing surfaces were exposed both to liquid water (with any dissolved salts contained therein) and also to a steam-air mixture. The seal was also contacted by the vapor-liquid interface. Thus all possible conditions for corrosion were duplicated within each cell. After the cells had been filled with the desired quantity of liquid, they were sealed. Pressure was applied by the hydraulic press to make a positive seal between the ball and seats, and heating was begun. The temperature was increased slowly up to a maximum of 100, 150, 200, 250 or 300 C. Values of temperature and pressure were recorded on a Macintosh computer equipped with "Lab View " data processing software and also recorded on conventional chart recorders.

For most experiments, heating to the set temperature took 1-2 hours. Thereafter, the temperature was maintained at the set value for six to eight hours. Temperature and pressure data were compared with the values listed in standard steam tables. If a value equal to the steam table pressure was recorded, then liquid water must have been present. It was therefore inferred that leakage was nil or minimal (certainly less than 2 cc per hour). The cell was then cooled, opened and the ball and seats were examined for signs of corrosion. Both the ball and seats were examined in the optical microscope, and in addition, the ball was examined in the Scanning Electron Microscope (SEM). Unfortunately the seats were too large to introduce into the specimen chamber of the SEM.

Experiments were carried out to maximum temperatures of 100, 150, 200, 250 or 300 C. An initial series of experiments was made using the 440 stainless steel ball and seat set, first using fresh water, and then with salt concentrations of 1% and 5% in water. Thereafter, the ball and seats were changed to stellite, and tests were carried out with 1% and 5% salt solutions, and with 1% and 5% solutions of ammonium sulfide in water.

4b Corrosion results

A typical plot of temperature versus pressure for a particular experiment is shown in figure 11 for a 1% ammonium sulfide solution environment and a cell temperature of 300 C over a total period of 7 hours. The plot shows successive values of pressure and temperature as the cell temperature increased. Also shown is the theoretical relationship between temperature and pressure obtained from the steam tables. It will be seen that initially, the temperature recorded by the thermocouple rose more rapidly than the steam pressure, implying a certain lag time to heat the water in the cell. However, after some time (1 - 2 hours), pressure and temperature stabilized at values in agreement with those given in the steam tables.

In almost all of the experiments, it proved possible to contain the steam pressure up to the maximum operating conditions. Reference to the steam tables shows that, at 300 C, the steam pressure is approximately 1,200 psi. We consider this to be a very good performance, and believe that mechanically at least, there is no reason why we should not be able to operate the valves at these high temperatures and pressures. This view does, however, suppose that the long term performance of the seal will be satisfactory, ie that there will be little or no corrosion. The ball and seats were therefore examined carefully after each experiment for signs of corrosion, and in cases where some corrosion was suspected, the ball was examined in the scanning electron microscope.

In the case of the 440 stainless steel, no corrosion effects were found with fresh water at temperatures below 250 C. However, some attack was seen at 250 and 300 C. X-Ray analysis was carried out to examine the corrosion products that were found on the surface of the ball, and even though the results may not have been quantitatively exact due to the shape of the ball, some interesting observations were obtained. These identified some regions of mild attack, and the production of corrosion products that were for the most part oxides of iron or chromium.

Upon completion of this series of experiments, further tests were made on the stainless steel (using new ball and seat sets as necessary) to investigate the effects of salt at concentrations of 1% and 5%. Significant corrosion was

found, the scale formed on the 440 stainless steel ball surface being mixed grey iron oxides and chromium oxide, as confirmed by SEM and X-ray diffraction studies. At the highest temperatures, pitting of the specimen surface was observed.

As a result of the tests using salty water, it became clear that 440 stainless steel is unlikely to provide satisfactory service in our down-hole valves. Accordingly, a further series of tests was carried out using stellite. No corrosion was observed at any temperature using 1% or 5% salt solutions, and so the experiments were repeated using 1% and 5% ammonium sulfide solutions in water. No corrosion was observed in these experiments either, and so it was concluded that, at least under the conditions investigated, stellite will be a satisfactory choice of material for the ball and seat combination.

It should be noted that a salt concentration of 5% is about five times greater than that commonly encountered in the Californian heavy oil fields, and that sulfur concentrations are generally low. In this respect, therefore, we are conservative in our evaluation. On the other hand, it should be recognized that our test period of about eight hours was short by comparison with the expected service life of the valve in operation, which may be several years, and we would recommend longer term testing before finalizing the design.

5 WELL COSTS

We have estimated the relative costs of drilling and completing a conventional well and a well equipped with twin horizontal drainholes and the associated completion equipment needed to inject steam and produce oil simultaneously (6). We took a typical Californian heavy oil field (Midway Sunset), and assumed a 500 ft. thick reservoir (300 ft net pay), lying between 1,500 and 2,000 ft. depth. The conventional well was assumed to be drilled to 1,900 ft (570m) depth, and completed with an 8 ⁵/₈ inch casing. The time required for drilling and completion was estimated as 9 days, giving a total well cost of \$320,000. The dual horizontal well was assumed to be drilled and

cased to 1630 ft with a $13 \frac{3}{8}$ inch casing, this diameter being necessary to accommodate the two $5 \frac{1}{2}$ inch intermediate liners that initiate the two drainholes. Thereafter, each of the drainholes was assumed drilled with a 350 ft radius of curvature to become horizontal at 1980 ft tvd, 20 ft (6m) above the oil-water contact. The horizontal sections were assumed to extend a further 1000 ft (300m). This well, including the tubing completion assembly, three-way valves and jet pump of Fig. 8, was estimated to cost \$619,550, with the main reasons for the increased cost being the greater cost of the vertical casing ($13 \frac{3}{8}$ inch vs $8 \frac{5}{8}$ inch, although the larger casing string was shorter) and the time and complexity of drilling the two horizontal drainholes (total drilling and completion time was estimated to rise from 9 days to 33 days). In other well configurations, where a cheaper completion is chosen (using a smaller diameter casing, silicate insulation of the steam tubing with gas-filled annular space, a rod pump etc), it is expected that the costs would be significantly reduced.

6 PRODUCTIVITY ESTIMATE

The cost estimate presented above shows that the twin horizontal well configuration will cost at most double the conventional well. However, we also expect that the twin horizontal well will have greater productivity than the single vertical well if only because the horizontal drainholes access the reservoir in a more effective manner, and because the pumps may be placed lower in the reservoir (see section 1). These two factors, together with the fact that no production time is lost while steaming, are expected to increase the productivity of the well by a factor of six, approximately. To this must be added the improvement in the quality of the steam injected into the reservoir because of the heating effect of the produced fluids in the vertical section of the well. The heat losses in wellbores with single and dual completions have recently been calculated by Barua (7), who has shown that significant reductions in heat losses may be obtained in wells containing dual tubing strings, whether these be conveying steam or produced fluids. A simple explanation of this effect for an insulated steam tubing is that the steam heat loss is directly related to the temperature gradient across the tubing insulation. When its outer surface is in contact with a hot fluid (presently the production stream), the heat flux through the insulation is obviously

reduced and the quality of the injected steam is greater, which tends to reduce the steam to oil ratio.

CONCLUSIONS

We propose a novel design of well to allow more economic recovery of heavy oil. The design calls for a vertical cased well from which are drilled two horizontal drainholes, running out on opposite sides of the vertical section. Steam is injected in one drainhole, while reservoir fluids are produced from the other drainhole. After some time the roles of the two drainholes are switched, the injector becoming the producer and vice versa. This allows each drainhole to operate in "Huff and Puff" mode. The downgoing steam and produced reservoir fluids are carried in dedicated tubings in the vertical section of the well, a configuration that reduces the heat losses from the steam, and reduces stresses on the casing and tubing strings resulting from the thermal cycling experienced in conventional "Huff and Puff" operations. Although such a well may cost nearly twice as much as a conventional well, we believe that its productivity will be at least six times as great.

The essential component of such a design is a system of down-hole valves (or equivalent flow control equipment) that will permit the switching of the steam and produced fluids at the bottom of the vertical section. These devices must withstand steam and reservoir fluids at high pressure and at temperatures approaching 300 C. Such valves are not available at present, but we propose that they may be conveniently made by modifying any of a number of commercially-available subsurface safety valves. We have evaluated type 440 stainless steel and stellite for their suitability in this application, and although we have found that the former is corroded in the presence of hot brine, the stellite appears satisfactory in both salt and sulfide-containing solutions over the range of interest. Further, trial sealing surfaces have been shown to remain completely leakproof at temperatures of 300 C with a pressure differential of 1200 psi. across the seal, in the presence of the corrosive solutions.

REFERENCES

1. Joshi, S.D. "A Review of Horizontal Well and Drainhole Technology" SPE paper 16868, presented at the 62nd Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Dallas, TX, 27 - 30 Sept 1987.
2. Butler, R. M. "A New Approach to the Modelling of Steam-Assisted Gravity Drainage", J.Cdn.Pet.Tech., May-June 1985, p.417-421
3. Gondouin, M. "Process for Conserving Steam Quality in Deep Steam Injection Wells." U.S. Patent Application, 1990.
4. Gondouin, M "Downhole equipment, tools and assembly procedures for the drilling, tie-in and completion of vertical cased oil wells connected to liner-equipped multiple drainholes" U S Patent Application 1991.
5. Gondouin, M. "Catalytic down hole reactor and steam generator." U. S Patent number 5,052,481, 1 October, 1991.
6. G. A. Cooper and M. Gondouin (1990). "Improved steam stimulation of heavy oil wells." First quarterly report on California Competitive Technology Project No CT 90 A - 046 - R
7. S Barua "Computation of Heat Transfer in Wellbores with Single and Dual Completions". SPE paper 22868, presented at the 66th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Dallas, TX, 6 - 9 October, 1991.

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Figure captions

- Fig 1. Drilling twin side-tracked starter holes.
- Fig 2. Cementing of twin intermediate liners.
- Fig 3. Sketch of a spherical seal ball joint.
- Fig 4. Schematic tubing completion assembly.
- Fig 5. Schematic valve configuration for "huff and puff" operation .
- Fig 6. Schematic three-way ball valve.
- Fig 7. Schematic three-way flapper valve.
- Fig 8. Tubing completion assembly including jet pumps and three-way valves.
- Fig 9. Section of the high pressure and high temperature test cell, showing the ball and two seats (shaded).
- Fig 10. Experimental apparatus for testing seals at high temperature.
- Fig 11. Typical test record, compared with the standard steam tables (Ammonium Sulfide 1% at 300 C, 6 hours).

OVEN

0" 1/2" 1"

END

**DATE
FILMED**

1 / 15 / 93