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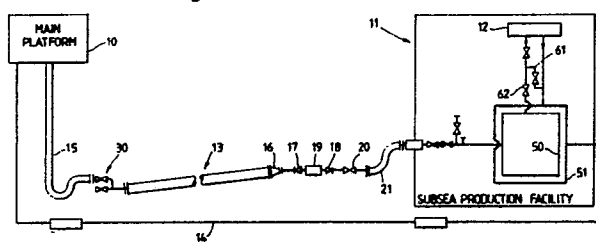
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(54) **Displacement of free fluid accumulations in pipelines.**

(57) a method of removing at least a substantial proportion of fluid left in a generally horizontal section of a pipeline, by injecting into the pipeline a pressurized, high expansion foam and advancing the foam through the pipeline section in contact with a layer of the fluid left therein to displace the layer towards a remote end of the pipeline by frictional pick-up of the layer by the foam and to effect mass transfer of a foaming agent from the foam to the fluid, followed by passing into the pipeline a pressurized gas to create turbulence in fluid left in the pipeline causing foaming of the fluid and to displace a substantial proportion of the foam left within the pipeline.

At least some of the bulk of the fluid in the pipeline may be displaced by injecting the foam so as to establish a transverse foam/fluid interface which is advanced through the pipeline at or above a minimum velocity required to maintain said interface leaving a residual amount of fluid which is treated as aforesaid. The method may include the further subsequent step of injecting into the pipeline a pressurized foam containing a treatment agent to displace residual foam left in the pipeline, and then allowing the foam to decompose in the pipeline to deposit the treatment agent within the pipeline either on the pipewall or in solution with any liquids remaining therein.

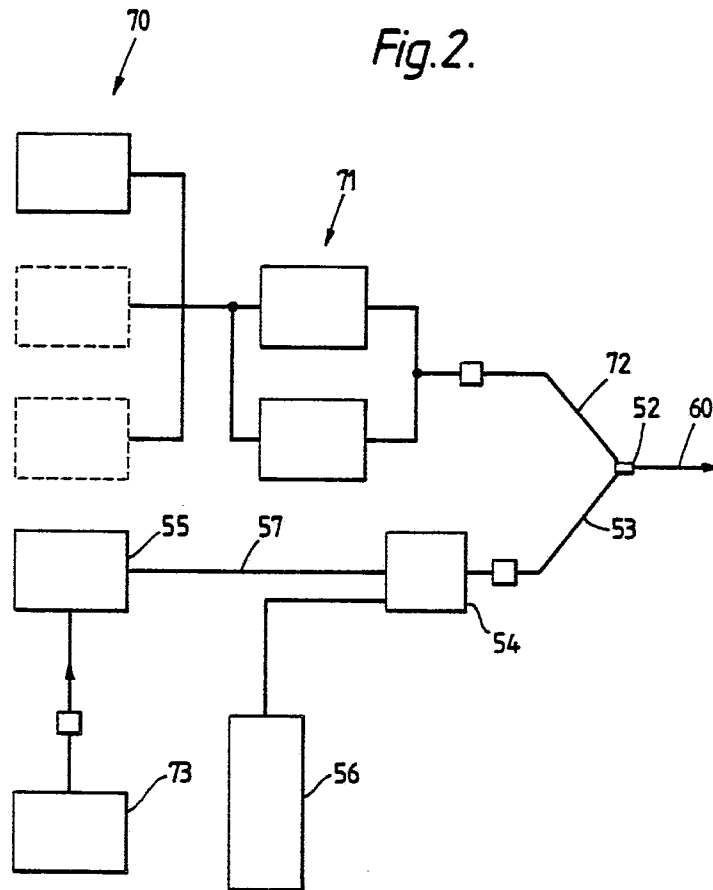
Fig.1.



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Fig. 2.



DISPLACEMENT OF FREE FLUID ACCUMULATIONS IN PIPELINES

This invention relates to the displacement of free fluid accumulations left in generally horizontal portions of pipelines.

In any offshore, hydrocarbon containing field such as one holding crude oil or gas, normally at least one platform or marine structure is installed at a judicious location within the known bounds of the field. The primary functions of such a platform are at least twofold. Operationally, it serves as a base for drilling the needed number of wells into the subterranean reservoir to tap into the stored hydrocarbons. Secondly it functions to receive, treat, and store hydrocarbons which are conducted from other wells within the same field.

Normally the other wells are dispersed about the field at sites where it is determined that the hydrocarbon source can be readily reached. Thus, any productive field will usually contain numerous wells disposed about the ocean floor at various distances from the main platform.

A number of pipelines are provided to extend across the seabed between the main platform and each satellite well site. These pipelines may include for each well a production pipeline, a test pipeline, a water injection pipeline, a gas lift pipeline and pipeline for utilities. After initial installation, at least some of these pipelines, in particular the gas lift pipeline, will require to be flushed out to remove water accumulated in sections of the pipeline extending generally horizontally across the seabed and filling a substantial proportion of the volume of such sections. Such sections may be inclined to the horizontal owing to the unevenness of the seabed so that there may be pockets of water accumulated at intervals spaced along the pipeline. It is also important to prevent the formation of hydrates which is likely to occur in subsequent use of the pipeline particularly in cold environments resulting in blockage of the pipeline especially at restricted sections thereof.

Conventionally such accumulations of water are removed by introducing a pig into the pipeline and applying a pressurized liquid into the pipeline to move the pig therethrough to physically displace the water. The pig may be mechanical or made of a gelled material to allow it to conform to the internal surface of the pipeline. However some pipelines are unsuitable for use of a pig, for example where the pipeline is formed with various internally extending obstructions which would tend to cause the pig to break up or where abrasives would cause an unacceptable loss of material.

The invention seeks to provide an expedient and economical method for removing free fluid accumulations in pipelines which can be applied to pipelines in which it is either not readily practicable to use a pig or where the invention offers a choice to using a conventional pig.

The invention provides a method for treating a pipeline which contains a residual amount of fluid in a generally horizontal section or sections thereof, to displace the residual fluid therefrom, which method comprises:-

injecting into the pipeline a pressurized, high expansion foam having a high refoamability and being compatible with said fluid in the pipeline section(s), which foam contains an amount of foaming agent in excess of the minimum amount thereof required to generate the foam;

advancing the foam through the, or each, of said pipeline sections in contact with a layer of said fluid left therein to displace said fluid towards a remote end of the pipeline by entrainment caused by frictional pick-up of the layer by said foam and to effect mass transfer of said foaming agent from said foam to said fluid;

discontinuing injection of said foam; and

passing into the pipeline a pressurized gas to create turbulence in said fluid containing said foaming agent, which is left in the, or each, of said pipeline sections causing foaming of said fluid within the pipeline and to displace a substantial proportion of the foam left within the pipeline from a remote end thereof.

By "high expansion foam", we mean a foam having at least a 75% gas phase content by volume. Preferably the foam will have at least a 98% gas phase content.

By "refoamability", we mean the tendency of the foam constituents, obtained when foam is allowed to partially 'break' or 'drain', to reform foam when agitated.

By "high" refoamability we mean the tendency to refoam to a foam volume greater than about 80% of the original. This is a measure of "repeatability" in foaming.

By "compatible", we mean a foam which does not rapidly break down when put in direct contact with the fluid to be displaced at the temperatures and pressures existing in the pipeline during a treatment in accordance with the invention, and which has a foaming agent capable of foaming the fluid accumulation(s) in the pipeline.

In performing a method in accordance with the invention in which a pressurized, high-expansion foam is injected into the pipeline, it is believed that two operating conditions may exist depending on the particular application, the amount of fluid in the pipeline section and other operating conditions. The "first mechanism" is a condition where the foam passes above a layer of liquid in the pipeline and, as described above, entrains that layer of liquid and also transfers thereto a foaming agent contained in the foam to allow the fluid to be readily foamed by the subsequent passage of a pressurized gas through the pipeline which also serves to displace a substantial portion of the foam left within the pipeline.

However, if the fluid occupies a sufficient volume of the pipeline section, the main bulk of such fluid may be initially removed by a mechanical "piston" displacement which will be referred to herein as a "second mechanism". In accordance with the second mechanism, a transverse foam/fluid interface is established within the pipeline and is advanced through the pipeline at or above a minimum velocity which is required to maintain the interface so that the bulk of the fluid is removed from the remote end of the pipeline by physical displacement, leaving the above-mentioned residual amount of fluid in the pipeline which is thereafter treated in accordance with the "first mechanism".

Where initially the amount of fluid in the pipeline is insufficient to establish a transverse foam/fluid interface then the removal of the fluid in the pipeline will be solely by the "first mechanism". Moreover, if during operation in accordance with the "second mechanism" the velocity of advancement of the interface falls below the above-stated minimum velocity, then the subsequent removal of the fluid will take place in accordance with the "first mechanism". Furthermore during an initial treatment in accordance with the "first mechanism" whereby the foam passes above the layer of fluid in the pipeline, it is possible that with a sufficient depth of fluid and a sufficient pressure of foam, extreme turbulence of the surface of the layer of the fluid could take place so that eventually a transverse foam/fluid interface is established in the pipeline enabling further displacement of the fluid to take place by the "second mechanism". It will therefore be appreciated that during a treatment operation of a pipeline, the displacement of the fluid may take place at different times by either the "first mechanism" or the "second mechanism". As stated above in other applications, the displacement may be solely by the "first mechanism".

Regarding the "second mechanism", the aforesaid minimum velocity required to maintain the transverse foam/fluid interface, which will be referred to as the "critical velocity", depends on factors such as the pipe diameter, the viscosity and density of the phases and therefore varies from application to application. However in dewatering a subsea gas lift pipeline, it is generally necessary to advance the aforesaid foam/fluid interface at a velocity in the range of about 3 - 15 ft. per second and usually at a velocity of at least 5 ft. per second. If the speed of advancement of the interface drops below the critical velocity, then a foam phase is established across the top of the fluid phase and displacement then reverts to the "first mechanism".

A relatively small amount of foaming agent, for example $\frac{1}{2}\%$ by volume, is required in the liquid phase of the foam in order to generate the foam when contacted with the gas phase but this concentration is variable depending on the nature of the gas and liquids in the system. However in a method according to the invention, an excess amount of foaming agent is used in order to achieve foaming of the residual fluid left in the pipeline for removal thereof by the subsequent injection of pressurized gas, which may be the same gas as that used for the gaseous phase of the foam. For example when a relatively small amount of fluid is to be removed from a pipeline, then the foaming agent may be provided in an amount of about 1 - 4 % by volume of the liquid phase of the foam. Where relatively large volumes of fluids are to be removed, then the foaming agent may be provided in an amount of about 5 - 15 % by volume of the liquid phase of the foam.

Generally the invention makes it possible to displace a fluid which will usually, but not exclusively, be a Newtonian fluid from a pipeline using a high expansion foamed fluid of chosen rheological properties as an interface between the in-situ fluid to be displaced and the displacing medium when the fluid displacement speed is at or above a defined "critical velocity" for the particular application so that the in-situ fluid is maintained in a state of extreme excitation such that, despite gravity, momentum effects ensure that the fluid travels totally in the direction of displacement with a minimum amount of in-situ fluid draining back into the foam.

While certain high expansion foamed fluids have been shown to maintain well defined interfaces with fluids travelling above the specified central velocities, it is a further advantage that the use of a high expansion foamed fluid, employing surfactants with well defined refoamability, will entrain any fluid which falls back through the interface and through entrainment carry this in-situ fall back or slip fluid along the pipeline,

A method according to the invention uses a high expansion foam in order to minimize the quantity of foam drain-off fluid left on the wall of the pipeline. The use of low viscosity, very low surface tension foaming agents with good refoamability ensures refoaming of any residual drain-off fluid when using a compatible gaseous displacement medium at the specified critical velocity.

5 In its broadest aspect, a method according to the invention is more widely applicable than to dewatering pipelines communicating between a main oil drill platform and associated satellite well sites. It could be used to remove other Newtonian or nearly Newtonian fluids from pipelines. For example, the method could be used to remove hydrocarbon condensates from other gas carrying pipelines having generally horizontal sections, or for removing solid particles carried in a free liquid accumulation left in other fluid pipelines. 10 Although for dewatering gas lift pipelines, nitrogen is the preferred gas used in the aforesaid method, other gases, for example air or gaseous hydrocarbons, could be used in other applications provided that the gas is compatible with the fluid to be removed from the pipeline.

In specific applications of the aforesaid method, it may also be desirable to treat the internal surface of the pipeline, for example to provide a protection against corrosion or to deposit a substance such as 15 methanol or iso-propyl alcohol (IPA), to inhibit the formation of hydrates. In such applications, it is preferred that the method includes the further step of introducing a pressurized, turbulent flow of a foamed fluid containing the surface treatment medium to displace any residual foam left in the pipeline, and then allowing such foam to decompose in the pipeline. Such a method could also be used to render inert pipelines which are no longer required after production at one site has been completed. All potentially 20 harmful materials are thereby removed from the pipeline which can then be capped and buried in a safe condition.

The residual foam left in the pipeline is thereby displaced by the methanol or IPA foam enabling most of the water still present in the line to become mixed with the methanol or IPA, which will help to reduce hydrate formation at a later date. The front of methanol foam is displaced at least to the end of the line and 25 all the foam is then allowed to decompose, having a short half life, thus ensuring that the methanol drops out and is distributed along the required length of the line.

Any loose debris in the free liquid contained in the pipeline is generally also carried and removed from the line.

Advantages of using such a method according to the invention for dewatering a pipeline over the above-described conventional method, include the facility to entrain in the foam and remove particulate debris in the pipeline, the economic use of a pressurized gas as the displacing medium as compared to pressurized liquid displacement of a pig and the facility to render inert the interior of a pipeline to prevent corrosion occurring after shutdown. 30

Possible applications of methods according to the invention include removing water from pipelines and 35 vessels; removing condensate and crudes from pipelines and vessels; laying down an inhibitor coating along a pipeline; removing hydrocarbons from pipeline depressions during commissioning; and, purging of pipelines and vessels for field abandonment and decommissioning. As most fluids can be foamed, there are a number of other possible applications, specifically in subsea multi-diameter systems.

An embodiment of the invention will now be described by way of example and with reference to the 40 accompanying drawings, in which:-

Figure 1 illustrates schematically a main oil drilling platform and an associated satellite well drilling template connected by a main gas lift line and a production line;

Figure 2 illustrates schematically an installation for location on the main platform for supplying pressurized foams to the gas lift line for the dewatering thereof;

45 Figure 3 illustrates graphically the pressure in the gas lift line at the main platform end during a first aqueous foam treatment;

Figure 4 illustrates graphically the pressure in the gas lift line at the main platform end during a second aqueous foam treatment;

Figure 5 illustrates graphically pressures recorded at the template end of the gas lift line during 50 aqueous foam treatment;

Figure 6 illustrates graphically pressures recorded at each end of the gas lift line during a methanol foam treatment; and,

Figure 7 illustrates graphically pressures recorded during gas lift startup procedure.

Referring to Figure 1 of the drawings, a marine platform or structure 10 is positioned at an offshore body of water. The structure is judiciously located to best produce a hydrocarbon containing field or reservoir within the underlying substrate. The platform includes primarily a deck which is normally positioned 15 to 7 metres beyond the water level. The deck, in the usual manner, will accommodate the means for drilling wells, receiving and treating produced hydrocarbons, and housing personnel necessary to operate the

facility. The deck supports storage means such as tanks, separators, and other facilities whereby the liquid and gaseous hydrocarbons can be initially treated and stored before being transshipped to shore. The latter can be achieved through the use of pipelines which extend from the platform (10) to the shore. Alternatively, tankers and other cargo carrying vessels capable of loading at the platform can be utilized to convey the hydrocarbon fluid.

At another well drilling site in the oil field, spaced from the main platform (10) a subsea production facility (11) is provided comprising an oil well drilling template having a fluid manifold system including a ring main (50) for a passing gas lift fluid to the well (12) and a ring main (51) for passing production fluids from the well (12).

The subsea template (11) is connected to the main platform (10) by a series of pipelines extending along the bottom of the sea, of which only the main gas lift line (13) and the production test line (14) are illustrated in Fig. 1. The gas lift line (13) communicates with the main platform (10) through a flexible riser (15). It communicates at its other end with the ring main (50) on the template through a disconnect assembly comprising a reducing spool (16), non-return valves (17,18) with a disconnect unit (19) therebetween, a manual gate isolation valve (20), and a flexible jumper lead (21).

The figure illustrates a multi-well installation but the invention is equally applicable to single satellite wells.

After installation, it is necessary to dewater at least some of the pipelines connecting the main platform to the template. Figure 2 illustrates equipment installed on the main platform (10) for supplying foamed liquids to the gas lift pipeline (13) for passing therethrough and via the ring mains (50,51) on the template (11) through the production pipeline (14) to dewater both pipelines. The equipment in this case comprises a number of 150,000 scf nitrogen tanks (70) and a nitrogen pumping unit (71) connectable through gas line (72) to a conventional foam generating T-piece (52). A liquid line (53) is provided for supplying liquid to the foam generating device from a pump (54). The pump (54) is connectable either through line (57) to a water storage tank (55) which in turn is connected to a storage tank (73) for a surfactant to deliver an aqueous liquid containing the surfactant for supply by the pump (54) to the foaming device (52). The pump (54) is also selectively connectable to a further tank (56) for containing methanol. The foam generating device (52) has a foam outlet line (60) connectable to supply foam to the main gas lift pipeline (13) at a pressure sufficient to effect displacement of residual water therein by a method in accordance with the invention.

Liquid surfactant and water is supplied to the foam generating device (52) to produce a pressurized, high expansion nitrogen foam which is introduced into the pipeline (13). One of the characteristics of nitrogen foam is its ability to continually reform and regenerate itself. For this to occur though, the foam is displaced continuously in turbulent flow through the pipeline.

As the foam is rapidly pumped through the line, the bulk of the water accumulation in the pipeline ahead of the foam will be swept forward by "piston" displacement in accordance with the aforesaid "second mechanism". Residual water will become entrained by the foam where surfactant dilution enables some of the foam generating chemical to become mixed with the free water in the line in accordance with the aforesaid "first mechanism". The surface tension of the entrained fluids are lowered, enabling them to foam and be carried out of the vessel.

This mixture of displacement and entrainment is used to dewater the pipeline (13). Any small items of loose debris will also be carried forward and removed from the line by the viscous, turbulent flow. After completion of this process the pipeline is essentially filled with a water/surfactant foam. A pressurized high velocity flow of nitrogen gas is passed through the pipeline to foam up the liquid with surfactant therein and then to remove the bulk of the foam.

Once the majority of the bulk water has been removed, the residue of the foam is displaced by a methanol foam when methanol from tank (56) is supplied by pump (54) to the foam generating device (52). This foam is injected down the length of the complete line, to create turbulence in some of the residual water causing it to foam and to be physically displaced. The bulk of the foam remains in the pipeline and is then allowed to decompose into its liquid and gas constituents in the pipeline. Any trace water still present is dosed with the methanol, helping to prevent hydrate formation once hydrocarbon gases are injected into the line. The required amount of methanol in the foam is influenced by the volume needed to dose the water remaining in the pipeline to a sufficiently high concentration in order that hydrates are prevented from forming under the pressure and temperature operating conditions of the pipeline.

The nitrogen foam can be injected in the line from the platform, immediately after the determination of free fluids has been undertaken. All of the equipment can be platform based subject to size limitations enabling this operation to be undertaken and the results evaluated prior to calling for a vessel with the relatively large quantities of methanol to be used.

In the above described application of a method according to the invention, no pigs are used due to the nature of the pipeline. However for debris pick-up and chemical operations, a pig may be used in the pipeline to separate fluids and gases from the foam.

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EXAMPLE

The following is a specific practical example of a procedure for carrying out a method according to the invention for dewatering a main gas lift pipeline, in accordance with Fig. 1, approximately 8 miles long and nominal 8 in. O/D and a production test pipeline.

The gas lift pipeline is a multi-diameter pipeline. The following table gives examples of diameter variations thereof:-

	<u>COMPONENT</u>	<u>Internal Diameter</u>
15	Riser (15)	4.1 in
	Spool Piece (30)	3.826 in
20	Main Gas Lift Line (13)	7.625 in
	Disconnect Assembly (16-20)	3.826 in
	Flexible Jumper Lead (21)	4.00 in
25	Gas Lift Ring Main (50)	5.187 in
	Well Crossover (61)	2 in
	Gas Lift Choke (62)	0.25 - 0.50 in

30 The line needed to be fully dewatered since the pressure of free liquids in the system caused hydrates to be formed in the gas lift line, as soon as hydrocarbons were injected, resulting in total blockage of the line.

A previous attempt to dewater the line using gelled polymer pigs, displaced by gas, had been unsuccessful, as the line was not suitable for this technique for two reasons. First, the line has numerous changes in internal diameter, and also has probes and other internal projections which cause the break up of the pigs. Secondly, the use of gas as a displacing medium would have resulted in only partial displacement of the gel. A mechanical pig is usually required to back up a gel pig to reduce gas breakthrough and therefore prevent gel being left in the line. This resulted in as much as 15% of the line volume being left full of water.

40 The sequence of the dewatering method in accordance with the method used to dewater the pipeline is as follows. A first phase in which a nitrogen purge of the pipeline was carried out to purge hydrocarbons, to carry out pressure/volume correlations to indicate the volume of liquids left in the line, and to identify maximum flowrates through any chokes and see if this will be an obstacle to carrying out the planned foam displacement method. A second phase in which dewatering of the pipeline is carried out using aqueous foam to effect bulk dewatering of the gas lift line. A third phase in which methanol foam is passed through the line to dose the entire length of the gas lift line with methanol. A fourth phase in which gas lift is commenced into the well (12) at the remote subsea production facility, leading to startup of production from the well (12).

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PHASE 1 - NITROGEN PURGING

During the gas lift line purge, a total of 255,600 scf nitrogen was used. A further 15,000 scf was used in the second series of pressure/volume tests (the first series of tests had been carried out at the start of the purging phase) and in the final stage where gas was flowed at high rates in order to establish constraints imposed by the pipeline geometrical configuration, 215,000 scf was used. The total nitrogen therefore consumed in the whole of Phase 1 was 485,600 scf (i.e. 4-tanks).

The nitrogen purge was carried out at pressures of between 150 and 210 psia at the main platform end of the gas lift line. Flowrates averaged 300 scf/min. and the temperature of the pipeline was about 40°F (4°C).

The pressure/volume relationships worked out for these tests gave an estimated liquids content of the gas lift line of the order of about 250 bbl or about 10% liquids content in the gas lift line, but this could be higher, e.g., possibly up to about 20% liquids content.

At the end of the purging phase at least 250 bbl water were still in the gas lift line to be removed. Straight dosing with methanol would be impractical, both in the volume of methanol required and in the ability to dose with sufficiently high concentrations at the end thereof at template (11).

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PHASE 2 - AQUEOUS FOAM TREATMENTS

Two aqueous foam treatments (Case 1 and Case 2) were carried out because the first was prematurely terminated in order to fully open up the chokes in the gas lift line. The restriction presented by these was considered too great for the passage of liquids whilst at the same time maintaining sufficient foam velocity in the line.

In these treatments, the surfactant used was SF12 (NOWSCO) which is an ammonia salt of an alcohol ethoxylate sulphate. This surfactant is available from NOWSCO WELL SERVICES (UK) Limited.

Figs. 3 and 4 graphically illustrate the pressure in the gas lift line at the main platform end thereof, during the two treatments respectively.

Immediately after the start of pumping in Case 2, there was a small fall-off in pressure which is attributed to the head of the foam as it progressed down the riser (15). The effect is more apparent in Case 2 than Case 1. A high concentration of surfactant (10% of liquid volume) was used in the lead foam with the view that this would be introduced into any liquids at the base of the riser (15). A neat 5 gallon slug of surfactant was dumped into the system at the start of operations for the same reason.

This was followed by a sharp increase in pressure at the main platform end, the rate of which was greater in the first case than the second. This accords with a pick up of liquids in the gas lift line at its lowest point at the base of the riser. It would be expected that less liquids would be present (if any) in Case 2 than Case 1 and the pressure response seems to confirm this.

When the rise in pressure went above 300/400 psi liquid pumping was stopped to allow the system to stabilize and nitrogen was used on its own to maintain foam velocities. This procedure was repeated throughout the programme whenever pressure peaking occurred. The rates of liquid injection, surfactant concentration and gas flow were individually varied in response to system performance.

In Case 2, a more controlled response was maintained as is shown on the graph of the pressure responses. This is thought to be the result of two factors -less liquids in the line and better control technique of the process.

In Case 1 when pumping was finally stopped (marked as Point A) the gradual fall-off in pressure over the following few hours was indicative that liquid was flowing through the chokes. It was here when it was decided to open up the chokes fully and make provision to vent to sea. Both these operations needed diver intervention.

The response of pressure at the template end of the gas lift line, shows the restriction in flow caused by the chokes more clearly. Figure 5 is a graph of recorded values and a clear change in gradient is seen which would be expected with a change in phase.

In the second aqueous foam treatment (Case 2) , the surfactant concentration in the foam was increased to try and compensate for lower velocities caused by the choke restrictions and to take advantage of the successful way the technique seemed to perform in the first run where the foam clearly seemed to be doing its job most effectively and holding together well.

The gas lift line was vented to the sea. Foam generation was stopped and nitrogen at about 3000 scf/min for 20 minutes was pumped to try and maximize turbulence and achieve as much foam regeneration as possible.

The slug catcher was emptied in batch-mode four times during the aqueous foam treatments. Of these, the first two batches were all oil but the last two were nearly all water. The base sediment and water (BS&W) readings were 0%, 3%, 100% and 98% respectively. An estimated 300 bbl of water was removed. Further water remained in the test line and was recovered in Phases 3 and 4.

Summary of Phase 2 Parameters (Aqueous Foam Treatment)

Initial Pumping Pressures of Foams - 200 psig but variable in response to system performance Ambient Temperature of Pipeline - 40°F (4°C).

	<u>Units</u>	<u>Treatment 1</u>	<u>Treatment 2</u>
Nitrogen	scf/min	1500-2500	1000-2600
Liquid	bb1/min	nil/0.25	nil/0.25
Surfactant	% vol of liquid vol	3% vol	5-10% vol
Estimated Speed in Gas Lift line (average)	ft/s	about 6.0	about 5.5
Treatment Time	h	3.5	2.5
Nitrogen used	scf	447,000	585,000*
Surfactant Used	bb1	----- 90 gal	-----
Water in Foam	bb1	10 bb1	11 bb1
Water Produced		300 bb1 $\pm$ 25%	

* Includes 55,000 scf purging to sea/purge pressure build-up and 55,000 scf high rate nitrogen circulation after purging.

The results showed that foam was sufficiently stable to displace liquids in a piston-like manner, and the regenerative ability of surfactant that "dropped out" appeared satisfactory.

Overall the treatment was successful and the gas lift line was substantially free of bulk water.

PHASE 3 - METHANOL FOAM TREATMENT

A similar equipment configuration was used in the preparation of the methanol foam as for the water-based foam. The following logistical and safety aspects are worth noting:

The methanol foam was mixed and pumped at the lowest pressures the system would allow in order to maximise velocities for a given nitrogen injection rate and to ensure the flowrates were within the capacity of the gas lift chokes. The starting pressure was about 100 psia and about 350 psia at the end of pumping. The treatment was sufficiently controlled that no peaks occurred in the pressure response which was one indication that the line was substantially clear of liquids.

No pressure rise was noted at the template end until the foam arrived. Figure 6 shows the pressure responses.

Since pressures across the chokes responded clearly to liquid flow as opposed to gas, a liquid slug of methanol could be introduced into the foam and could be detected at the template end of the gas lift pipeline. A sharp increase in pressure occurred almost exactly when it was predicted that the slug would reach the template, as indicated in Fig. 6. At this time, the system was closed in for several hours and the foam allowed to break. The foam treatment had succeeded in placing a highly concentrated methanol solution exactly in the zone where it was most needed (blind ends, low points etc. in the template pipework) and ready for the start of gas lift operations.

This neat methanol slug (12 bbl) was introduced some 30 minutes after the start of foam pumping, when progress had been estimated at 8200 ft along the gas lift line (at 100 psi). The line is some 42,000 ft long and the pressure response occurred at a point when progress was estimated at 48,000 ft (180 psi). Almost exactly at a calculated 42,000 ft, the pressure recorders at the template showed a small (10-15 psi) jump in pressure which was attributed to the foam phase now passing through the choke. This point helped to confirm that the liquid phase at the template was, indeed, methanol rather than further water which had been pigged out.

Just prior to closing-in the system a second methanol slug (12 bbl) was pumped with the view to placing it at the bottom of the riser to dose any liquids that may collect in that location whilst the line was left.

SUMMARY OF METHANOL FOAM PARAMETERS

15	Nitrogen Used	210,200	scf
	Surfactant Used	300	litres
	Methanol in Foam	5,556	US gals
20	Methanol in Slugs	24	bbl
	Methanol in Reserve	1,436	US gals
	Calculated Foam Velocity	About 6	ft/s
25	Treatment Time	3	h
	Water produced	Nil	
30	Methanol percentage in liquid phase of foam	about 95% i.e. 5% (vol) surfactant	

The surfactant used was a methanol foamer called FC431 available from the 3M Company. It is a fluoro-carbon methanol foamer. The foaming agent is generally present in an amount of about 1-25% (vol), e.g. 5% (by vol), of the liquid phase of the foam.

The absence of pressure peaks and the predictive way in which the gas lift line responded to the methanol foam treatment points to the objectives of Phase 3 having been achieved. The line had been dosed with methanol along its entire length and a liquid methanol slug was in the template.

The way in which the calculated displacement was matched by the actual pressure responses of the system confirms the line was free of bulk liquids and that the aqueous treatments had succeeded.

PHASE 4 - STARTUP OF GAS LIFT OPERATIONS

Lift gas was introduced into the gas lift line at pressures up to 1750 psig.

Just under 12 hours had elapsed since Phase 3 was concluded, allowing ample time for the methanol foam to break and drop out its methanol into any water left in the line. Generally 4 hours would be considered a required minimum time.

A 12 bbl slug of methanol had been left at the base of the riser (15) at the conclusion of the methanol foam treatment phase. A further slug of 20 bbls was introduced at the start of hydrocarbon gas pumping to further treat any liquids that may have collected, and also to fully saturate gas entering the line. Methanol dosing of the gas was started at a higher-than-normal rate of 5 gal/min. This lasted for just under 7 hours.

Pressure build-up in the gas line was at the rate of about 30 psi every 10 mins, with a gas flow rate of about 4 mmscfd.

At first, pressure was built up to about 650 psi against the valve in the gas lift line located where it goes onto the template and then against valve in the test line as it exits from the template up to about 1100 psi.

In the event, gas lift started at the following conditions:

Main Platform Injection Pressure 1530 psia
 Ring Main Pressure 1590 psig (reading high)
 Gas Injection Rate 4.8 mmscfd

5 Tubing Head Pressure 310 psig

The gas lift valve position in the well (12) is at 4110 ft BKB (540 ft).

Gas lift was confirmed by shutting in the gas lift line and monitoring well head pressure. All these results are shown in Figure 7. In addition, much increased gas flow was received back at the main platform (12).

10

Claims

1. A method for treating a pipeline which contains a residual amount of fluid in a generally horizontal
 15 section or sections thereof, to displace the residual fluid therefrom, which comprises:-
 injecting into the pipeline a pressurized, high expansion foam having a high refoamability and being
 compatible with said fluid in the pipeline section (s), which foam contains an amount of foaming agent in
 excess of the minimum amount thereof required to generate the foam;
 advancing the foam through the, or each, of said pipeline sections in contact with a layer of said fluid left
 20 therein to displace said layer towards a remote end of the pipeline by entrainment caused by frictional pick-
 up of the layer by said foam and to effect mass transfer of said foaming agent from said foam to said fluid;
 discontinuing injection of said foam; and,
 passing into the pipeline a pressurized gas to create turbulence in said fluid containing said foaming agent,
 which is left in the, or each, of said pipeline sections causing foaming of said fluid within the pipeline and to
 25 displace a substantial proportion of the foam left within the pipeline from a remote end thereof.
2. A method according to Claim 1, wherein at least some of the bulk of said fluid in the pipeline section-
 (s) is displaced by injection of said foam into the pipeline to establish a transverse foam/fluid interface
 which is advanced through the pipeline at or above a minimum velocity required to maintain said interface
 thereby to displace the bulk of said fluid from said remote end of the pipeline leaving said residual amount
 30 of said fluid in the pipeline which is treated as aforesaid.
3. A method according to Claim 2, wherein the interface is advanced at a velocity of about 3 - 15 ft. per
 second.
4. A method according to Claim 3, wherein said interface is advanced at a velocity of at least 5 ft. per
 second.
- 35 5. A method according to any of Claims 1 to 4, wherein the gas/liquid ratio (by volume) of said foam is
 at least 75%.
6. A method according to Claim 5, wherein said ratio is at least 98%.
7. A method according to any of Claims 1 to 6, wherein said pressurized gas is the same as that of the
 gaseous phase of said foam.
- 40 8. A method according to any of Claims 1 to 7, wherein said pressurized gas is selected from the group
 nitrogen, air and gaseous hydrocarbons.
9. A method according to any of Claims 1 to 9, wherein said foam is an aqueous foam.
10. A method according to Claim 9, wherein the liquid phase of said foam contains about 1 - 15% by
 volume of said foaming agent.
- 45 11. A method according to Claim 10, wherein the liquid phase of said foam contains about 3 - 10% by
 volume of said foaming agent.
12. A method according to any of Claims 1 to 11 including the further step of injecting into the pipeline
 a pressurized foam containing a treatment agent to displace residual foam left in the pipeline, and then
 allowing the foam to decompose in the pipeline to deposit the treatment agent within the pipeline either on
 50 the pipewall or in solution with any liquids remaining therein.
13. A method according to Claim 12, wherein the treatment agent comprises at least one of methanol,
 iso-propyl alcohol and corrosion inhibitors.
14. A method according to Claim 13 wherein said pressurized foam containing a treatment agent has a
 liquid phase which contains at least about 75% by volume of the treatment agent.
- 55 15. A method according to Claim 13 or Claim 14, wherein said pressurized foam containing a treatment
 agent has a liquid phase which contains about 95% by volume of the treatment agent.

Fig. 2.

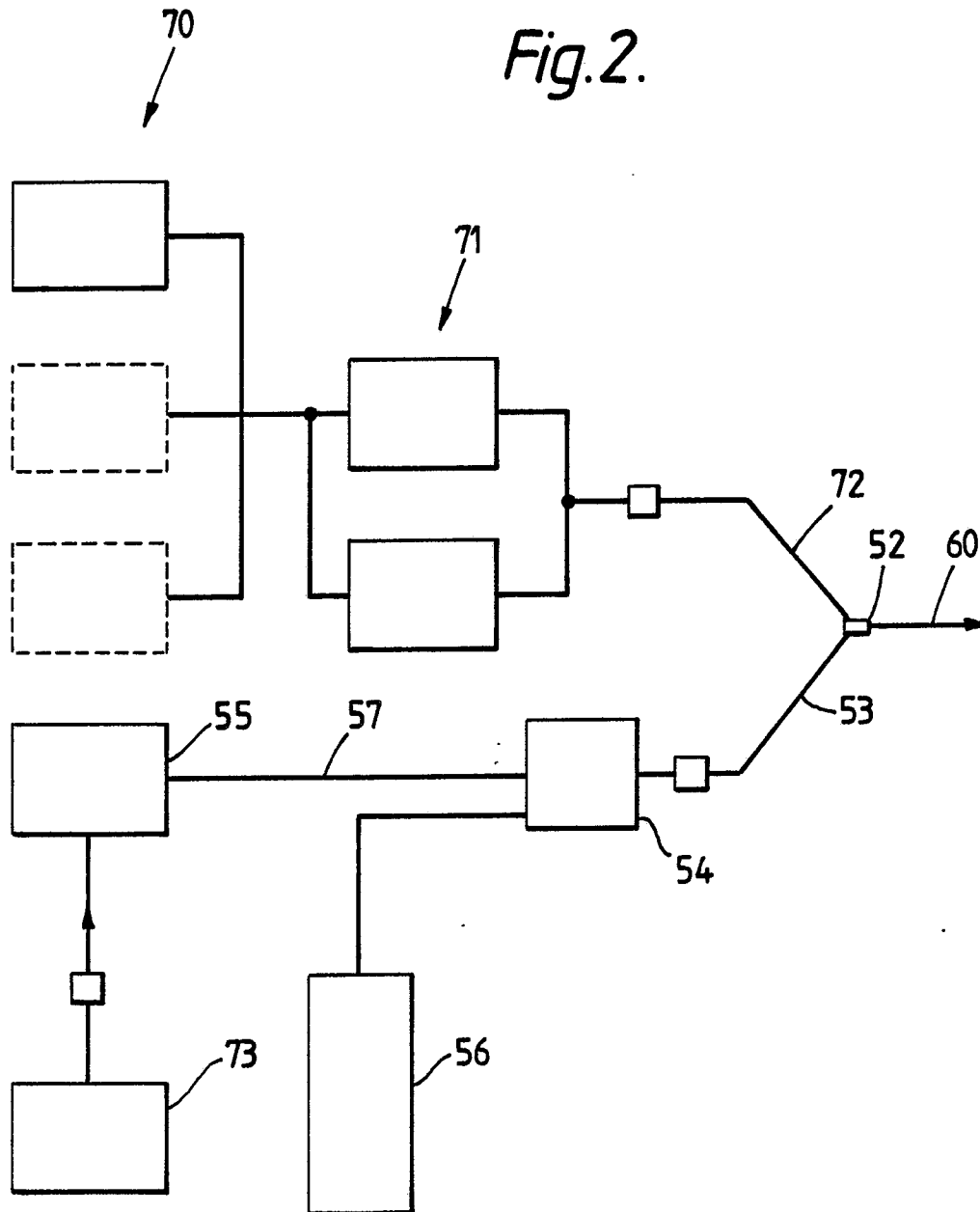


Fig.3.

AQUEOUS FOAM TREATMENT - CASE 1.

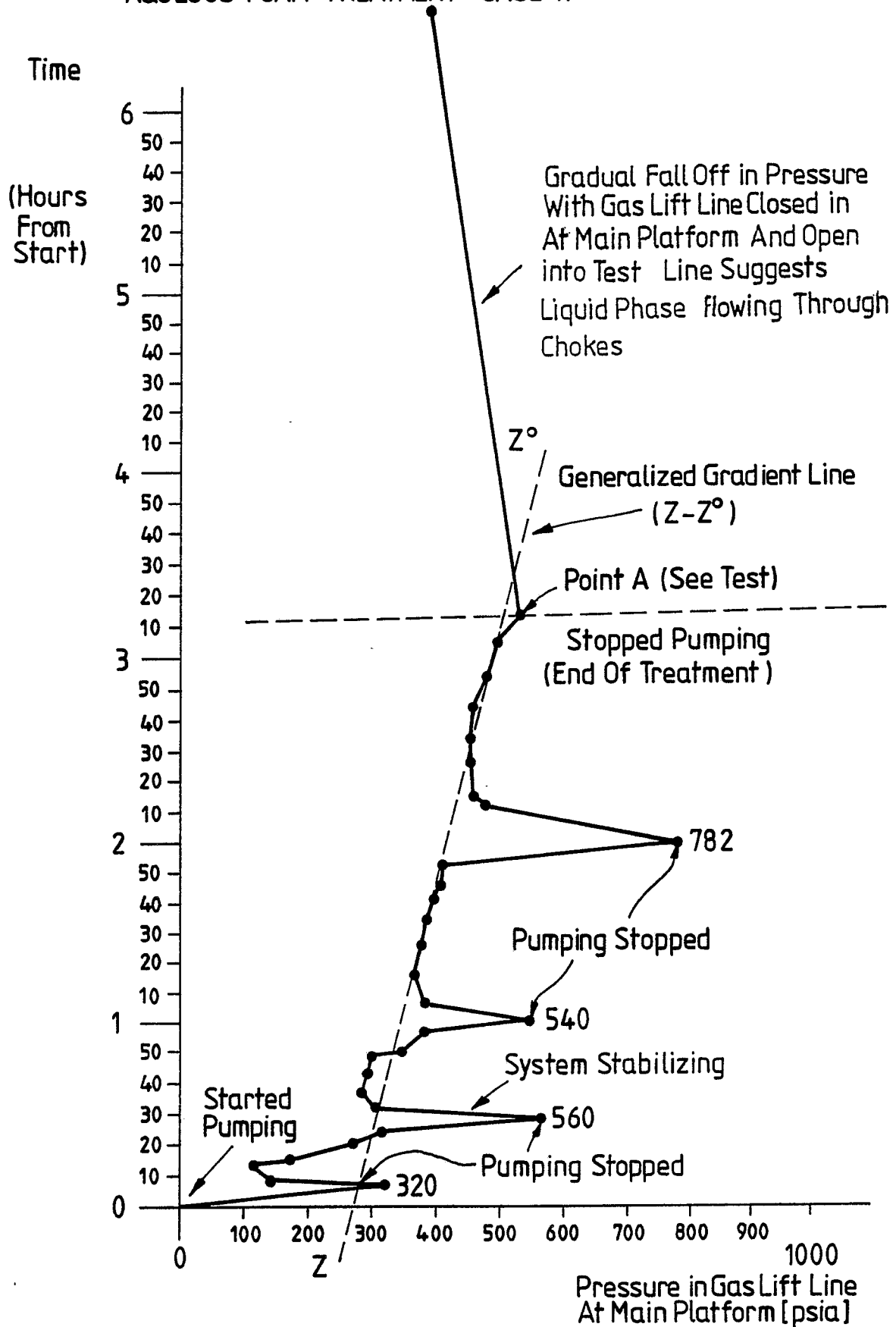


Fig.4.

AQUEOUS FOAM TREATMENT-CASE 2

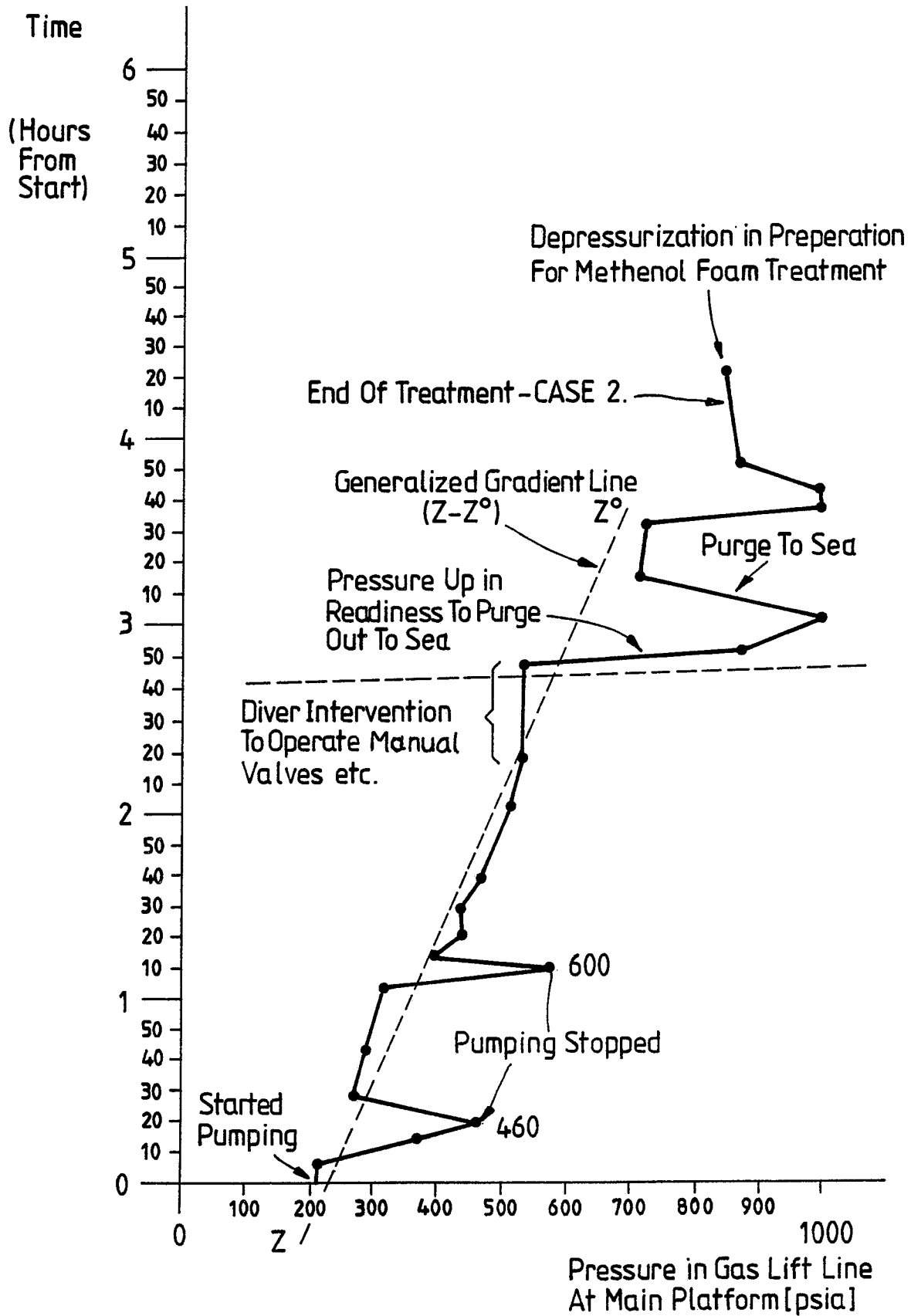


Fig. 5.

RECORDED VALUES AT TEMPLATE

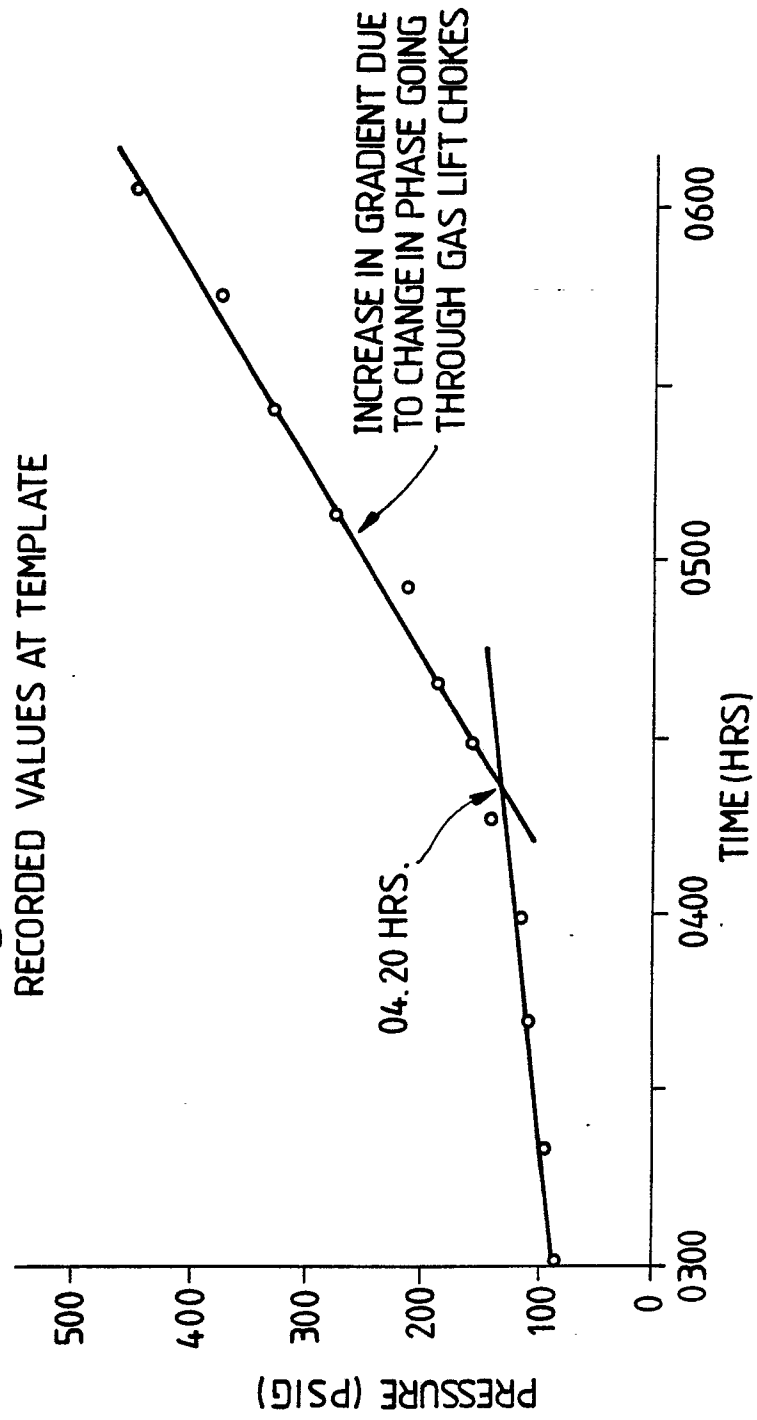


Fig.6.

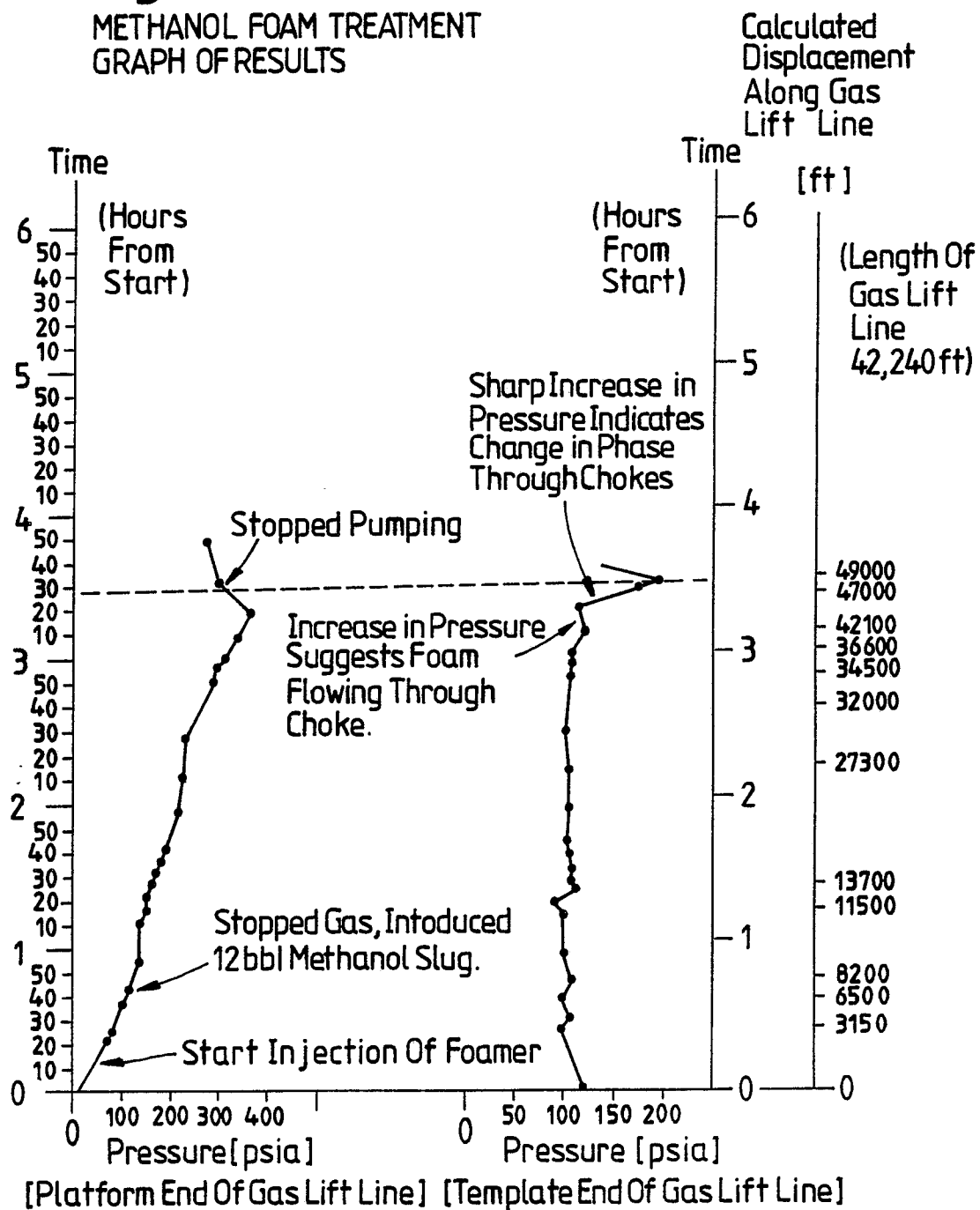
METHANOL FOAM TREATMENT
GRAPH OF RESULTS

Fig.7.

GAS LIFT STARTUP-RESPONSES OF WELL

