DYNAMIC SIMULATION OF MULTIPHASE PUMPS

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ABSTRACT

A 20'' pipeline connecting a well head platform to a production platform is operated under multiphase flow conditions by natural field pressure. Depending on the liquid and gas produced the actual multiphase flow regime in the pipe may not be stable under all operating conditions. Furthermore due to the increase in pressure losses when transporting high liquid flow the pressure level at the arrival on the production platform may be too low for the compressors and therefore this gas cannot be exported as such.

One answer could be to flare it or add an additional compression stage.

Another answer would be to use multiphase pumps to add energy to the effluent and stabilise the flow regime in the pipeline.

Three pump locations are possible:

- Topside on the departure platform
- Topside on the arrival platform
- Subsea on the seabed at the bottom of the riser of the arrival (production) platform

Multiphase flow simulations have been carried out for several steady state modes of operation, without and with the use of multiphase pumps, to illustrate how a multiphase pump can suppress severe slugging and reduce the injection pressure level at the pipeline inlet. The preferred location would be on the departure platform (at the point of highest energy level). In some cases this is not feasible. Here the other two pump locations were investigated. Very little difference has been found between the following two cases: pump installed subsea (immediately upstream of the riser) and topside on the production platform (downstream of the riser).

Analysis have also been carried out for some cases of transient modes of operation (typically, shutdown and start up). These analysis have permitted to quantify the response time of the pipeline and provided some indications concerning the operation of the pump (shutdown or start up sequence and timing).

1. INTRODUCTION

A 20'' multiphase pipeline connecting a well head platform to a production platform is operated under natural flow conditions. Two problems have been incurred :

- Depending upon the liquid and gas flow-rates the multiphase flow regime in the pipeline can be unstable due to the transient severe slugging phenomenon.
- Due to the increase in pressure drop when transporting multiphase flow with a larger liquid stream, the outlet pressure may not be too low to feed the export compressors.

Those problems can be solved by installing a multiphase pump to boost the required flow production while maintaining satisfactory pressure levels at pipeline inlet and outlet. Independently of its location, the multiphase pump permits either to reduce the pipeline inlet pressure or to increase the pipeline outlet pressure depending on the operator requirement.

For this purpose, to study the interaction of a multiphase pump with its downstream or upstream multiphase pipe, a pump module was added to a transient multiphase flow simulation code.

This tool was used to investigate the full multiphase production system, including a pipeline and a pump, for two pump locations (pump mounted subsea at the bottom of the riser of the receiving platform or pump mounted on the production platform) and for several scenarios of flow production (several sets of gas and liquid flow-rates). The start up and the shutdown of the multiphase production system have also been investigated and are explained in this paper.

2. MODEL DESCRIPTION AND INPUT DATA

2.1 TACITE CODE

The TACITE code, developed by IFP (Institut Français du Pétrole) together with TOTAL and ELF Exploration Production, is a compositional transient simulation tool for multiphase production pipelines taking into account complex fluid effects. TACITE is able to simulate transient and steady state multiphase flows, for the design and control of oil and gas production devices. The pump module integrated in TACITE is based on a rotodynamic (helico-axial) pump model.

2.2 MULTIPHASE PUMP MODULE IN TACITE CODE

The performance of a multiphase pump are calculated with the following data: the number of compression stages (one stage includes an impeller and a diffuser), the pump rotational velocity (speed) , the individual impeller characteristics and the process conditions.

The calculation of the pump performance in a steady state as in a transient mode of operation starts with the calculation of the performance of the first stage based on the flow conditions at the pump inlet (gas and liquid flow-rates, pressure, temperature, gas and liquid properties) and the pump speed. This calculation provides the flow conditions at the first stage outlet which can then be used to calculate the performance of the following stage. The calculation is carried out until the last stage to obtain the flow conditions at the pump discharge.

In the TACITE code, the calculation proceeds with a given value of the pipeline outlet pressure, the upstream pressures (intermediate or at pipeline inlet) being deducted from the pressure drop in the pipeline. In a transient mode and within the calculation process of the pump performance, the pump discharge pressure does not always correspond to the pressure specified by the TACITE code. When that is the case, the pump inlet pressure is adjusted until there is a satisfactory match between the two sets of data.

Due to the progressive flow reduction from the pump inlet to the pump discharge, the characteristics of the compression stages vary slightly from one stage to the other (diameters, blade angles), each stage being selected to provide the best overall performance (efficiency, pressure coefficient and minimum flow margin) at a given operating condition. Usually the impeller selection is made at the nominal flow condition.

As the pressures, flows and the pump speed may vary considerably during the operation of a pump, particularly during the start up and shutdown phases. The performance of each compression stage is calculated by using dimensionless coefficients. The dimensionless flow coefficient, *Fc,* is calculated from :

$$Fc = \frac{4Q}{\pi\left(D_e^2 - D_i^2\right)U}$$

where Q, D_e, D_i, U designate respectively the total volume flow at impeller inlet (sum of the gas and liquid volume flows), the impeller external and internal diameters and the impeller peripheral velocity.

This flow coefficient provides a dimensionless pressure coefficient which in turn provides the impeller manometric head based on single phase flow, with :

$$Head_{SP} = \frac{Pc_{SP}.U^2}{2g}$$

where $Head_{SP}$, Pc_{SP}, g designate, respectively, the impeller manometric head in single phase flow, the pressure coefficient and the gravitational acceleration.

The available manometric head in two phase flow is obtained by multiplying the single phase flow head by a coefficient which is a function of the gas - liquid volume fraction, *GLR* and the gas - liquid density ratio, *RoGL.* These two parameters are defined at actual conditions.

The impeller pressure rise in two phase flow may be calculated from :

$$Head_{TP} = \frac{X_g}{g}\frac{P_{in}}{\rho_{gin}}\ln\left(\frac{P_{in} + DP_{act}}{P_{in}}\right) + \frac{\left(1 - X_g\right)}{g}\frac{DP_{act}}{\rho_l}$$

where $Head_{TP}$, P_{in}, ρ_{gin}, ρ_l, DP_{act} designate, respectively, the two phase manometric head, the inlet pressure, the inlet gas and liquid densities, the impeller pressure rise while the gas mass fraction is defined by :

$$X_g = \frac{GLR.RoGL}{1 + GLR.RoGL}$$

Due to the process conditions a multiphase pump may be occasionally operating at reduced flow. To prevent the operation below a given minimum flow, a recycle line is installed to recycle a part of the process flow from the pump discharge back to the pump inlet. The recycled fluid may be either the liquid phase, the gas phase or the two phase mixture depending on the installation requirement. In the present study, the two phase mixture has been selected as the recycled fluid and the pump recycling is activated when the flow is below the minimum value.

2.3 INPUT DATA

Pipeline

The pipeline profile is plotted in Figure 1.

For the simulation, the pipeline has been divided in approximately 100 segments.

Process conditions

For the nominal flow-rate, the main process conditions are:

Pressure at pipeline outlet: 700 psig (48.3 barG)

Temperature at pipeline outlet: 100 °F

Gas flow-rate : 50 MMSCFD

Liquid flow-rate: 7,000 BLPD

Water cut: 50 to 60 %

Gas specific gravity: 0.60 to 0.75

Oil gravity: about 20° API

Oil viscosity : 250 to 700 cSt at 100 °F

3. SIMULATION RESULTS

3.1 OPERATION WITHOUT MULTIPHASE PUMPS

Nominal flow conditions

Calculations have been performed with the following input:

- gas flow-rate : 50 MMSCFD

- gas specific gravity : 0.63
- liquid flow-rate : 7,000 BLPD
- equivalent liquid viscosity : 1,000 cSt
- pipeline wall roughness : 50 microns
- pipeline outlet pressure : 700 psig (48.3 barG)

For this operating flow case, the following curves have been plotted:

- pressure versus time and distance (Figure 2)
- liquid volumetric fraction versus time and distance (Figure 3)
- gas mass flow-rate versus time and distance (Figure 4)
- liquid mass flow-rate versus time and distance (Figure 5)

After stabilisation of the numerical calculation (of the order of 10,000 sec), the TACITE code predicts the occurrence of terrain induced slugging in the second part of the pipeline (middle of the pipeline) with a frequency of approximately 35 minutes. The slugging effect is particularly important at the riser bottom of the receiving platform as shown by Fig. 3 (liquid fraction varying between 0.3 and 1), Fig. 4 (gas mass flow-rate varying between 0 and 300% of nominal flow) and Fig. 5 (liquid mass flow-rate varying from reverse flow to 1,000% of nominal flow).

Low gas flow-rate cases

These calculations have been performed on the basis of the nominal flow conditions, given above, except for the gas flow-rate which was varied from 100 to 40%. When the gas flow-rate is reduced over that range, there is very little reduction in the total pressure drop along the pipeline (from 10 bar at 100% gas flow-rate to 8 bar at 40% gas flow-rate) as shown on Figures 6 and 7.

There is also very little change in flow pattern as shown in Fig. 6. In the first part of the pipeline, the gas and liquid phases are stratified. Downstream in the middle of the pipeline (location 40 km), severe slugging occurs with the largest effect taking place at the bottom of receiving platform riser. The slug amplitude and slug frequency are relatively constant over a large range of gas flow-rate, the slug frequency varying from 35 to 25 minutes when the gas flow-rate varies from 100% to 40%.

While all other flow parameters remain constant, the pipeline liquid hold up increases considerably when the gas flow-rate reduces: from 27,700 BBL (4,400 m^3) to 44,700 BBL (7,100 m^3) when the gas flow-rate varies from 100 to 40% (Fig. 7).

High liquid flow-rate cases

Calculations have been performed on the basis of the nominal flow condition, given above, except for the liquid flow-rate which was varied from 100 to 300%. When the liquid flow-rate is increased over that range, there is a considerable increase in the pipeline pressure drop (from 10 bar at 100% liquid flow-rate to 15 and 18 bar at respectively 200 and 300% liquid flow-rate) as shown on Figures 8 and 7.

Compared to a gas flow-rate variation, the pipeline liquid hold up is relatively less dependant on a liquid flow-rate variation, increasing from 27,700 BBL (4,400 m^3) to 39,000 BBL (6,200 m^3) when the liquid flow-rate is multiplied by 3 (Fig. 7). However, the effect is more important on the flow pattern, the severe slugging tending to disappear as the liquid flow-rate is increased. This may be explained by considering the increases in gas density (higher pipeline inlet pressure) and gas velocity (higher liquid hold up), following a liquid flow-rate increase, providing a larger gas momentum and therefore a more effective entrainment of the liquid phase by the gas phase.

Effect of the gas specific gravity

All calculations above were performed with a gas specific gravity of 0.63. This value was obtained by a flash calculation of the gas and liquid phases based on one actual effluent composition.

An additional calculation has been carried out with a gas specific gravity of 0.725. Some results (pressure and gas mass flow-rate profiles) based on a specific gravity of 0.725 are presented on figure 9 showing very little difference with those corresponding to a specific gravity of 0.63 (Figures 2 and 3). One difference, however, may be noted concerning the slug period which is increased from 35 to 45 minutes when the specific gravity increases from the 0.63 to 0.725.

3.2 OPERATION WITH MULTIPHASE PUMPS

Calculations above have shown that :

- except when the liquid flow-rate is relatively large, severe slugging occurs in the pipeline, particularly, from the middle of the pipeline.
- In order to get (and maintain) 700 psig (48.3 barG) at the receiving platform, the pressure at the pipe inlet must be respectively equal to (and considerably higher than):

  a) 850 psia (58 bar abs) with 40% gas flow-rate and 100% liquid flow-rate,

  b) 856.5 psia (59 bar abs) with 100% gas flow-rate and 100% liquid flow-rate,

  c) 964 psig (67.5 bar abs) with 100% gas flow-rate and 300% liquid flow-rate.

The purpose of this section is to evaluate the capability of multiphase pumps to eliminate the severe slugging and to reduce the pressure at the pipeline inlet.

Two pump locations have been considered in the present study :

- Subsea : a multiphase pump mounted immediately upstream the riser of the receiving platform
- Topside : a multiphase pump mounted on the receiving platform.

The pump selection is not really influenced by the pump location, i.e. subsea or topside. This is due to the fact that for all three considered flow cases, the pump inlet conditions do not change significantly with the pump position.

The pump characteristics (Fig. 10) can therefore be used for both the subsea and the topside location.

The pump has been selected so that is is suitable for all three flow cases.

Nominal flow condition

The calculations have been performed for the nominal flow conditions (see Par. 3.1).

- ***Subsea pump***

The performance curve for the pump selection adapted to the nominal flow condition is shown in Figure 10.

After 25,000 seconds of numerical stabilisation, the calculation indicates that by lowering the pipeline inlet pressure to 667 psia (46 bar abs) the severe slugging has disappeared in the pipeline except for some pressure fluctuations at the bottom of the riser (Fig. 11). This may be explained by considering, partly, the increase in gas velocity (the average gas velocity increased from 8.9 ft/s to 10.5 ft/s (2.7 to 3.2 m/s) in the second part of the pipeline, respectively without and with the use of a pump) and, partly, the interaction of the pump and pipeline characteristics. Following a flow increase through the pump, the pump differential pressure tends to decreases (falling pressure-flow pump curve) up to some equilibrium, limiting the flow increase. The reverse mechanism applies to a flow reduction.

For the selected pump the pipeline and pump characteristics are:

pipeline inlet pressure	reduced from 855.5 psia (59 bar abs) to 667 psia (46 bar abs)
pipeline liquid hold up	reduced from 27,000 bbl (4300 m^3) to 25,800 bbl (4100 m^3))
pump inlet volume flow	250,000 bbl/d (1,656 m^3/h)
pump inlet GLR	31
pump pressure differential	174 psi (12 bar)
pump power	1,200 kW

- ***Topside pump***

When the pump selected for the above case is mounted on the production platform, the predictions of the TACITE code are relatively similar to the ones found in the previous case, except for the pipeline inlet pressure which is slightly higher and approximately equal to 690 psia (47.5 bar abs, Figure 12). Also the pressure fluctuations have totally disappeared along the pipeline, including at the riser location.

The pipeline characteristics being relatively similar for the two pump locations, the liquid volumetric fraction, gas mass flow-rate and liquid mass flow-rate are presented only in the case of the pump mounted on the receiving platform (Figures 13 to 15). These figures may be compared to Figures 3 to 5 for comparison with a pipeline production without flow boosting.

Low gas flow-rate case

The calculation has been performed for the nominal flow conditions (see Para. 3.1) except for the gas flow-rate which is equal 20 MMSCFD (40% of the nominal gas flow-rate).

- ***Subsea pump***

Similarly to the 100% flow case, after 40,000 seconds of numerical stabilisation, the calculation indicates that by lowering the pipeline inlet pressure (38 bar abs with the multiphase pump) the severe slugging has been eliminated in the pipeline except for some pressure fluctuations at the riser location (Figure 16).

For the selected pump the pipeline and pump characteristics:

pipeline inlet pressure	reduced from 841 psia (58 bar abs) to 551 psia (38 bar abs)
pipeline liquid hold up	reduced from 45,300 bbl (7,200 m^3) to 42,800 bbl (6,800 m^3)
pump inlet volume flow	103,000 bbl/d (684 m^3/h)
pump inlet GLR	14
pump pressure differential	(246 psi) 17 bar
pump power	950 kW

- ***Topside pump***

When the pump defined in the above case 1 is mounted on the production platform, the predictions of the TACITE code are relatively similar to the ones found in case 1 (Figure 17). However, the pressure fluctuations have totally disappeared along the pipeline, including at the riser location.

High liquid flow-rate case

The calculation has been performed on the nominal flow conditions (see Para. 3.1) except for the liquid flow-rate which is equal to 21,000 BLPD (300% of the nominal liquid flow-rate).

- ***Subsea pump***

Similarly to the 100% flow case, after some numerical stabilisation, the calculation indicates that by lowering the pipeline inlet pressure (841 psia or 58 bar abs with this pump selection) the severe slugging has been eliminated in the pipeline (Figure 18).

With that pump selection, the pipeline and pump characteristics are the following :

pipeline inlet pressure	reduced from 979 psia (67.5 bar abs) to 841 psia (58 bar abs)
pipeline liquid hold up	reduced from 39,600 to 36,500 bbl/d (6300 to 5800 m^3)
pump inlet volume flow	272,000 bbl/d (1800 m^3/h)
pump inlet GLR	11.4
pump pressure differential	232 psi (16 bar)
pump power	2,000 kW

- ***Topside pump***

With the pump mounted on the platform, the results of the calculation are relatively similar to case 1 (Figure 19).

Pump effect

The above pump has been selected to suppress the severe slugging as to lower significantly the pipeline inlet pressure (Figure 20).

However, on the basis of a constant pipeline outlet pressure, lower pipeline inlet pressures values could be obtained by increasing the number of compression stages and therefore the pump pressure rise. Similarly, on the basis of a constant pipeline inlet pressure, higher pipeline outlet pressures (i.e. greater than 715 psia or 49.3 bar abs) could be obtained by adding compression stages into the pump.

3.3 SHUTDOWN CASE

Emergency shutdown

For illustration purposes, the following scenario of emergency shutdown has been selected and analysed (Figure 21) : at first, the flow production (gas and liquid mass flow-rates) is abruptly reduced from 100 to 10% (in 500 seconds in the case of the simulation) then after one hour, the pump speed is reduced from 100 to 0% over a duration of one hour. It will be noted that even the time interval corresponding to the flow reduction may look important in comparison with the duration of an actual emergency shutdown, this time interval is still relatively small in comparison with the response time of the pipeline.

At first, the calculation is carried over 20,000 seconds to establish a relatively steady-state flow condition before the initiation of an emergency shutdown at the well-head platform. As the flow production is reduced, the pressure drops extremely rapidly at the pipeline inlet and progressively less in direction of the production platform (Figure 22 for a pump mounted on the platform). Before the speed of the multiphase pump is reduced, the gas and liquid flow-rates vary approximately from 10 (at the pipeline inlet) to 50%

(at the pump entrance) while relatively large flow variations are generated at the pipeline outlet.

The liquid volumetric fraction has been plotted in the case of an emergency shutdown (Figure 23) showing a large change in volumetric fraction between the period preceding the flow reduction and the period following the pump stop. In the first case, the liquid fraction is almost constant along the pipeline whatever the elevation of the pipeline is. In the second case, the liquid fraction tends versus the time progressively towards 0 at the highest pipe elevations and towards 1 at the lowest pipe elevations, confirming the validity of the model.

Other cases

Different cases of shutdowns (e.g. normal shutdown) as well as start-up scenarios can be specified and investigated in a similar fashion. From such studies operating scenarios can be optimised.

4. CONCLUSIONS

In this multiphase transportation case, the multiphase pump is operating with approximately the same inlet parameters, in steady state conditions, independently of its location (subsea or topside). This true here because the amount of gas by volume at pump inlet is relatively high (high Gas Liquid Ratio) and the water depth is moderate.

For an arrival pressure at the production platform of 715 psia (49.3 bar abs), a multiphase pump, permits to reduce the inlet pipeline pressure from 855 to 667 psia (59 to 46 bar abs) with the 100 % flow case (50 MMSCFD & 7000 BFPD), from 841 to 551 psia (58 to 38 bar abs) when the gas flow-rate is reduced by 60% and from 979 to 841 psia (67.5 to 58 bar abs) when the liquid flow-rate is increased by 200%.

The simulations carried out have demonstrated that:

- The production scenarios (start-up, shutdowns, etc.) can be studied with existing simulation tools ahead of actual production start-up.
- An optimisation of the multiphase production system can be achieved by adjusting the various parameters (flow production, pump speed, pipeline equilibrium pressure).
- The simulation tools can also be used to train operators by demonstrating the process implication of certain actions.

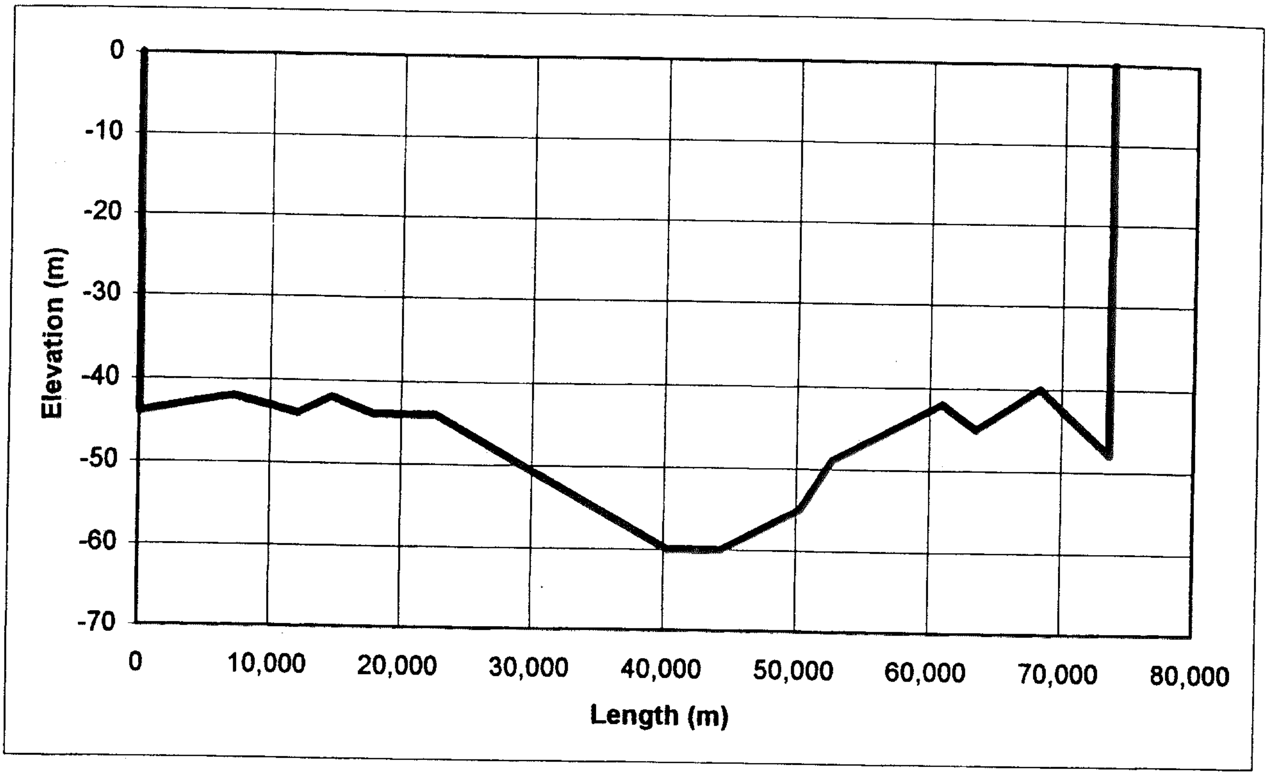
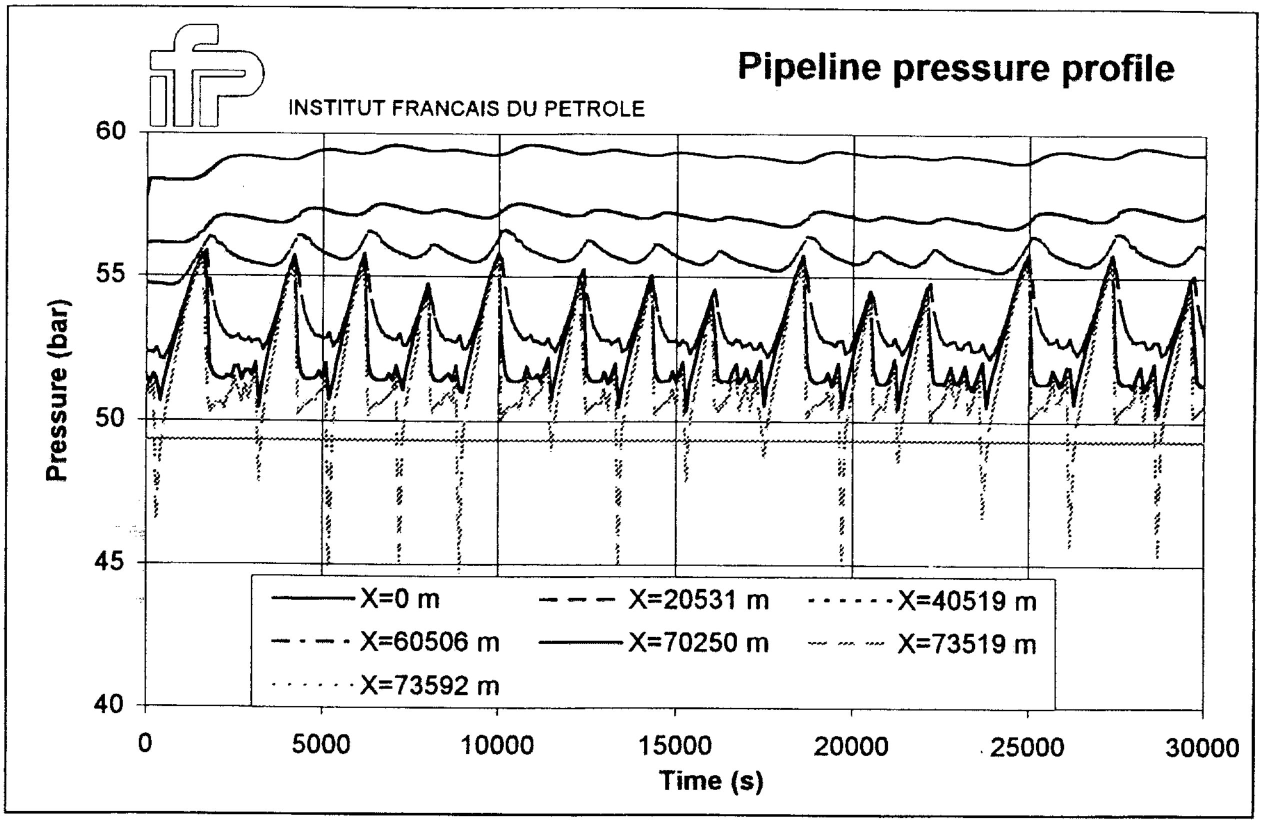


FIGURE 1 - Pipeline profile



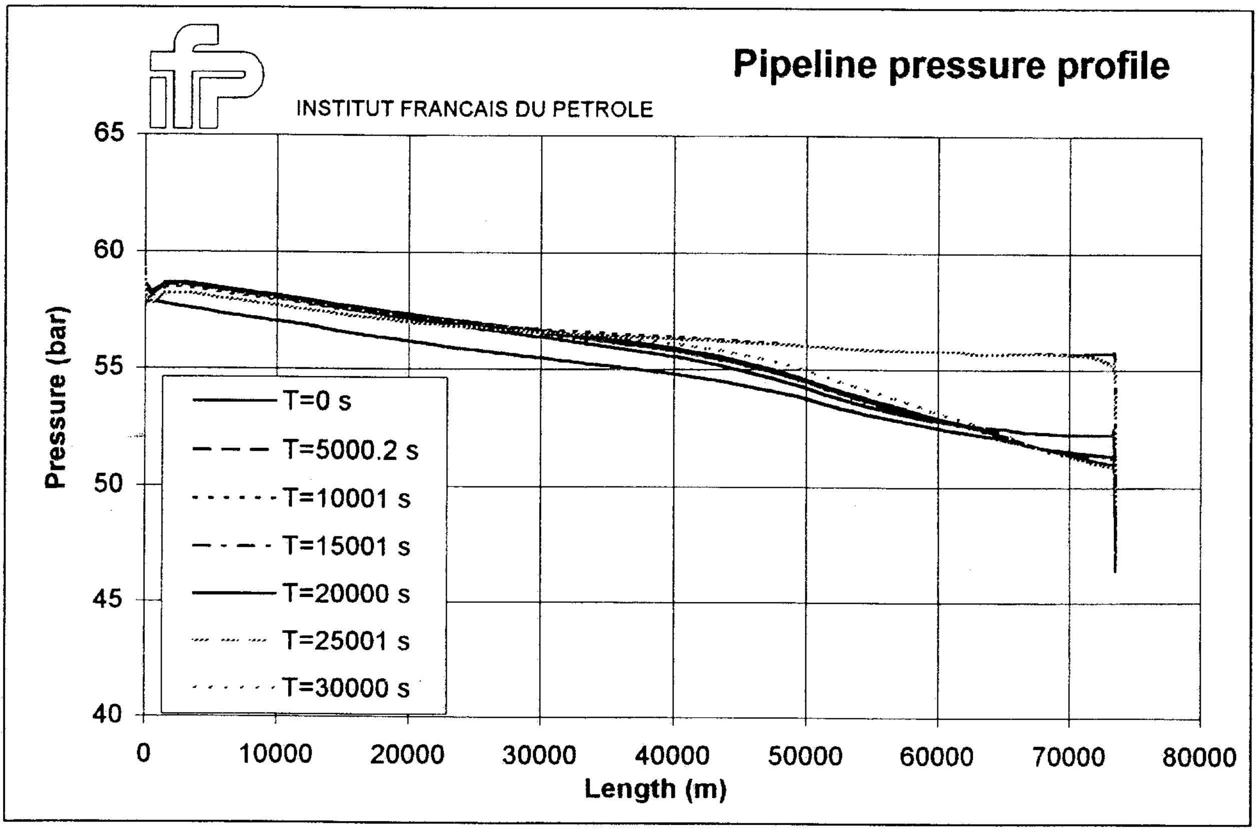
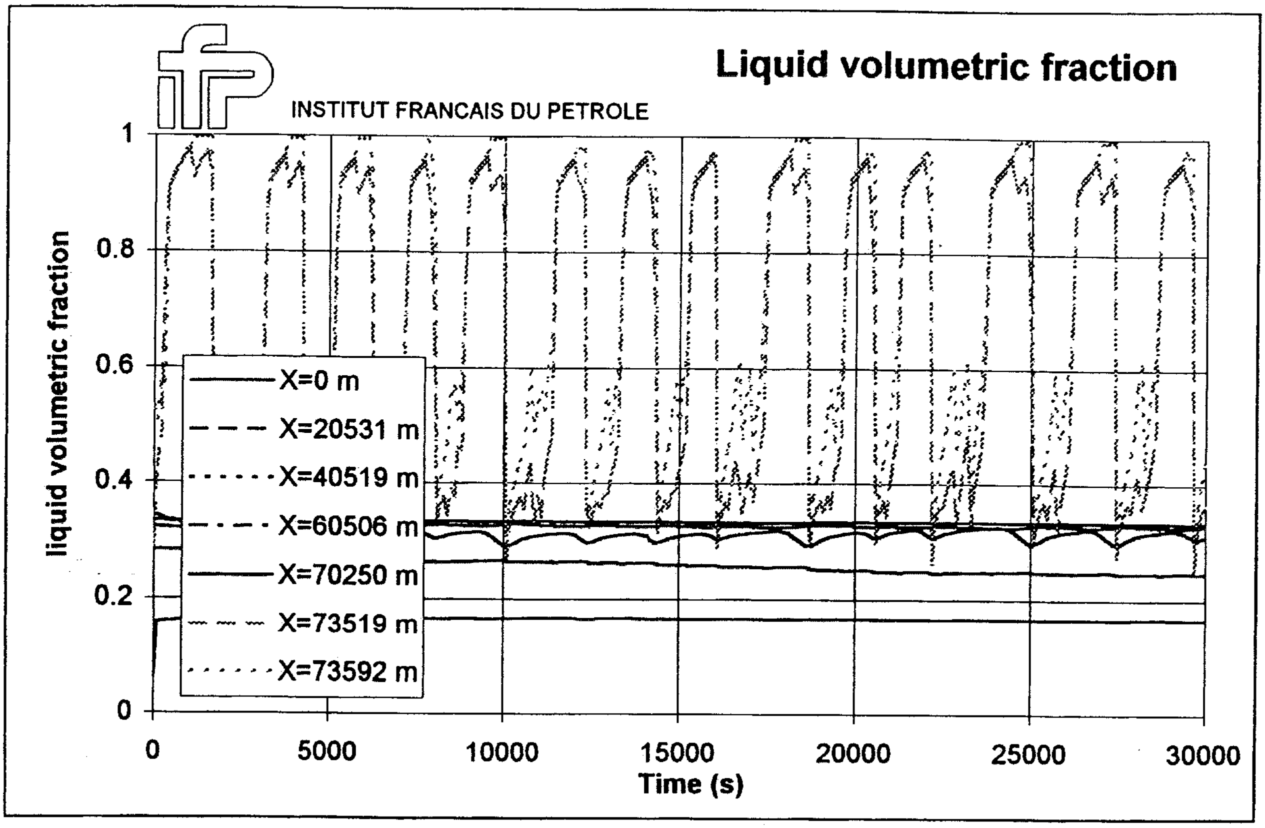


FIGURE 2 - Pipeline operation without multiphase pump
Flow conditions : 50 MMSCFD (100%) and 7000 BPFD (100%)



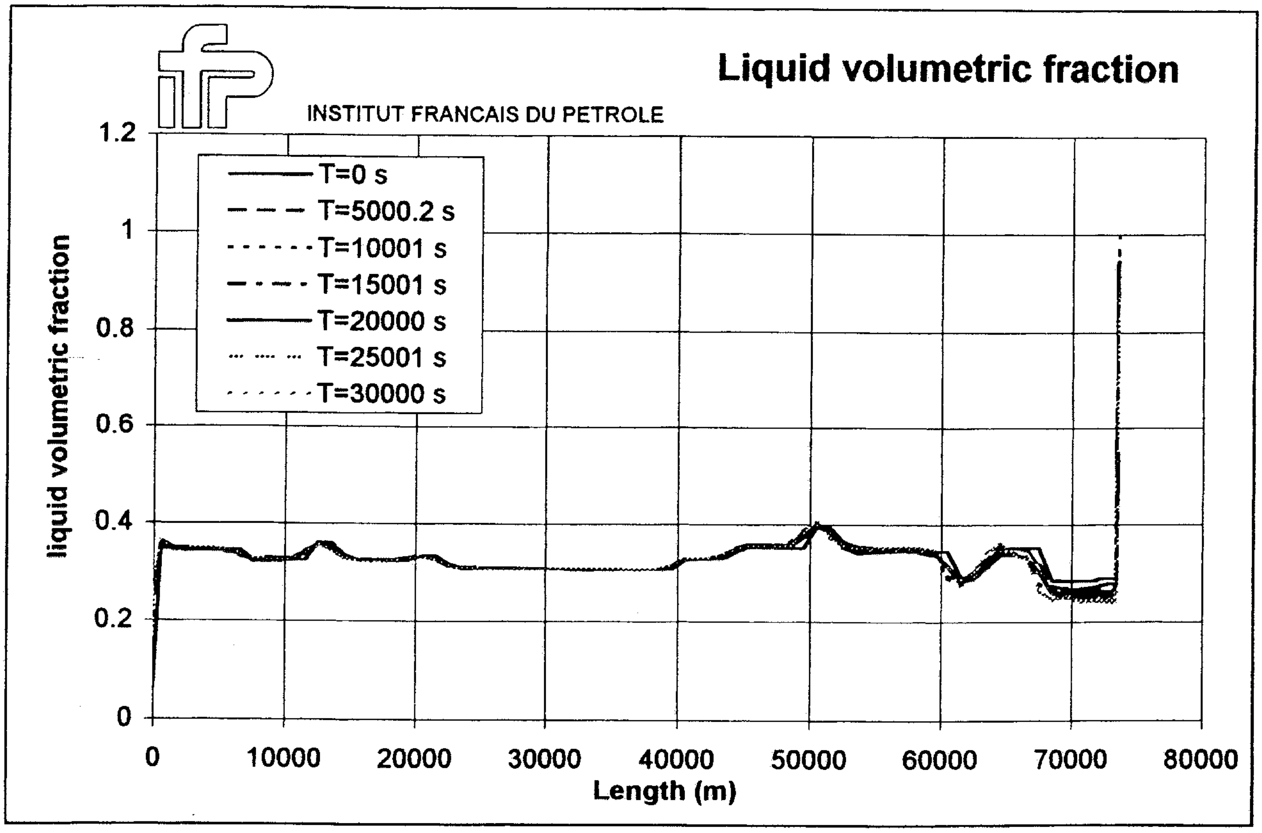
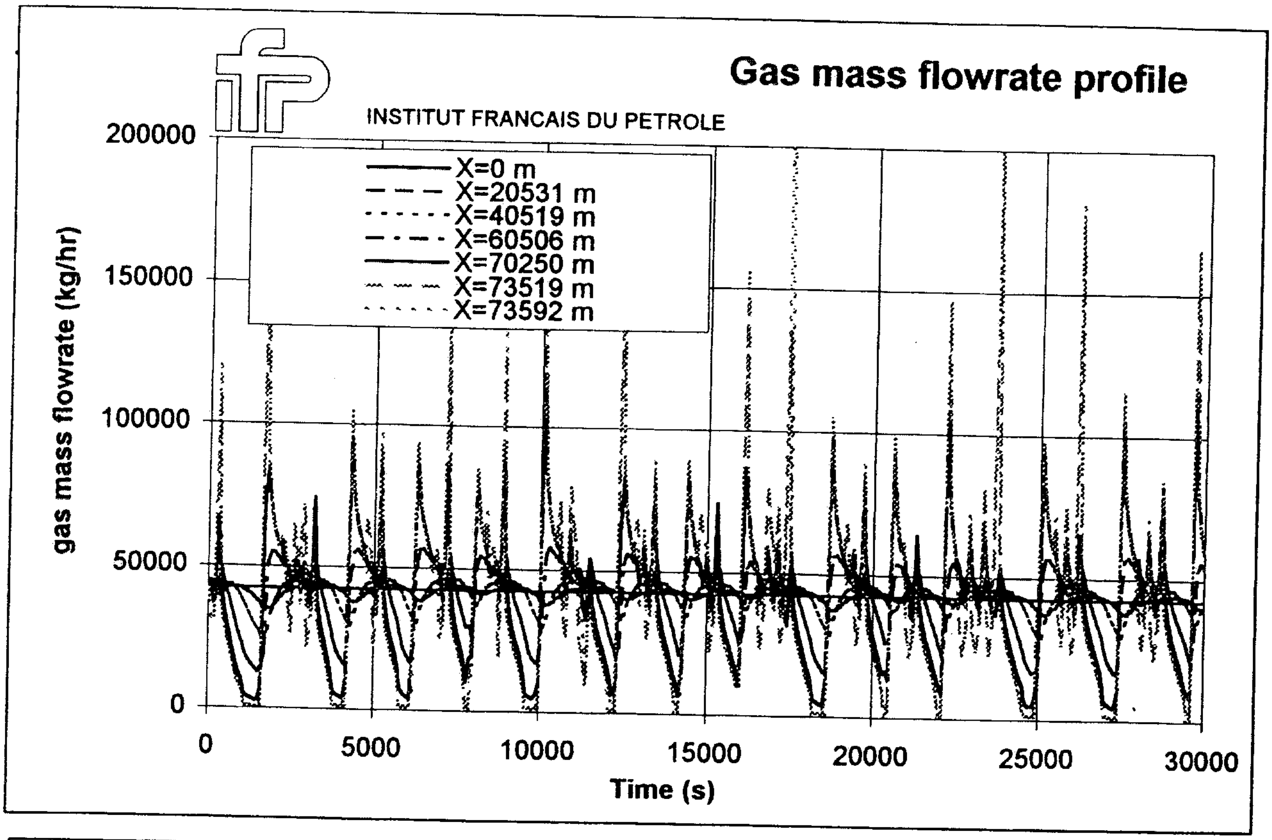


FIGURE 3 - Pipeline operation without multiphase pump
Flow conditions : 50 MMSCFD (100%) and 7000 BPFD (100%)



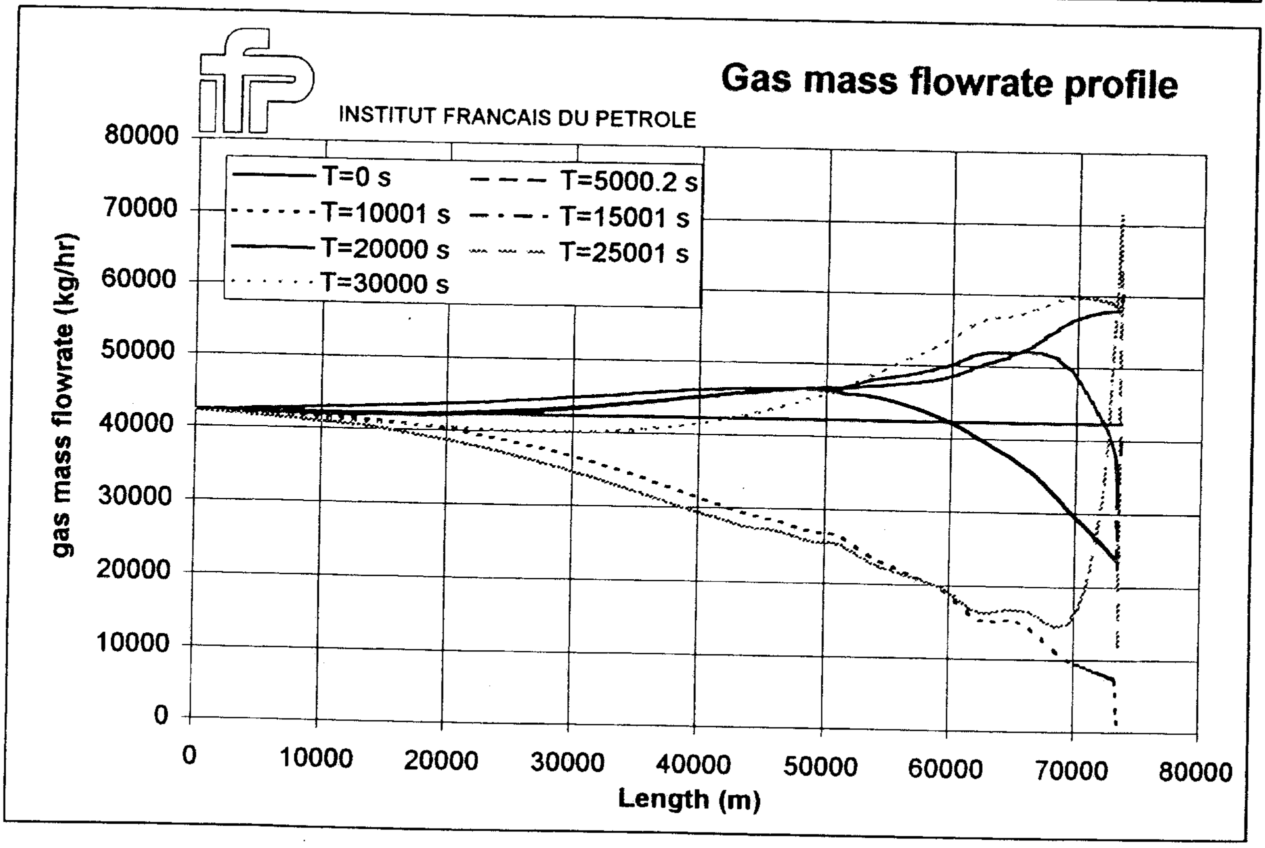
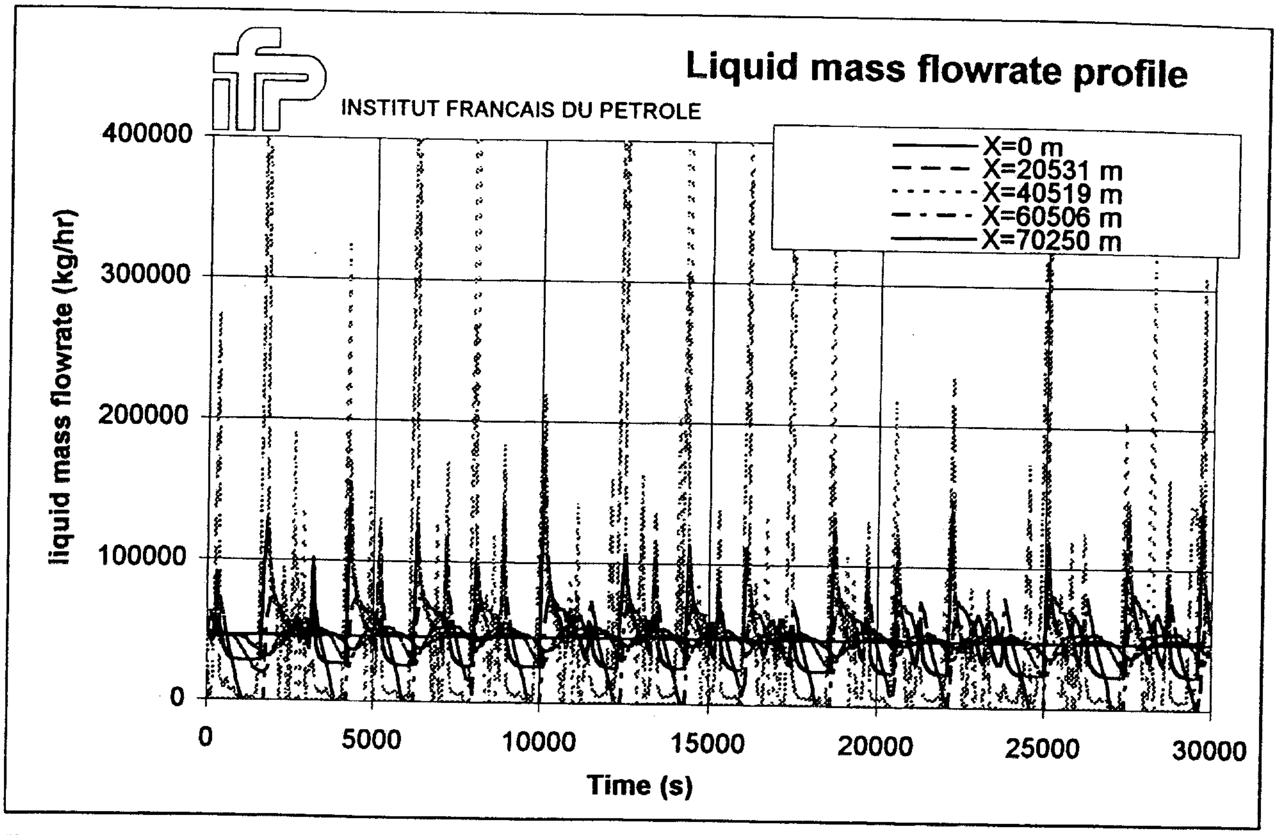


FIGURE 4 - Pipeline operation without multiphase pump
Flow conditions : 50 MMSCFD (100%) and 7000 BPFD (100%)



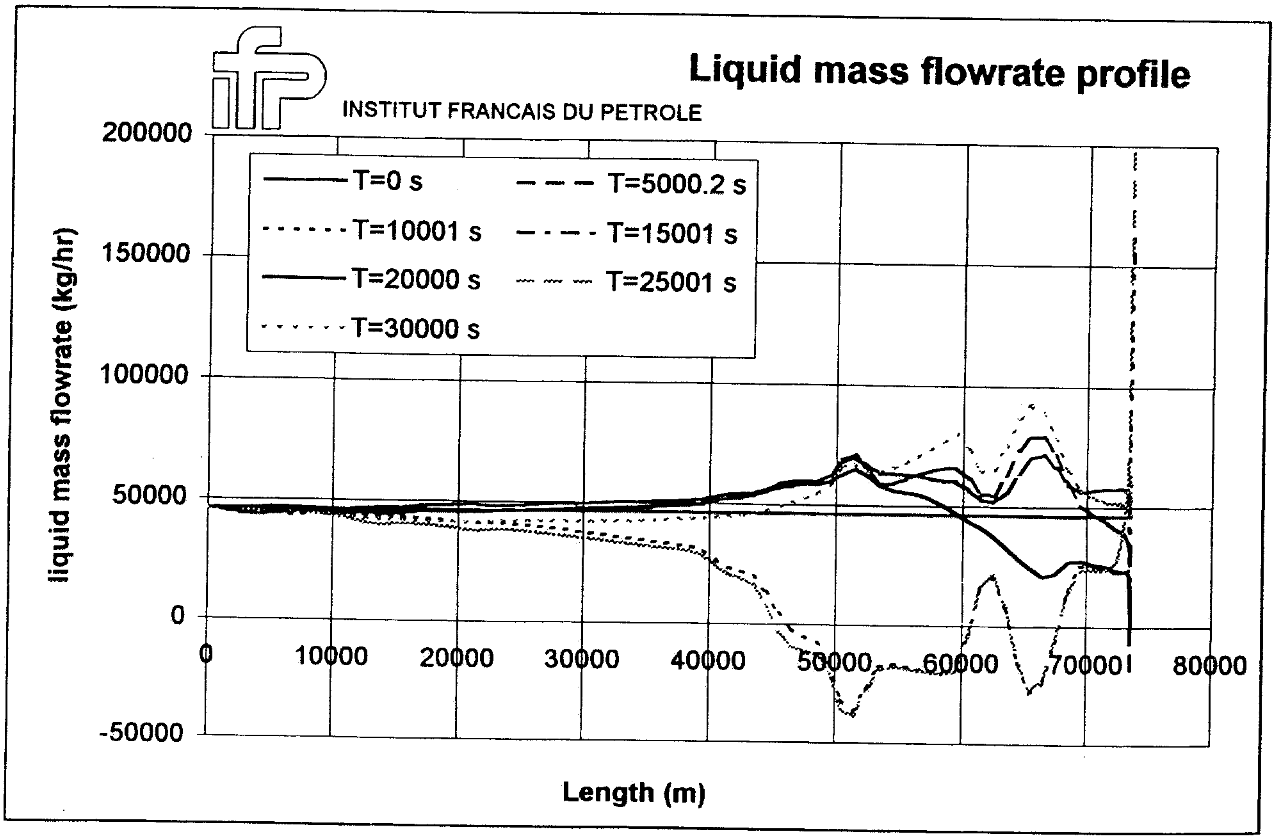


FIGURE 5 - Pipeline operation without multiphase pump
Flow conditions : 50 MMSCFD (100%) and 7000 BPFD (100%)

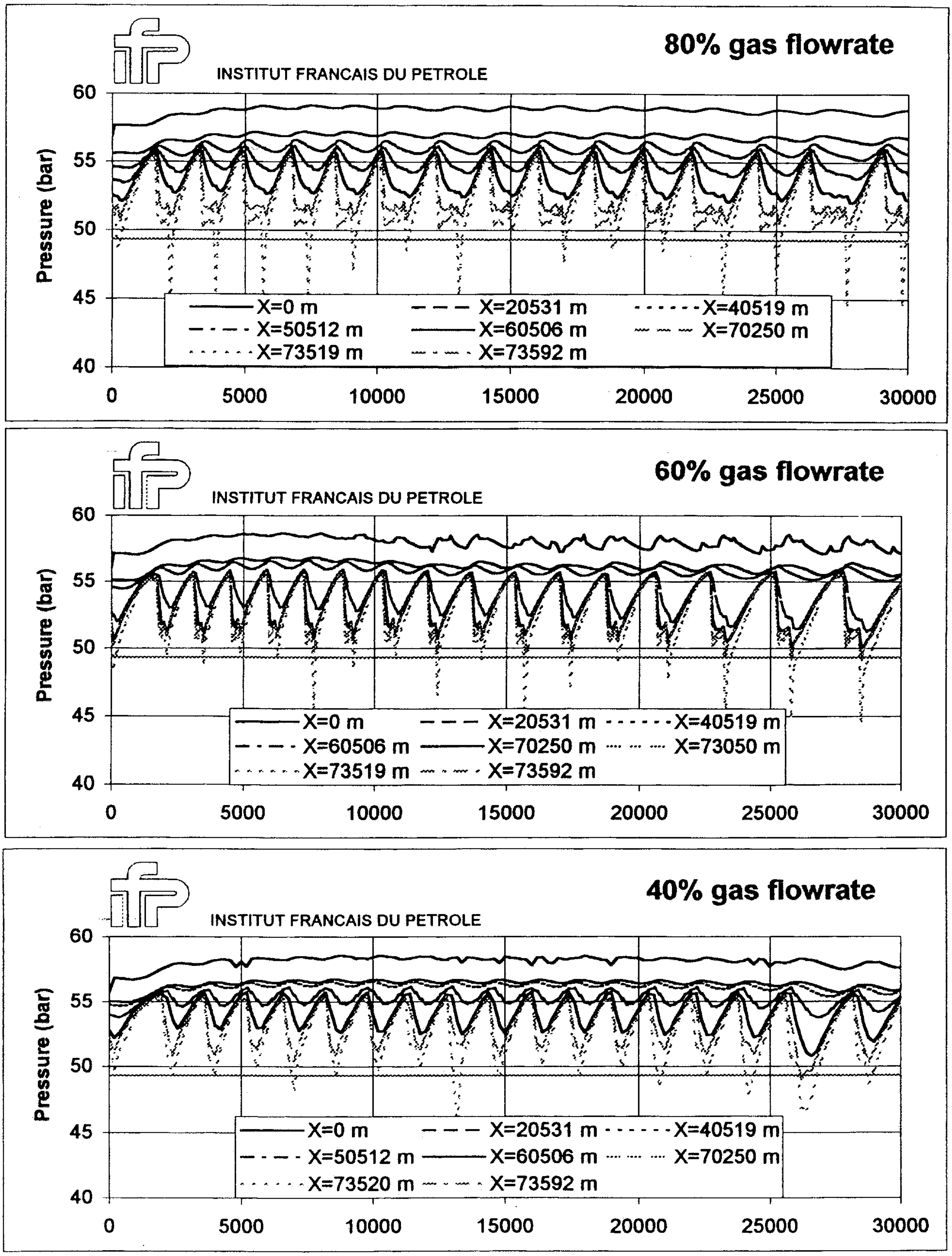
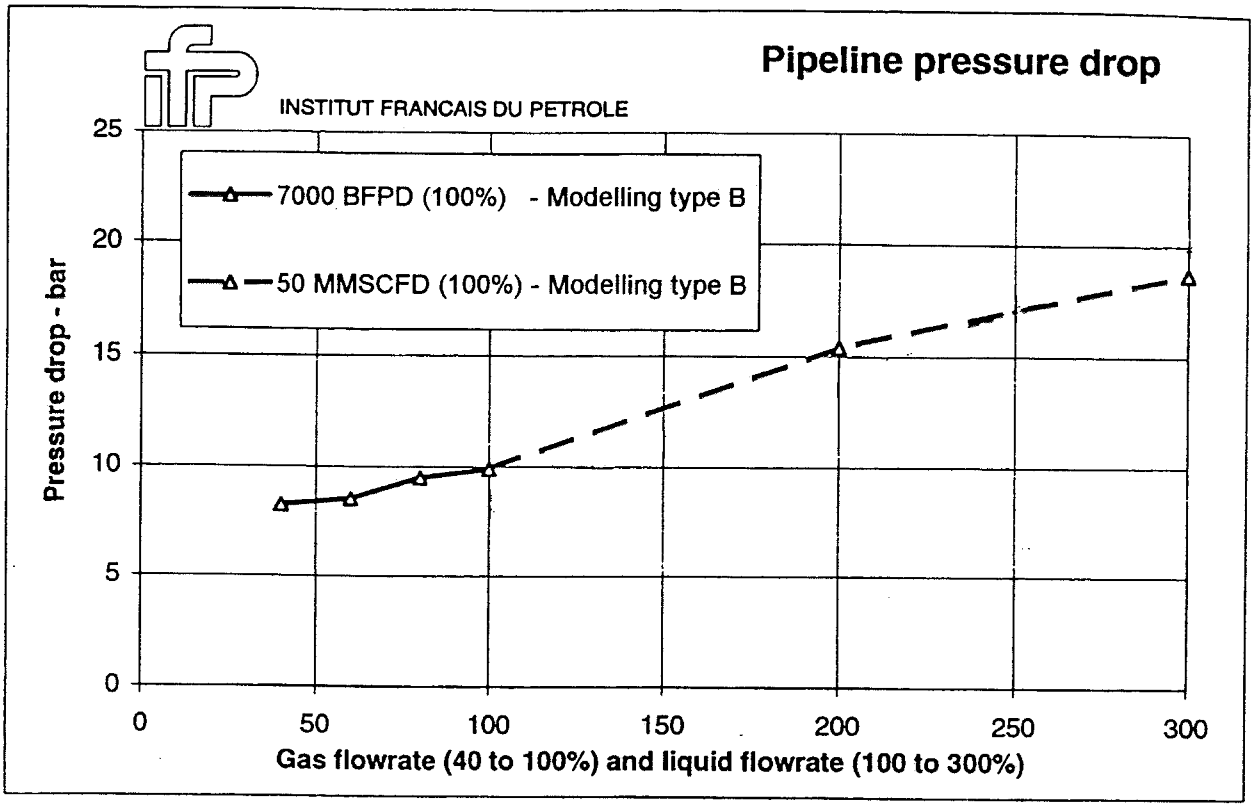


FIGURE 6 - Pipeline operation without multiphase pump
Pipeline pressure profile for various gas flowrates and
7000 BPFD (100%). Note:100% gas flowrate=50 MMSCFD



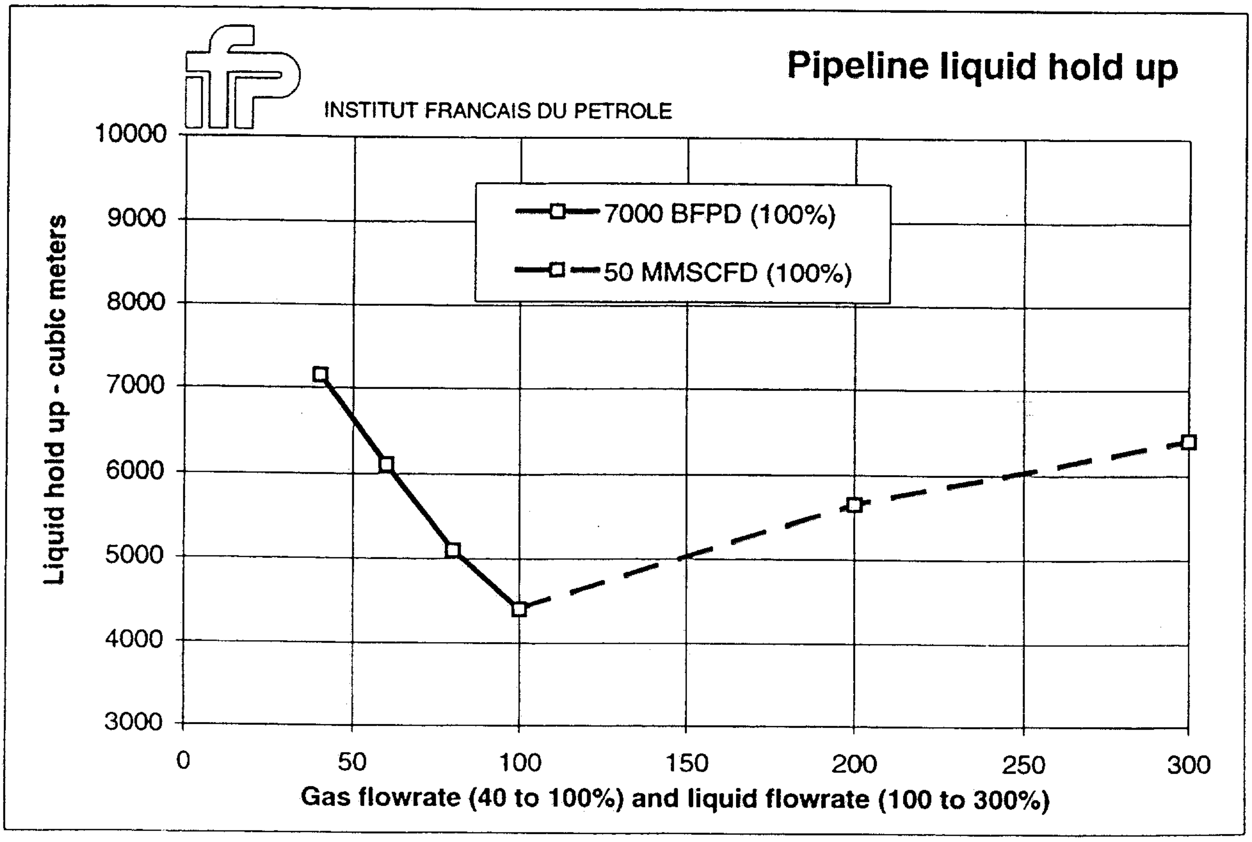
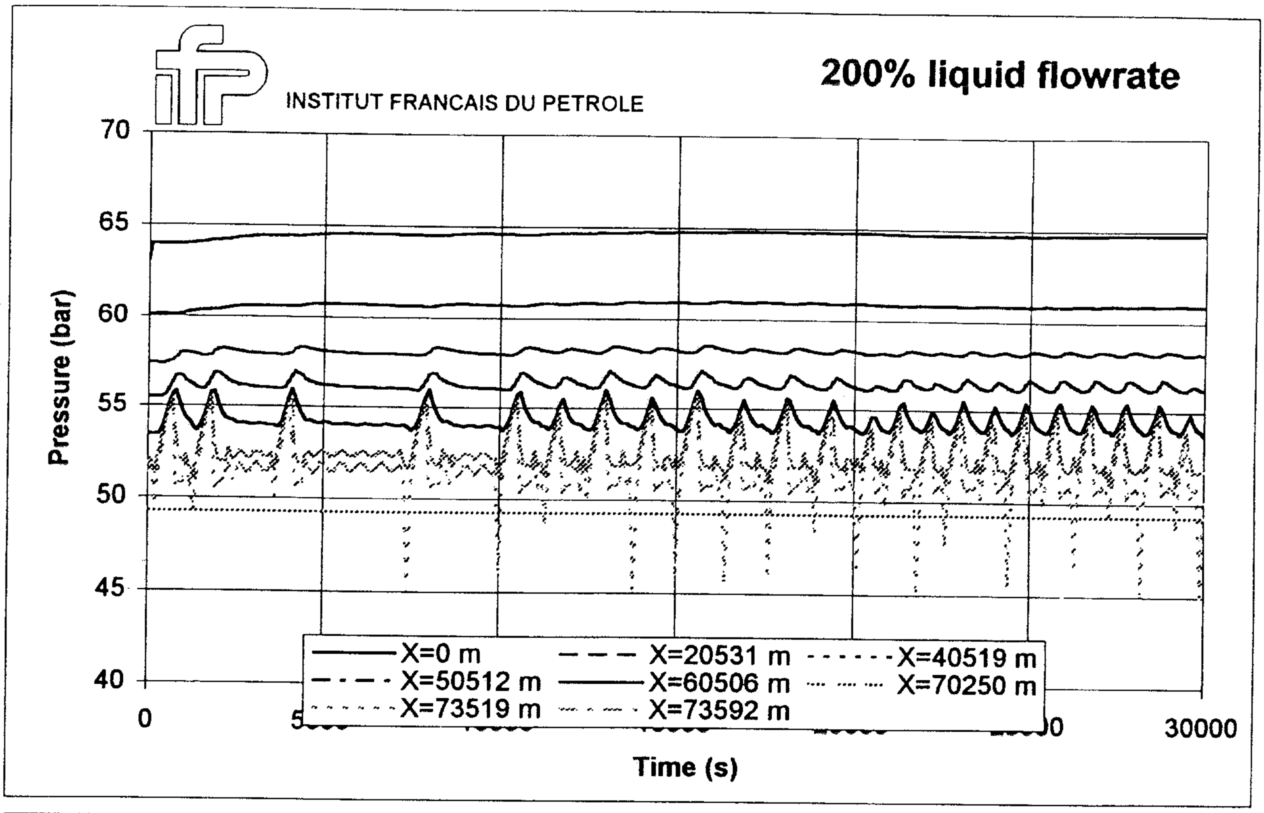


FIGURE 7 - Pipeline operation without multiphase pump
Pipeline pressure drop and liquid hold up for gas flowrate varying from 20 to 50 MMSCFD (7000 BPFD) and liquid flowrate varying from 7000 to 21000 BPFD (50 MMSCFD)



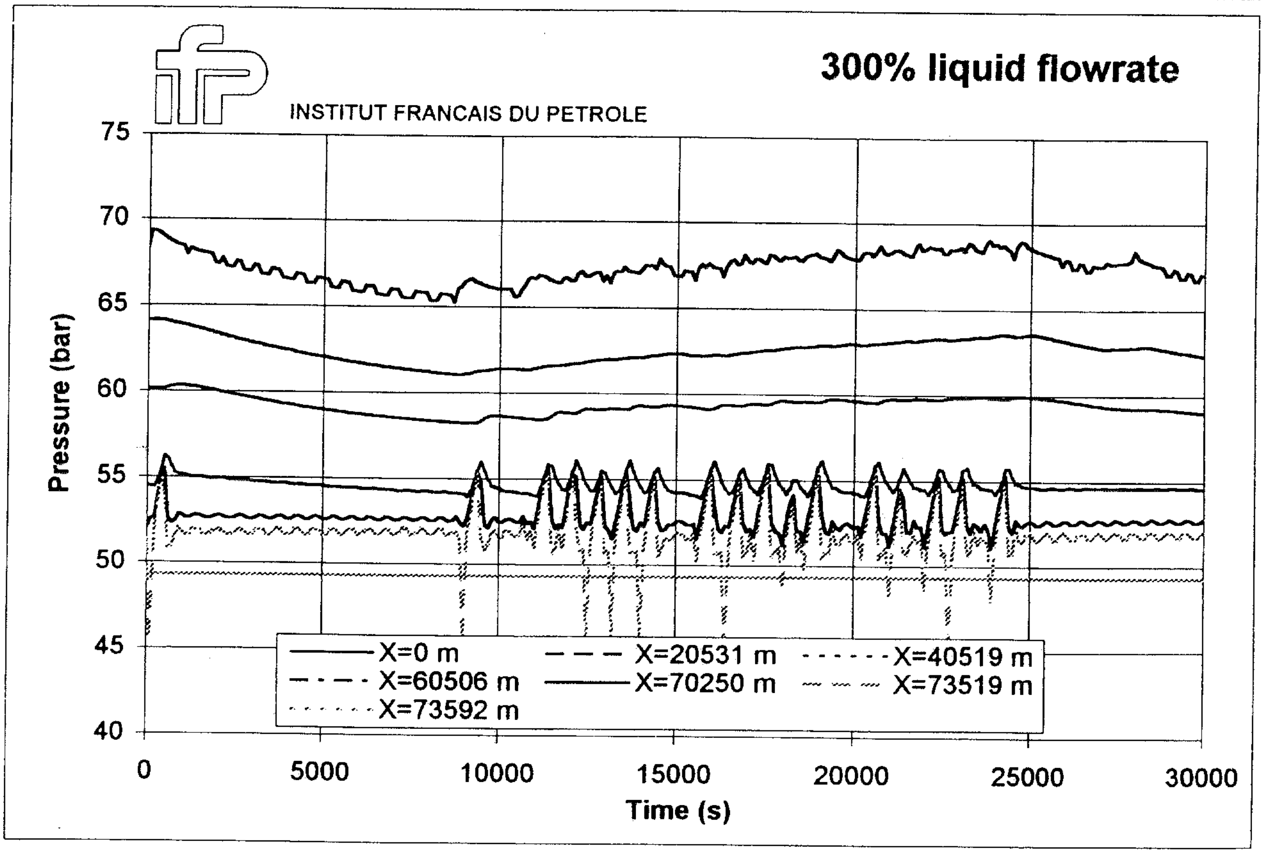
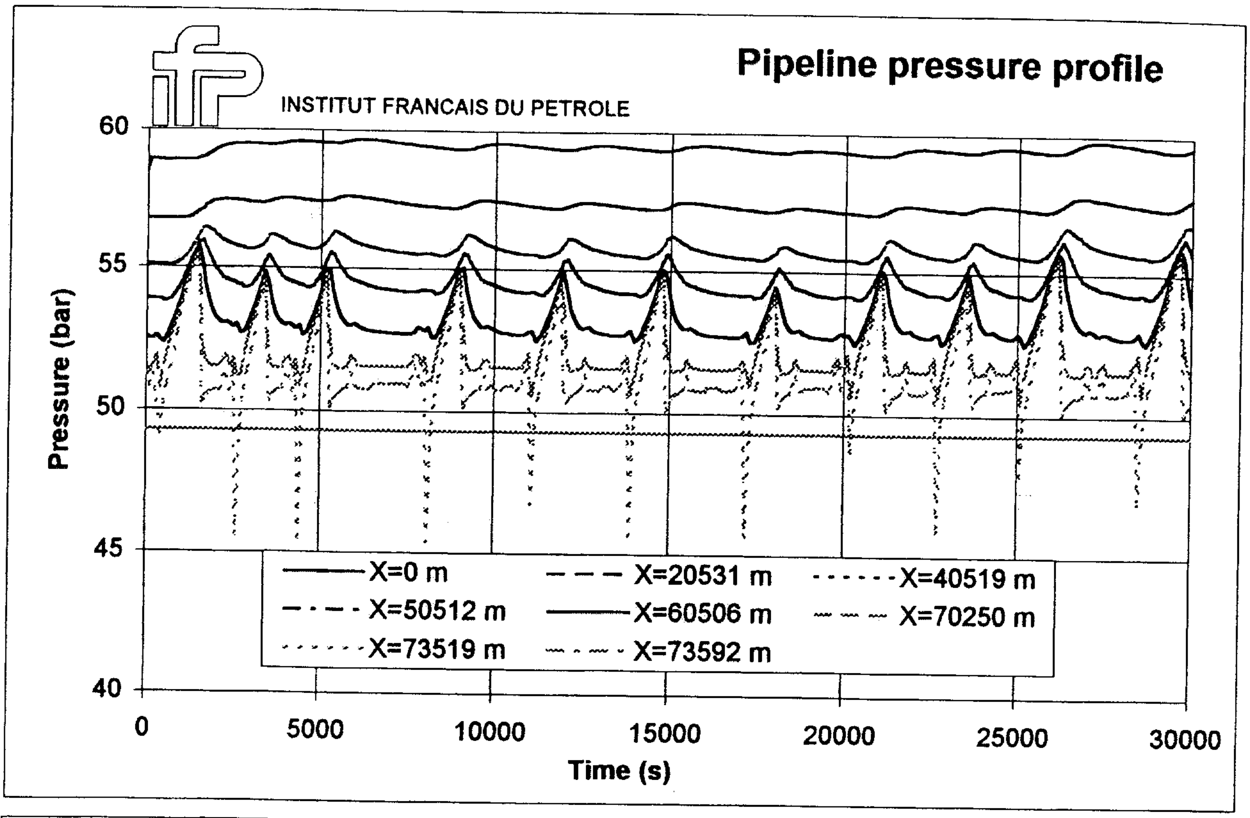


FIGURE 8 - Pipeline operation without multiphase pump
Pipeline pressure profile for various liquid flowrates and
50 MMSCFD (100%). 100% liquid flowrate=7000 BPFD



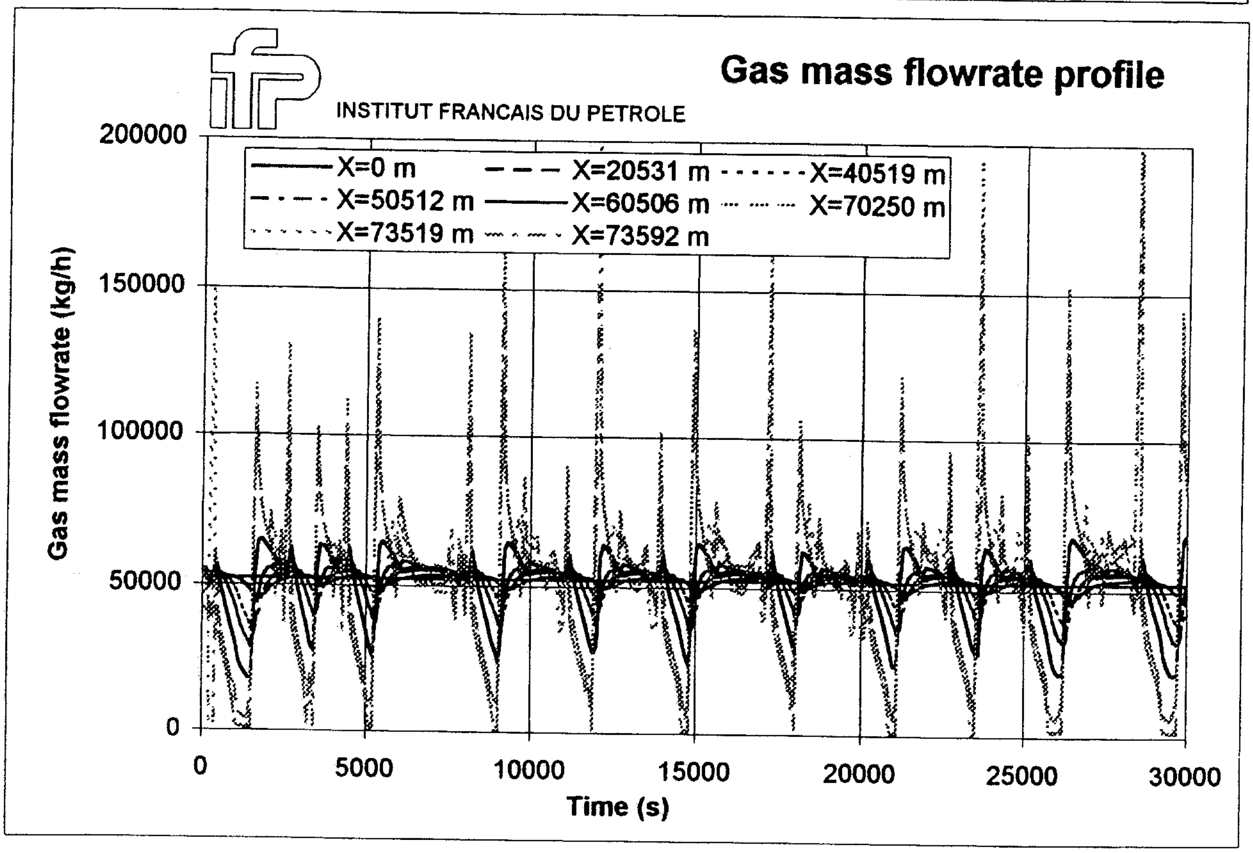
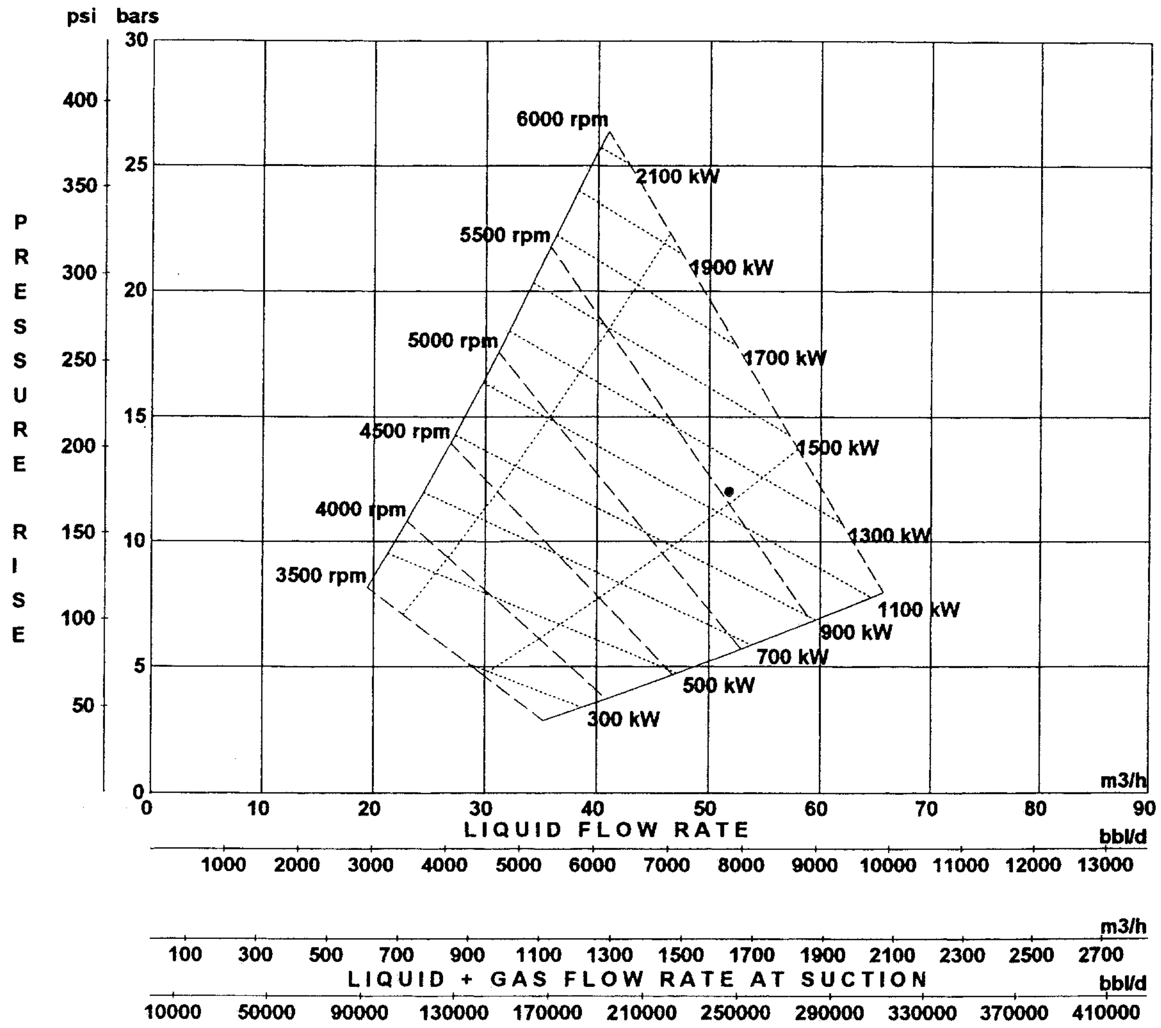
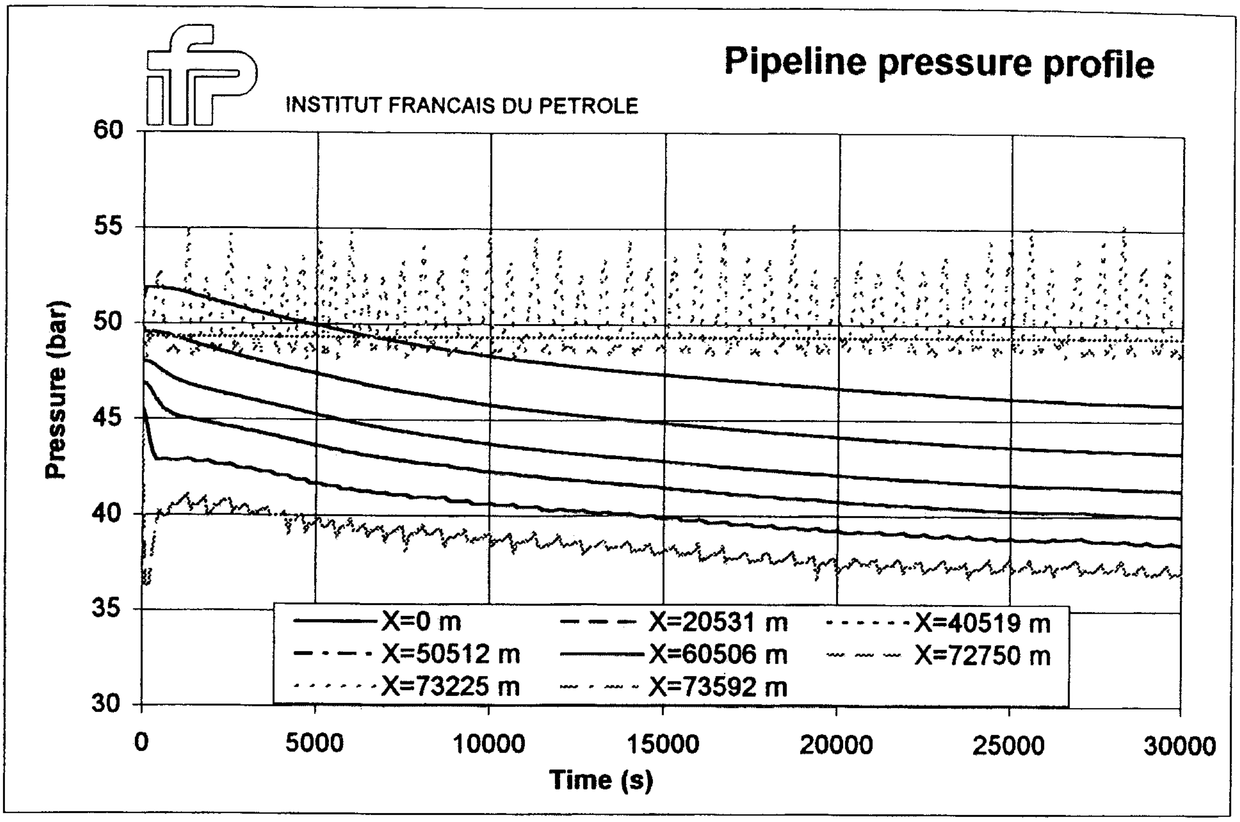


FIGURE 9 - Pipeline operation without multiphase pump
Flow conditions : 50 MMSCFD (100%) and 7000 BPFD (100%)
Gas specific gravity = 0.725

SULZER PUMPS LTD	MULTIPHASE PUMP PERFORMANCE CURVE	FIGURE 10 Date : Created by :
Pump Type : MPP 8	**Project :**	
SUCTION CONDITIONS : **Psuc : 39 bara / 565.5 psia** **GVF : 97 %** **GLR : 30.5 vol/vol**	Comments :	



File name : A30.MPP	Hydraulic results from DP2PHI - Vers. 3.1 (Apr.95) - IFP
Note : Above curves show the power absorbed by the sum of all stages, add mechanical losses to get the power required at the coupling	



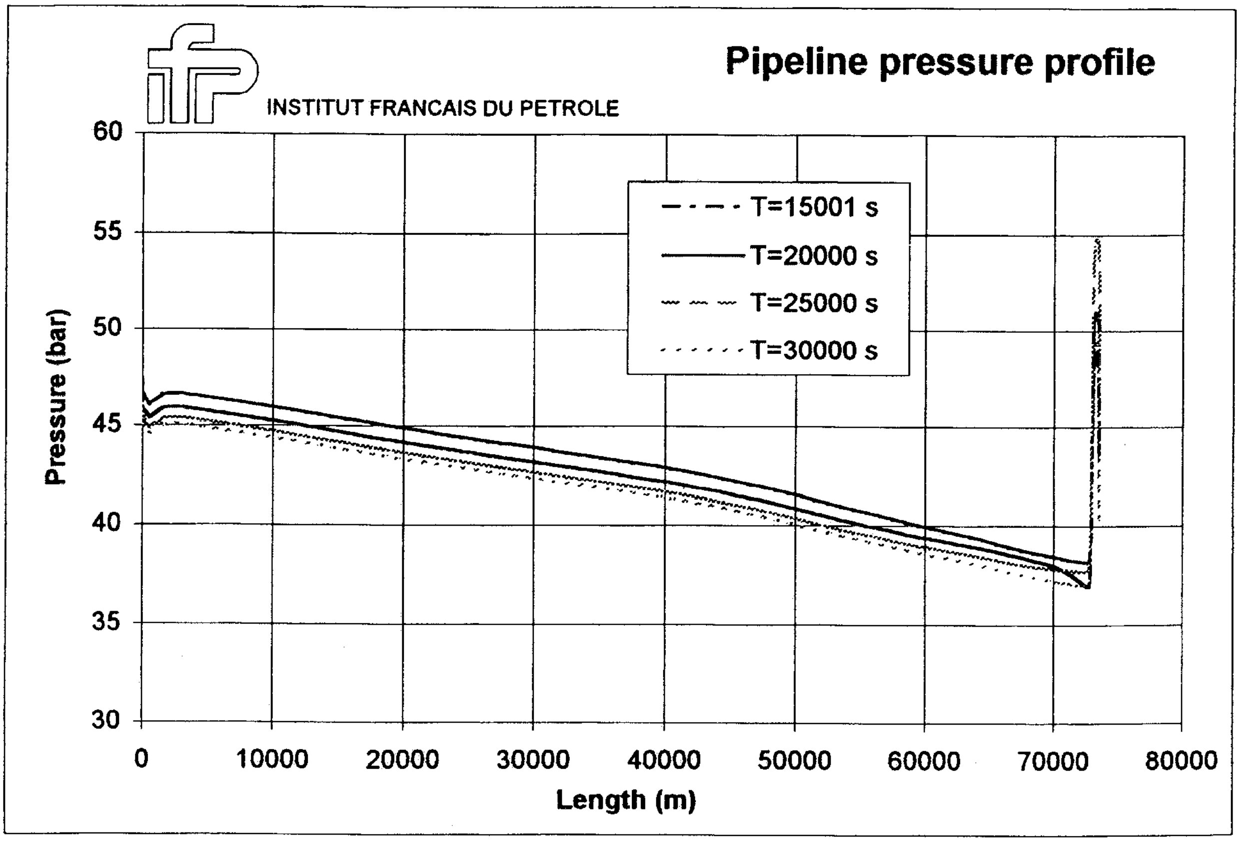
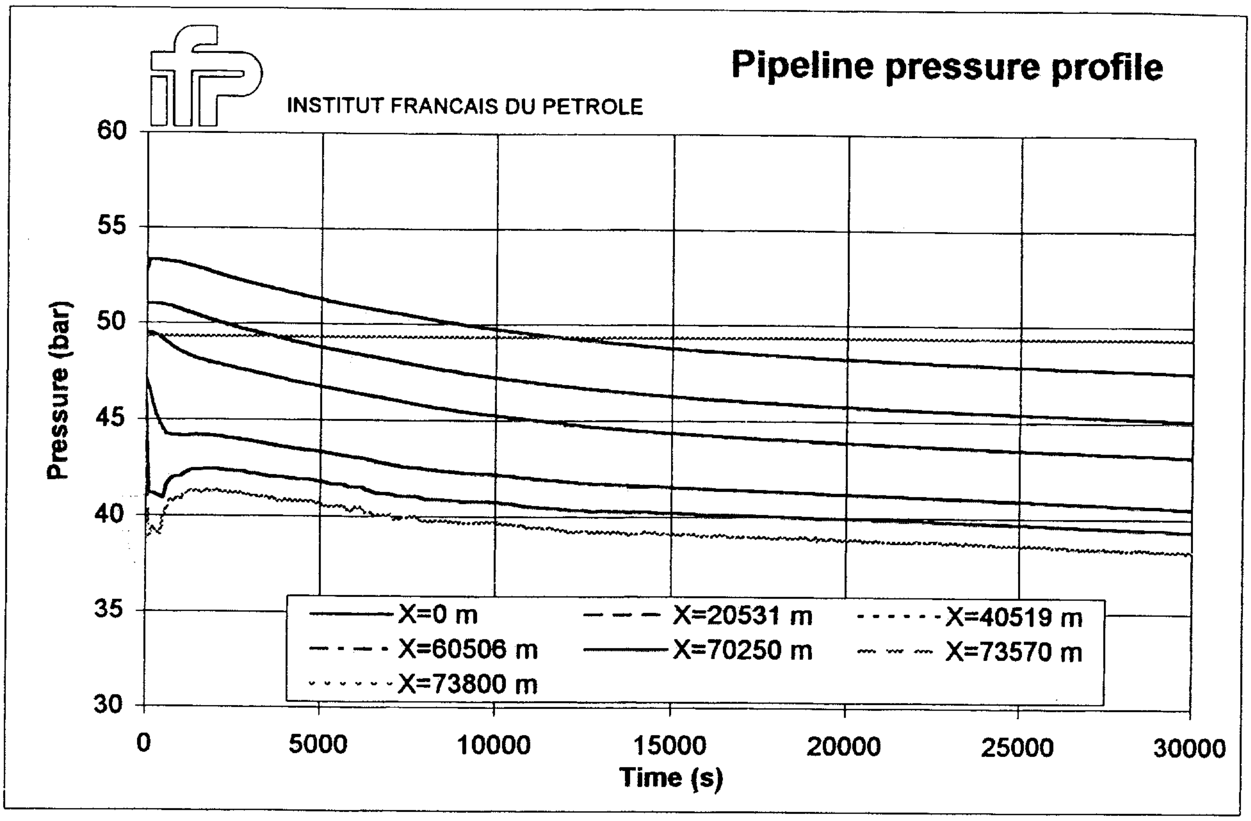


FIGURE 11 - Pipeline operation with a subsea multiphase pump installed at bottom of riser.
Flow conditions : 50 MMSCFD (100%) and 7000 BPFD (100%)



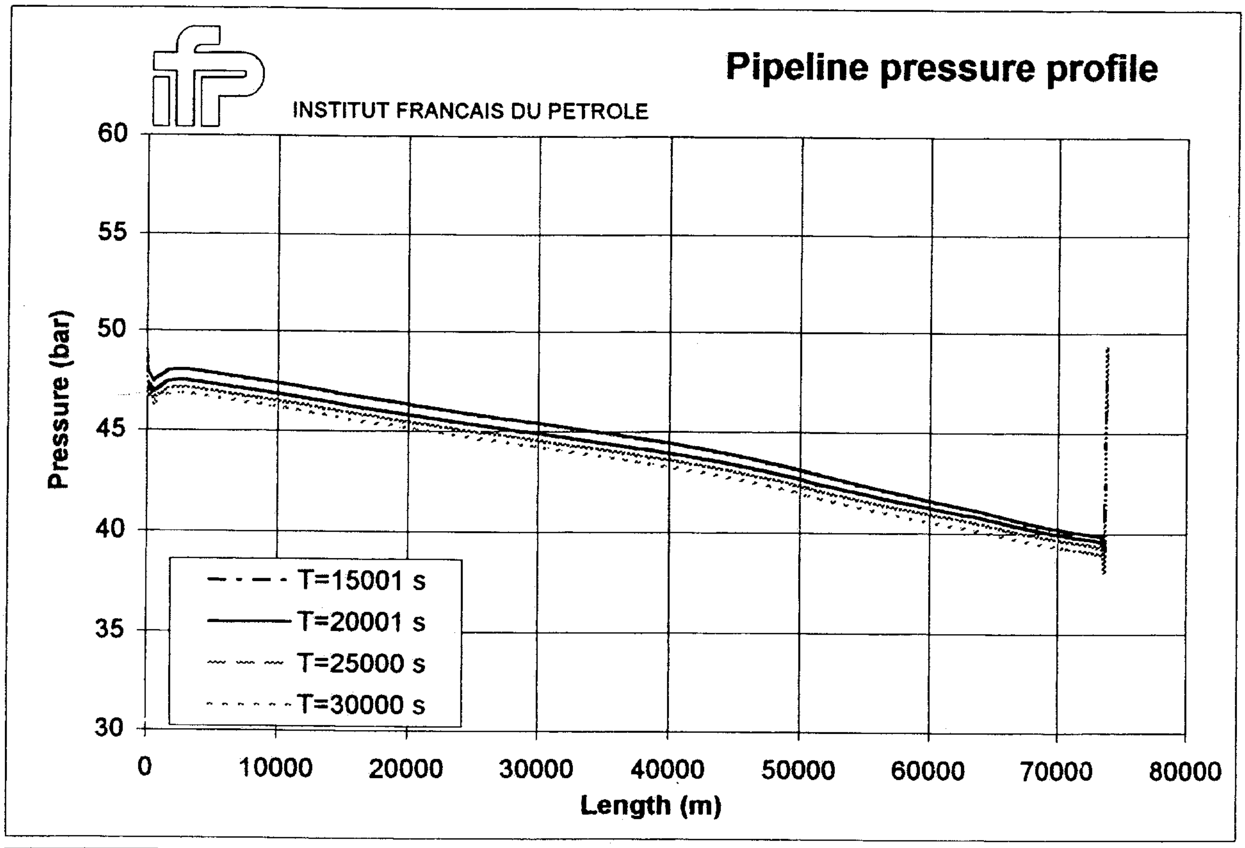
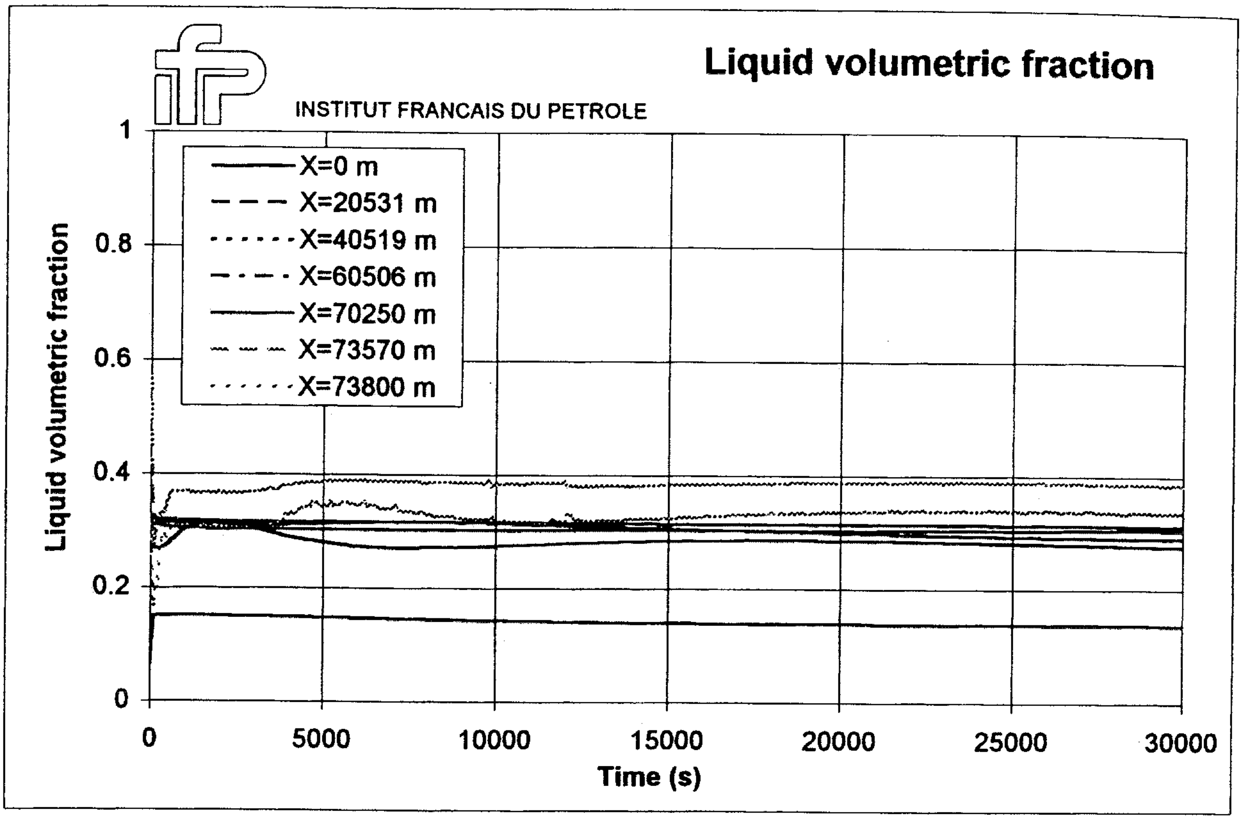


FIGURE 12 - Pipeline operation with a topside multiphase pump installed on the production platform.
Flow conditions : 50 MMSCFD (100%) and 7000 BPFD (100%)



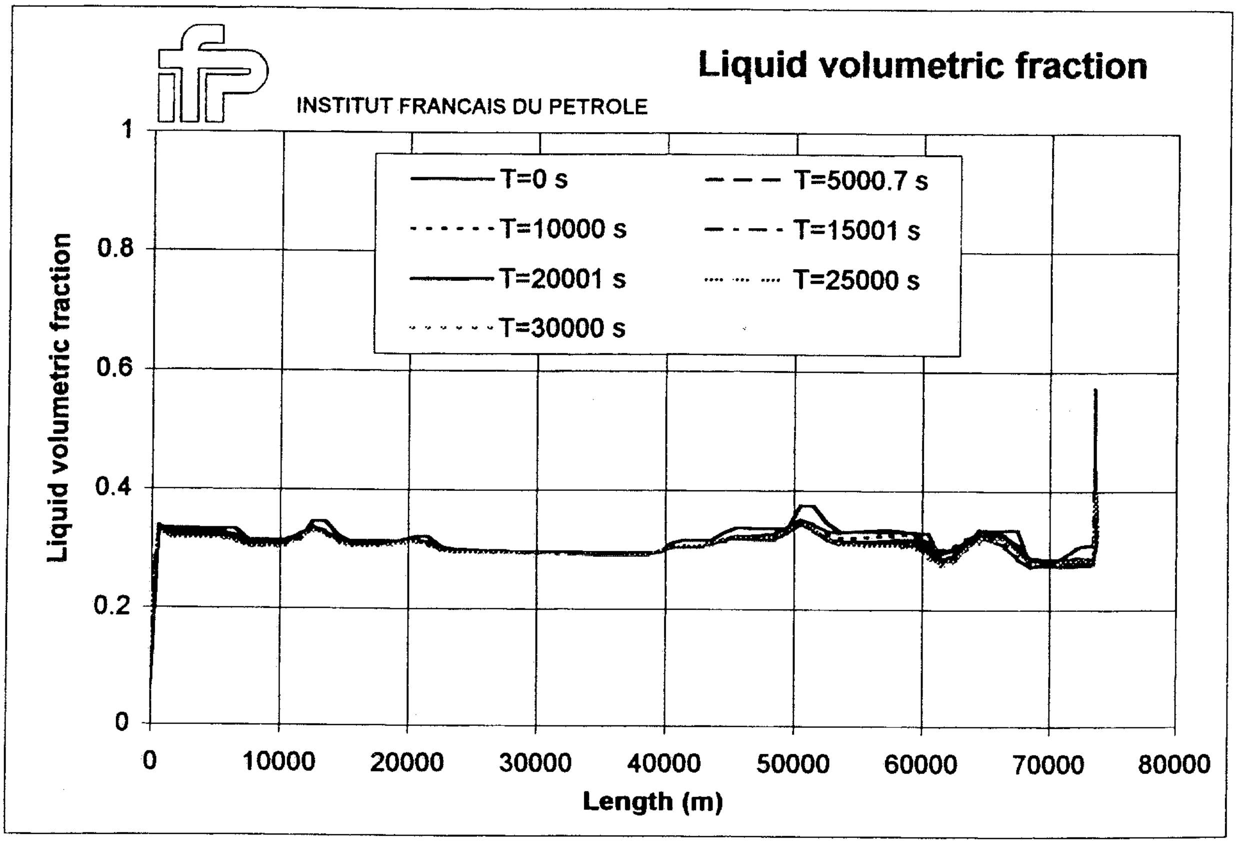
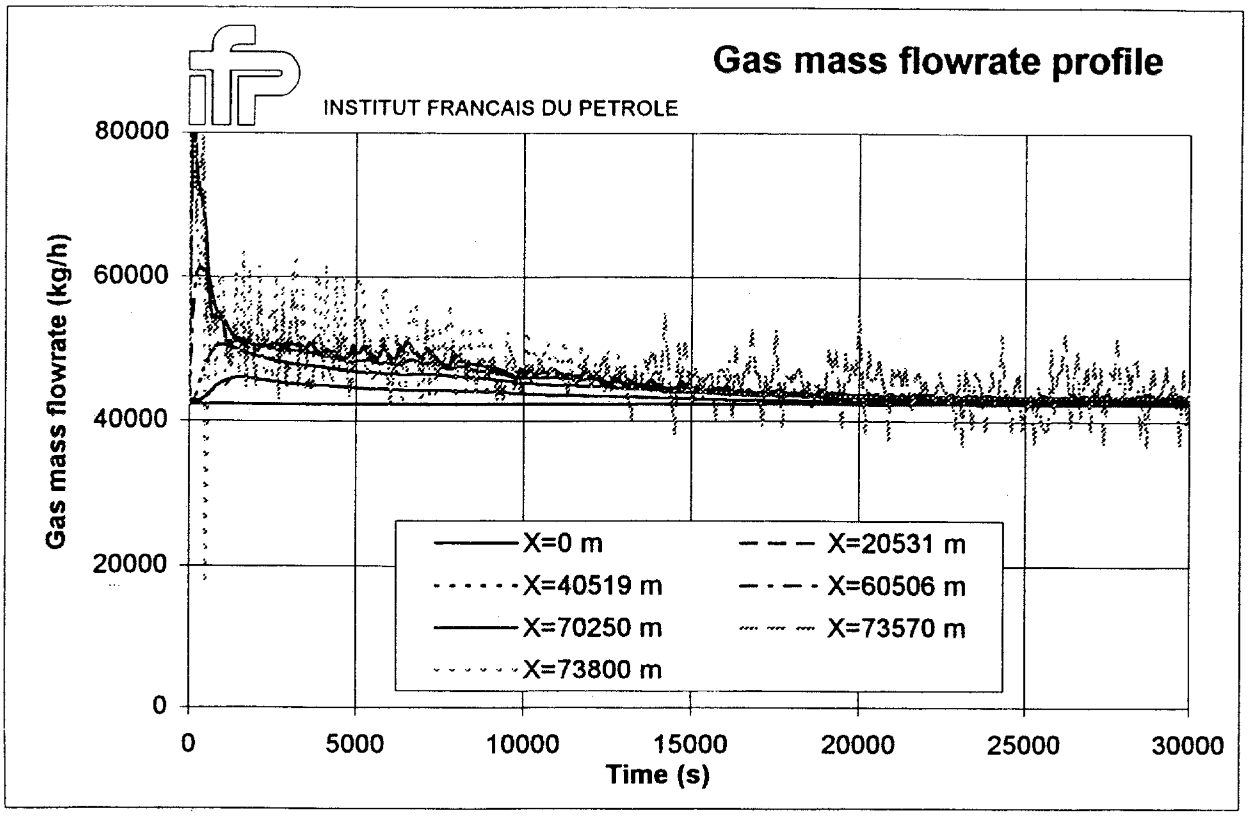


FIGURE 13 - Pipeline operation with a topside multiphase pump installed on the production platform.
Flow conditions : 50 MMSCFD (100%) and 7000 BPFD (100%)



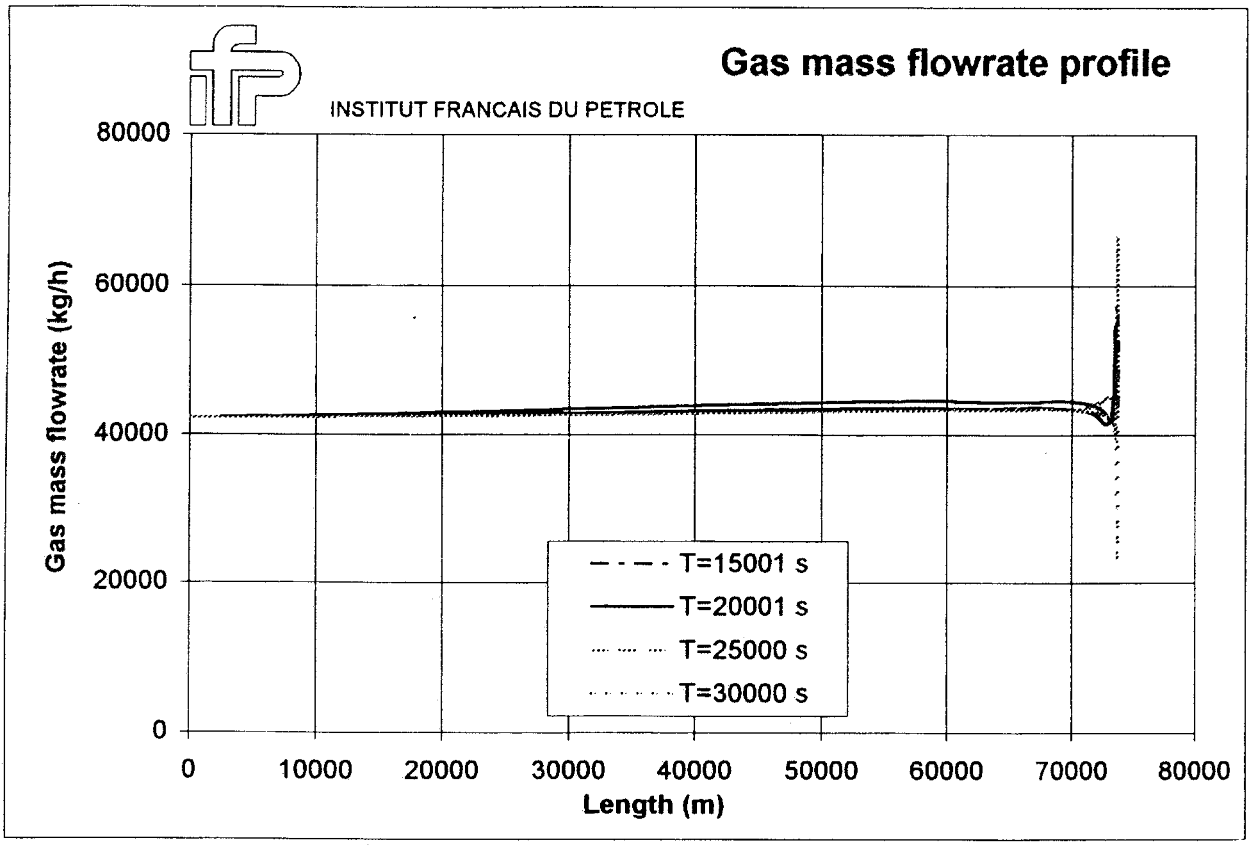
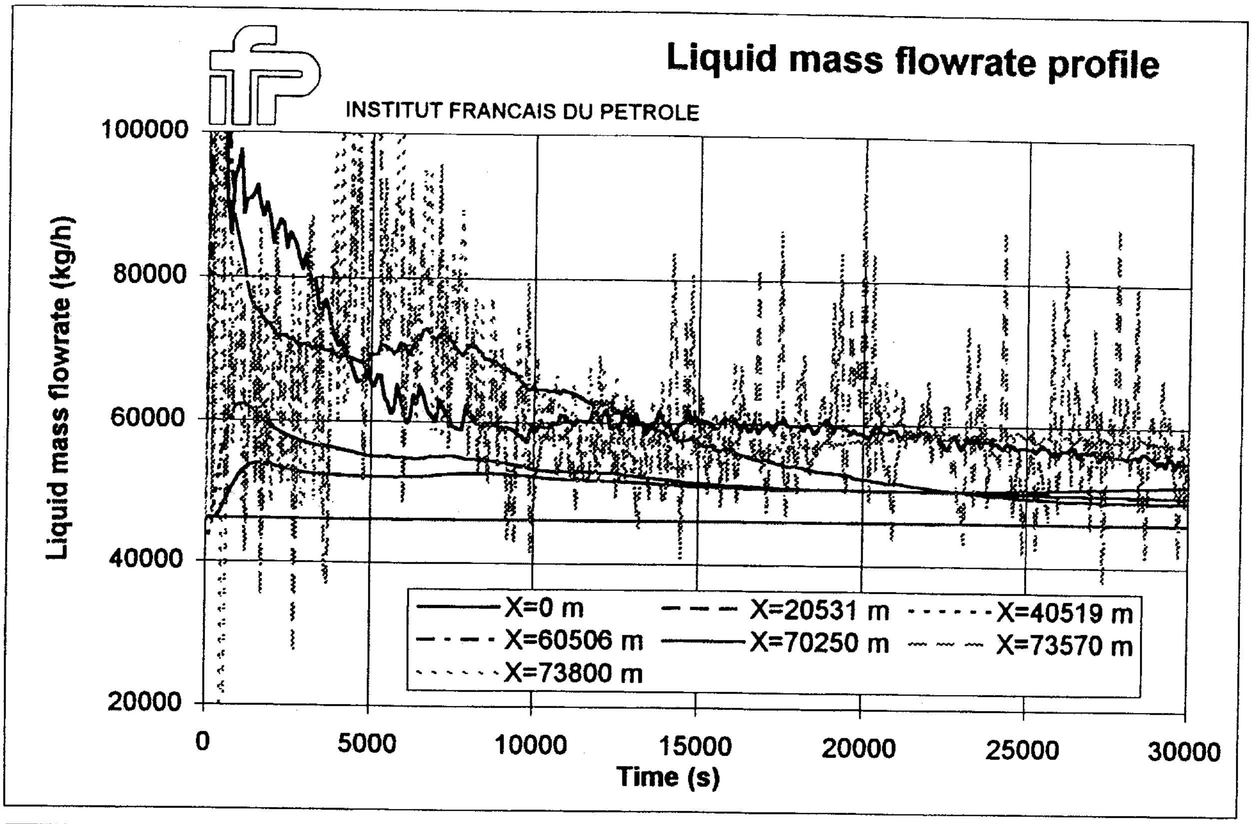


FIGURE 14 - Pipeline operation with a topside multiphase pump installed on the production platform.
Flow conditions : 50 MMSCFD (100%) and 7000 BPFD (100%)



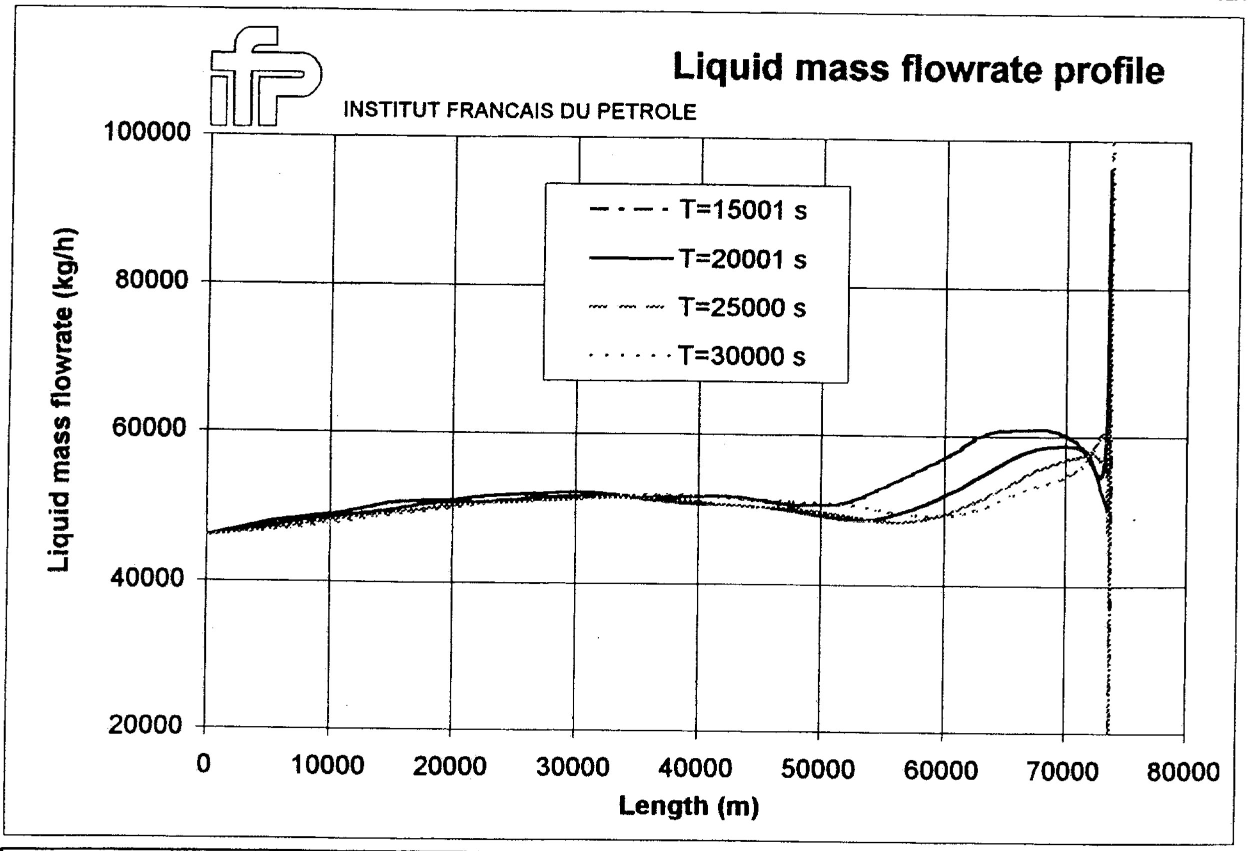
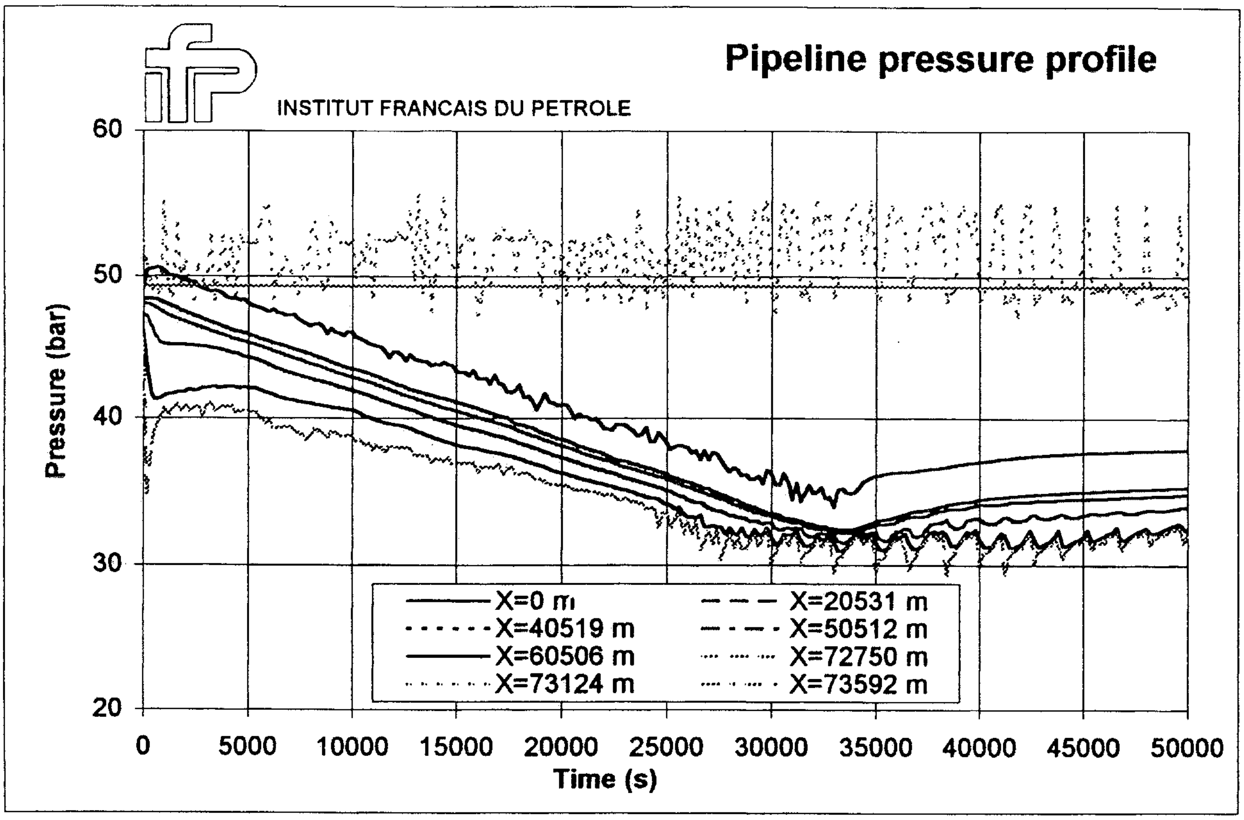


FIGURE 15 - Pipeline operation with a topside multiphase pump installed on the production platform.
Flow conditions : 50 MMSCFD (100%) and 7000 BPFD (100%)



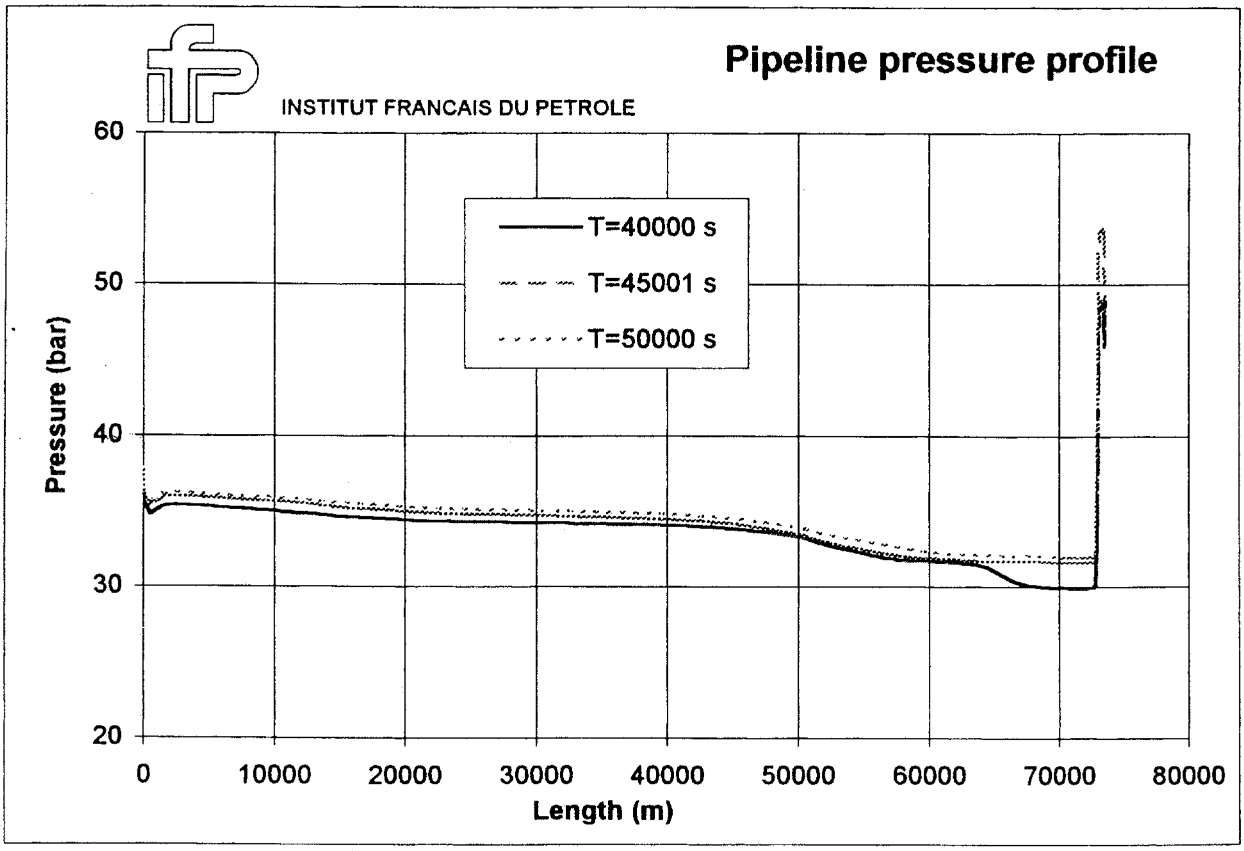
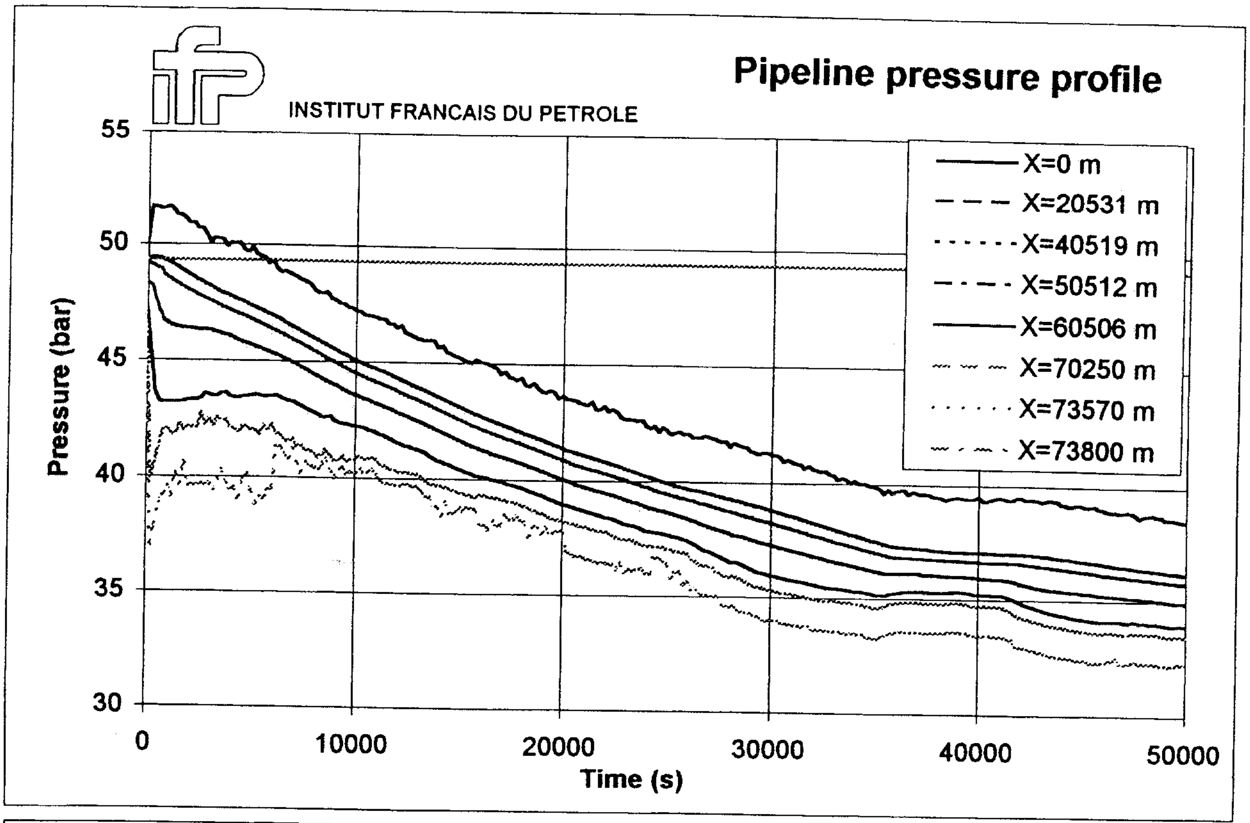


FIGURE 16 - Pipeline operation with a subsea multiphase pump installed at bottom of riser.
Flow conditions : 20 MMSCFD (40%) and 7000 BPFD (100%)



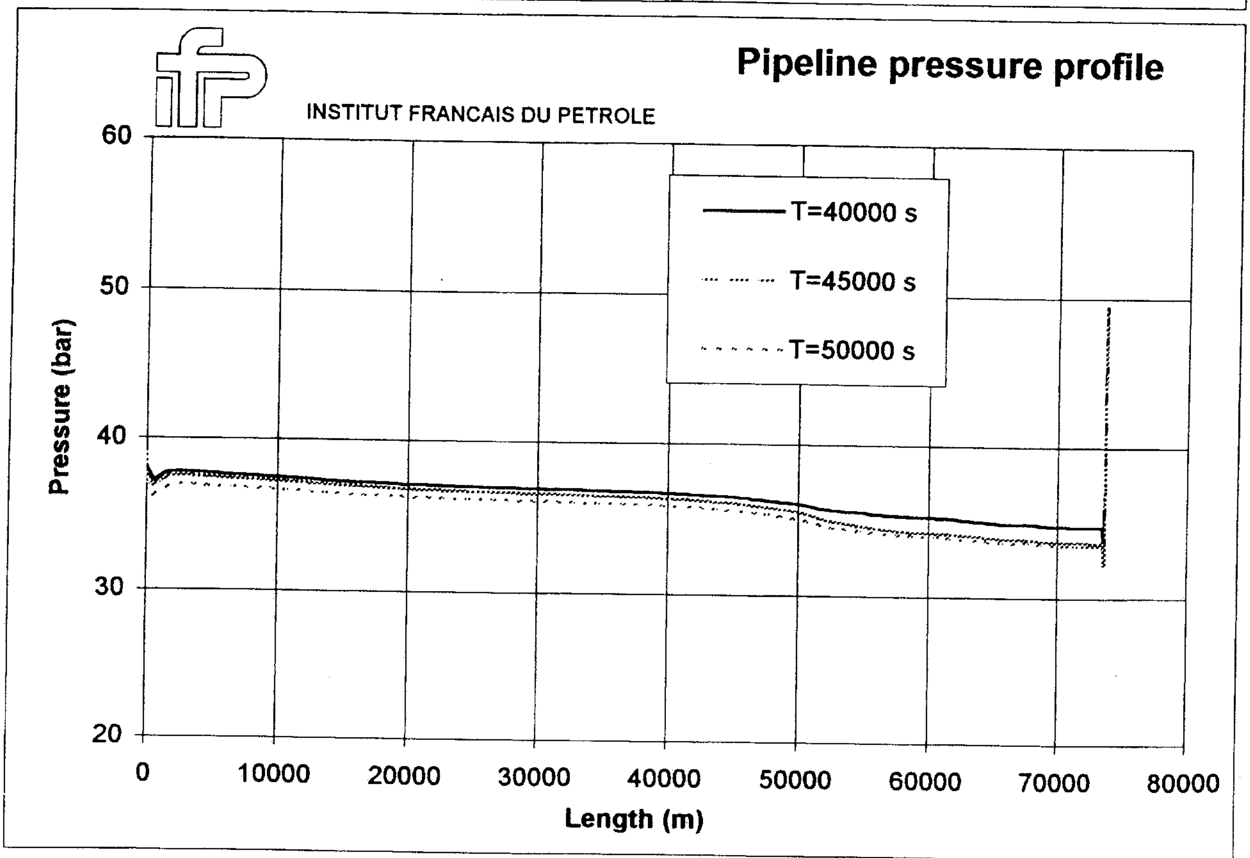
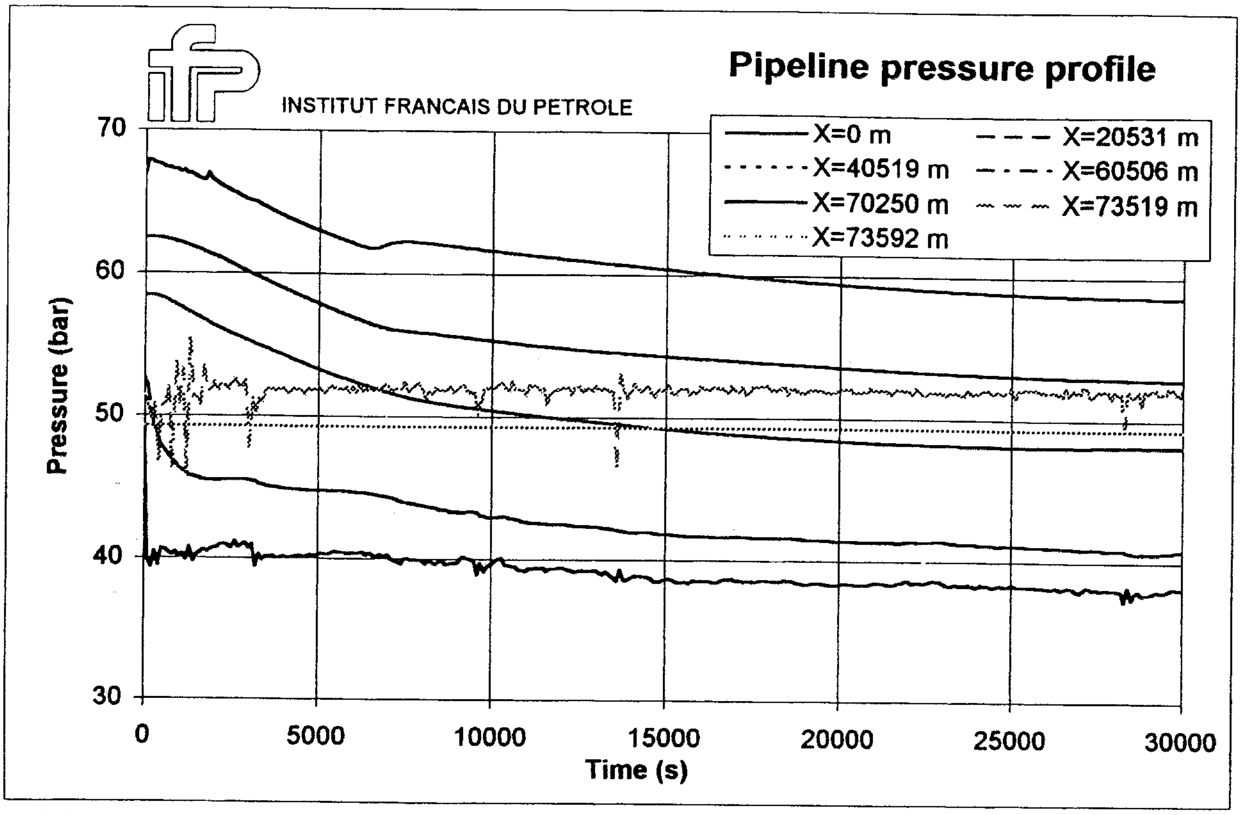


FIGURE 17 - Pipeline operation with a topside multiphase pump installed on the production platform.
Flow conditions : 20 MMSCFD (40%) and 7000 BPFD (100%)



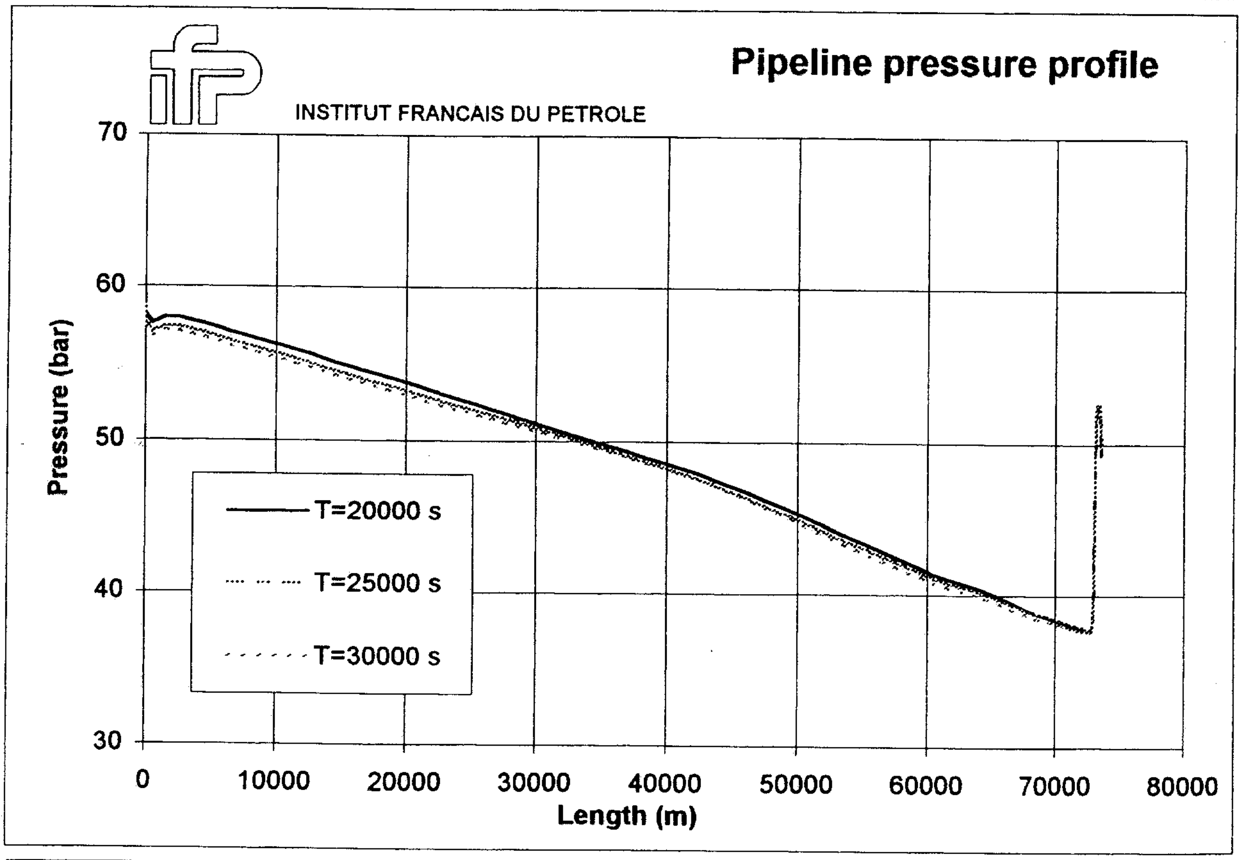
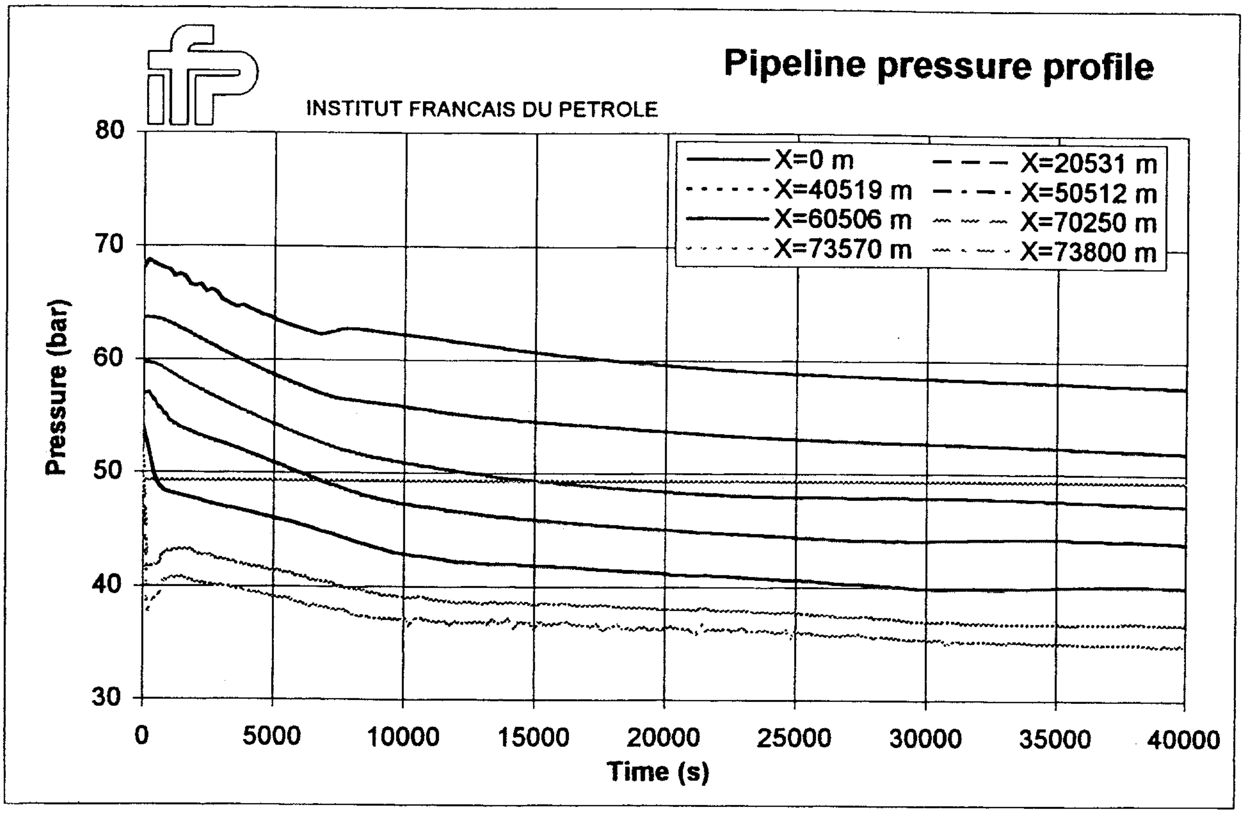


FIGURE 18 - Pipeline operation with a subsea multiphase pump installed at bottom of riser.
Flow conditions : 50 MMSCFD (100%) and 21000 BPFD (300%)



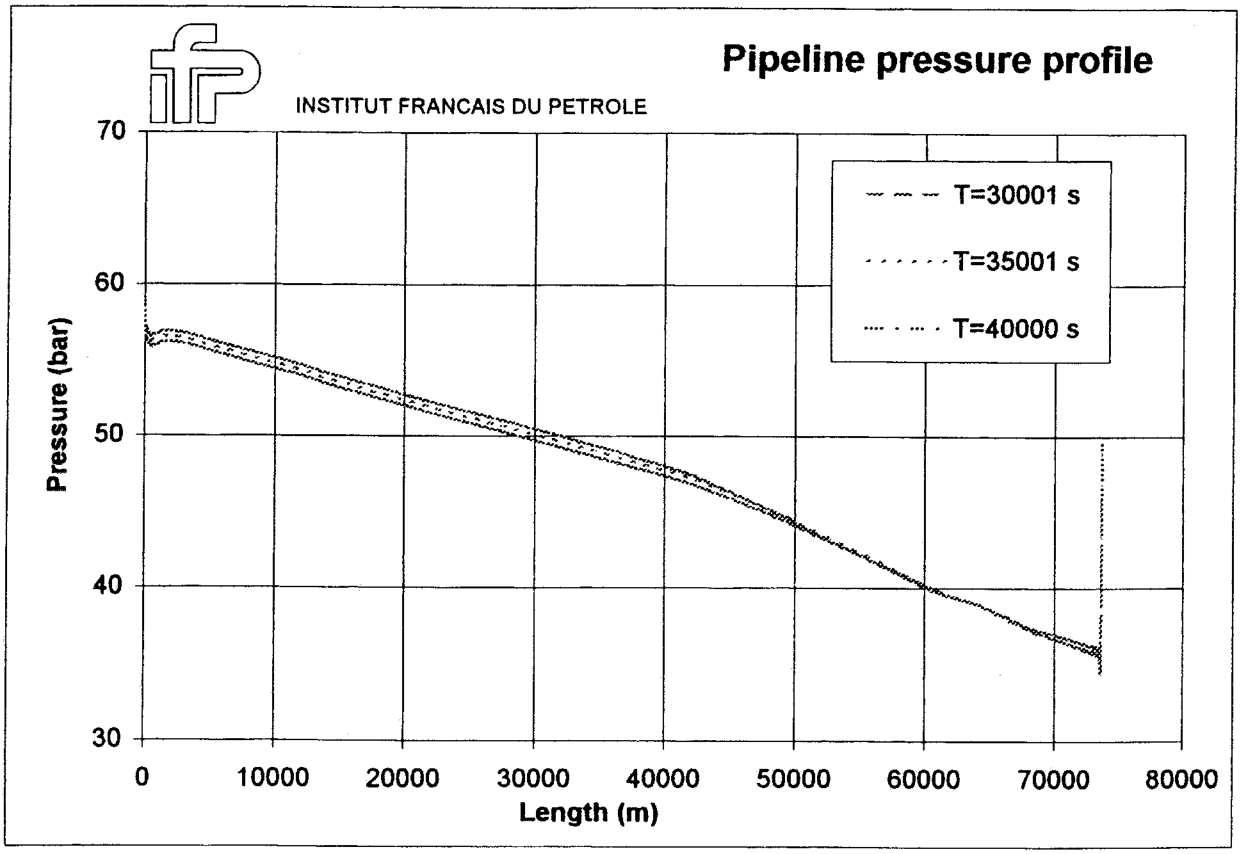
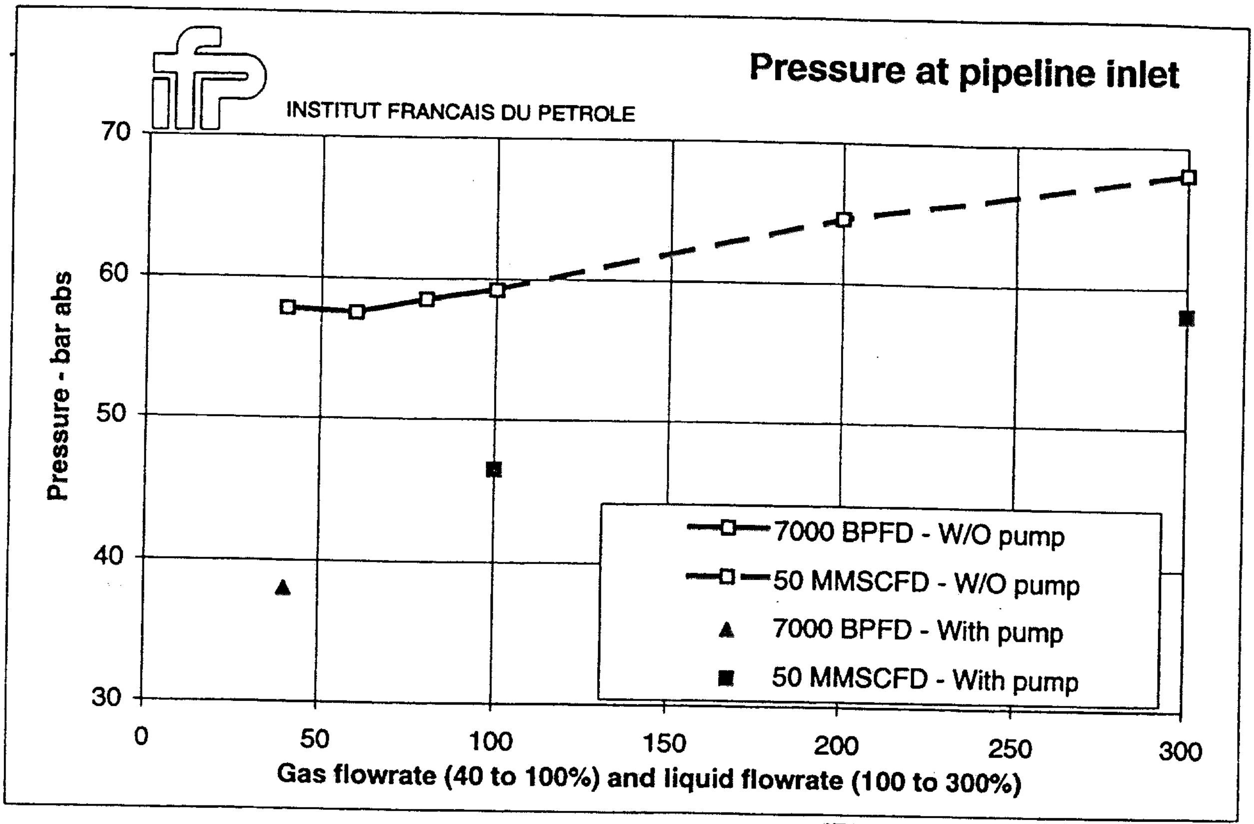


FIGURE 19 - Pipeline operation with a topside multiphase pump installed on the production platform.
Flow conditions : 50 MMSCFD (100%) and 21000 BPFD (300%)



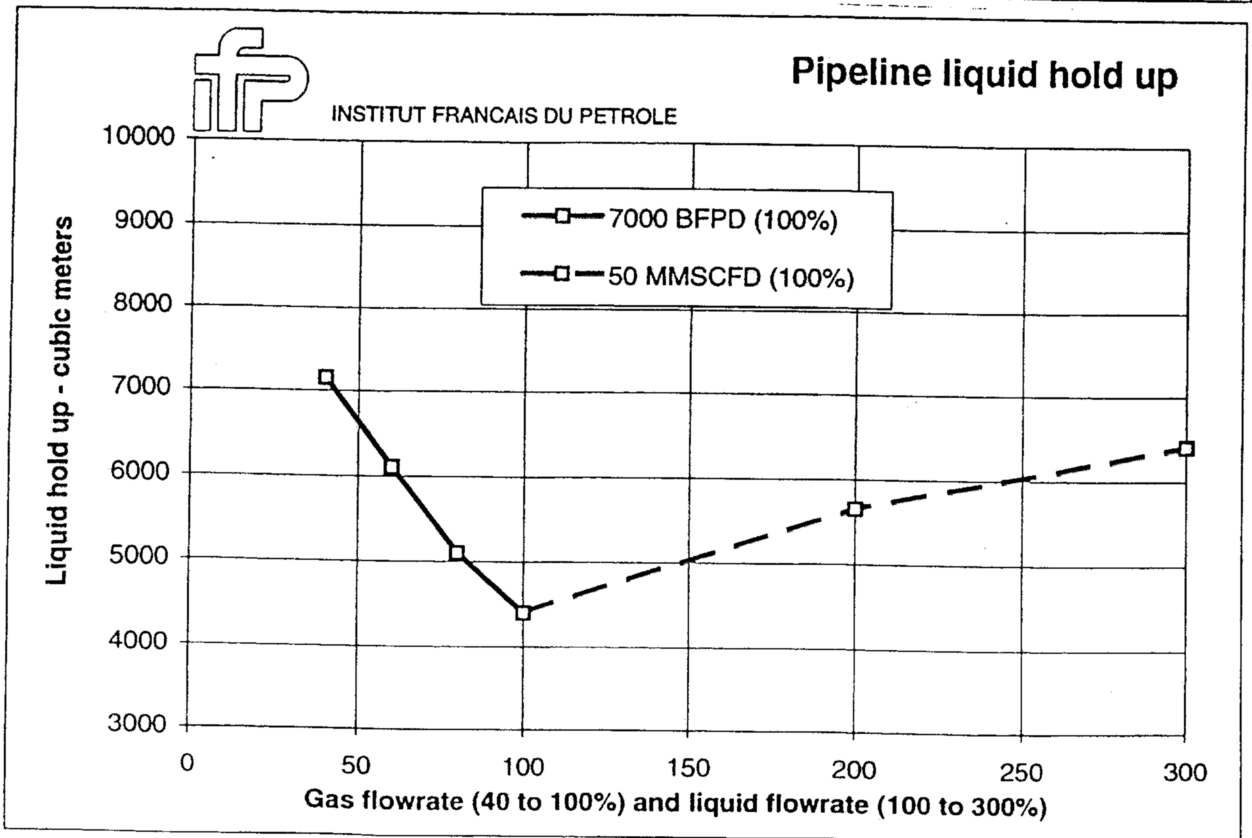


FIGURE 20 - Pipeline operation with a multiphase pump
Pipeline inlet pressure and liquid hold up for gas flowrate varying from 20 to 50 MMSCFD (7000 BPFD) and liquid flowrate varying from 7000 to 21000 BPFD (50 MMSCFD)

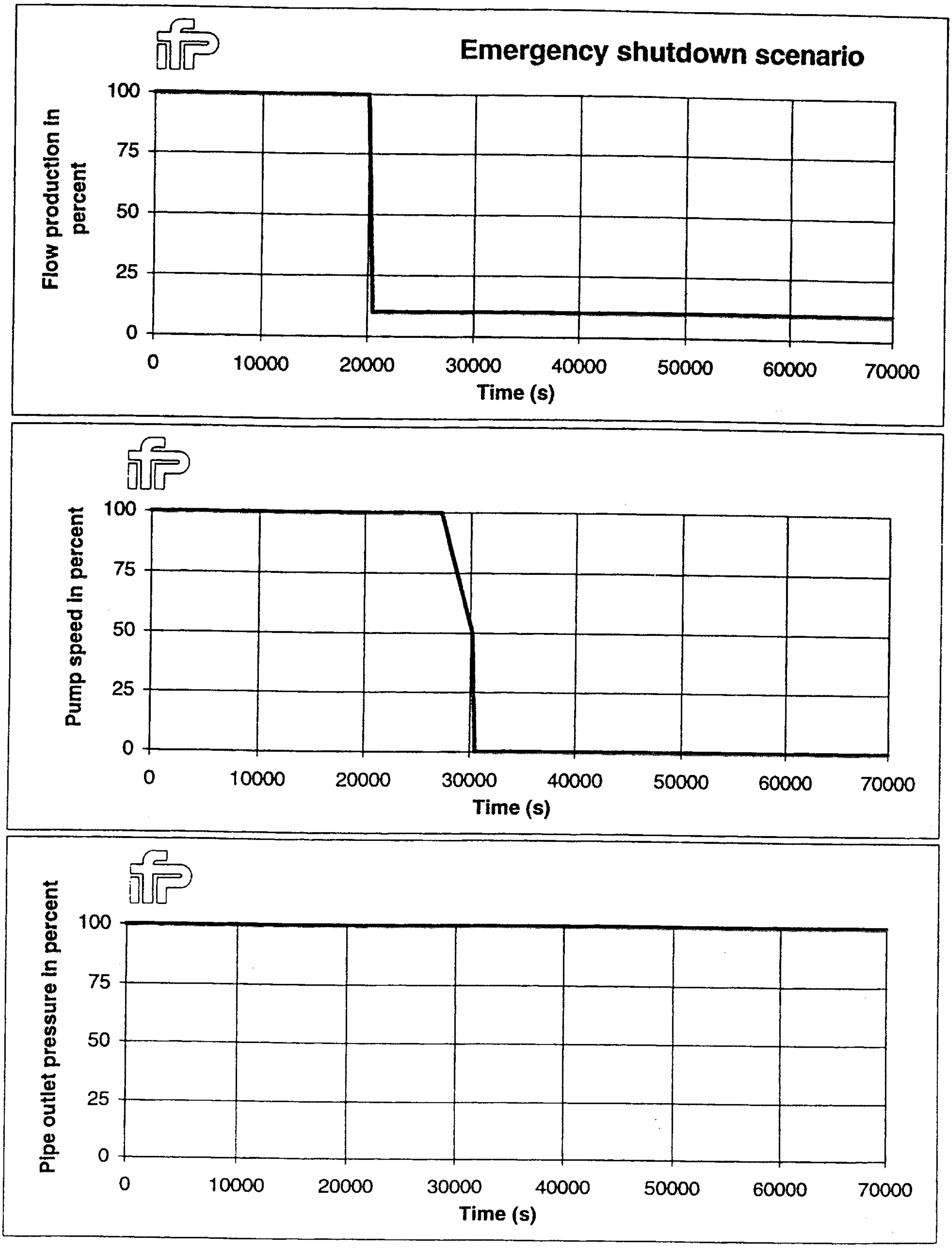
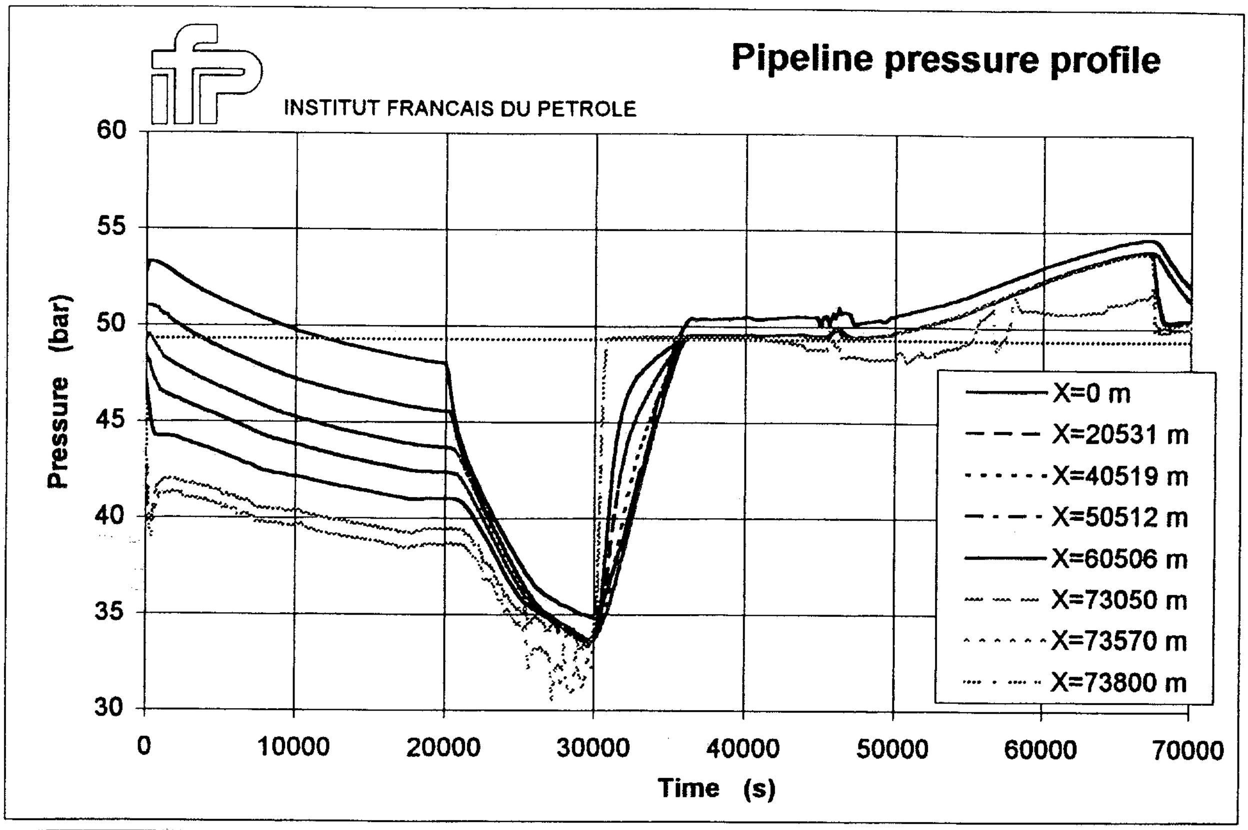


FIGURE 21 - Emergency shutdown : sequence of events.
Relative variations of gas and liquid flow, pump speed and pipeline outlet pressure versus the time.



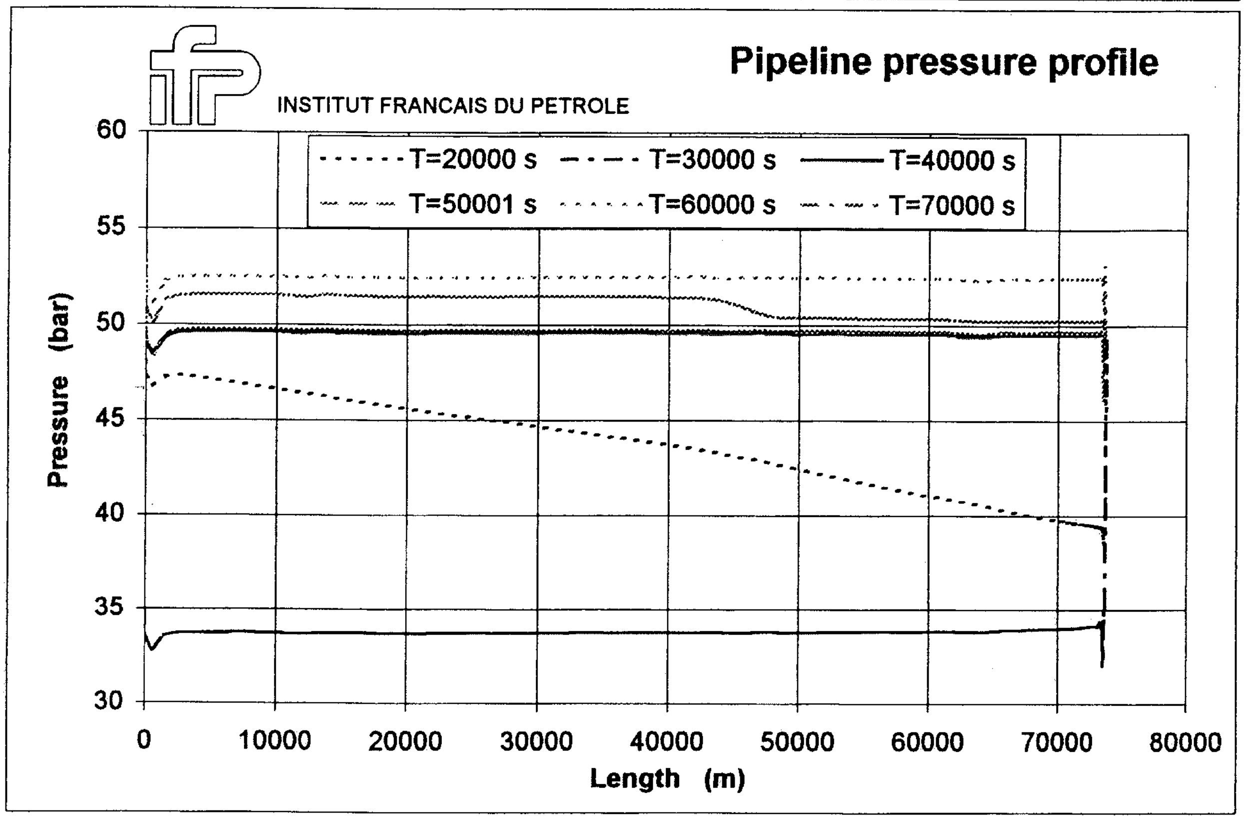
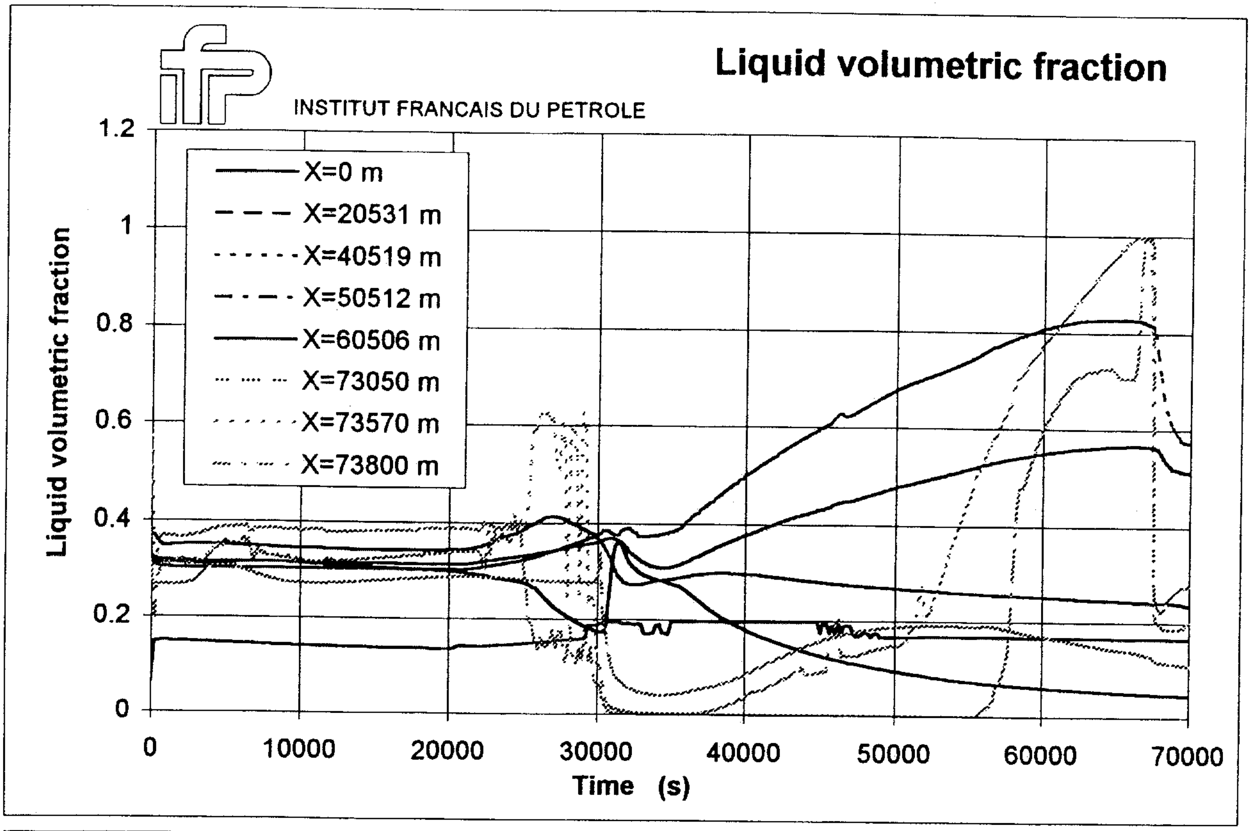


FIGURE 22 - Emergency shutdown with a multiphase pump mounted on the production platform.
Pressure variation versus the distance and the time.



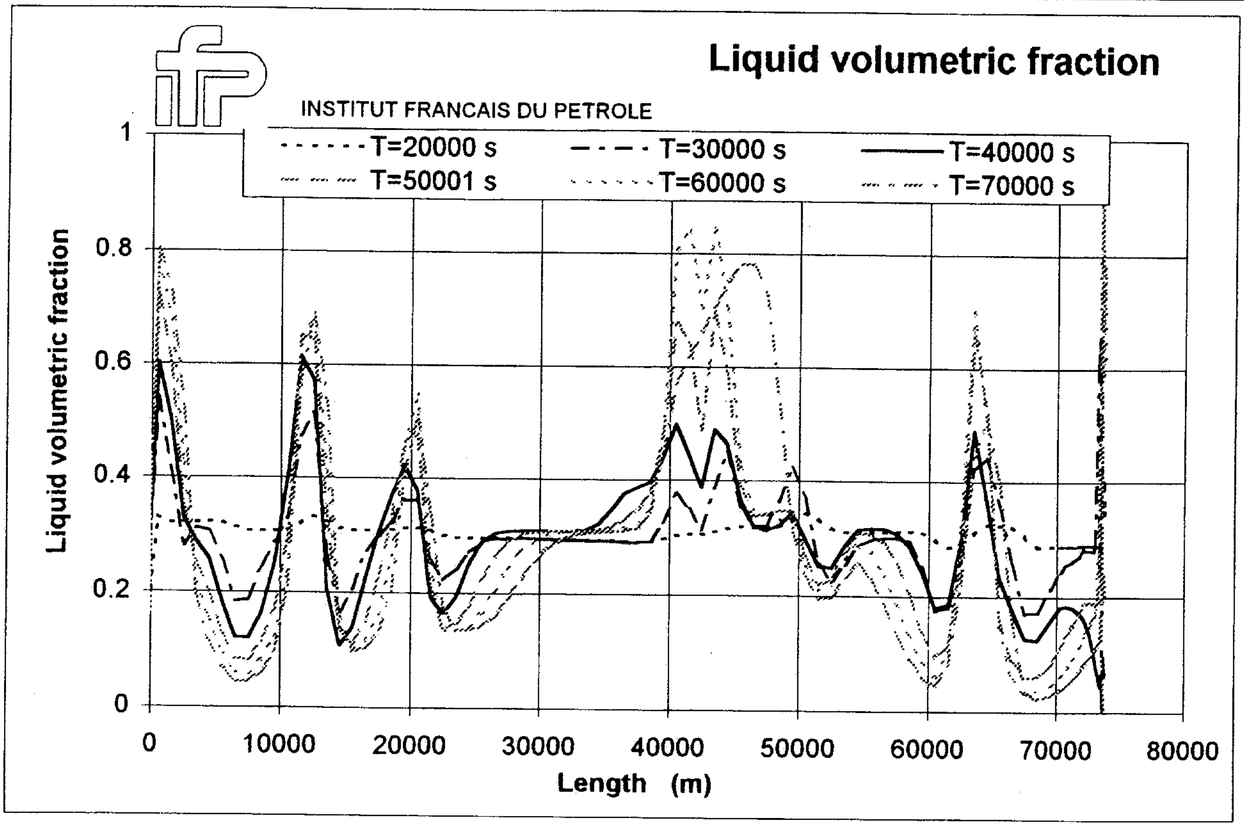


FIGURE 23 - Emergency shutdown with a multiphase pump mounted on the production platform.
Liquid volume fraction versus the distance and the time.