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SYSTEM TO INJECT STEAM AND PRODUCE OIL FROM THE SAME WELLBORE THROUGH
DOWNHOLE VALVES SWITCHING

Contract:DE-FG01-92 CE 15553

FIFTH QUARTERLY REPORT

December 1993

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SYSTEM TO INJECT STEAM AND PRODUCE OIL FROM THE SAME WELLBORE THROUGH
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ABSTRACT:

Although EOR by steam injection is used primarily to recover Heavy Oil, the same methods are also applicable to some Light Oil reservoirs. A typical example is that of the Shannon reservoirs in the Teapot Dome field, WY, operated by the DOE, for the US Naval Petroleum Reserve No.3.

To show that our technology is also applicable to steam injection in Light Oil reservoirs, a preliminary well design was prepared and submitted to the Naval Petroleum Reserve No.3. The Upper and Lower Shannon sandstone reservoirs, of low permeability, in the Teapot Dome field are both highly faulted and fractured. This is a situation where horizontal drainholes, oriented in such a way that they would intersect many of the pre-existing fractures and fault zones, would greatly

increase the wells productivity, as compared to the current practice of using only vertical wells and hydro-fracturation. Most of the existing wells in the steamflood area are stripper wells, producing less than 10 BOD/well. This low well productivity is due to a combination of factors: low permeability, thin pay zones, very low draw-down pressure and high WOR.

The proposed well design includes a single vertical casing, tied-in respectively to a liner-equipped horizontal drainhole drilled into the Lower Shannon and to a liner-equipped vertical hole drilled into the Upper Shannon. The two wells are operated in sequential "huff and puff", using two parallel vertical tubings, respectively dedicated to steam injection and to conveying the produced fluids to the surface, using a single rod pump. Operating problems associated with steam flashing from the produced water and with sand production from the poorly consolidated reservoirs are also addressed.

The capital cost of this well configuration is estimated to be roughly comparable with that of one vertical steam injector and one production well in the current steamflood. An itemized cost comparison will be made when itemized cost data for currently drilled wells in the steamflood will have been received from NPR # 3. The proposed test would allow to determine, at minimum cost, the benefits obtainable from the systematic use of horizontal drainholes in the Teapot Dome field and from the use of our technology for extending the area under steam injection to the thinner zones of the Lower Shannon, which are currently unexploitable. This represents about 65 % of the total Original Oil in Place and could greatly increase the oil recovery factor.

The corresponding proposed Teapot Dome well configuration, added to

those previously considered for various California Heavy Oil fields confirms the flexibility and adaptability of this technology to a large variety of field conditions, exhibiting a wide range of oil and reservoir characteristics.

The experiments made at UC Berkeley to verify the operability of sliding sleeve type three-way downhole valves are presented and reviewed. This concludes Tasks No.1 to No.4 of this Contract.

Calculations of steam tubing heat losses for various well configurations and types of tubing insulations have been made under Task No.5. The results are presented in graphical form and analyzed.

Similar calculations have also been made by Texaco and their thermal simulator results have been closely matched with their field measurements. These confirm the possibility of drastically reducing heat losses from a bare steam tubing when it is located adjacent to a parallel tubing carrying a hot liquid, within a common gas-filled annular space.

Progress made towards finding an Oil Operator willing to field-test our technology (Task No.6) is also briefly reviewed.

17. POTENTIAL APPLICATION OF OUR PROCESS AND DOWNHOLE EQUIPMENT TO LIGHT OIL RECOVERY BY STEAM INJECTION.

The application of steam injection methods to the recovery of Light Oil has been the subject of many publications and some screening guide rules have been published (Ref.8). The success of the steamflood implemented by the DOE in NPR # 3 shows that there are exceptions to these rules, especially in low-permeability fractured reservoirs. A similar case, described in Ref.9, has been made even more successful by the use of several horizontal wells. The additional possibility

offered by our process and hardware of operating two drainholes from the same casing, with higher-quality steam, and of using a single rod pump for both drainholes provides further significant savings in Capital and Operating costs. Their demonstration in a DOE-operated Light Oil field would greatly expand the US market for this new technology.

Two major problems in the Teapot Dome field are its low reservoir pressure (5 psig) and high WOR (≥ 10), which, in combination, require that an artificial lift device be located at, or near, the base of the curved portion of the horizontal drainhole. In view of the known problems usually encountered in operating rod pumps in such a well configuration, because of friction wear of the rods in the curved tubing and of pump wear and inefficiency in lifting a stream consisting mainly of boiling water, the production stream is lifted in two stages, first by steam-lift to the kick-off point into a downhole sump/separator and second from the sump to the surface by a vertical rod pump.

The required downhole equipment for this well configuration is described in Appendix 1

18- TESTS OF DOWNHOLE SLIDING SLEEVE VALVES WITH HIGH QUALITY STEAM

These are described in detail in Appendix 2, taken from Ref. 10. Previous tests, also made at UC-Berkeley, on metal/metal seals addressed the problem of selecting suitable metal alloys to withstand corrosion at steam temperature. The results of these tests were published in Ref. 11. A similar testing procedure was used to select suitable polymers for use as elastomeric seals ("O" rings and packings) at steam temperature and pressure in a modified commercially-available

sliding sleeve valve, a tubing plug mandrel and a modified separation sleeve. These components were assembled into a closed pressure cell equipped with thermocouples, and connected to a pressure recorder and a safety relief valve. The principle of the tests was the same as that of the tests of metal/metal seals, namely that a small volume of water is placed in the closed cell, thus partly filling its internal volume and the recorded increases in temperature and pressure, when the closed cell is placed inside a temperature-controlled oven, are compared with the Steam Tables for wet steam. The results of these tests, shown on Fig. 4.36 to 4.38 of Appendix 2, are in excellent agreement with the Steam Tables, thus demonstrating that liquid water remains in the cell for the whole duration (10 hours) of each run. This shows that an upper estimate of any steam leakage through all the polymeric seals of the various components of the cell during this entire period remains negligibly small. This confirms the technical feasibility of using such types of devices (Sliding sleeve valve and plug mandrels), all operable by wireline, to provide three-way steam flow control in our Downhole Equipment.

19- CALCULATIONS OF STEAM TUBING HEAT LOSSES

A simple configuration of concentric tubing, casing and hole was used in a thermal simulator available at UC-Berkeley.

Steam tubing heat losses depend upon the following main parameters:

- tubing depth,
- well configuration (hole, casing and tubing diameters)
- presence, type and thickness of tubing insulation.
- well head steam injection temperature
- steam injection rate

- injection time

These main variations are illustrated on Fig.3.2 to 3.21 of Appendix 3. Starting from an assumed 80 % quality steam at the well head, tubing heat losses result in a degradation of steam quality, which is easily calculated, for the assumed conditions.

In addition to the main parameters, listed above, there are various assumptions made in the program regarding the various heat transfer coefficients between tubing, insulation, casing, cement and formation, which result from the various modes of heat transfer: conduction, forced convection inside the tubing, natural convection and radiation in the tubing/casing annular space. These coefficients are usually obtained from correlations based on a number of assumptions, such as: presence and characteristics of scale inside the tubing and casing, spatial distribution of steam and condensate in the tubing and annular, average characteristics of the insulation both on the tubing and at the joints, cement and formation properties, etc...

In view of the many assumptions used in any simulator it is prudent to match the computer results with direct measurements. This was not done for the simple concentric arrangements considered at UC-Berkeley but, more importantly, a more sophisticated thermal model including two parallel tubings in a gas-filled casing was matched by Texaco with field measurements in an experimental well equipped with various temperature sensors (Ref.12). Of particular interest is Run No.1 which corresponds to the parallel flow of boiling hot water (4 % steam quality in one tubing, co-currently with 60 % quality injected steam in the adjacent tubing. This resulted in a calculated steam quality of 55.2 % at 900 ft depth. Both tubings were bare and, contrary to the configuration which we propose, the two tubing streams are co-current

instead of being counter-current. Nevertheless experience with tubular heat exchangers would indicate that heat transfer from the hot water tubing to the annular gas space would be comparable, regardless of the difference in water flow direction. The fact that the Texaco simulator closely matched the Kern River field measurements is far more important than the differences due to the direction of the hot water flow in this representative case of a typical dual-tubing well configuration. This test's results are shown on Fig. 13 of Appendix 4 which is an excerpt taken from Ref. 12.

The steam tubing heat loss is only 4.3 % of the 5771 MBTU/h (138 MMBTU/D) injected at the top of the steam tubing, or a heat loss of 6.5 MMBTU/D. Its comparison with the heat loss (Fig. 3.5 Appendix 3) of a bare tubing in a 1,000 ft well, calculated with the UC-Berkeley simulator for the two tubing diameters (well configurations 1 and 2) bracketing that of the Texaco field test, shows that the heat loss is reduced by more than 50 % from its expected value even after one month of injection. A further reduction of about 30 % would also be achieved by coating the steam tubing with a Calcium Silicate foam insulating layer using the inexpensive process described in Ref. 13. This is shown by comparing Fig. 3.6 with Fig. 3.5 of Appendix 3. The combination of a low-cost steam tubing insulation with the patented well configuration in which the gas-filled annular space contains a parallel bare production tubing, in addition to the insulated steam tubing, will result in a total reduction of more than 80% of the steam tubing heat loss, comparable with that obtainable with the very costly Thermocase tubing.

20. STEPS TAKEN TOWARD COMMERCIALIZATION

Conversations are in progress with several California Operators of Heavy Oil fields regarding a Field Test, in addition to the proposal to NPR #3 (Appendix 1) for a similar test in a Light Oil field.

A re-imbursable Research Grant was obtained from the State of California for the construction and shop testing of the Downhole Equipment to be used or installed in the California field test(s).

These are necessary steps for the commercialization of this new technology, at a time when very low oil prices force most Operators to avoid or reduce the financial risks inherent in any such enterprise.

CONCLUSIONS: The technical feasibility and the wide applicability of the process and Downhole Equipment developed under this Contract have now been demonstrated. Their cost effectiveness and benefits to an Operator are expected to be shown in at least one forthcoming field test, following the manufacturing of all the required equipment for the specific well configurations encountered in the field test(s).

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Appendix # 1

POTENTIAL FOR IMPROVING ECONOMICS IN THE TEA-POT DOME FIELD (NPR # 3)

1. CASE HISTORY:

The DOE, as operator of the Naval Petroleum Reserve No. 3 (NPR # 3), has shown that the light oil (32 API) from the Upper and Lower Shannon sandstone reservoirs of the Tea Pot Dome field can be successfully produced by Steamflooding. Well productivity in most wells, however, is less than 10 BOD/well. This is primarily due to the very low reservoir pressure, the small thickness of the two main producing zones and their low to medium permeabilities and low GOR (32 SCF/B) of the oil. (Ref. 1)

The use of steam injection in the Shannon reservoir has been shown to reduce oil viscosity (0.4cp @ 400 F) and to increase the oil recovery by water at 400F by a factor of 1.5 and it presently accounts for the major part of the 1,800 B/D oil production. Other mechanisms which have not been quantitatively evaluated include steam and dry heat distillation of oil ahead of the steam front. The field WOR is about 10, so that the average well production in the steamflood area is about 7.5 BOD and 75 BWD, for a total liquid volume of 82.5 B/D.

The Shannon reservoir is known to be highly fractured, as a result of faulting, and additional flow paths are also created by thermal stresses and systematic fracturing operations in this shallow reservoir. Nevertheless, with respective net pay thicknesses of about 45 ft and 25 ft for the upper and lower zones, at average reservoir pressures as low as 5 psig (20 psia) at the top of each zone, the calculated average draw-down in a vertical dual-producer well under pumping is only about 26 psi for the lower zone and 32 psi for

the upper zone. This very low draw-down, combined with the tendency of any pump to cavitate when steam flashes from the produced water makes it very difficult to economically produce oil from the lower zone.

This is why the present targets for Steamflooding are limited only to a 768 ac. area of the field where both zones are present and to the 280 ac. area where the Upper Shannon is cleaner and thicker. In reality this development plan leaves out most of the Lower Shannon remaining oil (93.4 MMB OIP), which represents 65% of the total Original Oil in Place.

2. POTENTIAL IMPROVEMENT OF THE LOWER SHANNON OIL RECOVERY BY STEAM.

To improve the recovery of oil from the Lower Shannon it is proposed to use horizontal drainholes to increase the sand face area in this thin layer and to further increase well productivity by intersecting a much greater number of existing mostly vertical fractures. This can be done by orienting the horizontal drainhole NW-SE. The expected average gain of well productivity is a factor of 3, for a liquid production of about 250 B/D/w.

These are well-proven advantages of horizontal wells over vertical wells in thin fractured reservoirs. In addition, the use of a horizontal well as steam injector/producer results in the formation of a rising steam chamber spreading laterally along the roof of the reservoir, while hot oil drains downwards along the sides of the steam chamber. This process is described and modeled by R. Butler in Ref. 2. In a first step, we propose to operate in "huff and puff" so as to reduce heat loss to the overburden. In a later stage, the same well configuration may be used for a steamflood.

Present drilling practice in the Shannon reservoir is to use air

or foam drilling for producer wells. This reduces the overbalanced drilling fluid pressure and minimizes formation damage in this low permeability shaly sand. It is unlikely that the same approach would be successful in drilling horizontal drainholes in a soft formation. In this case it is necessary that the drilling fluid pressure be sufficient to maintain hole stability under the vertical stress due to the overburden. It is likely that a low filter loss oil base mud would be preferable. In that case, conventional mud motors and well proven techniques would be applicable to drill the horizontal drainholes.

To increase the draw-down, the lifting device must be located at an elevation as low as possible. For this reason, the proposed horizontal drainhole should be drilled only a few feet above the base of the Lower Shannon and, preferably, should be connected to a sump kept at a low pressure by a pump or a gas-lift valve.

The corresponding horizontal drainhole trajectory is shown on Fig. 1. The kick-off point is preferably just above the Shannon Bentonite layer, in order to avoid the risk of damage to the larger vertical casing by thermal expansion of Bentonite. With a medium radius of curvature (250 to 300 ft), the drainhole penetrates first the Shannon Shale and Bentonite layers, then the Upper Shannon Sand, the 50 ft-thick Inter-Ridge impervious silt, the Lower Shannon Sand and into the Steele Shale where it turns upward to re-enter the base of the Lower Shannon Sand and to level-off in the sand a few feet above its base.

The drainhole is equipped with a liner which is cemented in its curved part and selectively perforated "in situ" in its horizontal part. The lifting device is located near the lowest point of the drainhole. To overcome the problem of steam flashing from the produced

water, which may be very severe at low pressure, it is also necessary to provide a path for venting the evolving steam. An obvious choice is through the casing/tubing annular, as presently done. In the case of a medium curvature horizontal well, however, any steam or gas evolved must first be conveyed to the kick-off point through the liner. For this reason it is proposed to lift the oil to that point, and to dump it into an oil sump connected to the gas-filled casing/tubing annulus at near atmospheric pressure. After separation from liquid phases in the inclined liner and the vertical sump, the steam/gas mixture is discharged into the gas-filled annular space between casing and tubings (see Fig. 2). To lift 250 B/D of liquid (mostly water) over a 300 ft height in a 2" ID tubing requires steam at about 30 psig (45 psia) and a GLR of 50 (see Ref. 3). The additional 800 psig (815 psia) steam consumed for gas lift is thus only:

$$50 \text{ cf/B} \times 250 \text{ B/D} \times 0.57 \text{ cf/lb @ 815 psia} / 9.18 \text{ cf/lb @ 45 psia} =$$
$$776 \text{ lb/D of steam or } 2.2 \text{ B of water for } 22.5 \text{ BOD.}$$
This would increase the SOR by only 0.1, or roughly 1 % from its present value of 10. Even if the accuracy of the curves of Ref. 3 is relatively poor for shallow wells, the steam consumption for steam lift is unlikely to increase the SOR by more than a few percents, which could easily be offset by potential SOR reductions associated with the use of horizontal drainholes and of higher quality injected steam. For practical purpose, the additional operating cost of steam lift may be negligible.

It is indeed a commonly recommended practice to use gas lift for producing crude at or near its bubble point. The same technique should be just as effective for steam lifting a liquid stream consisting for 90 % of boiling water. Conventional spring-loaded gas lift valves

have been successfully used in steam lift operations.

The use of a vertical sump/separator vented into the casing annulus at near atmospheric pressure is also a proven method to provide sufficient NPSH for an efficient operation of a conventional rod pump, with minimum risk of cavitation.

To maximize well productivity a vertical well, drilled below the kick-off point of the horizontal drainhole, is used to recover oil from the Upper Shannon. Its 6 5/8" OD casing is connected by a cross-over to the larger surface casing, and both casings are run-in together and cemented in the same operation, using a stab-in cementing string connected to the 6 5/8" shoe. This completion method is essentially that which is described in Ref. 1 and used for the steam injectors. It is our understanding that there are no shallow aquifers above the Shannon sands, which have to be protected by a surface casing. If this is not the case, of course, a surface casing will have to be set first to cover such an aquifer, prior to drilling deeper. It is assumed that the hook load of the DOE's drilling rigs is sufficient to handle the tapered casing string, which, although shorter than the currently used 5.5" casing string of dual producers, is somewhat heavier, because it consists of a 10.75" upper string, to about 200', combined with about 160' of 6 5/8" tail pipe to cover the Upper Shannon and most of the Inter-Ridge silt.

The horizontal drainhole is drilled, completed and temporarily closed with a wireline retrievable plug before any gun perforating (underbalanced) and completion of the vertical well, so as to minimize the risk of formation damage in the Upper Shannon. For the same reason and perhaps to reduce cost, the vertical hole required for the tapered casing may be air/foam drilled, as currently done for producer wells.

3.COMBINED OPERATION OF THE HORIZONTAL DRAINHOLE WITH A VERTICAL WELL

To further improve the economics of recovering oil from both zones of the Shannon reservoir, it is proposed to operate the horizontal drainhole in the Lower Shannon and the vertical cased well in the Upper Shannon in the sequential "huff and puff" mode, with one of them under steam injection, while the other is under production. This mode of operation has a number of economic and technical advantages:

1) a single well site for two separate drainage areas about 350 ft apart, equipped with a single rod pumping unit.

2) dedicated tubings for conveying respectively steam and produced fluids, so that cyclic thermal stresses are minimized,

3) switching from "huff" to "puff" using only wireline tools,

4) reduction of steam tubing heat losses because the gas-filled casing/tubing annulus is kept at a high temperature by the hot bare production tubing, thus reducing the temperature gradient across the insulated wall of the steam tubing.

The fluids produced from the vertical well would also be steam lifted from a point about 40' below the lowest perforation to the top of the sump/separator and then pumped from the common sump bottom to the surface with a single rod pump. This well configuration and new operating mode are expected to result in significantly lower capital cost per barrel of oil produced. It would also greatly increase the economically-viable area of the reservoir for steam injection.

4.DOWNHOLE EQUIPMENT FOR A DEMONSTRATION OF THE PROPOSED TECHNOLOGY

The surface hole, presently cased with a 8 5/8" casing to 94' in Ref.1's example dual producer of the steamflood would be replaced

by a somewhat larger hole (13"), cased with a longer and larger casing (10.75" OD) to about 150'. The bottom joint is a special casing joint (11.75" OD) comprising, from top to bottom:

- an H joint for two 5" ID holes, with an adjacent 5" ID sump and at least two steam feeder lines (see Fig.3)
- a 5" ID deviated curved channel and a 5" ID vertical channel, adjacent to the bottom part of the sump (see Fig.4).
- a cross-over to the 6 5/8" tail pipe (about 140' long and terminated by a 6 5/8" cement float collar and shoe).

This special joint, developed with partial DOE funding, would be provided to NPR # 3 at no cost, except for shipping cost from Southern California to the selected well site.

Following cementation of the tapered casing string with the usual thermal cement, in a conventional stab-in cementing operation through a work string inserted through the 5" ID vertical channel below the H joint and connected to the 6 5/8" shoe at the end of the tail pipe, a horizontal drainhole is drilled through the deviated 5" ID channel and completed with a 4.5" Hydril liner, cemented only in its curved part. Conversely, after completion of the horizontal drainhole, the 6 5/8" vertical casing is gun perforated (underbalanced) and completed with a 4.5" Hydril steam tubing and a concentric 2 7/8" production tubing terminated by a gas lift valve mandrel and packer.

Included in each of the two 5" channels are lock mandrels for wireline-set 5" Baker plugs. The lower one is used as liner hanger for a 4.5" Hydril pipe in either the horizontal drainhole or the vertical well. The upper mandrel is used as hanger for a short 2 7/8" production tubing string terminating about 50 ft below the base of each reservoir layer and equipped with a packer and a retrievable 1" gas lift valve.

The packer closing the 4.5"/2 7/8" annulus is preferably of the cup type to allow free thermal expansion of the 2 7/8" production tubing in the concentric 4.5" pipe during the initial steam injection cycle.

Steam feeder lines connect a wireline-operated sliding sleeve three-way valve, at the top of the H joint, to the top of each 4.5" liner/2 7/8" tubing annulus.

In any of the two 4.5" pipes, deviated or vertical, with the gas lift valve seated and the top of the production tubing open, the drainhole or well is in the producing mode. The steam-lifted production stream is discharged into the top of the common sump/separator. Steam is conveyed from the choked three-way valve to the 4.5"/2 7/8" annulus by the corresponding steam feeder line. In both the horizontal drainhole and the vertical well, produced fluids fall and accumulate in a first sump below the producing zone, before being lifted to the common sump. These first sumps are respectively the bottom of the 4.5" cemented liner in the horizontal drainhole and the bottom of the 6 5/8"/4.5" annular space in the vertical well. The flashed steam and the lift steam are vented to the surface, so that the rod pump can operate more efficiently to lift the liquid accumulating in the common sump.

Conversely, with the gas lift valve removed and the top of the 2 7/8" tubing plugged-off, the drainhole or well is in the steam injection mode, with steam supplied through the full opening three-way valve to the 4.5"/2 7/8" annulus. In horizontal drainholes drilled in fractured reservoirs, some operators distribute the injected steam along the perforated interval by means of a smaller tubing inserted in the production tubing. The proposed well configuration allows the use of this practice, if it is found advantageous in the Shannon sand.

The same method, using a coiled tubing, may be used for cleaning the horizontal drainhole if sand accumulates into the 4.5" liner.

Retrieval of the gas lift valve and transfer of the production tubing plug are done through the steam tubing, after retrieval of the plug at the base of the sliding sleeve. These are conventional wireline operations, which should be very inexpensive in such shallow wells.

5. DRILLING THE HORIZONTAL DRAINHOLE

Drilling small-diameter deviated and horizontal drainholes through a casing as small as 4.5" OD (4" ID) has been done repeatedly in many soft formations, using existing "slim hole" bottom hole assemblies, with 1.5" or 1.75" OD downhole motors (Ref.4). Bits and under-reamers of suitable diameter are also commonly available. These tools have been used with various mud types as drilling fluid. Hole stability is generally easier to achieve with smaller diameter holes.

If, however, air drilling is considered as necessary in the Shannon larger downhole motors are available for air or foam drilling (Ref.5). With a 13 3/8" OD special casing joint, it would be possible to use Christensen's 4.75" OD motor to drill a drainhole through the 5.5" ID seal bore of a Baker F 6 5/8" OD seating nipple. This would allow the use of a less expensive 4.5" API tubing as drainhole liner, which would partly offset the additional cost of the larger surface hole and 13 3/8" upper casing string. A modified special casing joint would have to be used, in conjunction with a tubing retrievable H joint, but the operating mode and operational flexibility would remain unchanged.

Rotary techniques with tools equipped with a deflection sleeve have also been demonstrated by Amoco, which are capable of drilling shallow horizontal wells (Ref.6) of short radius of curvature, at

low cost (\$60,000).The adaptation of this new rotary drilling tool to air drilling also appears feasible,if this is preferred.

6. CONCLUSIONS

The use of horizontal drainholes in the thin,highly fractured Lower Shannon is expected to greatly increase well productivity and to increase the amount of recoverable oil by steam injection.

A well configuration combining a horizontal drainhole in the Lower Shannon with a vertical well in the Upper Shannon appears feasible at a cost comparable with that of two of the presently used wells in the steamflood area,but it provides much higher productivity.

The sequential "huff and puff" operating mode in such a twin drainholes well configuration provides additional economic benefits.

An artificial lift method is proposed to overcome the problems associated with very low reservoir pressure and with steam flashing from the large volume of produced water.It maximizes well draw-down and pump efficiency.

A review of recent drilling literature shows that there are several proven methods and tools which could be used for drilling the horizontal drainhole.

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FIG. 1 - DRAINHOLE TRAJECTORIES
(Not to scale)

FIG. 2 OVER-ALL WELL
AND DRAINHOLE COMBINATION

FIG. 4 CROSS-SECTION AA
(HORIZONTAL)

FIG. 3 - SCHEMATIC DIAGRAM
OF SPECIAL CASING JOINT
(NOT TO SCALE)

Naval Petroleum Reserve No. 3 Reservoir Summaries

Shannon

Reservoir	Primary	EOR
Reservoir Type:	Sandstone, offshore bar in 2 upwardly coarsening sequences	Sandstone, offshore bar in 2 upwardly coarsening sequences
Approximate Productive Area:	3,800 Acres	125 Acres
Depth:	250' - 950'	250' - 520'
Porosity:	20%	20%
Permeability:	20 md	20 md
Thickness:	2 Benches, 30' per bench	2 Benches, 30' per bench
Number of Producing Wells:	337	107
Original Oil in Place (OOIP):	143.85 MMSTB	36.633 MMSTB
Estimated Ultimate Recovery:	9.056 MMSTB or 6.3% OOIP	12.333 MMSTB or 33.7% OOIP

Appendix # 2

4.2.2 Polymer Seal

Commonly used oil and gas downhole equipments undergo serious physical and chemical deterioration from the combined influence of stress, sour fluids (H₂S, CO₂ etc.), temperatures and pressures. Usually this deterioration results in leaking seals or equipment failure.

Since the main interest of this test was to determine whether polymer seals could withstand temperatures of up to 260 °C and pressure of 680 psi, a very simple experiment was carried out in the lab. A test cell was designed by modifying a Baker sliding sleeve valve model "L". The sliding sleeve is opened and closed with a shifting tool, and flow from below can be plugged off with an insert packoff with a plug bottom that can be run and pulled with wireline. These are downhole flow control devices that are mounted in the production tubing and used to establish tubing to annulus communication. A model "L" sliding sleeve is shown in Fig. 4.33.

Fig. 4.33 Model "L" sliding sleeve valve (Baker Co.)

4.2.2a Experiment and Results

The main experimental unit consisted of a 2 3/8" x 1.87" model "L" sliding sleeve valve which was placed vertically in a specially made rectangular shaped metal box, wrapped with a 2 1/2 " wide and 120" long heavily insulated flexible electric heating tape to achieve the desired temperatures. The sliding sleeve valve and plugs were obtained from Baker CAC, 180 Canada Large Dr. Ventura, CA 93002. A tubing connector whose threads matched the threads on each end of the valve was cut in half, and the cut ends were closed by welding a new piece on them. On the end of one of the newly modified pieces some openings were left for thermocouples, a pressure transducer and a pressure release valve. These newly made pieces were attached to the bottom and top ends of the sliding sleeve valve and so a completely closed cell was attained. Two thermocouples were placed in the sliding sleeve, one to measure the temperature of the cell and the other to operate a temperature controller. One pressure transducer was also fitted on to the sliding sleeve valve to read pressure inside the valve. In addition, a steel tube with o-rings inside was built and fitted on the sliding sleeve valve to close the ports.

The experiment was carried out by placing the cell vertically in the box. A quantity of water was injected into the cell from the pressure release valve opening and then the pressure release valve was placed in its place and then the cell was wrapped with the electrical heating tape. The experiment was carried out for two different configurations, by using a Baker model "L" sliding sleeve with two polished bores and inserting into it a model JSE separation sleeve and a model FSG tubing plug. The separation sleeve and tubing plug were modified in a way so that an extra polymer seal could be used. Attached below the lock

mandrel were one or other of two plugs, the one allowing axial flow and no access to the side exit (Separation sleeve), and the other blocking the axial flow and allowing flow down hole to exit the tubing into the annular space (Tubing plug) (see fig 4.34). Values of temperature and pressure were recorded on a Macintosh computer equipped with 'Lab View' data processing software. The general arrangement of the test apparatus is shown in Fig. 4.35. The data recorded from the experiment were later analyzed using data handling and graphics softwares (e.g., 'Microsoft Excel', 'Kaleidgraph'), and presented in the form of plots of temperature versus pressure.

Heating to the set temperature took about 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 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. The cell was then cooled, opened and visually examined for signs of corrosion.

Experiments were carried out to maximum temperatures of 200 °C and 260 °C. Experiments proved that it was possible to contain the steam pressure up to the maximum operating conditions. Reference to the steam tables shows that, at 260 °C, the steam pressure is approximately 680 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.

Plots of temperature versus pressure for different experiments are shown in figures 4.36 to 4.39 for cell final temperatures of 200 and 260 °C over a period

• Fig. 4.34 A: Tubing plug, B: Separation sleeve.
•

Fig. 4.35 A schematic illustration of a sliding sleeve valve test apparatus.

Fig. 4.36 Temperature vs pressure at 200 °C with distilled water, unplugged.

Fig. 4.37 Temperature vs pressure at 260 °C with distilled water, unplugged.

Fig. 4.38 Temperature vs pressure at 200 °C with distilled water, plugged.

Fig. 4.39 Temperature vs pressure at 260 °C with distilled water, plugged.

of 7 hours. The plots show 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 table. 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 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. As a result of these experiments no leakage was seen at all.

Appendix # 3

CHAPTER THREE

HEAT LOSS CALCULATIONS

3.1 HEAT LOSSES FROM STEAM INJECTION WELLS

Whenever a temperature gradient exists within a system, or when two systems at different temperatures are brought into contact, energy is transferred. There are three fundamental types of heat transfer: conduction, radiation and convection.

Conduction is a process by which heat flows from a region of higher temperature to a region of lower temperature within a medium (solid, liquid, or gaseous) or between different media in direct physical contact. In conduction heat flow, the energy is transmitted by direct molecular communication without appreciable displacement of the molecules. The more rapidly the molecules are moving, the greater will be the temperature as well as the internal energy of an element of matter. Radiation is a process by which heat flows from a high temperature body to a body at a lower temperature when the bodies are separated in space, even when a vacuum exists between them. Convection is a process of energy transport by the combined action of heat conduction, energy storage and mixing motion. Heat is transferred by a fluid that carries heat from a source to a sink.

When the steam is first injected into the borehole, due to the large temperature differences between the formation and the steam, there will be a high loss of heat to the surrounding formations. As a result of this, the temperature adjacent to the wellbore will rise very quickly. Wellbore heat losses can be high enough, especially in wells that are deep or where steam injection rates are low, to reduce steam to hot water at the formation rockface.

Heat losses to the formations is one of the serious economic limitations in the application of steam injection to increase oil production from viscous oil reservoirs. Since thermal oil recovery methods depend upon the ability to provide a maximum amount of heat to the reservoir, heat losses between the surface and injection interval must be minimized. Because the segment of the formation adjacent to the wellbore largely controls the heat transfer rate, the heat transfer rate will become relatively constant when this portion has reached a temperature close to that of the steam opposite it. The temperature of the steam and formation then increase very slowly with time.

Depth, injection rate, injection-string radius, surface injection temperature and the physical properties associated with the steam-formation system affect heat loss rate and as a result the steam quality that is delivered to the formation.

The steady-state rate of heat loss per unit length of pipe is directly proportional to the temperature difference and inversely proportional to the overall specific thermal resistance of the system (Prats, 1986). As pointed out by Ramey (1962), and Willhite (1967), the rate of heat losses is a monotonically decreasing function of time, this function of time being a measure of how fast the earth can conduct the heat away from the injection well.

It is useful to know the amount and the distribution of heat in the reservoir to determine the attractiveness of the steam injection project for heavy oil recovery. Therefore estimating the heat losses to the formations adjacent to the reservoir is essential.

The following equations and expressions were derived by (Prats, 1986). The basic equation used to calculate heat losses per unit length of pipe, Q_{ls} , is

$$Q_{ls} = (T_b - T_A) / R_h$$

R_h is usually represented as $1/(2\pi rU)$,

U : the overall coefficient of heat transfer, Btu/sq-ft-D-°F

r : an arbitrary radius that usually coincides with the radius of one of the surfaces across which the heat loss is being determined, ft

Q_{ls} : the rate of heat loss per unit length of pipe, Btu/ft-D

R_h : thermal resistance per unit length of pipe, (Btu/ft-D-°F)⁻¹

T_A : ambient temperature, °F

T_b : bulk temperature of fluid, °F

$$Ql = Q_{ls}.d$$

Ql : rate of heat loss, Btu/D,

d : depth, ft.

For the insulated tubing held concentrically within the casing the heat resistance elements are combined to obtain the overall coefficient of heat loss.

Fig. 3.1 shows the temperature distribution in an insulated injection well.

Fig. 3.1 Temperature distribution in an insulated injection well.

- T_f : temperature of flowing fluid, °F
- T_{ti} : temperature of inside tubing surface, °F
- T_{to} : temperature of outside tubing surface, °F
- T_{ins} : temperature of the outside surface of the insulation, °F
- T_{ci} : temperature of inside casing, °F
- T_{co} : temperature of outside casing, °F
- T_e : temperature at cement-formation interface, °F
- T_A : undisturbed temperature of the formation, °F

The typical elements offering resistance to heat loss from the tubing include: fluid film on inside of tubing wall "f", scale or dirt on tubing pipe wall "pi", tubing pipe wall "p", contact between outside of tubing and the insulation "po", insulation "ins", radiation and convection from insulation "rc,an", cement "cem", altered zone around cement "Ea", conduction into the earth "E". R_h can, be written as follows (Prats, 1986):

$$R_h = \frac{1}{2\pi} \left[\frac{1}{h_f r_{ti}} + \frac{1}{h_{pi} r_{ti}} + \frac{\ln(r_{to}/r_{ti})}{\lambda_p} + \frac{1}{h_{po} r_{to}} + \frac{\ln(r_{ins}/r_{to})}{\lambda_{ins}} + \frac{1}{h_{rc,an} r_{ins}} + \frac{\ln(r_{co}/r_{ci})}{\lambda_p} + \frac{\ln(r_w/r_{co})}{\lambda_{cem}} + \frac{\ln(r_{Ea}/r_w)}{\lambda_{Ea}} + \frac{f(t_D)}{\lambda_E} \right]$$

h_f : film coefficient of heat transfer, Btu/sq ft-D-°F

h_{pi} : film coefficient of heat transfer at inner radius of pipe, Btu/sq ft-D-°F

h_{po} : film coefficient of heat transfer at outer radius of pipe, Btu/sq ft-D-°F

h_{fc} : coefficient of heat transfer due to forced convection, Btu/sq ft-D-°F

$h_{rc,an}$: coefficient of annular heat transfer due to radiation and convection,
Btu/sq ft-D-°F

r_{ti} : inner radius of pipe, ft

r_{to} : outer radius of pipe, ft

r_{ins} : external radius of insulation, ft

r_{ci} : inner radius of casing, ft

r_{co} : outer radius of casing, ft

r_w : wellbore radius, ft

r_{Ea} : altered radius in the around wellbore, ft

λ_p : thermal conductivity of pipe, Btu/ft-D-°F

λ_{ins} : thermal conductivity of insulation, Btu/ft-D-°F

λ_{cem} : thermal conductivity of cement, Btu/ft-D-°F

λ_{Ea} : thermal conductivity of earth in altered zone around wellbore,
Btu/ft-D-°F

λ_E : thermal conductivity of the earth, Btu/ft-D-°F

where $f(t_D)$ is a time function that represents the thermal resistance of the earth as a function of time, given by Willhite (1967). The function $f(t_D)$ has been discussed by a number of authors (Ramey, 1962), (Willhite, 1967), (Moss and White, 1959), (Huygen and Huitt, 1966). Heat losses from wells never reach a steady state but the rate of heat loss is a monotonically decreasing function of time as shown by Ramey (1962) and Willhite (1967). The boundary condition used to obtain $f(t_D)$ is governed by the thermal resistance between the injection string and the borehole wall, R_h' , which is related to R_h and $f(t_D)$ by

$$R_h' = R_h - \frac{f(t_D)}{2\pi\lambda_E}$$

The dimensionless time, t_D , is based upon the thermal properties of the earth:

$$t_D = \alpha_E t / r_w^2$$

or if there is an altered zone ,

$$t_D = \alpha_E t / r^2 Ea$$

where α_E is thermal diffusivity of the earth, ft^2/D , and t is the time from the initiation of heating, days. The value of $f(t_D)$ is not sensitive to values of $R_h \lambda_E$ for values of $t_D \geq 100$ and is then given by (Ramey, 1962)

$$f(t_D) \cong \frac{1}{2} \ln(t_D) + 0.403$$

for $t_D \geq 100$. For values of $t_D \leq 100$, Willhite (1967) has published a table of the f function for a range of values of both t_D and $R_h \lambda_E$. Those values are given in table 3.1.

t_D	$2\pi R_h \lambda_E$													
	100	50	20	10	5	2	1	0.5	0.2	0.1	0.05	0.02	0.01	0
0.1	0.313	0.313	0.314	0.316	0.318	0.323	0.33	0.345	0.373	0.396	0.417	0.433	0.438	0.445
0.2	0.423	0.423	0.424	0.427	0.43	0.439	0.452	0.473	0.511	0.538	0.568	0.572	0.578	0.588
0.5	0.616	0.617	0.619	0.623	0.629	0.644	0.666	0.698	0.745	0.772	0.79	0.802	0.806	0.811
1	0.802	0.803	0.806	0.811	0.82	0.842	0.872	0.91	0.958	0.984	1	1.01	1.01	1.02
2	1.02	1.02	1.03	1.04	1.05	1.08	1.11	1.15	1.2	1.22	1.24	1.24	1.25	1.25
5	1.36	1.37	1.37	1.38	1.4	1.44	1.48	1.52	1.56	1.57	1.58	1.59	1.59	1.59
10	1.65	1.66	1.66	1.67	1.69	1.73	1.77	1.81	1.84	1.86	1.86	1.87	1.87	1.88
20	1.96	1.97	1.97	1.99	2	2.05	2.09	2.12	2.15	2.16	2.16	2.17	2.17	2.17
50	2.39	2.39	2.4	2.42	2.44	2.48	2.51	2.54	2.56	2.57	2.57	2.57	2.58	2.58
100	2.73	2.73	2.74	2.75	2.77	2.81	2.84	2.86	2.88	2.89	2.89	2.89	2.89	2.9

Table 3.1. Time function $f(t_D)$ for the radiation boundary condition model (Willhite, 1967).

T_{ci} , temperature at inner radius of casing, °F, is

$$T_{ci} = T_A + \frac{(T_b - T_A)}{2\pi R_h} \left[\frac{\ln(r_{co}/r_{ci})}{\lambda_p} + \frac{\ln(r_w/r_{co})}{\lambda_{cem}} + \frac{\ln(r_{Ea}/r_w)}{\lambda_{Ea}} + \frac{f(t_D)}{\lambda_E} \right]$$

T_{ins} , temperature at exposed face of insulation, °F, is

$$T_{ins} = T_b - \frac{(T_b - T_A)}{2\pi R_h} \left[\frac{1}{h_f r_{ti}} + \frac{1}{h_{pi} r_{ti}} + \frac{\ln(r_{to}/r_{ti})}{\lambda_p} + \frac{1}{h_{po} r_{to}} + \frac{\ln(r_{ins}/r_{to})}{\lambda_{ins}} \right]$$

For free convection in the annulus, the coefficient of heat transfer by radiation and convection in the annulus, $h_{rc,an}$ is given by Willhite (1967) as

$$h_{rc,an} = 4.11 \times 10^{-8} \left[\frac{1}{\epsilon_{ins}} + \frac{r_{ins}}{r_{ci}} \left(\frac{1}{\epsilon_{ci}} - 1 \right) \right]^{-1} F(T_{ins}, T_{ci}) + \frac{1}{r_e} \frac{\lambda_{a,a}}{\ln(r_{ci}/r_{ins})}$$

where

$$F(T_{ins}, T_{ci}) = [(460 + T_{ins})^2 + (460 + T_{ci})^2] (920 + T_{ins} + T_{ci})$$

$$\lambda_{a,a} = 0.049 \lambda_a N_{Gr}^{0.333} N_{Pr}^{0.407}$$

$\lambda_{a,a}$ is the effective thermal conductivity of the air in the annulus, where

$$N_{Gr} = \left(\frac{g_c (7.12 \times 10^7)}{g} \right) \frac{(r_{ci} - r_{ins}) g \rho_{an}^2 \beta_{an} (T_{ins} - T_{ci})}{g_c \mu_{an}^2}$$

N_{Gr} is the Grashof number, and the Prandtl number N_{Pr} is valid for $5 \times 10^4 < N_{Gr} N_{Pr} < 2.510^8$.

ϵ_{ins} and ϵ_{ci} are the emissivities of the inner and outer surface of the annulus, and are dimensionless. β is the thermal volumetric expansion coefficient ($^{\circ}F^{-1}$).

3.1.1 Factors That Affect Heat Losses

3.1.1a Effect of Tubing, Casing and Hole Sizes on Heat Losses When Injecting Steam Through Bare Tubing, Calcium Silicate Insulated Tubing and Thermocase

The scope of this study is to find out the effect of different tubings, insulators, casings and hole sizes on heat losses when injecting steam through the following three types of tubing: bare tubing, calcium silicate insulated tubing and Thermocase for a depth of 1000 ft, injection temperature of 600 °F and pressure of 1543 psi and a period of 20 days.

The structure is explained as follows: the annulus contains a stagnant gas with zero gauge pressure at the well head, casing is cemented to surface and the tubing is set on a packer.

Seven different well configurations were used to find out the effects of many arrangements of tubing, insulator, casing and hole sizes. Results are shown in figures 3.2, 3.3 and 3.4. The values shown in Table 3.2 were used in plotting heat loss versus radius.

CONFIG. No	1	2	3	4	5	6	7
OD_{tub} , in	1.66	2.375	2.375	2.875	3.5	3.5	2.875
ID_{tub} , in	1.38	1.995	1.995	2.441	3.068	3.068	2.441
OD_{ins} , in	2.375	3.5	4.5	4.5	4.5	5	4.5
OD_{cas} , in	8.625	9.625	10.75	11.75	13.375	13.375	7

ID_{cas} , in	:	7.511	8.544	9.768	10.776	12.348	12.348	6.276
OD_{hole} , in	:	10.625	12.25	12.25	14.76	17.5	17.5	9.625
α_E	:	0.96 sq ft/D						
$\epsilon_{ins} = \epsilon_{ci}$	:	0.9						
λ_E	:	24 Btu/ft-D-°F						
λ_{cem}	:	12 Btu/ft-D-°F						
$\lambda_{ins(Thermocase)}$	:	0.0552 Btu/ft-D-°F						
$\lambda_{ins(CalciumSilicate)}$	:	0.96 Btu/ft-D-°F						

Table 3.2 Seven different well configurations data.

In the case of the bare tubing where no insulator is used, keeping injection tubing size as well as casing and hole sizes as small as possible will result in less heat transfer to the surrounding formations and higher quality steam delivered to the reservoir. The situations below where bare tubing was used confirms this stated theory.

From Fig. 3.2 we can see that, with tubing size increasing, the heat loss rate increases. As is seen in Fig. 3.2, keeping the tubing sizes constant, for example 2.875" for well configurations 4 and 7, the heat loss increases with increasing casing and hole sizes. Almost doubling the casing and hole sizes doubles the heat loss.

For the same sets of tubing and casing dimensions, heat loss values were calculated for different insulation treatments of the steam tubing. Results of these calculations are shown in Fig. 3.3 for calcium silicate insulation, and in Fig. 3.4 for "Thermocase" insulation. Comparing figures 3.2 and 3.3 it is seen that

Fig. 3.2 Heat losses for various casing and tubing configurations. The horizontal lines link the sets of relevant dimensions for each particular configuration. Bare tubing.

Fig. 3.3 Heat losses for various casing and tubing configurations. The horizontal lines link the sets of relevant dimensions for each particular configuration. Calcium silicate insulated tubing.

Fig. 3.4 Heat losses for various casing and tubing configurations. The horizontal lines link the sets of relevant dimensions for each particular configuration. Thermocase.

although the relative ranking of the different configurations are similar, the effect of the calcium silicate insulation is to reduce the heat losses in most cases by a factor of 3 or 4.

An even greater decrease in heat loss is seen in the final situation in which "Thermocase" is used. The greater insulation coupled with its extremely low thermal conductivity are the reasons that Thermocase is almost 13 times more effective than calcium silicate and almost 47 times more effective than bare tubing in particular cases. Using the same situations as with the bare tubing and calcium silicate insulation i.e. increasing hole size, etc. the result concluded is that Thermocase is much more effective in controlling heat loss. Fig. 3.4, however, shows that with different well configurations for Thermocase as well as for the calcium silicate insulator, the different sets of dimensions produce the same ranking in heat losses as for the insulated situation.

3.1.1b Effect of Injection Time, Injection Depth and Injection Temperature on Heat Losses

If we assume that tubing, casing hole size and geothermal properties of the well are constant, the major factors that affect heat losses are, injection time, injection depth, injection rate and injection temperature and pressure.

Figs 3.5 through 3.18 demonstrate the effects of these factors. The selected values of tubing, casing, insulator, hole sizes and geothermal properties used to obtain the results shown on these figures are listed in Table 3.2. Values selected for these results are representative of an average situation. Seven different well

configurations were used and also some additional calculations were done for well configuration number 3.

1- Injection Time vs Heat Loss

Figures 3.5, 3.6 and 3.7 demonstrate the variation of heat losses with time under the conditions of depth of 1000 ft, injection temperature of 600 °F and injection pressure of 1543 psi, and Fig. 3.8 shows the variation of temperature at the hole bottom with time. As expected, the variation of heat losses with time is very rapid at the beginning due the fact that a tremendous amount of heat is lost to the surrounding formation because of temperature differences. At later times, however, the bottom-hole temperature increases very slowly (see Fig. 3.8). Thus, even after eight years of injection there is still a substantial temperature drop in each of the well configurations illustrated. This trend is most noticeable when steam is injected through bare tubing (Fig. 3.5) as compared to when it is injected through calcium silicate insulated tubing (Fig. 3.6). When injected through Thermocase (Fig. 3.7), it is not that noticeable.

Fig. 3.8 shows the effect of injection time on casing temperature when steam is injected through bare tubing, calcium silicate insulated tubing and Thermocase for the above stated conditions of depth, temperature and pressure. These particular well configuration data were obtained from Table 3.2 (well configuration number 3). The figure clearly shows that for all three different cases casing temperature at early times increases very rapidly, but very slowly thereafter. The casing temperature at early time is around 340 °F for bare tubing, increases to about 475 °F after 500 days and reaches almost 490 °F after almost 8 years. For calcium silicate insulated tubing, the casing temperature is about 130

Fig. 3.5 Injection time vs heat loss for injection depth of 1000 ft and injection temperature of 600 °F. Bare tubing.

Fig. 3.6 Injection time vs heat loss for injection depth of 1000 ft and injection temperature of 600 °F. Calcium silicate insulated tubing.

Fig. 3.7 Injection time vs heat loss for injection depth of 1000 ft and injection temperature of 600 °F.
Thermocase

Fig. 3.8 Injection time vs casing temperature for injection depth of 1000 ft and injection temperature of 600 °F. Well configuration No. 3.

°F at early time and increases to about 200 °F after 500 days and about 215 °F after almost 8 years.

However, when steam is injected through Thermocase, the casing temperature does not change dramatically. As is seen in Fig. 3.8, casing temperature at early time and even after 8 years does not change more than 10-15 °F. This clearly indicates that Thermocase is a very good insulator and steam can be delivered to the reservoir almost without any heat loss. In conclusion, it should be observed that there is a large difference between casing temperatures when steam is injected through bare tubing as opposed to calcium silicate insulated tubing or Thermocase. Obviously, injecting steam through bare tubing is not advisable. Heat losses are so high that steam can not be delivered to the rockface with high temperatures. Most or even maybe all of the injected steam will condense before it reaches the reservoir, especially if the reservoir is a deep reservoir. Even for shallow reservoirs it is not very economical when the cost of generating steam and the amount of heat lost are considered.

2- Injection Depth vs Heat Loss

The prediction of wellbore heat losses is particularly important for deeper wells, especially when steam injection rates are low. Under such conditions, the heat lost from the injection tubing to the surrounding formation can be a substantial fraction of the total. Figures 3.9 through 3.14 show the effect of injection depth on heat losses. Steam was injected through bare tubing, calcium silicate insulated tubing and Thermocase with injection temperature of 600 °F, and injection pressure of 1543 psi for a period of 20 days.

As expected, heat losses increase with increasing depth for all three different injection tubings and the seven different well configurations. Such is due to the fact that the longer section of the borehole needs to be heated up causing a large amount of heat to be lost before it reaches the reservoir. Comparing figures 3.9 through 3.11, it is evident that when steam is injected through the bare tubing under the same conditions as mentioned above heat losses are much higher than when steam is injected through calcium silicate insulated tubing and Thermocase.

This means that the amount of heat lost through the bare tubing is extremely high compared to the other two tubings leading to the conclusion that bare tubing will not be satisfactory for deep wells. On the other hand, both calcium silicate insulated tubing and especially Thermocase are quite suitable materials to be implemented in deep well situations due to their high resistance to the heat transfer.

Figures 3.12, 3.13, 3.14 give examples showing the effect of injection temperature and depth as a function of time. It is clear that regardless of injection temperature heat loss increases with increasing injection depth for all three cases. The figures show an almost linear relationship between injection depth and heat loss. Figures 3.12, 3.13, 3.14 give the amount of heat lost after 20 days of steam injection as a function of depth and injection temperatures. Data for these plots were obtained from Table 3.2 and configuration No. 3.

Fig. 3.9 Injection depth vs heat loss for injection temperature of 600 °F after 20 days. Bare tubing.

Fig. 3.10 Injection depth vs heat loss for injection temperature of 600 °F after 20 days. Calcium silicate insulated tubing.

Fig. 3.11 Injection depth vs heat loss for injection temperature of 600 °F after 20 days.
Thermocase

Fig. 3.12 Injection depth vs heat loss as a function of inject. temperatures after 20 days for well configuration No. 3. Bare tubing

Fig. 3.13 Injection depth vs heat loss as a function of injection temperatures after 20 days for well configuration No.3. Calcium silicate insulated tubing.

Fig. 3.14 Injection depth vs heat loss as a function of injection temperatures after 20 days for well configuration No. 3. Thermocase.

3- Injection Temperature vs Heat Loss

The primary goal of steam injection projects is to deliver steam of a specific temperature to heavy oil-containing reservoirs. One of the main reasons that high temperature steam is injected into the reservoir is that by the time the steam reaches the oil containing formation it has lost lots of heat on the way to the surrounding formations. The heat loss is higher with higher injection temperatures, which suggests an advantage in injecting saturated steam rather than superheated steam. Generating superheated steam also costs more than saturated steam. On the other hand, superheated steam's initial heat content is higher than saturated steam's initial heat content. One advantage of superheated steam over saturated steam is that superheated steam might reach the reservoir without condensation. Saturated steam could be used economically if heat losses are minimized by special well design techniques and through the use of insulators.

Figures 3.15 through 3.17 show heat loss as a function of injection temperature and depth (1000 ft) at the end of 20 days. These figures indicate that higher steam injection temperatures cause a higher amount of heat lost to the surrounding formations for the three tubing types and all seven well configurations. The reason is that steam at high temperature tends to release more energy than low temperature steam.

Fig. 3.18 shows large differences in casing temperature when steam is injected through bare tubing, calcium silicate insulated tubing and Thermocase for a depth of 1000 ft and after 20 days. Data used for this figure were obtained for configuration No. 3. As the figure exhibits, there is a very small change of the

Fig. 3.15 Injection temperature vs heat loss
for injection depth of 1000 ft after 20 days.
Bare tubing.

Fig. 3.16 Injection temperature vs heat loss for injection depth of 1000 ft after 20 days. Calcium silicate insulated tubing.

Fig. 3.17 Injection temperature vs heat loss for injection depth of 1000 ft after 20 days. Thermocase.

Fig. 3.18 Injection temperature vs casing temperature for injection depth of 1000 ft after 20 days. Well configuration No. 3.

casing temperature when steam is injected through Thermocase. An example of this can be seen in Fig. 3.18. The process is as follows: the injection temperature at the surface was initially 328 °F; casing temperature was about 100 °F after 20 days; when the injection temperature was increased to 668 °F, still the casing temperature was around 110 °F for the Thermocase. Under the same conditions, the casing temperatures for calcium silicate insulated tubing were about 130 °F and 175 °F respectively, and for the bare tubing the casing temperatures were about 205 °F and 495 °F. This clearly shows the obvious contrasts between insulated tubing and uninsulated tubing, and it also shows how unsatisfactory it would be if steam were injected through bare tubing because of the very high heat losses for high steam injection projects.

3.2 STEAM QUALITY

The main objective in thermal recovery processes is to search for more efficient, environmentally acceptable and cost-effective methods to increase oil production. Heat loss prediction and thus a suitable well design will lead us to spend the least energy to increase oil production.

Once heat loss is known, steam quality can be calculated at the reservoir depth. Steam quality at the hole bottom is usually lower than that at the surface. Higher hole bottom steam quality can be obtained by lowering hole bottom pressures by using a combination of high steam rate, small tubing size, and high injection steam quality. The bottom hole steam quality, X_q , (Boberg, 1987), is

$$X_q = X_s - \frac{QD}{m_s H_{wv}}$$

- X_q : the bottom-hole steam quality (lb vapor/lb vapor plus liquid)
- X_s : surface-injected steam quality (lb vapor/lb vapor plus liquid)
- Q : wellbore heat loss rate (Btu/hr-ft)
- D : depth (ft)
- m_s : mass rate of steam injection (lb/hr)
- H_{wv} : specific latent heat of vaporization at injection temperature and pressure (Btu/lb)

In a steam injection project, steam is the heat transfer source used for heating up the formation. For the process to be effective, a sufficient quality of steam must be delivered at sufficient rates, but not all the heat injected or generated in a reservoir stays in it. Because of the following heat loss sources only a part of the heat supplied to the steam in the boiler goes into formation heating: surface steam generator and surface piping, wellbore (tubing-casing), over and underburden formations. It is very important to optimize the use of injected steam because of the high steam cost.

3.2.1 Injection Depth vs Steam Quality

Predicting the quality of steam flowing down the injection tubing to the reservoir is very important in thermal efficiency estimates. It is very well known that steam quality decreases as heat losses increases. Since heat loss increases with depth, steam quality decreases.

Figures 3.19, 3.20 and 3.21 show the relationship between depth and steam quality as a function of injection rate for an injection temperatures of 636 °F, an

Fig. 3.19 Depth vs steam quality as a function of injection rates for injection temperature of 636 °F after 20 days, well configuration No. 3. Bare tubing.

Fig. 3.20 Depth vs steam quality as a function of injection rates for injection temperature of 636 °F after 20 days, well configuration No. 3. Calcium silicate insulated tubing.

Fig. 3.21 Depth vs steam quality as a function of injection rates for injection temperature of 636 °F after 20 days, well configuration No.3. Thermocase.

injection pressure of 2000 psi and steam quality of 85 % after 20 days of steam injection through bare tubing, calcium silicate insulated tubing and Thermocase. Data used for these plots were obtained from Table 3.2 and configuration No. 3. At a given injection rate the heat loss is directly proportional to the depth. When heat losses are high, steam usually condenses before it reaches the reservoir. Condensation occurs when a saturated vapor comes in contact with a surface whose temperature is below the saturation temperature. From figures 3.19, 3.20, and 3.21, it is also observed that injecting steam with low injection rates decreases steam quality with injection depth.

When steam is injected through a bare tubing with low injection rate the quality drops very dramatically. As it is demonstrated in Fig. 3.19, when steam is injected with injection rate of 1000 lb/hr steam quality drops from 85 % to almost 0 % at the depth of 500 ft. This shows that heat losses are extremely high and no steam can be delivered to the reservoir at this depth before it completely condenses. When the injection rate is increased to 9000 lb/hr, steam quality at the same depth is about 75 %. Injecting steam to a deeper reservoir will further decrease the steam quality. For example when steam is injected through bare tubing with an injection rate of 9000 lb/hr, the steam quality drops from 85 % (at the surface) to 44 % at the depth of 2500 ft.

Similar observations were made when steam is injected through calcium silicate insulated tubing and Thermocase. As is seen in figures 3.20 and 3.21, steam quality decreases with increasing injection depth. Due to lower heat losses, compared with the bare tubing, however, steam quality does not drop as rapidly as it did in the case of bare tubing. For example at 500 ft depth, steam quality is about 68 % when it is injected through calcium silicate insulated tubing and 83.5

% when it is injected through Thermocase. Even at the depth of 2500 ft it is about 0 % for calcium silicate tubing and it is about 79 % for Thermocase. Injecting steam at much higher injection rates does not change steam quality very much in spite of increasing injection depth. In the case of using Thermocase as the injection tubing, steam quality drops only from 85 % (at the surface) to about 83.8 %, whereas, for calcium silicate insulated tubing it drops from 85 % to about 75 %.

From these results it is clear that for a successful steam injection project a shallow depth is preferred: because heat losses are minimal in shallow reservoirs, and at greater depth higher steam temperatures are required because of higher formation pressures. In addition, steam should be injected with high injection rates and qualities to increase efficiency of the steam injection project. The other important point is that, in order to deliver steam to reservoirs with high qualities, heat losses must be minimized. These heat losses can be minimized by using some sort of insulator. From our study it appears that regardless of injection and borehole conditions Thermocase is the most satisfactory means of heat loss minimization.

3.3 CONCLUSIONS

Estimation of heat losses is a very important part of heavy oil recovery projects. Heat losses can be decreased by injecting steam through insulated tubing, and especially the use of Thermocase will further decrease heat losses. Carefully designed well configurations also decrease heat losses. When steam injection and hot oil production is carried on in the same borehole significant advantages can be gained. Either when steam is injected through insulated

tubing and oil produced through small size uninsulated tubing or through the annulus, heat losses can be decreased. Furthermore, constant steam injection and oil production in the same borehole saves time and money.

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