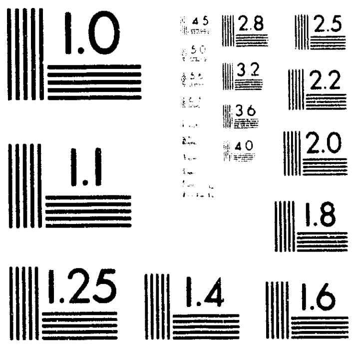
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S-CAL RESEARCH CORPORATION

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

Contract: DE-FG01-92 CE 15553

FOURTH QUARTERLY REPORT

September 1993

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FOURTH QUARTERLY REPORT

ABSTRACT:

A Major Oil Operator indicated that they are considering drilling and completion of two horizontal wells to reach the same reservoir area in the Midway-Sunset field.This gave us an opportunity to show them the potential benefits of using a single cased well equipped with two laterals,instead of two conventional horizontal wells.

Contrary to the design reported in the 3rd Quarterly Report,which addressed the case of re-entry into an existing 7 in. cased well,this new case will require drilling a new well.Because of the relatively higher expected fluid production rate,larger-diameter laterals will be needed.Correspondingly,this calls for a larger casing diameter.

Two basic designs have been produced,for two different casing diameters,respectively 8 5/8 in.and 10 3/4 in.,in order to meet the technical requirements of this Operator.A major difficulty in this case is the very low reservoir pressure (50 to 75 psig).This,and the need to cut capital costs led us to consider two different artificial lift systems.We expect to receive from this Major Operator sufficient

information about current costs in this area to make in the near future an itemized comparison of the costs of our various well configurations with those of two conventional horizontal wells.

The addition of the downhole equipment for two new larger well sizes to the equipment required for re-entry into an existing 7 in. casing provides greater flexibility to address a greater variety of specific field applications.Contacts are being pursued with this Operator and with other Oil Companies suceptible of Field-Testing this new technology.

13.GENERAL CONCEPTUAL DESIGN FOR A NEW WELL EQUIPPED WITH TWO LATERALS

The general concepts of using downhole three-way valves on the steam tubing and of incorporating into the same tubular joints all the other elements for downhole flow control with those required for drilling and tie-in of the laterals remains the same as that presented in the 3rd Quarterly Report.Because it is now for a new well,these special joints are now part of the new cemented casing string,instead of being inserted and hung into a pre-existing cemented cased well.

The main advantage of starting from scratch is that the diameter allowed for the special joints is much greater.It is equal to that of the API couplings of the new casing string.Conversely,the larger joint diameter allows the use of larger curved channels,serving both as whipstocks during drilling and as hangers/packers for the tubulars of the dual laterals.This is summarized in Table 1 below:

TABLE 1 - DIMENSIONS OF VARIOUS WELL CONFIGURATIONS (inches)

Case:#1 Re-entry	New Well No.1	New Well No.2

Vert.hole			
OD bit	9.875	11.0	13.5
Casing			
OD	7.0 API	8.625 API	10.75 API
Curved Channels			
minimum ID	2.313	3.813	4.75
Horiz.hole bit			
OD	2.25 HP jet	3.5 diamond	3.75 hole opener
Liners			
OD/ID	2.0/1.782 CT	2.875/2.375 NUE	4.5/3.958 Hydril
Window			
(height)	76	126	214
Pump			
OD	1.0 (in liner)	1.75 (in liner)	2.5 (in prod.tbg.)
Prod.Tbg.			
OD	2.875 VAM	4.5 VAM	>= 2.875 API
Steam Tbg.			
OD	2.375 API	2.375 API	3.5 API/2.875 NUE
3-way valve			
OD	2.875	2.875	3.5 (retr.sleeve)
Pumping Unit			
Number	1 or 2	1 or 2	1 + steam lift

14. MAIN DIFFERENCES IN WELL OBJECTIVES

The re-entry into an existing 7 in. cased well for drilling two medium-radius laterals with a high pressure water jet nozzle using a 2.0 in.OD coiled tubing is the least expensive well program,but its flow rate capabilities are obviously more limited,especially in under-pressured reservoirs.In such cases,it is necessary to maximize the draw-down by locating the pump as close to the base of the reservoir as possible,i.e.in the bent part of the liners.This is associated with several other constraints:

1. At the pump inlet,the suction pressure is very low and much below the boiling pressure of the hot produced water.Even when the reservoir oil contains little or no dissolved gas,steam flashing from the produced stream may produce gas locking in the rod pump.This is best avoided by proper selection of the pump type.Several devices are available to eliminate gas lock:National Supply Oilmaster Gas-lock breaker,Harbison-Fisher Lock-No plunger,or Sargent 927 2-stage charger valve.

2. Drilling horizontal laterals with a coiled tubing string is a relatively new development.Its use in California with HP water jet nozzles has been very limited.It has been the subject of a DOE-funded field test by Petrolphysics,Inc.in a UNOCAL well.The horizontal reach obtainable with this Ultra-Short radius drilling technology does not exceed 150 ft and the directional control provided by very small diameter orientation tools is often considered insufficient by Oil Operators.It is expected that the use of a larger coiled tubing (2" instead of 1.25") in a medium curvature hole (300 ft instead of 3 ft) will greatly improve the directional control of the laterals,but this remains to be demonstrated in the unconsolidated sand reservoirs of California.

3. Gravel packing of long horizontal sections is not always successful,so that,in unconsolidated reservoirs,the risk of some sand production with the heavy oil is quite high.This requires frequent pulling out of the rod pumps and occasional cleaning of the liners.

4. Friction of the rods against the curved cemented liners may result in damage to the rods and to the liners,despite the use of rod centralizers.

Because of these technical limitations,most Oil Operators have developed,mostly by trial and error,their own rules regarding acceptable compromises in their well design and operating procedures. These experience-based technical compromises may vary widely among Operators (see App.1 and 2).It has become apparent that Major Oil Operators are often preferring larger diameter tubulars despite their higher cost,because they allow easier and cheaper maintenance and repairs of the downhole equipment over the lifetime of the well. The differences in tax treatment of operating expenses and of capital costs may lead to different technical compromises for smaller Oil Operators,who are often short of capital.This explains why different Operators may prefer some technical compromises over those of other Operators and justifies the need to be able to present a variety of different technical solutions to gain wider acceptance of any new oil production technology.

15. MAIN DIFFERENCES IN DOWNHOLE EQUIPMENT AND OIL-LIFTING PROCEDURES

The design of New Well No.1 is presented in Appendix 1.It uses a proven drilling technology used repeatedly by a reputable drilling Contractor,who also develops and manufactures its own downhole motors and diamond bits.The small ID (1.995") of the 2.875 OD liners precludes the use of a production tubing in the curved part of the laterals.Consequently,any steam flashing at the pump inlet must go through the pump without leaving any residual gas phase susceptible of accumulating to produce gas lock.Consequently,like in the case of a coiled tubing liner,the rod pump must be equipped with a device for preventing gas lock.To a certain extent,the inclination of the pump which reduces the difference in elevation between the standing valve and the traveling valve also facilitates the natural removal of steam from the pump body,by gravity forces.The use of a rod pump in a curved liner also imposes a limit to the allowable pump stroke length.To offset the relatively short stroke,the duration of the pumping cycle must be reduced at the risk of higher wear of the rods,especially in the curved part of the rod string.These same conditions apply to the design based on re-entry of an existing 7" casing and,in addition,the smaller pump diameter further restricts the pumpable volume,below the value specified by the Operator for Well No.1.

The design for Well No.2 resulted from the desire expressed by the Operator to keep its current practice of providing a path for venting any steam flashing or other gas phase into the casing/tubing annulus. In that case,the well configuration must provide a natural downhole gas/liquid separator.In view of the very low (=<75 psig) reservoir pressure,however,the hydrostatic head in that separator must be as low as possible,without causing cavitation in the pump.For this reason the well design presented in Appendix 2 (Fig.1) first reduces the net density of the fluids in the curved part of the production tubing by steam lift,to reduce the back-pressure on the reservoir.The flashed steam and lift steam combined gaseous phase is then separated out from the liquid phase in a downhole vertical separator and vented into the low-pressure casing/tubings annular space and conveyed to the surface where it is re-condensed.The liquid phase accumulates in the sump of the vertical separator,from which it is lifted by a single vertical rod pump through the vertical production tubing.The pump standing valve isolates the downhole separator from the hydrostatic head of the pumped liquids in the production tubing.The downhole gas/liquid separator consists of the near vertical third channel and the H joint in the two lower casing joints.

In the design of this New well No.2,a significant difference in the three-way sliding sleeve valve,in this case,is that the sleeve,in its closed position,allows a limited flow of steam into the curved liner/tubing annulus through a choke to supply the lift steam to the bottom tubing-pressure-controlled gas lift valve.The sliding sleeve in the 3.5" OD valve is wireline-retrievable through the vertical production tubing in the event that the choke holes in the "closed" part of the valve body get clogged and require cleaning.

In this design,switching the right lateral on Fig.1 of Appendix 2 requires the same wireline operations as in two previous designs.The main difference in the well configuration is the existence of a short (ca.300 ft) 2 7/8 " OD tubing string in the curved portion of each lateral.Each tubing string is terminated by a retrievable standing valve and by a 2.375 side pocket mandrel (Merla TMPEX) equipped with a 1" OD spring-loaded retrievable gas-lift valve.The top of each curved tubing is hung and sealed into the upper 4.75" min.ID landing nipple profile seal bore of the lateral,by means of a lock mandrel (Baker type F) terminated by a threaded connection.As such,each short tubing string is easily retrievable to provide full access into the 4.0"ID liner.

The Operator's current practice is to clean-out any accumulated sand production in the liner using the production tubing after each steaming cycle.This operation in a conventional single lateral well requires pulling-up the rods and pump.With the present design,the vertical production tubing and rod pump is left untouched.The retrieval of the short curved tubing and all sand removal operations are done with a 2 7/8 " cleaning string,through the 5.0" ID steam vent opening on the top of the H joint.

The vertical production tubing is hung from the well head and inserted into its dedicated third opening in the top of the H joint.The tubing and rod string are free to thermally expand into the lower casing joint,which is filled by the separated produced liquid phase.Communication between this sump and the 5.0" ID near vertical channel is provided by a sliding sleeve circulation valve above the lower landing nipple of that channel.

The top special casing joint is no longer needed,because the PBR of the production tubing is eliminated.Because of the longer window height,two 30 ft joints are required to provide two windows,one on top of the other.A preferable alternative in cases when the azimuthal directions of the two laterals may be different is to overlap the two windows within the same bottom joint of the casing.This is the case for well site presently considered by the Operator.

16.COMPARATIVE COSTS

An itemized cost comparison of the design for New Well No.2 with the current project of the Operator (2 conventional horizontal wells equipped with a 7" casing,a 5.5" liner,a 2 7/8" tubing and a rod pump requires reliable itemized cost data,which have been requested from the Operator.

It is apparent that,where the diameter of the liners can be reduced and the pump can be anchored in the liner itself,the design of Well No.1 may be somewhat cheaper,because of the smaller casing diameter.The requirement of two rod pumps,however,is especially onerous.Serious consideration should be given to the use of a single rod pump,used alternatively in each lateral.This requires that the total time required for steam injection and steam soak be equal to the production time in each lateral.The economic optimization of these exploitation parameters must be done for each field and oil viscosity. It is likely that previously established operating criteria for vertical wells are not directly applicable to wells equipped with twin laterals.

The design for re-entry into an existing 7" casing is obviously the lowest cost approach,but its application is limited to lower rate wells,and it makes use of a coiled-tubing drilling technique which is still considered experimental by many Operators.Its use in normally-pressured reservoirs would make it possible to use a single pump of diameter >=2 ",anchored in the 2 7/8" vertical tubing to produce an increased fluid volume at minimum cost.

APPENDIX # 1

CONCEPTUAL DESIGN OF A TWIN LATERAL WELL MEETING AN OPERATOR'S REQUIREMENTS

OPERATOR'S REQUIREMENTS:

A new well in the Midway Sunset Field,equipped with two horizontal laterals reaching into the adjacent lease (700 ft reach) with medium radius of curvature (200 to 300 ft) to reach two separate layers updip in the reservoir,each with a thickness of 50 to 70 ft.

The oil is viscous (14 API) and requires steaming.The expected well productivity is 150 B/D and must be capable of operating as follows:

- One lateral under steam injection,while the other is under production,
- One lateral shut-in while the other is producing,
- Both laterals under production.

The well completion must allow to drill and complete the second lateral after the first one has been placed under "huff and puff" operation,to better determine the economics of adding the second lateral.

Drilling of the laterals will use conventional drilling tools of proven performance.The rod pump(s) will be located in the bends of the laterals to maximize the draw-down (reservoir pressure is very low 150 to 200 ft of hydrostatic head).By locating the vertical well downdip from the target zones,the pump may be located at,or below,the mid-level of the lower target,by deviating the laterals at more than 90 degrees from the vertical.The updip path of the laterals allows to locate their kick-off points in a region of positive head,despite the 200 to 300 ft radii of curvature.

Both laterals must be completed with gravel-packed perforated liners of sufficient ID to carry out logging and cleaning operations during the well lifetime.

Most importantly,the Capital and Operating costs of the well must be minimized.

SELECTED WELL FEATURES TO MEET THE OPERATOR'S REQUIREMENTS,USING VARIOUS S-CAL RESEARCH PATENTED TECHNOLOGIES:

1.The well will be operated by the process described in US Patent No.5,085,275,to minimize heat losses in the tubing and surface steam lines.It will thus be equipped with two parallel tubings in a gas-filled annular space.The tubings,dedicated respectively to steam injection only and to oil production only,have the following characteristics: Steam tubing: 2 3/8" OD

Production Tubing: 4.5" OD.This large diameter is required for using proven drilling techniques,by Slimdrill.They use a 2 3/8" OD conventional drill string (with Hydril couplings),so as to provide a 1.9'ID space for the 1.75"OD orientation device.We believe that the use of a 2 3/8" OD coiled tubing would allow a reduction of the production tubing diameter to 4",but Slimdrill has not drilled any deviated wells through any pipe of diameter smaller than 4.5".The couplings of their drill string are 2.74"OD,whereas the coiled tubing would only be 2.38"OD,but they have no previous experience with it.In view of the fact that 4" tubing is not as commonly used as 4.5",it was preferred to use the larger diameter well and a proven drilling method.

2.The three-way downhole valves required for the use of that process will only include one patented sliding-sleeve valve and two retrievable plugs,all of them operated by wireline to minimize costs. Such a type of valve was successfully tested for steam operation at UC-Berkeley.

The dual tubing completion and pressure-tight connections to the twin laterals and dual tubings,including all downhole valves,plugs will be made-up with the three lowermost joints of the vertical well casing, using our patented technology.The elimination of a dual tubing hanger and packer is aimed at reducing capital cost.These three casing joints also contain the Polished Bore Receptacles or Thermal Expansion joints of both tubings. They also include the 4.0"ID whipstocks required to kick-off the bit and drill the two laterals.They also include the pressure-tight liner hangers of both laterals.The liners of the laterals may be 2 3/8" OD special tubing or,preferably a 2.38" OD coiled tubing.In either case the liner allows the use of a 1.5" OD rod pump and is large enough for using 1 11/16" logging and cleaning tools.

4.To provide sufficient space for both tubings,a 8 5/8"OD casing is required.With API couplings of 9.625" OD,the borehole must be at least 11" ID.For this reason the maximum OD of the three special casing joints may be 9.625".The 4.5" tubing will have VAM couplings. (see Fig.0)

5.Each liner will be gravel-packed in the reservoir and cemented in the bend.It will then be selectively perforated "in-situ" using our patented hydraulic slot-cutting tool.This allows to use the liner itself as drill string,at least for the final part of the lateral drilling process (at an angle greater than 90 degrees).

6.To further reduce drilling cost,drilling and completion of each lateral is preferably done through tubing,thus allowing maximum benefit of coiled tubing drilling techniques.It also allows to drill the second lateral at a later date using only a service rig and a coiled unit,without any need for pulling tubings or removing the well head.

7.The proposed completion also allows the use of other methods of artificial lift using available equipment: intermittent gas lift,jet pumps or hydraulic pumps if these are preferred at a later date.

DESCRIPTION OF THE THREE SPECIAL CASING JOINTS

The top 9.625" OD special casing joint is required to carry the PBR or Thermal Expansion joints of both tubings.The uphole casing is preferably 8 5/8" OD,so a reducer coupling is used to connect it to the 9 5/8"OD joints below it (see Fig.1).Another,more costly alternative is to continue with a 9 5/8"OD casing uphole.In that case the higher cost of the larger casing and bigger hole may be partly offset by the use of API couplings on the 4.5"production tubing string,instead of more costly VAM couplings.

The middle special joint (Fig.2) includes,from the top down:

- a threaded internal upset coupling from the upper 9 5/8" OD casing to the 8 5/8" middle joint,
- a top part consisting of a 9 5/8" casing pup joint in which a pup 4.5" tubing joint and the novel three-way sliding sleeve valve for the 2 3/8" steam tubing are housed.
- a bottom part of 9 5/8" OD,including:

1) a novel H joint for two 4.5 "OD,3.958" ID tubings,made of a welded assembly,for the top part,which is also welded to the bottom

section.Its cross-section is shown on Fig.2a.

2) a bottom section machined from 9.625" bar stock in which two curved channels have been drilled.These channels also present the standard profile of commercial 4.5" landing nipple joints at their upper end (OTIS Type X) (3.813 "ID drift) in their vertical upper part.The channel beginning below the 4.5" upper branch of the H joint is also cut with such a landing nipple profile below its bend and both channels are terminated by API female threads for 4.5"OD nipple joints,inclined at an angle of 1,5 degrees.

The three-way valve lateral ports are in communication with two pairs of steam feeder lines exiting respectively below each of the two landing nipples profiles in the lower branches of the H joint assembly at the upper end of the bottom section.Each pair of steam feeder line presents symmetrical positions with respect to the casing axis,to reduce thermal stresses in the cemented casing,when in operation.

The bottom special joint (Fig.3),is made from a welded assembly. It is connected to the bottom section of the middle joint by means of two short 4.5"OD nipples and by two 9.625"OD side slips,each one bolted respectively into the bottom section of the middle special joint and into the top plate of the lower casing joint.Each slip presents two central wedges fitting between the two joints and one wedge above and below,fitting into the corresponding end piece of the two casing joints.These side slips add sufficient rigidity to the casing string in flexion perpendicular to the plane of the axes of the two short connecting nipples (see Fig.3a).

The welded assembly of the lower casing joint consists of:

- one straight but inclined 4.5" OD tubing element,at a 1.5 degree angle,welded at its upper end to the machined top plate and at its bottom end to a 8.9" OD machined middle spacer,

- one branched 4.5" OD tubing element including an inverted Y tubing also welded at both ends respectively to the top plate and to the middle spacer,
- two 4.5" landing nipple profiles machined into the spacer,one at an angle of 1.5 degrees,the other vertical,
- two 4.5" tubing elements welded to the lower surface of the spacer one of them is inclined parallel to the one above it,the other almost vertical (0.85 degree kick-off angle)

The ends of the two left side inclined tubing elements,respectively welded above and below the spacer are cut into elliptical windows fitting the inner wall of a 9.625 OD casing cover,to serve as drilling whipstocks.Each of these is also welded at both ends,respectively to the bottom of the upper plate and to the top surface of the spacer,for the upper whipstock and to the bottom surface of the spacer and to the upper surface of the bottom plate,for the lower whipstock.

The inclined tubing end elements (whipstocks) are made of hardened steel.They are each welded to a 9.625" OD casing cover element along the edge of an elliptical window.The upper casing element covers the upper tubular elements and is welded at both ends respectively to the upper plate and to the upper side of the spacer.The lower 9.625"OD casing element covers the interval between the lower side of the spacer block and the top surface of the bottom plate,just above the 8 5/8"OD casing/float shoe.

The base of the bottom plate is threaded and connected to a conventional 8 5/8 " casing float shoe in flow connection with the nearly vertical left branch of the inverted Y joint bottom tubing.

MAKE-UP OF THE THREE SPECIAL CASING JOINTS

The bottom special casing joint is run into the hole and held in the deck's slips.The two inclined 4.5" short nipple joints are also pre-positioned,while the elevator picks up the middle special casing joint.Both short nipples are threaded into both end pieces.After pressure testing of these connections,the side connecting slips are bolted-in,respectively to the lower and middle casing joints.

The middle special joint is run into the hole and held in the slips.

The top special casing joint is placed in the elevators and its lower end is connected to the middle joint threaded insert.The Thermal Expansion joint of the 2 3/8 " tubing is run-in and connected to the top of the three-way valve.The PBR for the 4.5" tubing is then run-in and connected to the top of the 4.5" tubing pup joint in the middle joint.These two tubing connectors have a 10 ft stroke and enlarged diameters,so that they must be staggered to fit inside the 8.9"ID casing.The top special casing joint is then run into the hole and the remainder of the 8 5/8 " OD uphole casing is made-up and run-in in the usual way.

CEMENTATION OF THE CASING STRING

A cementing string,equipped with a 3.5"OD tail pipe is inserted into the production tubing PBR and the tail pipe end,equipped with a lock mandrel,is set into the lower 4.5"OD landing nipple of the vertical channel below the the three-way valve.Through the tail pipe,the cementing string is thus in flow continuity with the casing shoe,so that conventional stab-in cementing operations can proceed to displace the slurry behind the casing string,which may be reciprocated or even rotated during cement displacement.At the end of the cement placement however,the casing string is oriented so that both casing windows face the updip direction.After the slurry has been displaced,the tail pipe is removed.The lower plug is retrieved and the cementing string is then used for drilling the first lateral,as soon as cement has set. Holes in the casing elements covering the welded assembly of the lower casing joint allow the slurry to be displaced around each of the 4.5"OD tubing elements,within the lower casing joint,thus providing added protection against any leaks in the event that cracks later develop in the welds,due to differential thermal stresses,after many temperature cycles.The low thermal conductivity of the cement and its large heat storage capacity also tend to smooth temperature variations between these various tubing elements under the various modes of operation of the twin laterals.The 8 5/8" casing is cemented all the way to the surface with a high temperature cement grade,as usual for any thermal well.

DRILLING THE LATERALS

The drill string consists of a 3" or 2.5"bit,a BHA including a 1.75" OD Bent Housing,a 1.75" OD Downhole Motor (Slimdrill or Sperry),an adjustable bent sub,2.5" stabilizers and a 2.375" Hydril drill string or a 2 3/8" coiled tubing.The cement plug in the whipstock window is drilled-out and the lateral is kicked-off at an angle of about 1.5 degrees from the vertical through the casing window.After angle building,using the bent sub,the upward straight section of the lateral is drilled to a 700 ft reach.These operations may require tripping to change bits and/or motors.The bent housing may also be later replaced by straight housing.The last dull bit and worn-out motor may be abandoned in the hole,after retrieving the orienting tool and cable,to avoid the need to re-enter the hole with a different liner string, thus saving rig time and reducing the risks of getting the new liner string stuck,a frequent occurrence when re-entering a deviated hole drilled in soft formations,especially for angles greater than 90 degrees.

GRAVEL PACKING AND CEMENTING THE LINER

Each liner string includes a wireline-operated circulation/cross-over valve located near the base of the bend.The liner is cut-off from the motor and a gravel slurry is displaced,under normal circulation,behind the liner wall.A retrievable plug is set below the circulation valve. The circulation valve is then opened and additional gravel slurry is injected by reverse circulation,until sand-out.A cement slurry is then displaced behind the liner in the bend,all the way to the whipstock. The circulation valve is closed and the liner string is pushed into the hole a few feet to latch a lock mandrel into the lower landing nipple above the whipstock.The packing of the lock mandrel provides an additional seal to the top of the cement sheath.The uphole liner string is then disconnected from the lock mandrel and pulled out. After the cement has set,the wireline-retrievable plug is pulled-out of the cemented liner.

IN SITU SLOTTING OF THE GRAVEL-PACKED LINER

Our patented hydraulic slot-cutting tool is run-in to the end of the liner by means of a smaller-diameter coiled tubing.The tool is then hydraulically opened up so that the cutting wheels punch through the liner wall.The slot is created by steadily pulling out the coiled tubing.The length of each slot is controlled by cyclic variations of the hydraulic pressure at the surface.When all the selected zones have been slotted,the tool is closed and pulled out of the well.

THROUGH-TUBING OPERATIONS

All the preceding operations may be done through the 4.5" tubing.For this reason,it is cost-effective to run the two tubings into their respective PBRs and to nipple-up the well-head immediately after cementing the casing,so that the drilling rig may be demobilized even before drilling and completing the laterals.All work related to the laterals may be done with a service rig and/or a coiled tubing unit plus a small mud pump.This is a significant cost-saving feature of this new technology.The service rig is also used to run-in and set the rod pump in its seat.The location of the pump in the curved part of the liner calls for rod centralizers to reduce friction and wear of the liner and curved channels.Additional protection is provided by two rollers located respectively at the top and bottom of the H joint in the middle special casimg joint.

POTENTIAL ADDITIONAL USES OF THE BOTTOM VERTICAL CHANNEL

Besides its use for conveying the cement slurry to the casing shoe,the vertical channel may be used to drill another lateral,or a rat hole to serve as sump into which sand production may be dumped when cleaning the H joint and curved channels.If a third lateral is drilled from it,it will always be operated in the same mode as the lowermost inclined lateral.

OPERATING MODES OF TWO LATERALS

1) one steaming while the other is producing.This is shown on Fig.4. When the role of each well is changed,the sliding sleeve is set to its new position and the wireline-retrievable plug in the lower branch of the H joint (steamed lateral) is removed.The rod pump is pulled up into the 4.5"production tubing.The plug is transferred by wireline through the 2 3/8" steam tubing into the other lower branch of the H joint,using a kick-off tool and the rod pump is set into the other lateral,guided into it by the upper end of the plug,serving as a whipstock.In reality,the 1.75"OD transferable plug is set within a 4" lock mandrel permanently set into each of the two upper 4.5" landing nipple profiles.This allows the transferable plug to be pulled out to the surface,through the 2 3/8 OD (1.9"ID) steam tubing and the seals re-dressed if necessary.Any wear and tear caused by the rods in the curved channels occurs in the permanent lock mandrels,which are easily retrievable through the 4.5" tubing when the rods have been pulled. All these operations only require a service rig and a wireline unit.

2) one shut-in while the other is producing.The sliding sleeves in the three-way valve are both shifted to their closed position by wireline through the steam tubing.

3) both laterals producing.The sliding sleeves are both opened.The plug is removed from the previously steamed lateral.This requires pulling-out the rods from the production tubing.The sleeves may be protected by a blank channel through which a rod pump is run-in and set in the liner of the previously steamed lateral.A polished rod of the diameter of the blank channel is located in the rod string and inserted through the channel so as to close it.In this way the fluids lifted from both laterals are commingled in the H joint and conveyed

through the production tubing to the surface.Steam pressure may be maintained in the steam tubing if the loose fit between the polished rod and the blank channel is sufficient to drain any steam condensate from the higher pressure steam tubing into the H joint.

POTENTIAL FOR FURTHER PROGRAM OPTIMIZATION

The preceding description applies to a vertical cased well,with an approximate depth of 750 ft and two cemented laterals (Fig.5).Drilling in a soft overburden,it may be cost-effective to use a deviated cased well with a large radius of curvature to accomodate the 8 5/8 casing string while reaching an angle of about 70 degrees (Fig.6).The casing is identical to the previous one,except that the length of the 8 5/8 casing is greater.The twin laterals,however,are much shorter and the angle build-up required for each of them is less than 30 degrees,thus greatly reducing their drilling time.If the curved section of each lateral is drilled in an impervious formation,its cementation may be omitted.Because the top of the H joint in this well configuration is now at a much lower elevation,it may also be possible to locate the pump in the 4.5" production tubing,above the H joint.This allows the use of a single pump of greater diameter.The elimination of one whole pumpimg unit and one rod string may thus offset the higher cost of the cased well.This cost optimization can only be evaluated if accurate drilling cost data are available,for that specific well site.

CONCLUSIONS

The application of our technology in the present conceptual design meets all the requirements of the OPERATOR for a new well with a 8 5/8 casing.A 7 5/8 casing might be used later if the drill string/liner is a 2 3/8 coiled tubing,but this technology is still experimental. The limiting factor is the clearance around the orientation tool. Smaller diameter casings would reduce the diameter of the laterals to the point where existing orientation tools,downhole motors and pumps could not be used.Jet drilling techniques might be used instead,with 2"OD coiled tubing liners,but the pressure drop through them at rates of 200 B/D might become too large.Other methods of artificial lift might also have to be used instead of rod pumps.For these reasons,the present conceptual design appears to be the lowest cost,minimum risk solution to the OPERATOR's problem,with available technology.The availability of some Government funding to build,test the new downhole equipment and tools and to cover part of the expense of a Field Test in California is also a favorable factor.

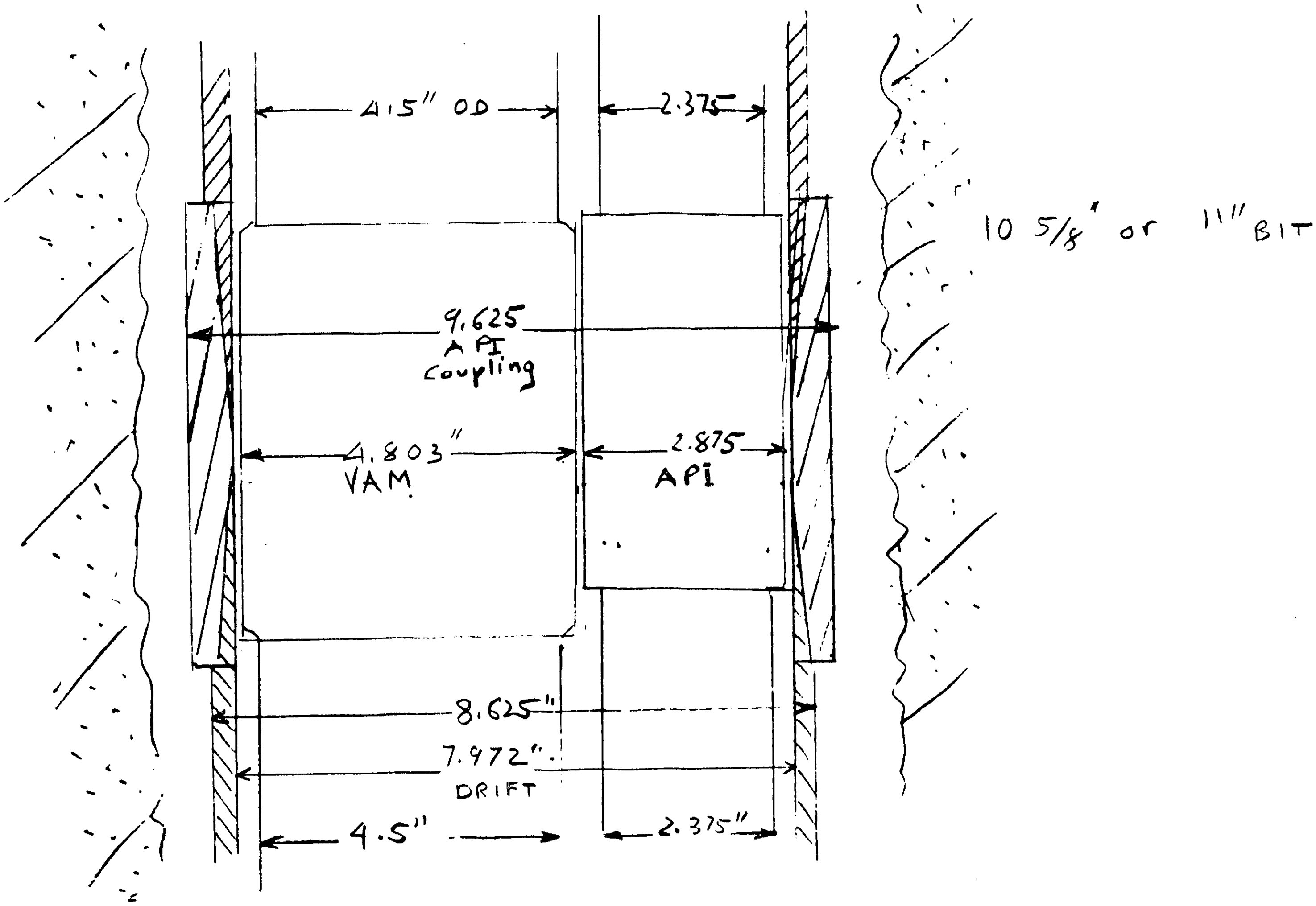

FIG. 0. UPHOLE TUBULARS

Scale: 1 cm = 1"

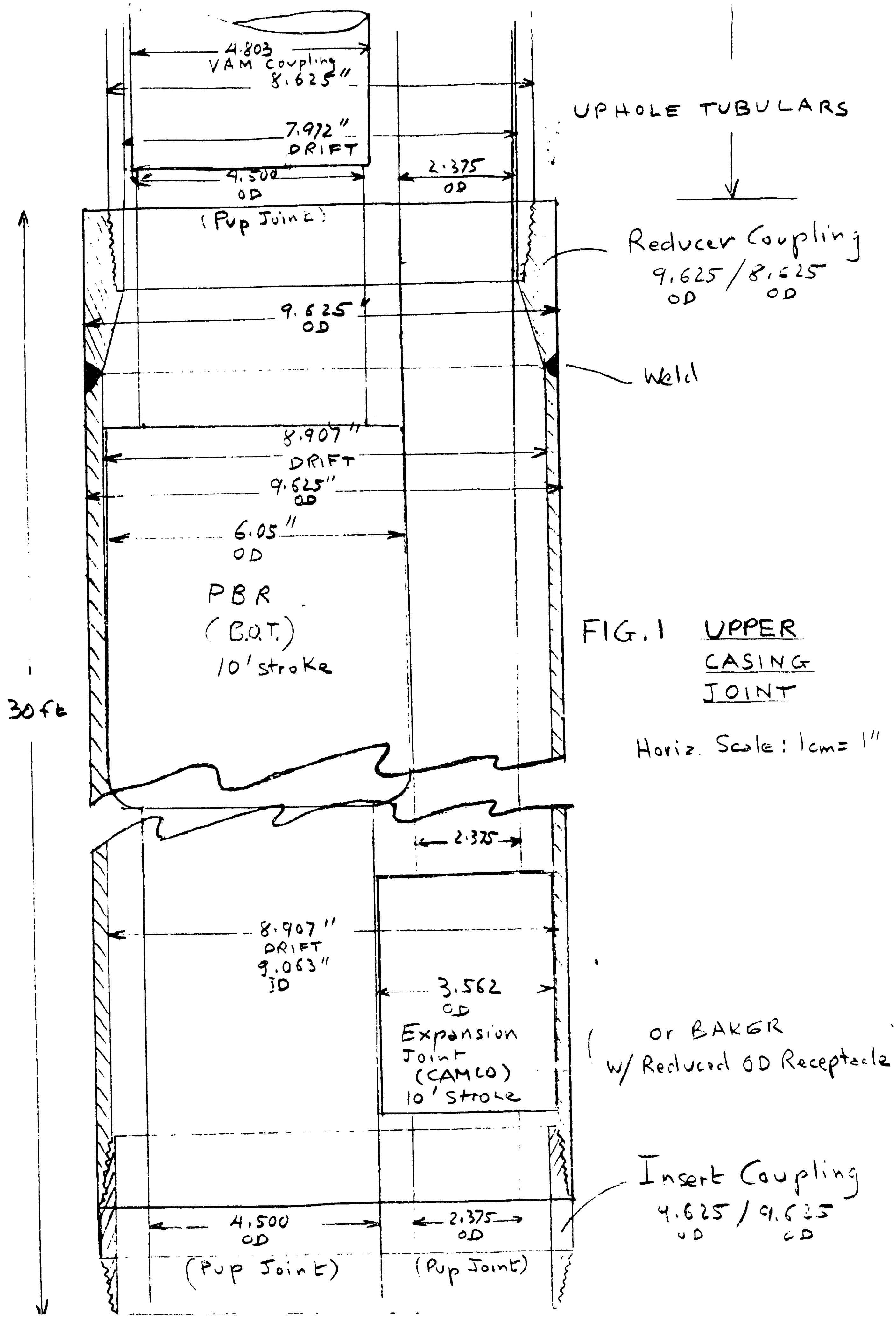

FIG. 1 UPPER CASING JOINT

Horiz. Scale: 1cm = 1"

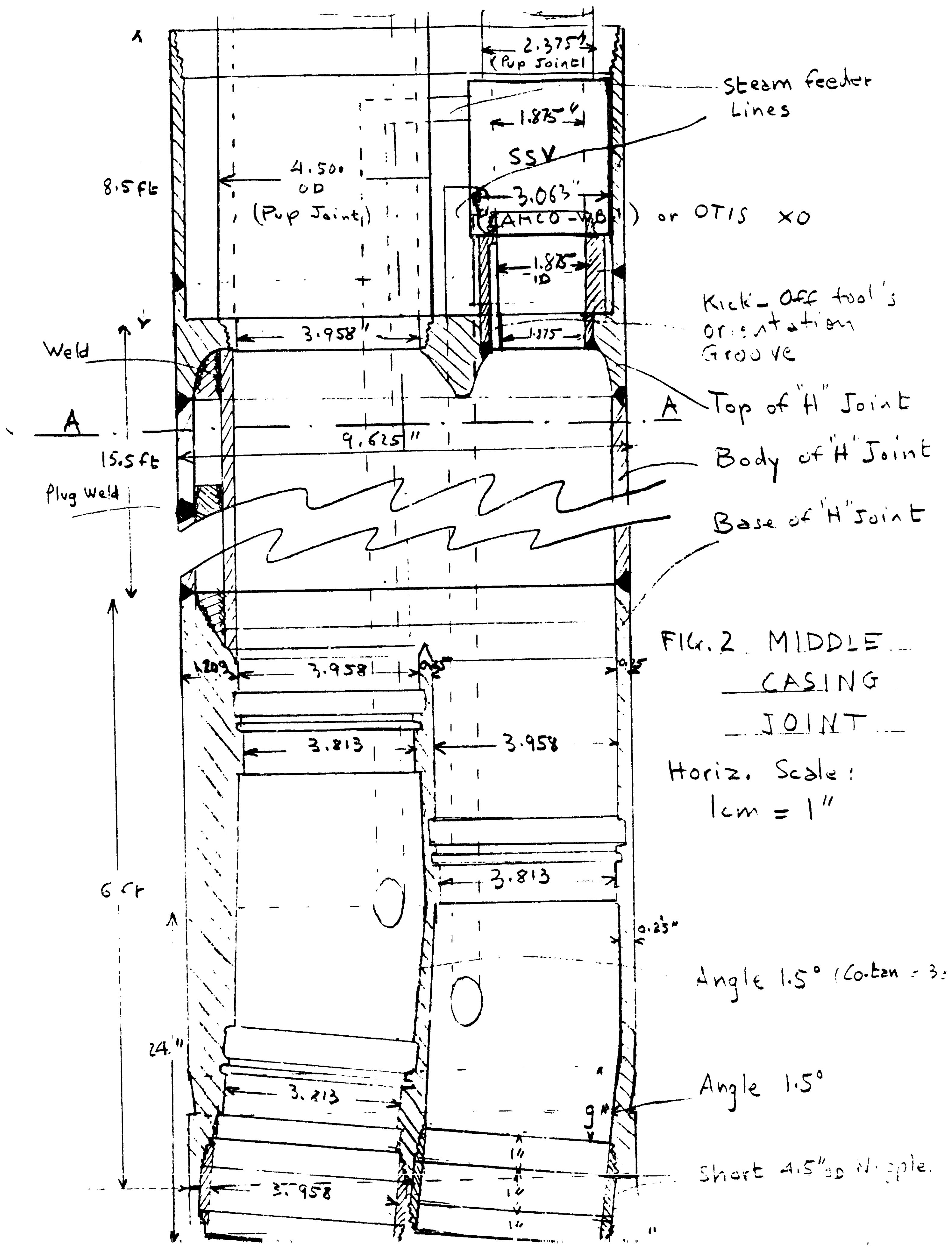

FIG. 2 MIDDLE CASING JOINT

Horiz. Scale: 1cm = 1"

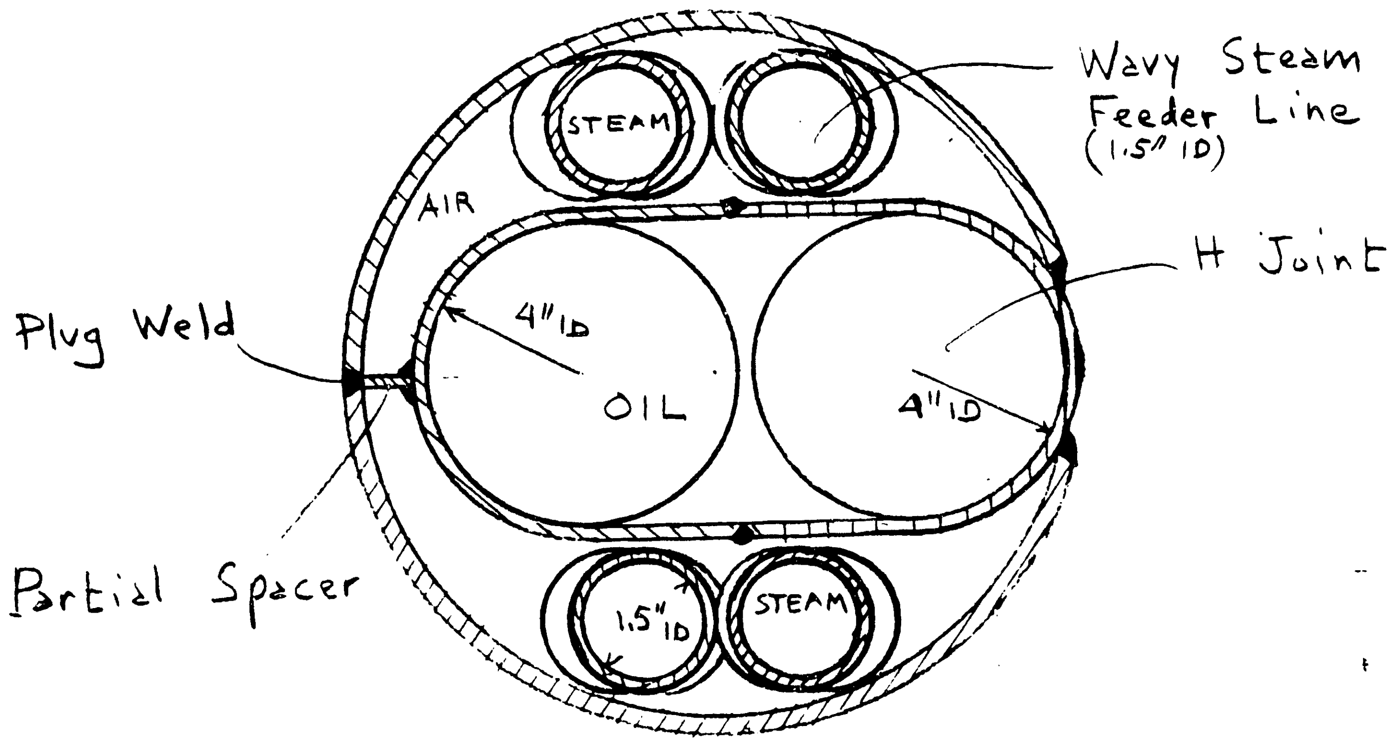

FIG. 2A (REF. FIG 2)

Cross Section AA of H Joint and Wavy Steam Feeder Lines

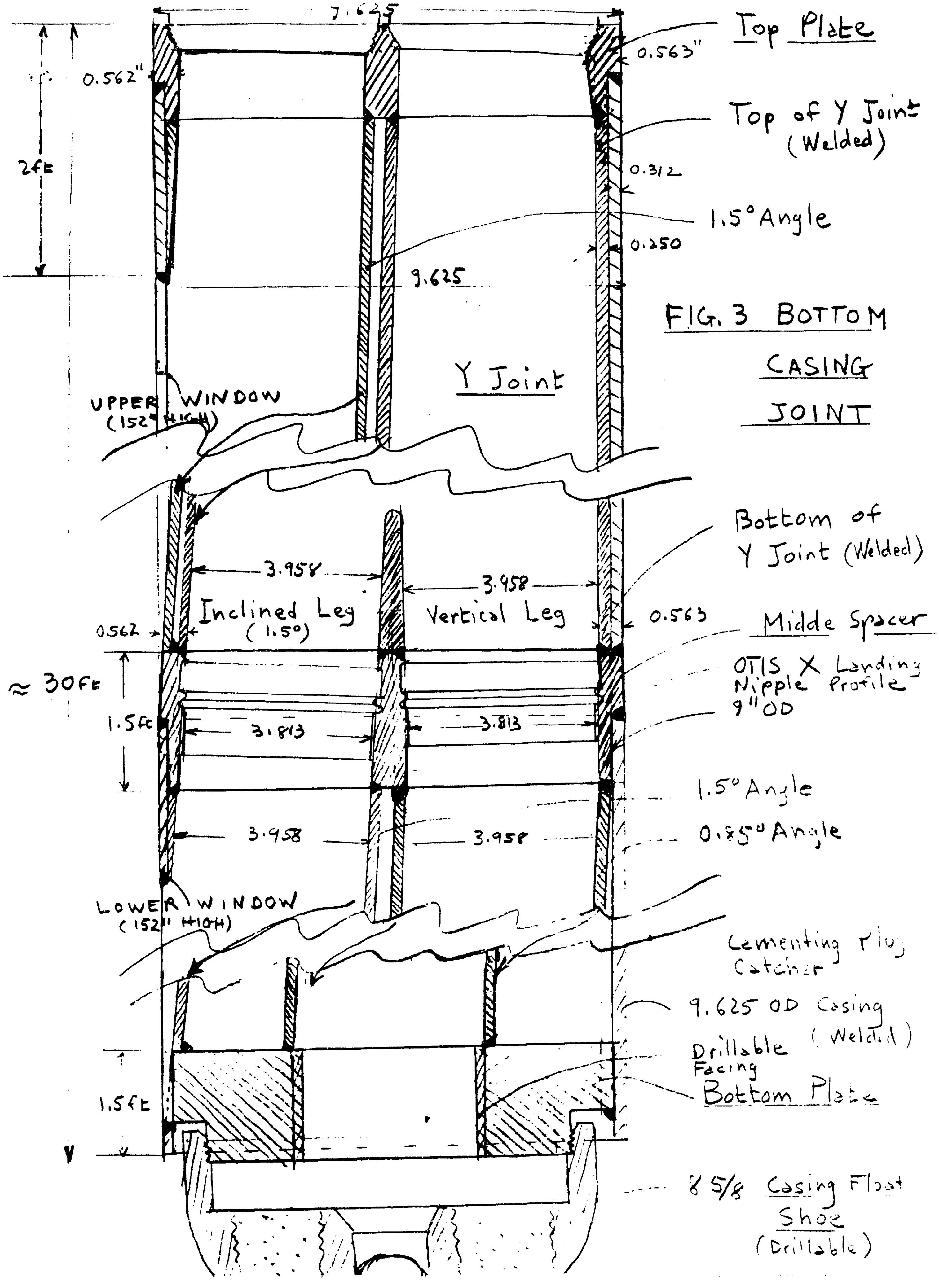

FIG. 3 BOTTOM CASING JOINT

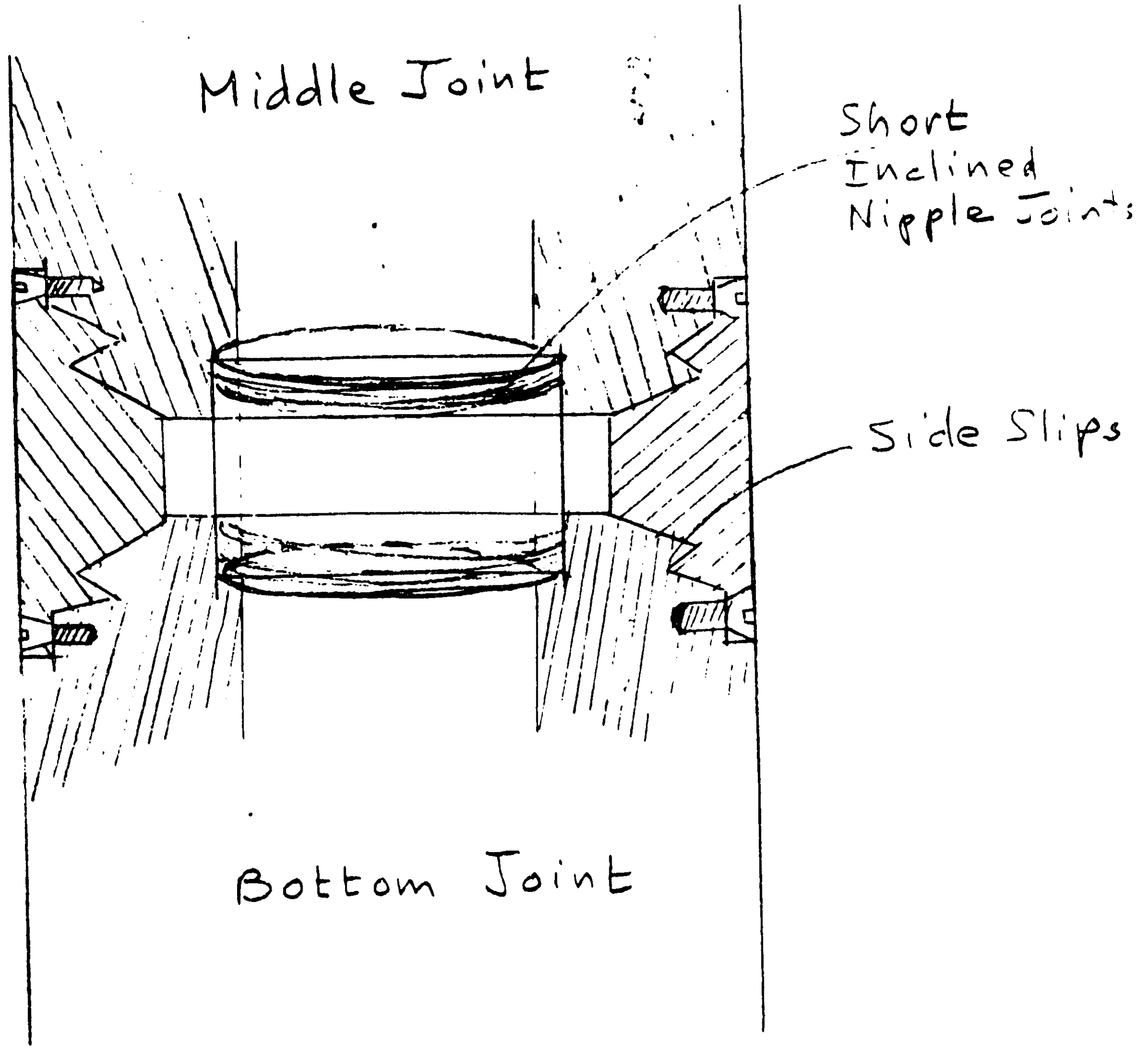

FIG. 3A Connection between Bottom and Middle Joints

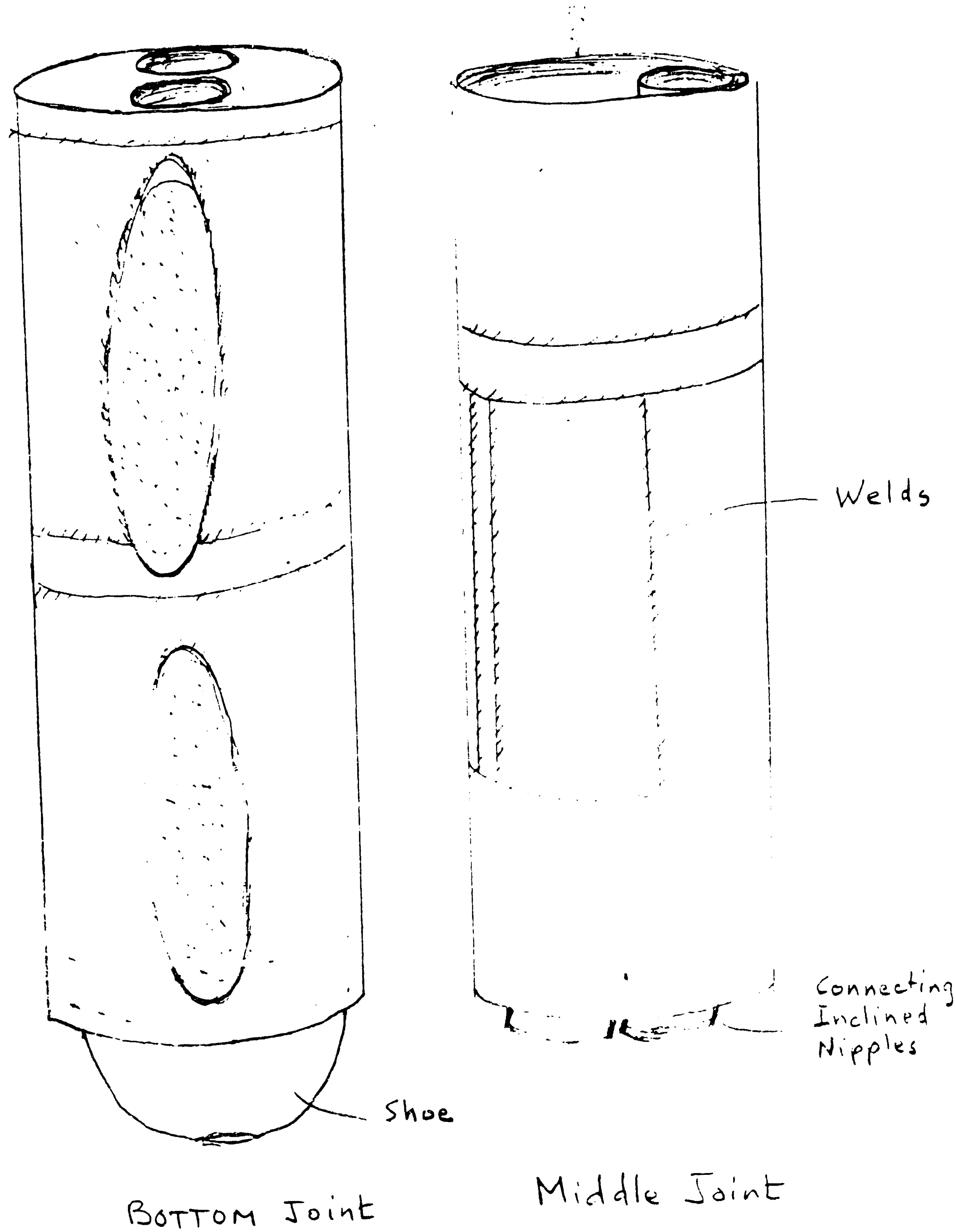

FIG. 3 B. SKETCH OF TWO LOWEST JOINTS OF SPECIAL CASING

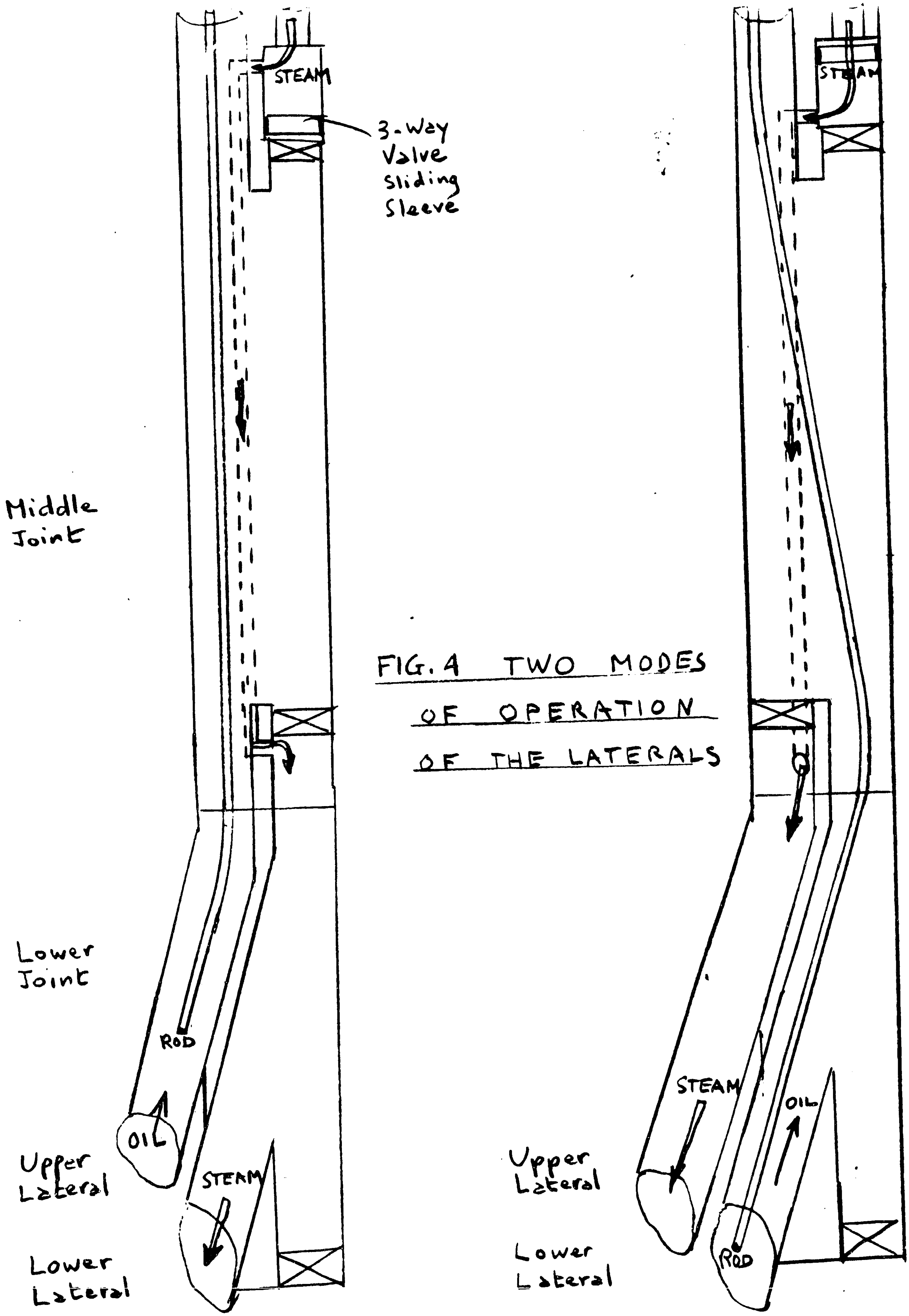

FIG. 4 TWO MODES OF OPERATION OF THE LATERALS

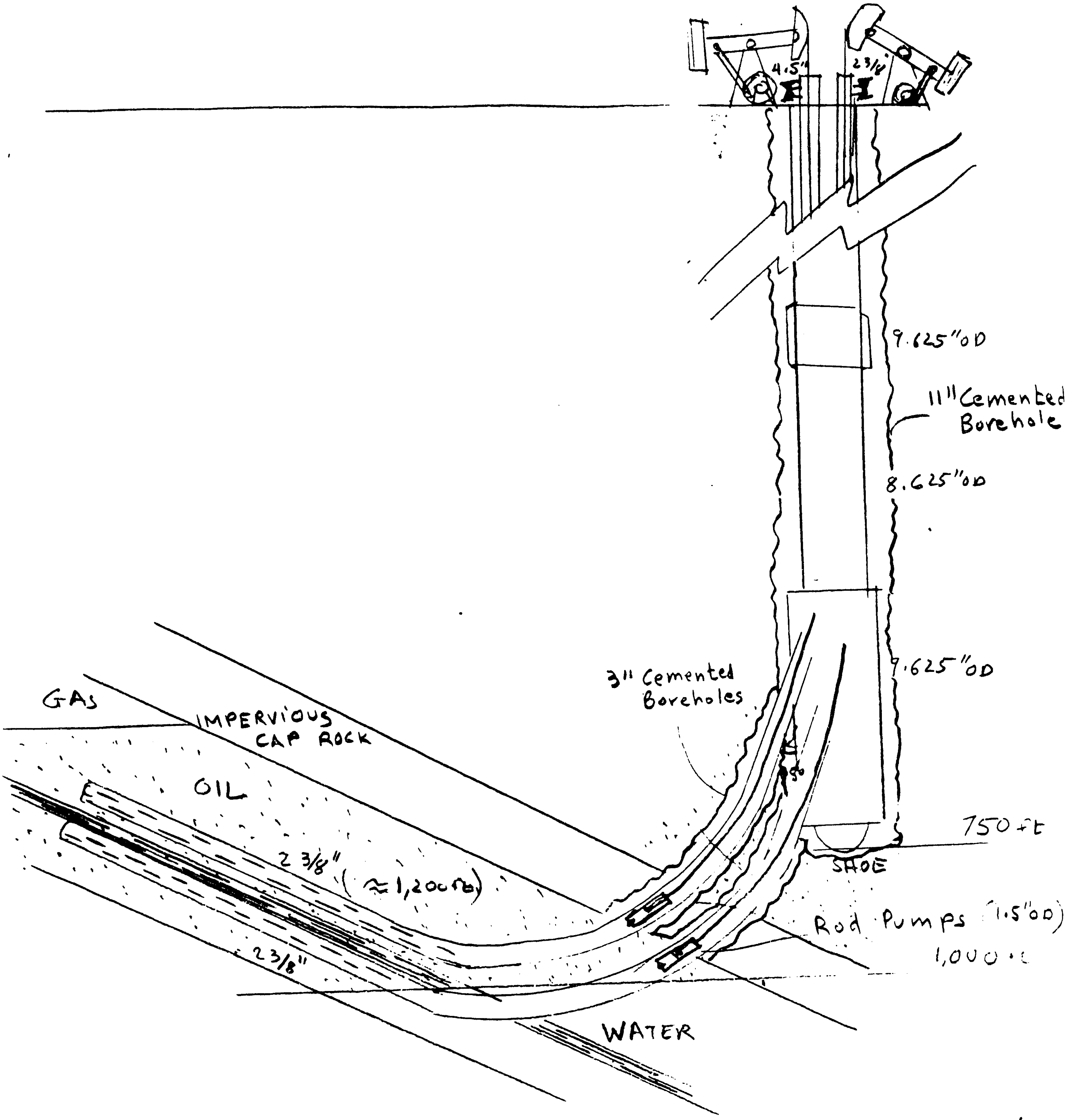

FIG. 5 BASIC WELL CONFIGURATION

(NOT TO SCALE)

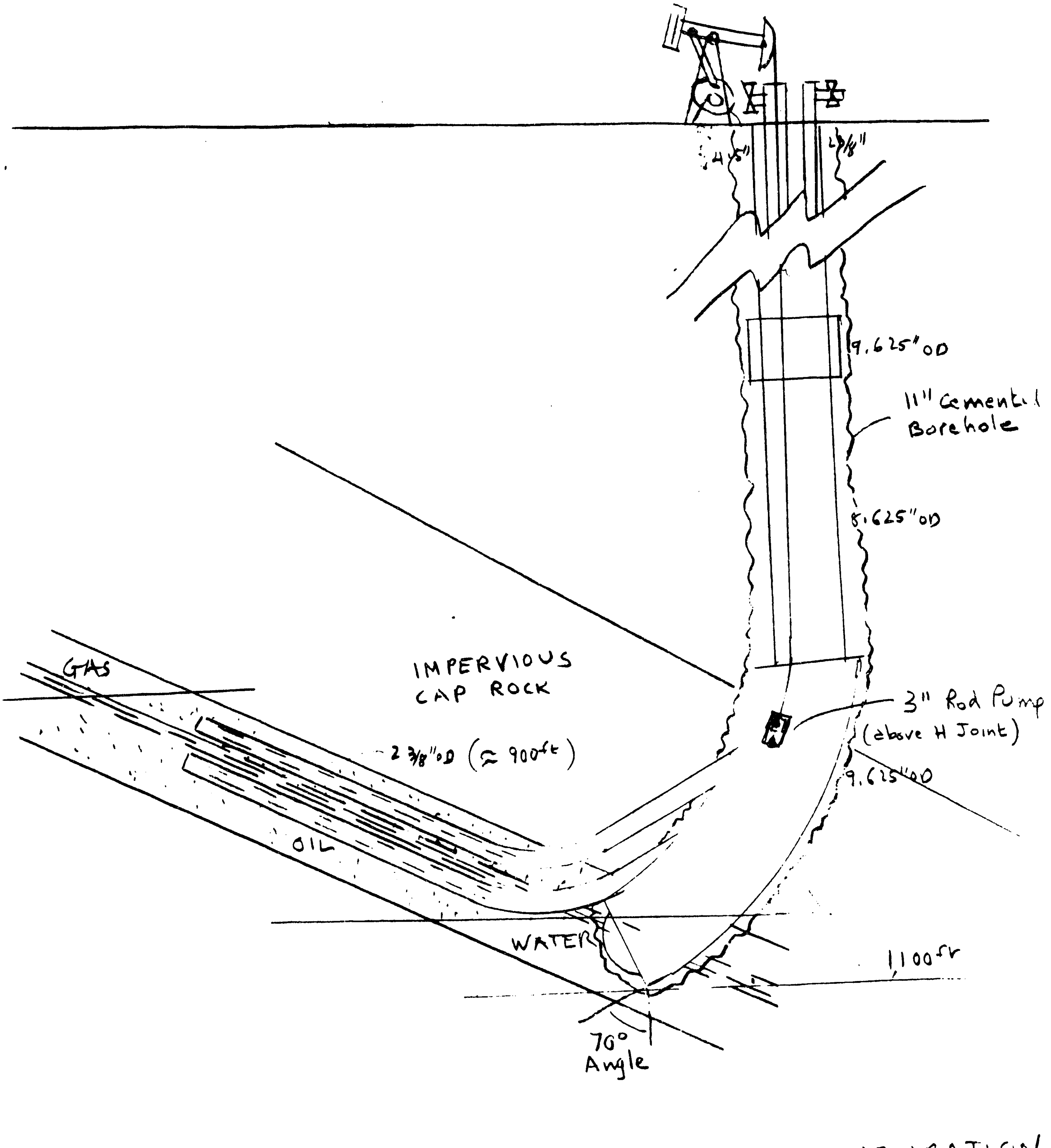

FIG. 6 OPTIMIZED WELL CONFIGURATION

(NOT TO SCALE)

APPENDIX # 2

TECHNICAL COMPARISON OF REVISED TWIN LATERALS CONCEPT COMPATIBLE WITH THE OPERATOR'S CURRENT PRACTICE

1.ADDITIONAL REQUIREMENTS BY THE OPERATOR FOR ITS MIDWAY-SUNSET PROJECT

The OPERATOR presently considers using two separate horizontal wells completed as follows:

- 7 in.OD vertical casing down to about 750 ft,
- a 5.5 in.OD perforated liner in a medium curvature hole of 700 ft horizontal reach,
- a 2.875 " OD special tubing hung from the surface,down to about 1000 ft.,with selectively perforated intervals,
- a rod pump anchored at the tubing bottom,
- a walking beam pumping unit.

The rationale for these design features include:

- dealing with steam flashing from the produced water below the pump inlet by venting it to the surface through the casing/tubing annulus,
- maintaining fluid level in the liner annulus above the pump as low as possible while avoiding pump cavitation,to maximize well draw-down,
- periodic use of the tubing as a cleaning string for removal of any sand accumulation in the liner.The tubing size selected by the OPERATOR reflects these various requirements.

2.REVISED TWIN LATERALS CONCEPT (see Fig 1)

Additional information about the reservoir oil indicates that it is essentially gas-free and that steam flashing does not result in any adverse foaming of the produced stream in either the tubing or the annulus.This suggests the feasibility of using steam-lift to bring the produced stream from the bottom of the tubing to the kick-off point.This approach effectively uses the liner/tubing annulus and the two lower special joints as a downhole separator,with the de-gassed liquid stream lifted to the surface by a single rod pump.The capital cost savings resulting from the elimination of one pump,rod string and pumping unit are estimated at about $ 70,000 and the associated reduction in operating cost is also significant.

The previous concept was also modified to allow the use of 2.875" production tubings to conform with the OPERATOR's current practices. This requires a larger liner and whipstock channels of ID comparable with that of 5.5" pipe within the two lower special casing joints.

Correspondingly,the diameter of the casing must be increased to 10.75" with couplings and special joints of 11.75" OD.The drift ID of these channels is 4.92",except in the landing nipple profiles where it is reduced to 4.75" in the polished bore of a Baker 5.5" OD landing nipple type F,model 3600.

These landing nipples and channels provide ample space for running through it a bottom hole assembly equipped with either a Christensen 3.5" OD diamond bit,bi-center type,capable of drilling a 5.5' hole when outside the casing.Other possible drilling tools include a 3.5" OD hole opener by Drilling Service,capable of drilling a 6' hole,or a Servco (Smith International) rock bit type underreamer of 3.625" when collapsed,but capable of drilling a 6.5" hole.The enlarged hole may then be equipped with a 4.5" OD hydril liner,which may either be gravel-packed and cemented as previously described,or installed by any other method preferred by the OPERATOR.

Each of the two machined window in the bottom special casing joint is 5.0" ID wide and 214" long,for a 1.5 degree kick-off angle.If they are exactly one above the other,this would make the bottom casing joint length about 40 ft.An alternative to reduce its length to a value closer to 30 ft would be to orient the two windows in two different directions so that the middle spacer provides an overlap for the bottom of the upper window and the top of the lower window.Fig.2 shows a cross section of the middle special casing joint in that case.

The machined windows,with much smoother edges than those obtained by conventional milling of a cemented casing,provide an easier path for the BHA,drill string and liner than such conventional windows,even when considering the short restrictions to 4.75" ID produced by the landing nipples.

As previously described,each 4.5"OD liner is hung into the lower landing nipple of respectively the upper and lower deviated channels by means of a lock mandrel equipped with a pressure-tight packing to provide a reliable leak-proof connection between casing and liner.

A short length (about 300 ft) of 2,875 " OD NUE production tubing is inserted into each of the upper and lower deviated channels and through them into the 4.5" OD (4.090" ID) liners.They are hung respectively into the upper landing nipple of the upper lateral and into the lock mandrel of the upper landing nipple of the lower lateral.Each short tubing is terminated at the bottom by a standing valve and a tubing-conveyed 1" gas-litt valve assembly.The steam feeder line for the lower lateral is extended down to the bottom casing joint and opens below the upper landing nipple into the whipstock channel.From there the steam used for lifting the produced fluids up to the kick-off points is conveyed down the liner/tubing annulus to the gas-lift valve.

Steam lift is required when the three-way sliding sleeve valve for the producing lateral is closed.To provide the small steam flow rate required for steam-lift,the sleeve,in its closed position,opens through a choke channel into the steam feeder line.Steam thus flows at a reduced pressure into the liner/tubing annulus and through the gas lift valve into the short tubing.The average density of the steam/liquid mixture flowing upward in the short tubing reduces the head over this 250 ft difference in elevation to a small fraction of the liquid head,thus minimizing back-pressure against the reservoir. The light mixture flows into the H joint,at the casing pressure and is separated into a gaseous stream,vented into the casing annulus,and a liquid stream falling down into the 5.5" OD (5.0"ID) near-vertical channel,which is closed at the bottom by the cemented casing shoe. A circulation sliding sleeve valve in the lower part of that channel conveys the separated liquid into the annular space of the bottom casing joint.A single rod pump,anchored at the bottom of a 2 7/8" (or larger) production tubing,inserted in this annulus,lifts the liquid to the surface oil/water separator.

Steam injection into the upper lateral requires setting a plug in the short tubing top and switching the three-way valve to the open position to the steam feeder for this lateral.These operations are done entirely by wireline through the steam tubing.

Steam injection into any one of the laterals requires closing the top of the curved production tubing with a plug.This done by wireline through the steam tubing while shifting the sleeve in the three-way valve to its open position to the other lateral's steam feeder.

In either case,steam is conveyed into each lateral's annulus with minimum pressure drop.If it is required to use a tubing string for cleaning a lateral,this is done without pulling-out the pump and rods and by pulling out the curved production string and its gas-lift valve through the 5"ID steam vent at the top of the H joint.A tubing string with a selectively perforated section of the desired length is then run-in the liner for cleaning purposes.When the lateral has been fully cleaned,the short tubing string is re-hung in its corresponding lock mandrel and production and/or steaming can resume in both laterals.

These operations require only a wireline unit,in addition to the type of service unit rig presently used with the OPERATOR's current design,but all other operations,normally required for switching from "huff" to "puff" when liner cleaning is not needed,require no service rig.

Everything else is done by wireline,at a cost which is expected to be significantly lower than that of pulling the curved rods and pump from each of the two wells in the OPERATOR's current scheme.

In view of its extended length and small diameter,a horizontal well is subject to a significant fluid pressure drop through the liner,which may affect the distribution of steam and oil rates along the length of each lateral.This problem is also encountered in vertical wells penetrating very thick reservoirs.It is usually remedied by varying the density of casing perforations along the length of the sand face.This selective perforating is technically preferable to the use of uniformly slotted liners,but much more costly when using conventional gun-type perforators.This is one more reason,besides that of improving the gravel-pack quality,for which we propose to perforate the liner "in situ",following the displacement of a water/sand gravel packing slurry behind the unperforated liner.For this operation,a hydraulically-operated slot-cutting tool has been designed for use in uncemented small-diameter liners.This tool allows to vary the distribution of the number of slots along the liner length to optimize the rates of injected steam and of produced fluids along the gravel-packed portion of the liner.

In uniformly slotted liners,some operators improve the steam distribution by inserting the steam tubing to various successive measured depths during the steaming cycle,using a service rig to periodically change the steam tubing length during the cycle.The same method can be used in the present well configuration.The procedure may be the same as that described for sand cleaning,using a tubing string terminated by a cup packer and run from the surface through the 5" ID top steam vent of the H joint and into the upper 5" lock mandrel.Steam injected into the liner/tubing annulus above the cup packer then flows into the tubing through the gas-lift valve seat and is distributed to any selected perforated interval of the liner. This would,of course,require a service rig,or a coiled tubing unit,but it would not require any work on the pump and rods.

Other alternatives in which only the short (300 ft) tubing would be permanently equipped with a cup packer and pushed deeper into the liner,by the steam pressure,while being restrained by a sand line or wireline from the surface should also be considered (Fig.3).The largest measured depth which could be reached to deliver steam from the bottom end that short tubing is limited to 300 ft from the top perforation in the liner,but this might be sufficient in many cases.

Because the vertical production string is free to expand within the near-vertical 5.0" ID channel,the 4.5" PBR is eliminated and a standard 10.75 "OD casing joint is substituted for the upper special joint.

3.CAPITAL COST SAVINGS

Cost reductions:

- one pumping unit
- only one complete rod string (1100 ft instead of about 1400 ft)
- one rod pump
- mob/demob of a drilling rig at one site
- site preparation and cleaning at one site
- one 9 7/8" hole 750 ft deep
- one 7" casing string 750 ft long
- two 4.5" liners,each about 1,050 ft long vs.two 5.5" liners of equivalent lengths
- one complete 7" thermal casing cementation

Cost additions:

- drilling a 13.5" hole vs a 9 7/8" hole 750 ft deep
- one 10 3/4" casing string 690 ft vs.one 7" casing string 750 ft
- a 50% larger volume of HT cement
- stab-in cementation vs.through casing cementation
- two special casing joints,including the three-way valves,the H joint and the dual whipstocks with lock mandrels,etc.($ 50,000)
- two gas-lift valve assemblies

4.CONCLUSIONS:

We believe that the cost reductions largely offset the cost additions but we need actual cost data from an OPERATOR's AFE in order to determine the potential capital cost savings.

We also see potential operating cost reductions,provided that the wireline operations are done properly and efficiently by a competent contractor.These are all done in near-vertical large channels and should be considered of a routine nature,once the operating scheme of a thermal well with twin laterals has been fully demonstrated.

The use of a near-vertical single rod string is inherently less susceptible to wear and tear than the use of two curved rod strings.

Steam lift of dead heavy oil has been successfully used in the past for shallow wells in other fields.A complete literature survey on this subject is likely to reveal which pittfalls should be avoided,but there is sufficient flexibility in the revised concept to include many additional features.

The orientation of the two whipstock windows in two different directions allows to bring the horizontal part of the two laterals along two parallels separated by the OPERATOR's selected interval of 100 ft.

The revised configuration (No.2 well) may easily be converted to that of two single horizontal wells sharing the same casing,but each one with its own pump and conventionally operated in "huff and puff". This only requires the removal of the steam tubing and its three-way sliding sleeve valve,the production tubing and its rod pump are also pulled-out from the casing annulus.Two tubing strings are then inserted through the two 5" ID openings in the top of the H joint and into their respective 4' ID liner,equipped with a pump and rod string.

Each lateral can then be operated in the conventional way,using two pumping units.This well configuration still provides the same tubing heat loss reduction advantage of our patented process,but it still uses two curved rod strings and requires a service unit to pull-out the pump from its anchor at the start of each new steaming cycle.

Even if the OPERATOR decides to return to this final well configuration and conventional operating mode,there may still be some small cost savings in the tie-in of two laterals to a single larger diameter vertical casing.At the same time the technical feasibility of connecting multiple deviated laterals to a single casing by leak-proof methods will have been demonstrated at very low cost.This may be a valuable step prior to the use of our tie-in procedure and equipment by the OPERATOR's Offshore drilling department,when they need to maximize the use of existing platform slots by adding new laterals to existing cased wells.

The Well No.2 configuration provides sufficient flexibility to test a variety of operating procedures,including all those presently considered by the OPERATOR to quantitatively evaluate their relative effectiveness and costs.

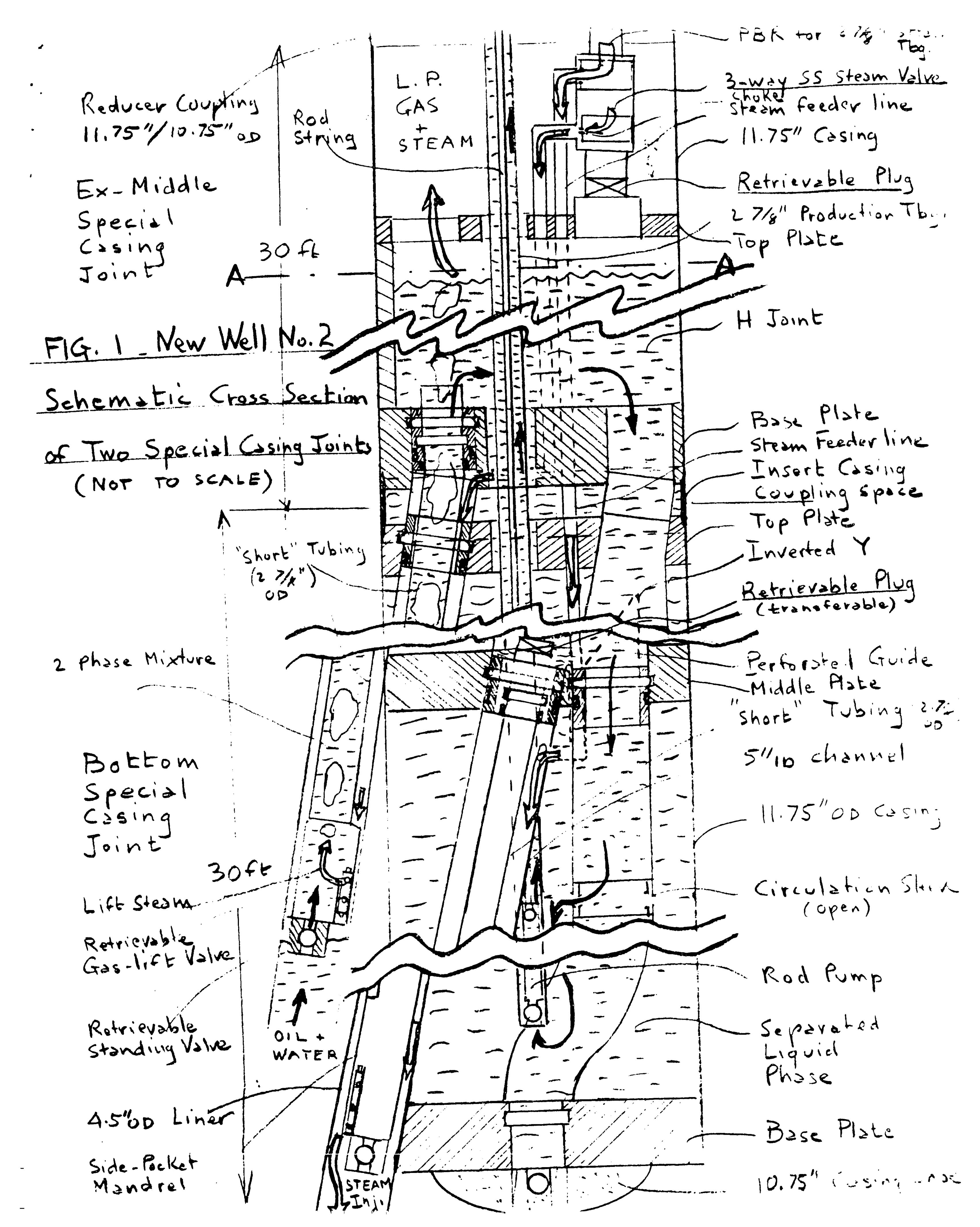

FIG. 1 _ New Well No. 2

Schematic Cross Section of Two Special Casing Joints

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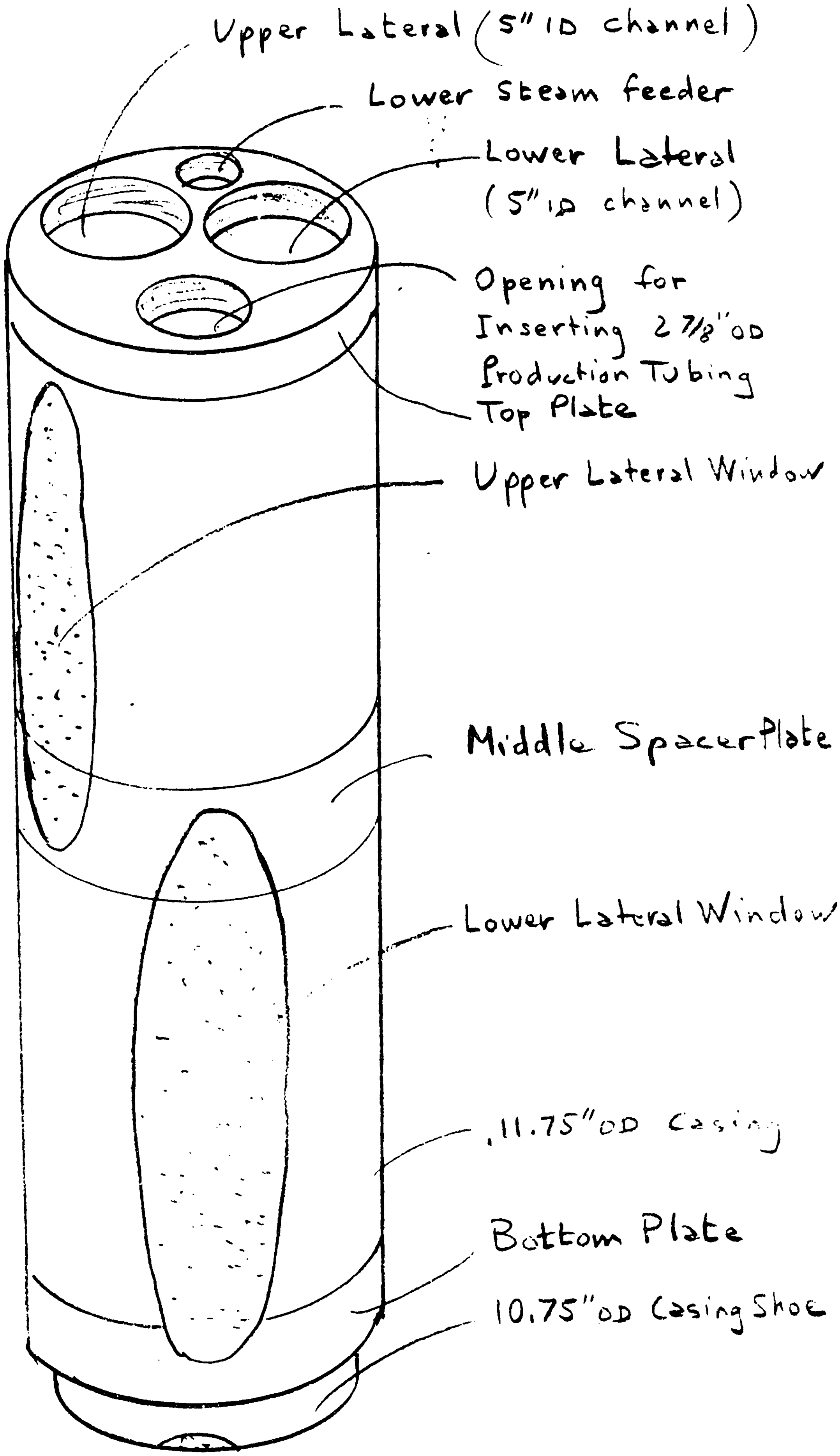


FIG. 1A Perspective View of Bottom Casing Joint

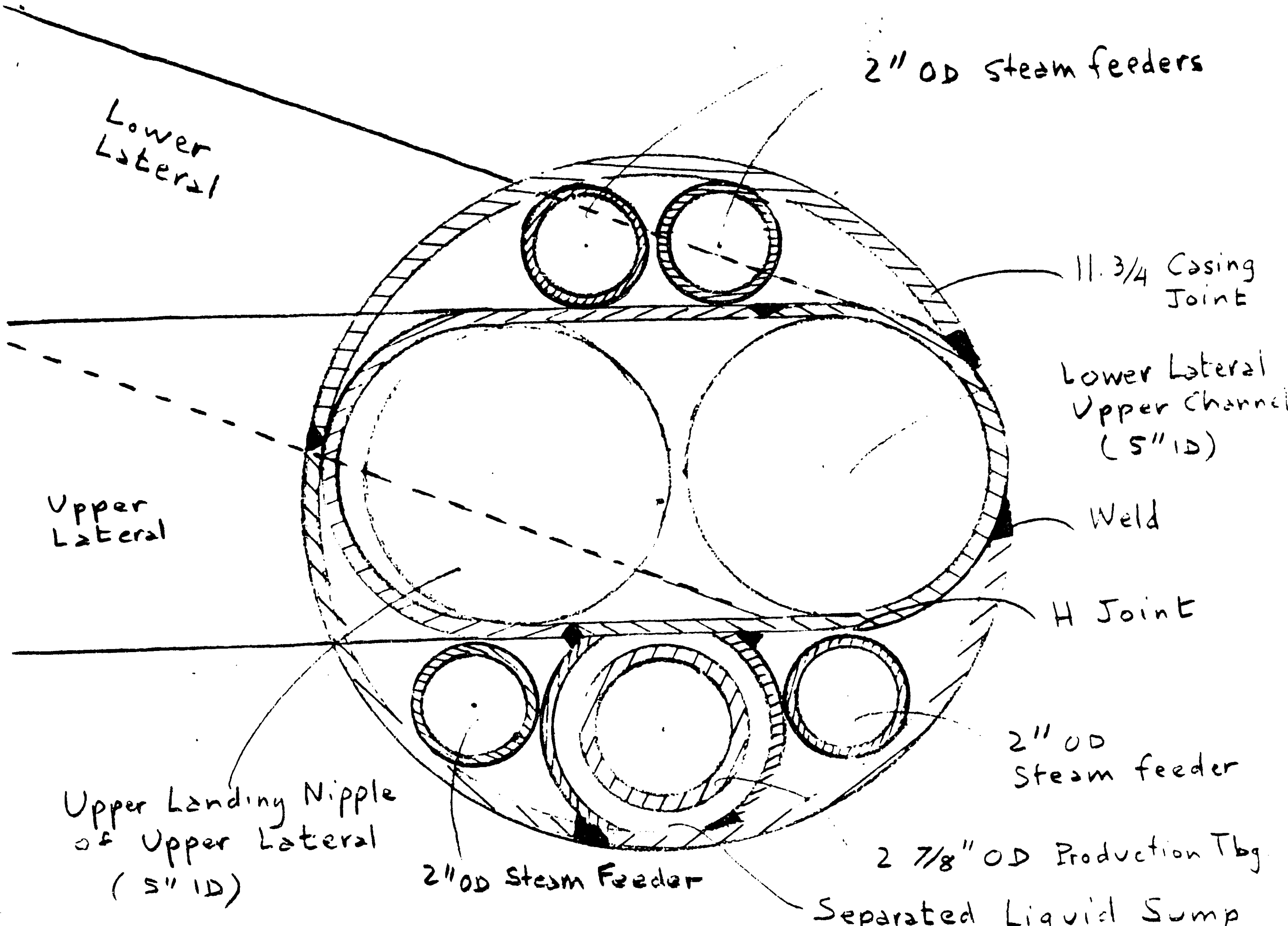
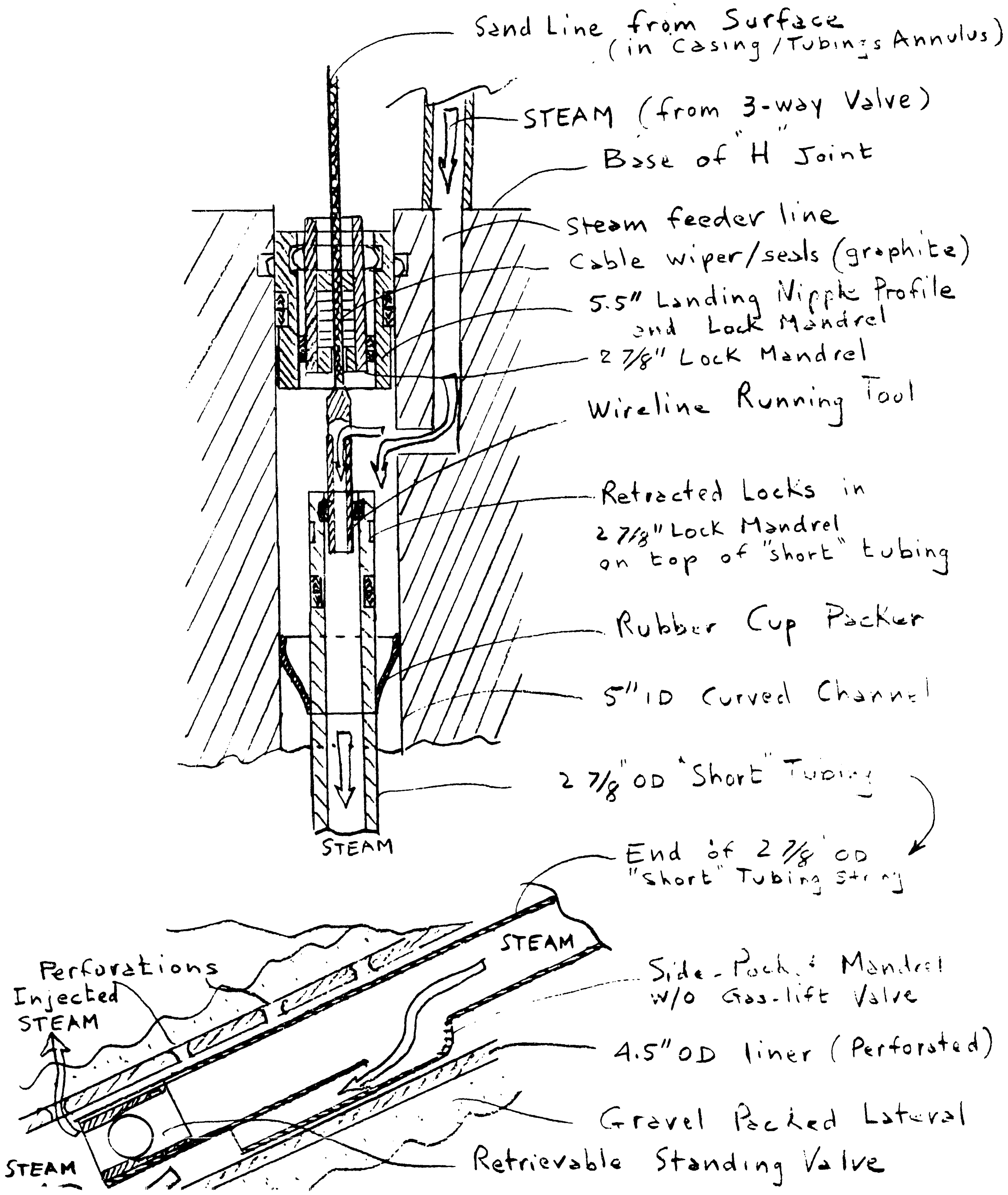


FIG. 2 Cross Section 'AA

of "H" Joint

Scale: 1cm = 1"

FIG. 3 Selective Steam Injection Within the Liner



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