Main Index

NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORWEGIAN SOCIETY FOR OIL AND GAS MEASUREMENT

NORTH SEA FLOW MEASUREMENT WORKSHOP 1993
26 - 28 October, Bergen

# *Platform Trial of a Multiphase Flow Meter*

by

Mr. J.S. Watt,
CSIRO Division of Mineral and Process Engineering,
Australia

# PLATFORM TRIAL OF A MULTIPHASE FLOW METER

G.J. Roach, J.S. Watt, H.W. Zastawny, P.E. Hartley, W.K. Ellis, A.McEwan, V.Sharp

CSIRO Division of Mineral and Process Engineering
PMB 5, Menai 2234, NSW, Australia

This paper describes a trial of a new multiphase flow meter (MFM) on the Vicksburg offshore production platform on Australia's North West Shelf. The flowmeter is based on two specialised gamma-ray transmission gauges mounted on a pipe carying the full flow of oil, water and gas.

Measurements were made on the full and reduced flows of oil/water/gas mixtures from each of nine single wells, and on five combined flows of different pairs of wells. These measurements were made by two MFMs, one mounted on a horizontal and the other on a vertical, section of a pipeline linking the test manifold and test separator. The flows measured ranged from 130 to 2900 BPD for oil, 230 to 5100 BPD for water, and 0.5 and 1.9 million cubic feet per day for gas. The water ranged from 17 to 95 %, with a mean of 73%.

The r.m.s. difference between the flow rates determined by the MFM and by the separator output meter was determined by least squares regression. The ratio of r.m.s. difference and mean flow rate was 8.9% for oil, 5.6% for water and 8.2 % for gas for flows in the vertical pipeline and slightly larger for flows in the horizontal pipeline. These ratios include not only the errors in the multiphase flow meter but also the combined errors of the separator and separator output meters.

## 1. INTRODUCTION

The extraction of fluid hydrocarbons from their geological reservoirs involves the piping of multiphase mixtures of crude oil, (salt) water and gas from each well. Knowledge of the flow rates of each component, in each well pipeline feeding to the production platform, is required to control production. Current practice is to feed sequentially the outputs from each well to a common test separator system, and to measure the flow rates of each (single phase) component after separation. The time to determine the flow rates for each well is many hours, and the determination can also be unrepresentative because the flow rate is sampled for only a small part of the total production time of a well.

The oil industry requires a multiphase flow meter (MFM) which is compact, measures the flow rates continuously, and can be mounted directly onto each well pipeline [1,2,3]. Use of such a meter should lead to

a) the replacement of the need for test separators, initially in non-critical applications and later, after the MFM technology has been proved to be dependable, in most new offshore platforms,

b) the reduction in the cost of subsea piping because the outputs of two or more wells can be commingled and flow through a single flowline from satellite platform to central facility,

c) the reduction in capital costs of new platforms because the heavy test separator can be replaced by the light MFM,

d) better reservoir management, production allocation, and optimisation of total oil production over the field lifetime.

Not only would new oil fields be exploited more economically, but it should make possible the production of oil from wells in greater depths of water and the development of off-shore oilfields which were previously marginal.

Various organisations are developing multiphase flow meters for oil, water and gas in pipelines. The most promising approaches are those based on nuclear [4,5,6,7], capacitance [8,9], and microwave [5,10] techniques. The target is to determine the mass flow rate of each component to about 5-10% relative ($1\sigma$). Most of these techniques have been tested on laboratory loops, but few tests have been undertaken on production pipelines. None of these prototype meters developed to date have been demonstrated to cover all the flow conditions occuring in pipelines from oil wells.

CSIRO is undertaking a three stage program to develop and prove techniques for the on-line determination of the mass flow rates of oil, water and gas in pipelines, and to license and transfer the technology to ensure that the multiphase flow meter (MFM) becomes commercially available to the oil industry. Both gamma-ray and microwave techniques are being developed.

This paper describes the use of gamma-ray transmission techniques to determine the mass flow rates of oil, water and gas, and the trial of the multiphase flow meter based on these techniques, on production pipelines on an offshore oil platform.

## 2. THE MULTIPHASE FLOW METER

The strategy adopted by CSIRO in developing the multiphase flow meter is to make measurements directly on the well pipelines. This approach has the advantage over MFMs used on sample bylines in that it avoids the errors caused by non-representative sampling from mainline pipe to sample byline. It does, however, make the analysis more complex since measurements must be made on the heterogeneous mixture of oil, water and gas in the pipeline.

The most common flow regimes for oil, water and gas in pipelines from oil wells are slug flow for horizontal pipes and plug flow for vertical pipes. In slug flow, slugs of liquids including some gas fill the whole cross-section of the pipe, and consecutive slugs are separated by a layer of liquid as a film beneath a gas pocket above. The velocities of the liquids and gas in the slug, the front of the slug, and the liquid in the film, are all different. Even for a two component mixture of a liquid and a gas, the translation of measurements made on the mixture in the pipeline into mass flow rates involves using models of the flow regime.

The CSIRO techniques developed for the determination of mass flow rates of oil, water and gas are based on

* single energy gamma-ray transmission measurements (Figure 1) to determine the mass per unit area of fluids in the gamma-ray beam as a function of time,

* cross-correlation of gamma-ray transmission measurements, with one gauge upstream of the other, to determine flow velocity,

* dual energy gamma-ray transmission (DUET) measurements to determine the approximate mass fraction of oil in the liquids,

* pressure and temperature measurements, and

* knowledge of the specific gravities of oil and (salt) water, and the solubility of the gas in the liquids, all as a function of pressure and temperature.

The measurements are first used to identify the flow regime. They are then combined in models of the identified flow regime to give the mass flow rates of each component. Computer programs process the measurements made on horizontal and on vertical pipelines to give the mass flow rates of oil, water and gas.

## 3. PLATFORM TRIAL

The most important aspect of tests of a multiphase flow meter on an oil platform is to test it over a wide range of flow rates, pressures, and volume fractions of oil, water and gas. Measurements made on only one well, even with variations in flow conditions, would provide an insufficient test of a multiphase flow meter. To ensure a wide range of flow conditions, one of our sponsors (Western Mining Corporation) suggested that measurements be made on a pipeline connecting the test manifold to the test separator on their Vicksburg offshore platform. A variety of flow conditions could be achieved by sequentially routing through this test pipeline the flows from each of the nine separate wells feeding the platform, and combinations of these well flows.

### 3.1 Vicksburg platform and oil wells

A full scale trial of the MFM was undertaken on the Vicksburg platform during February and March, 1992. This platform, on the Northwest Shelf off-shore from Onslow, West Australia, is a combined drilling and oil production platform operated by Western Mining Corporation. The wells intersect a thin layer of oil about 1500 metres below the sea bed. The platform stands in about 20 metres of water, and the main deck is about 20 metres above sea level. The oil wells mainly tap the South Pepper (SP) field; and some of the well pipelines are essentially horizontal at the depth of the oil accumulation. One well drains the North Herald field, and the multiphase mixture is piped first to a satellite (monopole) platform and thence 5.6 km along the sea bed to the Vicksburg platform. Eight South Pepper and one North Herald wells were operating at the time of the field trial. The densities of oil and water from these wells are respectively 0.81 and 1.03 g $cm^{-3}$ at STP.

### 3.2 Gauges

In laboratory experiments, gamma-ray transmission techniques accurately determined the flow rates of water and air in both horizontal and vertical sections of a water/air loop [5]. We decided that gauges would be installed on both vertical and horizontal sections of the test pipeline during the entire platform trial. Although this required the use of four rather than two gauges, the simultaneous measurements made would give a much better assessment of the comparative advantages of installing gauges on horizontal or vertical production pipes.

Four gamma-ray transmission gauges were used during the trial. The two DUET gauges were based on measurement of the transmissions of $^{241}$Am (energy 59.5 keV) and $^{133}$Ba (about 356 keV) gamma-rays. The two density gauges were based on measurement of the transmission of $^{137}$Cs gamma-rays (662 keV). Lead collimation in the radioisotope containers restricted the gamma-rays passing through the oil/water/gas mixture to a narrow beam. The intensities of detected gamma-rays at the two different gamma-ray energies in the DUET gauge were simultaneously measured using pulse height analysis. The mass per unit area (g $cm^{-2}$) of fluids in the gamma-ray beam is determined from the detected intensities of the $^{133}Ba$ and $^{137}Cs$ gamma-rays. The detected intensity of $^{241}Am$ gamma-rays depends both on mass per unit area of fluids and on the effective atomic number of the fluids.

The four gauges were mounted about the test pipeline. A shielded radioisotope source holder was located on one arm of a C frame. The gamma-ray detector, high voltage supply and pre-amplifier were housed in a flameproof enclosure attached to the other arm of the C frame. The gamma-ray detector, a NaI crystal/photomultiplier combination, was surrounded by a heating element and thermostat to keep its temperature constant at about 40° C. The electrical pulses from the photomultiplier were routed via the preamplifier to an amplifier and signal processing unit whose output was in turn routed to an IBM compatible 386SX computer. Signals from the fluid pressure and temperature sensors were also routed to the same processing unit. Both the processing unit and computer were mounted in a control room on the platform.

### 3.3 Test pipeline

The test pipeline (Figure 2), set up by Western Mining Corporation for the platform trial, linked the test manifold to the test separator. The test pipeline was 73.7 mm nominal bore. The gauges were mounted external to the pipeline carrying the oil/water/gas mixture (Figure 1), no penetration of the pipeline being necessary other than for the pressure and temperature sensors through standard fittings. The DUET gauges were mounted on a 2 m length aluminium alloy section of the pipeline near the end of a long run of horizontal pipe (Figure 2). One was mounted directly about the pipeline, and the other with an extended path length of about 200 mm. The pressure sensor was mounted immediately upstream of the first DUET gauge, and a temperature sensor about 12 metres upstream. The density gauges were mounted near the top of a vertical section of pipe.

The pressure immediately prior to the test separator on the Vicksburg platform is normally low, about 600 kPa. A choke was installed immediately prior to the test separator, increasing the pressure in the test pipeline to close to well head pressure (WHP), and making it possible to make measurements on flows at different pressures.

### 3.4 Measurements

Measurements were made on oil/water/gas mixtures passing through the test pipeline. Most measurements were made with flows from only one well at a time in the test pipeline. In these cases, measurements were first made with the choke immediately prior to the separator set to about the same diameter as that of the choke near the Christmas tree. A second measurement was then made with the separator choke reduced in size, thus changing the flow conditions. Measurements were also made with the combined flows from pairs of wells. In these cases, the separator end choke had to be set wide open to maintain normal production, and thus the pressure in the test pipeline was much lower than well head pressure.

The range of flow parameters in the test pipeline during the MFM measurements was large (Table 1).

### 3.5 Results

Much of the results and discussion is based around two wells: SP4 and SP7. SP7 is typical of most wells coming directly to the platform, which exhibit regular and frequent slugging. SP4 is a typical "terrain slugging" well. The terrain slugs develop in the subsea flowline between the well head and the Vicksburg platform, a distance of about 1.8 km for the SP4 well. The intermittent nature of terrain slugging gives rise to large variations of liquid and gas flow rates, as well as mass per unit area in the test pipeline, versus time.

*a) Mass Per Unit Area of Fluids Versus Time*

The detected intensities of gamma-rays from $^{133}Ba$ (horizontal pipe) or $^{137}Cs$ (vertical pipe) gauges give the total mass per unit area (g $cm^{-2}$) of liquids and gas in the gamma-ray beam. This is determined independently of the distribution of the liquids and gas in the gamma-ray beam, i.e., it gives no information of spatial distribution of liquids and gas in the pipeline. In practice, spatial distribution can often be inferred, e.g., during the passage of slugs, the oil/water/gas mixture is reasonably uniform across the whole cross-sectional area of the pipe.

Figure 3 shows the time variation of the mass per unit area of fluids in the gamma-ray beam in the vertical section of the test pipeline for the SP7 well at two different pressures, for the combined streams of SP5 and SP6 wells, and for the SP4 well. The counts were summed over 10 milli-seconds periods, and the records in Figure 3 show the mass per unit area determined each 10 ms period over a total time of about 17 seconds. Superimposed on the obvious changes in mass per unit area in each record is "noise" due to the statistics of counting over the 10 ms periods.

The plots for the SP7 well (top left and right, Figure 3) both show the fairly regular slugging behaviour in the vertical pipeline, typical for flows from wells close to the platform. The frequency of slugging is different because of the different pressures in the pipeline. The velocities of the slugs are 10 and 5.5 m $s^{-1}$, and the slug lengths are about 5 metres (top left) and 8 metres (top right). The low mass per unit areas between the slugs corresponds to the film.

The plot for the combined flows of the wells SP5 and SP6 (bottom left, Figure 3) shows a much more frequent slugging. The velocity of the slugs, about 14 m $s^{-1}$, is much higher than the velocities for the SP7 well. The length of the slugs is about 2 metres.

The plot for the SP4 well, which is 1.8 km from the platform, is typical for terrain slugs; the record over the 17 second period is highly irregular. Records for consecutive 17 second periods do not show a regular repetition pattern. The flow rate of the liquids is highly irregular, varying very considerably with time over periods of tens of minutes.

*b) Velocity Versus Time Over 40 Minute Periods*

Figure 4 shows results of measurements of mass per unit area (in the gamma-ray beam) in the vertical section of the test pipe, for flow from the SP8 well. Both gauge outputs are shown. Cross-correlation of the gauge outputs gives a measure of time delay for the slugs to pass from one to the other gauge. There is a close correspondence between upstream and downstream gauge outputs with the slugs seen on the downstream gauge output being delayed by about 0.4 seconds compared with the same slug on the upstream gauge.

Figure 5 shows the velocities for flows from the SP4 and SP8 wells, the former corresponding to terrain slugging and the latter to frequent, regular slugging. The velocities were determined every 17 seconds by cross-correlation of the outputs of the gauges mounted on the horizontal pipe. The velocity for the flow of the SP8 well varies little with time over the whole 40 minute period recorded, the standard deviation being about 6% relative. The variation in velocities is much greater for the SP4 well, with a standard deviation being 37% relative. The wider range of velocities shown for SP4 is a true measure of the large variations in flow which occur over the 40 minute period.

Velocities can be accurately determined by cross-correlation techniques in a time short compared with the response time of the separator and the time of passage of terrain slugs. The time necessary to determine the average velocity of the flow from a well depends more on the inherent nature of the flow, as for terrain slugs, than the response time of the mass flow meter.

*c) Flow rates of liquids*

Figure 6 shows the liquid flow rates for wells SP7 (left) and SP4 (right) determined from the mass per unit area measurements by gamma-ray transmission and the cross-correlation of the $^{137}$Cs transmitted intensities to measure time delay and hence velocities. Well SP7 has frequent and regular slugging (Figure 3) and the flow varies little with time. Well SP4 has terrain slugging, and the flow varies by over a factor of five with time. This gross variation of flow with time was also observed in changes in flow rates as measured by the oil and water meters (at the separator outputs) which record little flow between the terrain slugs and very high flows during these slugs.

*d) Gauge Versus Separator Output Flow Rates*

The measurements of mass per unit area, pressure and temperature were combined using models of flow regime to determine the flow rates of the total liquids (i.e., oil + water) and of gas. The DUET measurements were used to determine the ratio of the mass fractions of oil and water. All the results were then combined to determine the volume flow rates of oil, water, liquids, and gas.

The results of determinations of the volume flow rates of oil, water, gas and total liquids in the vertical pipe are shown in Figure 7. Each point in this Figure corresponds to the flow rate averaged over a forty minute period. Each flow rate was measured twice, in consecutive forty minute periods, and results for both periods are shown as separate points on the graphs. For each of the eight wells, measurements were made corresponding to the flows at two choke settings. For the five combinations of two wells, measurements were made corresponding to only one choke setting. Results of one of the two SP7 well measurements has been left out of the final gas calculations because there was a significant decrease in gas lift during the measurement period.

R.m.s. differences were calculated by least squares regression of volume flow rates as determined by the gamma-ray transmission gauges and by the relevant separator output meter. The ratios of r.m.s. difference and mean flow rate, expressed in per cent, are given in Table 2. These relative errors include errors in the MFM determination and also errors in the determination by the separator/meter combination, not just of the MFM alone. The Table 2 results show that the volume flow rates of oil, water and gas have been determined to within the range of 5 and 9% relative for the vertical pipe, and 8 and 14% relative for the horizontal pipe.

## 4. DISCUSSION

### 4.1 Vicksburg platform trial

The accuracies of the determinations of the volume flow rates of oil, water and gas are particularly pleasing because of the wide range of flow rates and flow conditions in the pipe. Most of the measurements were made on mixtures with high water cuts. The water cuts covered the wide range of 17 to 95%, with a mean of 72%. Three well streams had water cuts of about 95%. Many of these high water cut mixtures corresponded to oil in the water phase. The determination of flow rates of mixtures with high water cuts is a problem for capacitance techniques and, because of this, conductivity measurements are being developed to measure the flow rates of oil in the water phase. The present MFM results show the versatility of the CSIRO multiphase flow meter in its ability to determine flow rates covering the whole range of water cuts.

The equipment used for the Vicksburg trial performed reliably under typical oil field conditions and over a reasonable length of time. The equipment design met all offshore safety criteria, e.g., electrical zoning, etc.

The results for the measurements on the vertical pipe are better than those for the horizontal pipe. Hence, at least for the flow conditions in wells feeding to the Vicksburg platform, gauges mounted on vertical pipes would be preferred to those mounted on horizontal pipes.

The results of the platform trial are excellent considering that this was the first field trial of the MFM on production flows of oil, water and gas. The accuracies of flow determination obtained are sufficient for many applications on production pipelines.

### 4.2 Further work

The MFM is being trialled again, between August and November 1993, at oil processing facilities on Thevenard Island, West Australia. These facilities are operated by West Australian Petroleum Pty. Ltd. This trial will provide tests on flow conditions different to those encountered on the Vicksburg platform, and involve the use of both gamma-ray transmission and microwave techniques on a 137 mm bore pipeline.

Mineral Control Instrumentation Ltd [11] has been selected as licensee for the MFM. CSIRO and MCI will test the commercial prototype in a long-term trial starting in April, 1994, and the fully commercial version of the MFM will be available to the oil industry late in 1994.

## 5. CONCLUSION

The mass flow rates of oil, water and gas have been determined with an accuracy between 5 and 9% relative by gamma-ray transmission techniques. These measurements were made on the flows from eight wells, and five mixtures of two wells, on the Vicksburg offshore oil platform. The multiphase flow meter performed reliably under typical oil field conditions, and its design readily met offshore safety criteria of this platform.

A further field trial is being undertaken from August to November, 1993, on production pipelines. The commercial prototype MFM will be jointly tested by CSIRO and the commercial licensee, Mineral Control Instrumentation Ltd., in a long-term trial in 1994. The fully commercial version will be available late in 1994.

## 6. ACKNOWLEDGMENTS

The authors wish to thank both D. Nairn and D. Stribley of the Australian Mineral Industries Research Association (AMIRA) for their efforts in coordinating the project; and Western Mining Corporation staff, Mr N. Keron, for his suggestion that the MFM be tested on the Vicksburg Platform, and for his and other platform staff support during these platform trials. The work described in this paper has been financially supported in part by the Energy Research and Development Corporation (ERDC) of the Australian Government, The Shell Company of Australia Ltd., West Australian Petroleum Pty. Ltd. (WAPET) and Western Mining Corporation.

## 6. REFERENCES

[1] S. Ashkuri and T.J. Hill. Measurement of multiphase flows in crude oil production systems, *Petroleum Review* **39** (466): 14-17, 1985.

[2] R.C. Baker and E.R. Hayes. Multiphase measurement problems and techniques for crude oil production systems, *Petroleum Review* **39** (466): 18-22, 1985.

[3] A.W. Jamieson, R.G. Smeenk and P.B. Vriezen. Multi-phase flow measurements at production platforms, *Petroleum Review* **39** (466): 23-29, 1985.

[4] T. Tomada, M. Komaru, S. Badono, K. Tsumagari and D. Exall. Development of gamma-ray oil/water/gas fraction meter for crude oil production system, Industrial Flow Measurement On-Shore and Off-Shore (Proc Int. Conf., London, 1987).

[5] J.S. Watt, H.W. Zastawny and N.G. Cutmore. Progress towards development of a mass flow meter for oil, water and gas, pp. VI1-VI6 in Vol. 1 of Proceedings of First Off-Shore Australia Conference 1991, Australian Exhibition Services Pty. Ltd., Melbourne, 1991.

[6] M.D. Rebgetz, J.S. Watt and H.W. Zastawny. Determination of volume fractions of oil, water and gas by dual energy gamma-ray transmission, *Nucl. Geophys*. **5** (4): 479-490, 1991.

[7] B.H. Torkildsen and A.B. Olsen. Framo multiphase flowmeter, Paper presented at the North Sea Flow Measurement Workshop, Peebles, Scotland, 26-29 October, 1992.

[8] E. Dykesteen and O. Midttveit. A flow regime independent multiphase flowrate meter, Paper presented at the North Sea Flow Measurement Workshop, Peebles, Scotland, 26-29 October, 1992.

[9] D. Brown. The multi-component multiphase flowmeter, Paper presented at the North Sea Flow Measurement Workshop, Peebles, Scotland, 26-29 October, 1992.

[10] Gaisford S., Amdal J. and Berentsen H., 1993. Offshore multiphase meter nears acceptable accuracy level, *Oil & Gas Journal* **91**(20): 54-58.

[11] Mineral Control Instrumentation Ltd., P.O. Box 64, Unley, SA 5061, Australia.

TABLE 1. RANGE AND MEAN OF TEST CONDITIONS DURING PLANT TRIAL.

| | Range | Mean | Units |
|---|---|---|---|
| Oil | 130 - 2900 | 1018 | BPD |
| Water | 230 - 5100 | 2731 | BPD |
| Total liquids | 1350 - 6370 | 3740 | BPD |
| Water cut | 17 - 95 | 72 | % |
| Gas | 0.5 - 1.9 | 0.89 | MMSCFD* |
| Gas/oil ratio | 390 - 3700 | 870 | SCFD/Barrel |
| Pressure | 640 - 2800 | 1350 | kPa |
| Temperature | 28 - 74 | 56 | °C |
| Velocity | 3.5 - 13.1 | 7.4 | m/s |

* million standard cubic feet per day at STP.

TABLE 2. RATIOS OF RMS DIFFERENCE ($\sigma$) AND MEAN FLOW RATE

| Flow of | Vertical pipe | | Horizontal pipe | |
|---|---|---|---|---|
| | $\sigma$/mean % | Correlation Coefficient | $\sigma$/mean % | Correlation Coefficient |
| Oil | 8.9 | 0.994 | 9.0 | 0.995 |
| Water | 5.6 | 0.991 | 8.3 | 0.982 |
| Gas | 8.2 | 0.985 | 14.4 | 0.952 |
| Liquids | 5.2 | 0.991 | 8.4 | 0.978 |

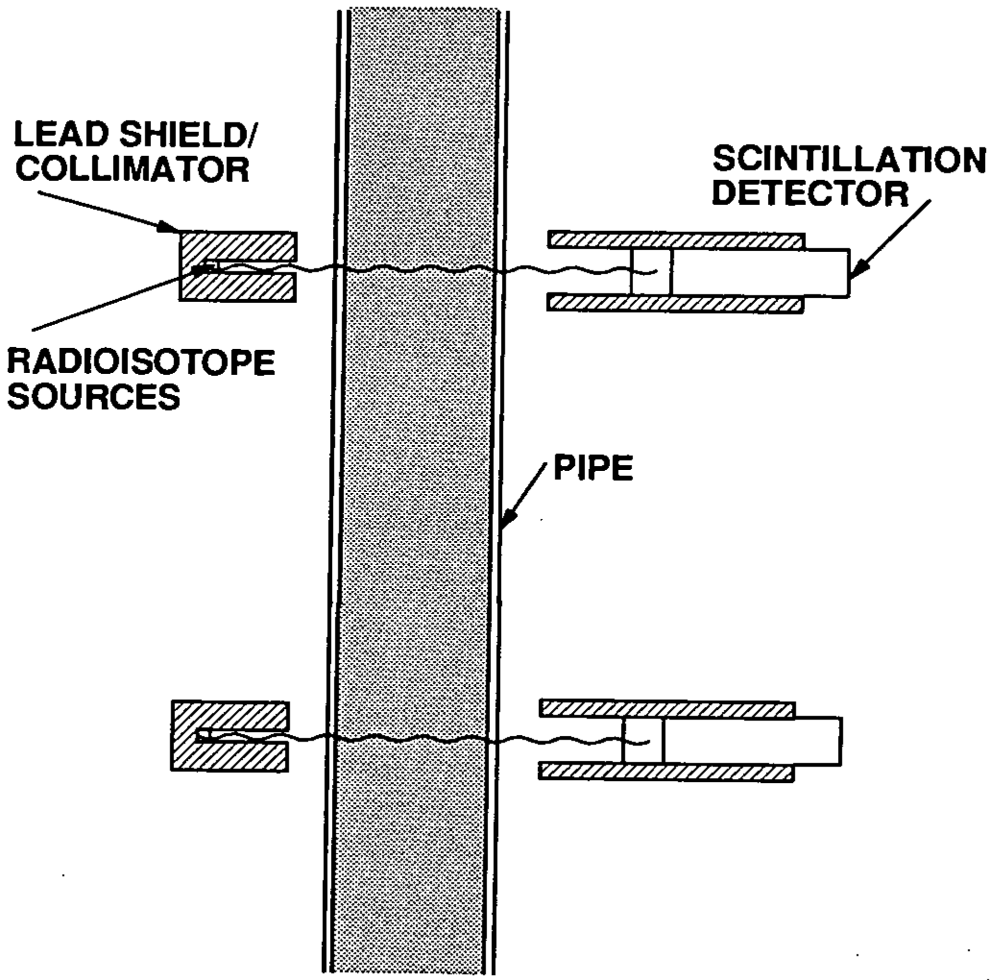


Figure 1. Gamma-ray transmission gauges mounted about pipeline.

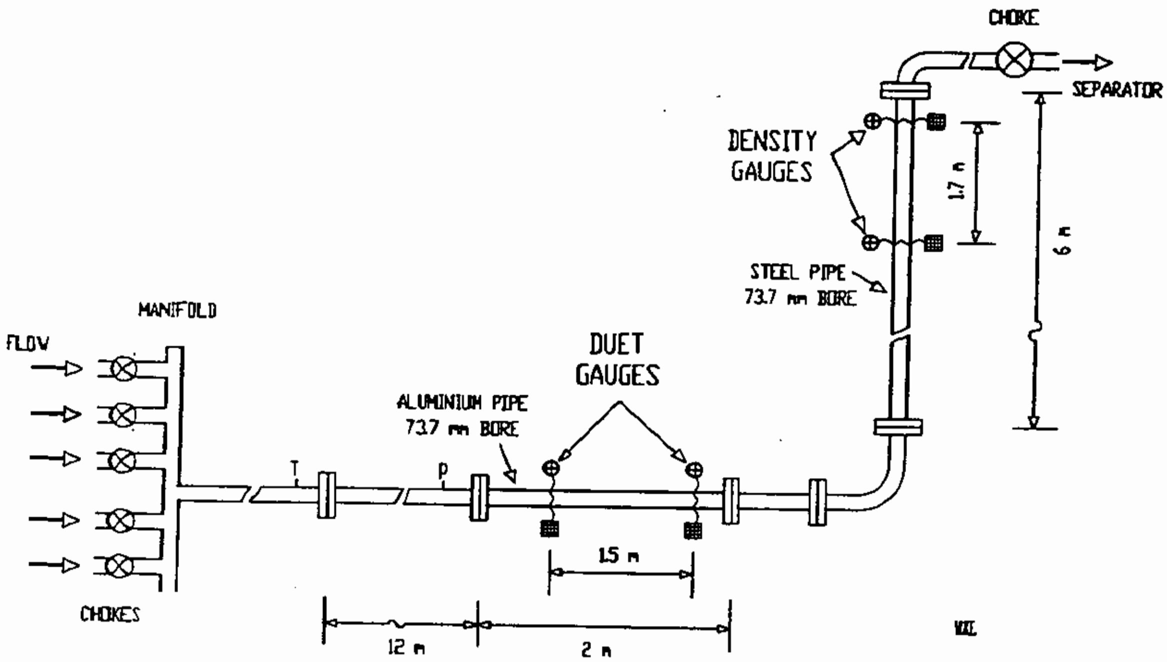


Figure 2. Schematic of the test pipeline joining the manifold and the test separator on the Vicksburg platform. P and T indicate pressure and temperature transducers.

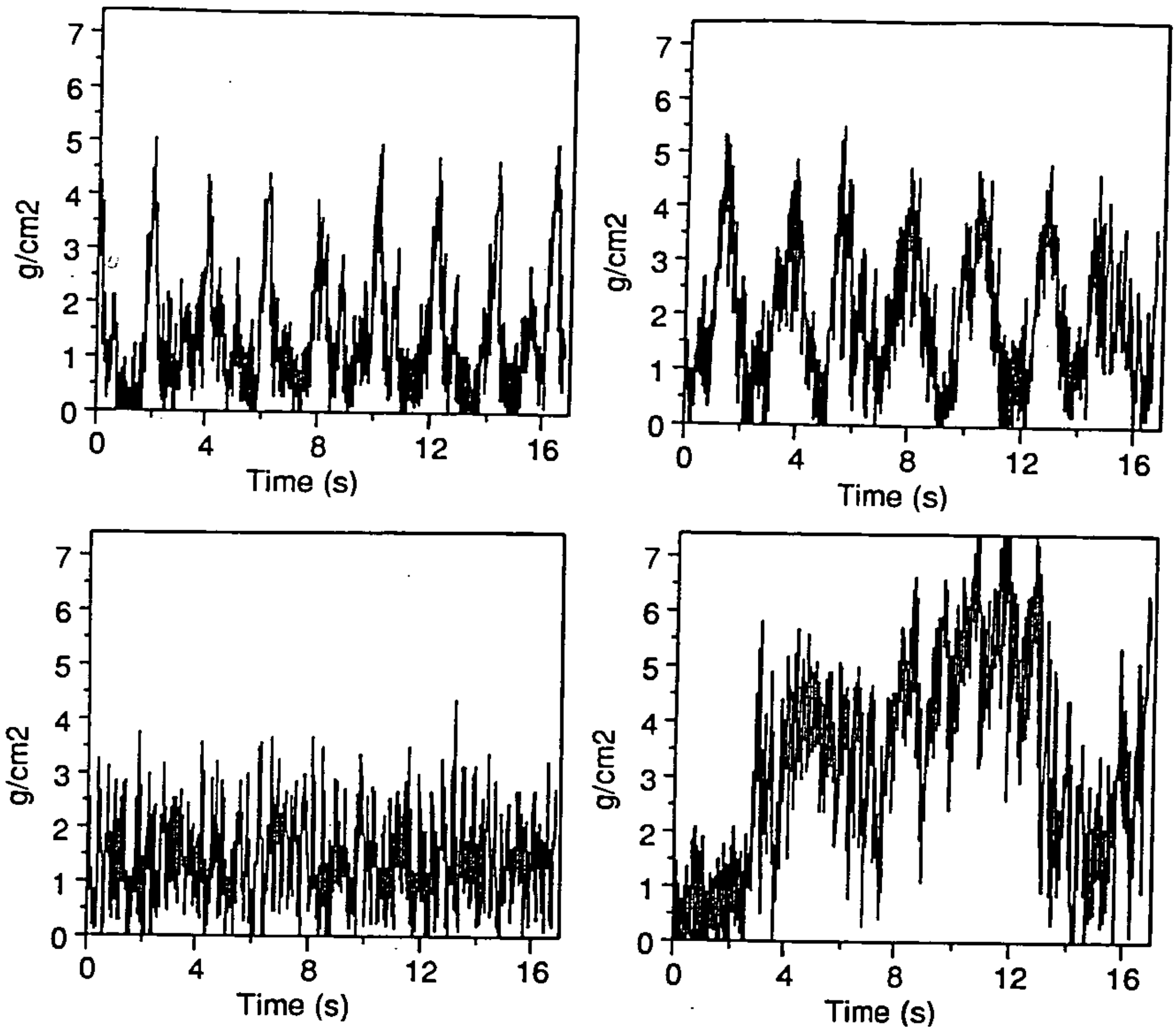


Figure 3. Variations of mass per unit area of liquids in the gamma-ray beam with time, for the flows for the SP7 well at two different pressures (top left and right), for the combined flows from the SP5 and SP6 wells (bottom left), and for the SP4 well (bottom right), in the vertical section of the test pipeline.

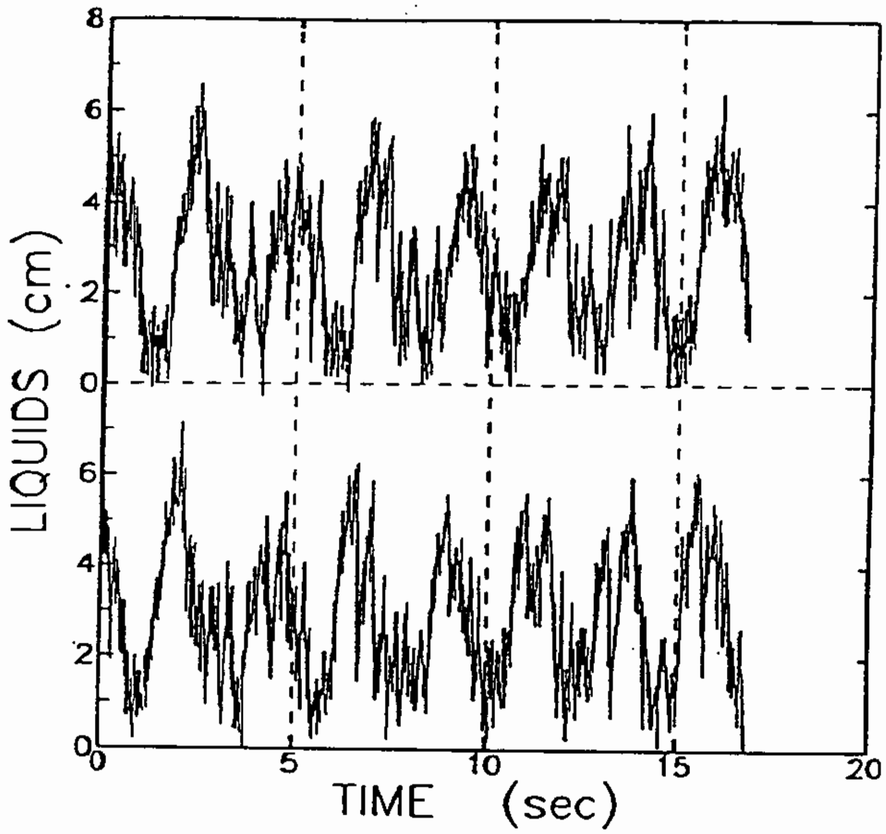


Figure 4. Variation in mass per unit area of liquids (in the gamma-ray beam) with time for the two gauges mounted on the vertical pipeline. The time delay between the upstream gauge (lower record) and upstream gauge is 0.4 seconds.

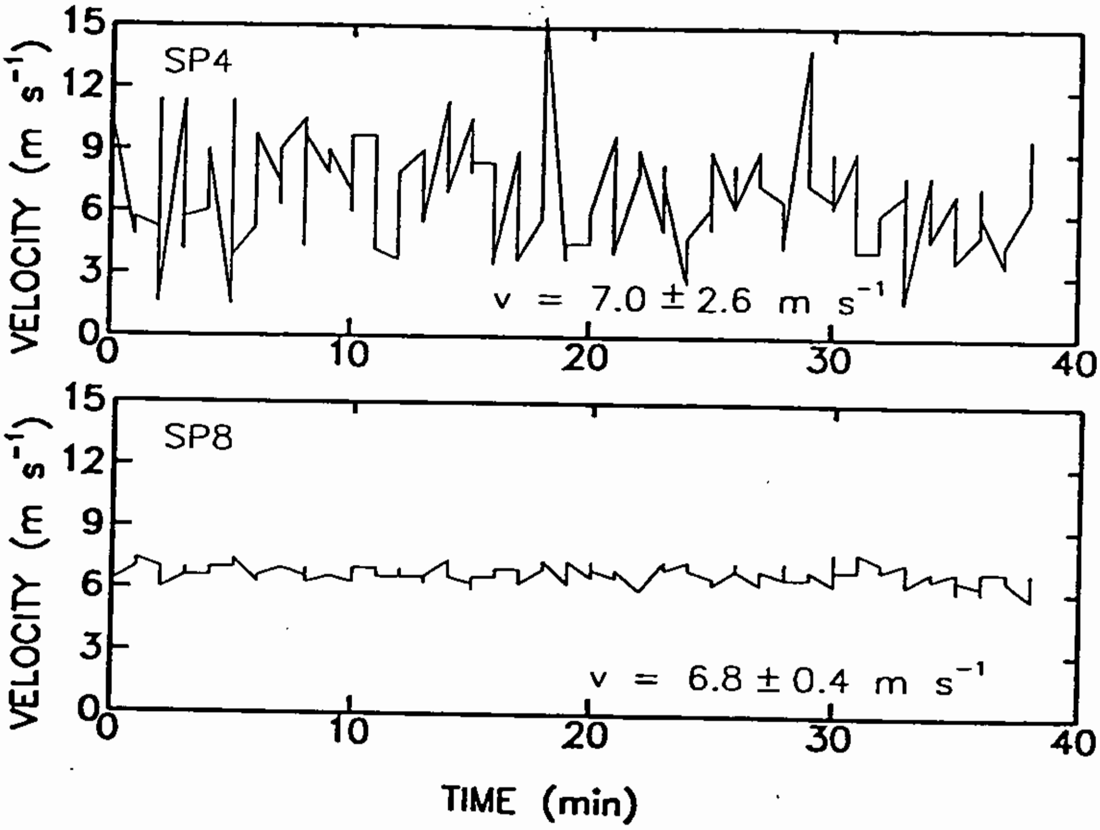


Figure 5. Velocity versus time for the flows from the SP4 and SP8 wells, determined by cross-correlation averaged over 17 second periods.

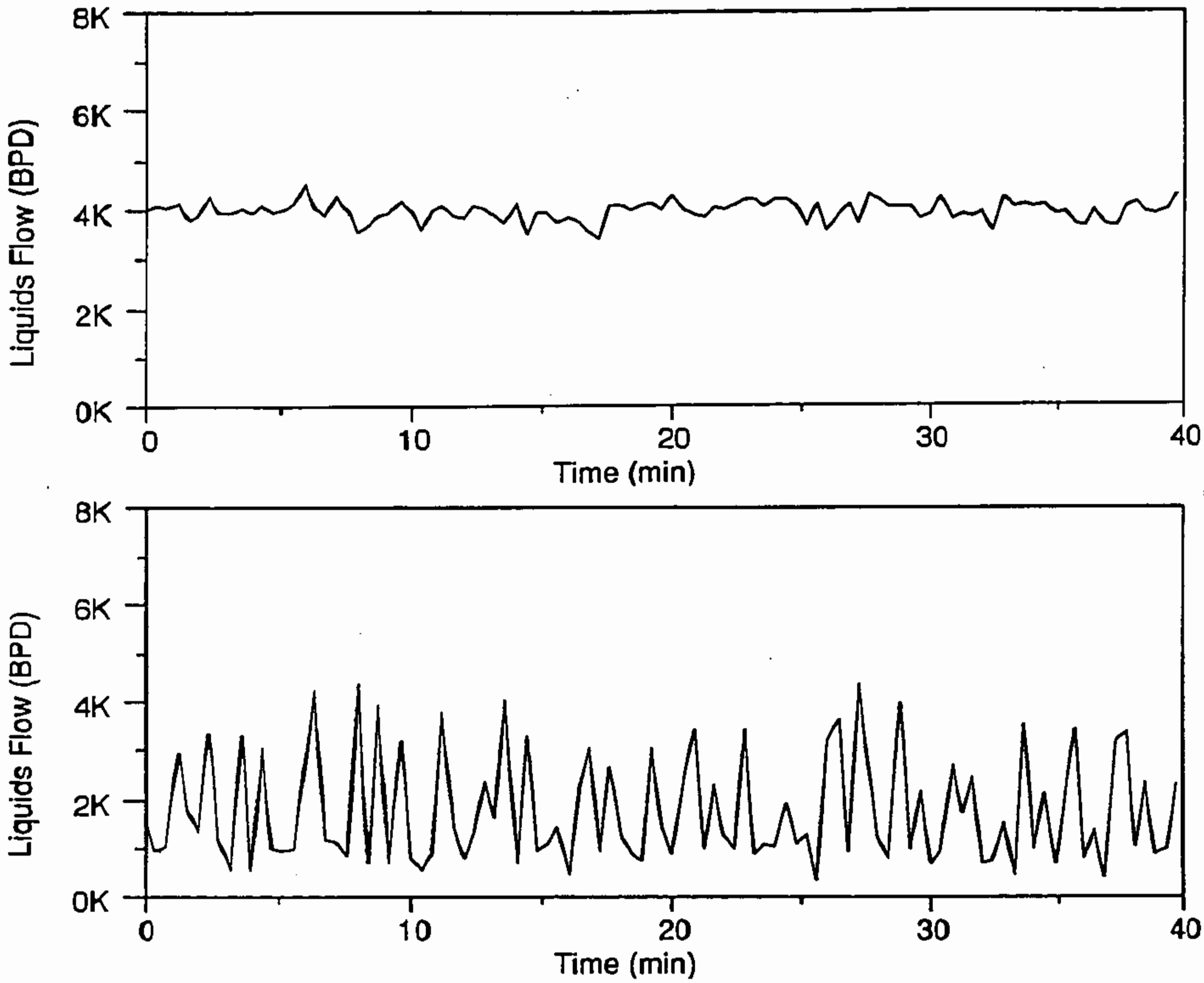


Figure 6. Variation of the volume flow rate of the liquids (oil + water) with time for the flow of SP7 and SP4 wells in the vertical section of the test pipeline.

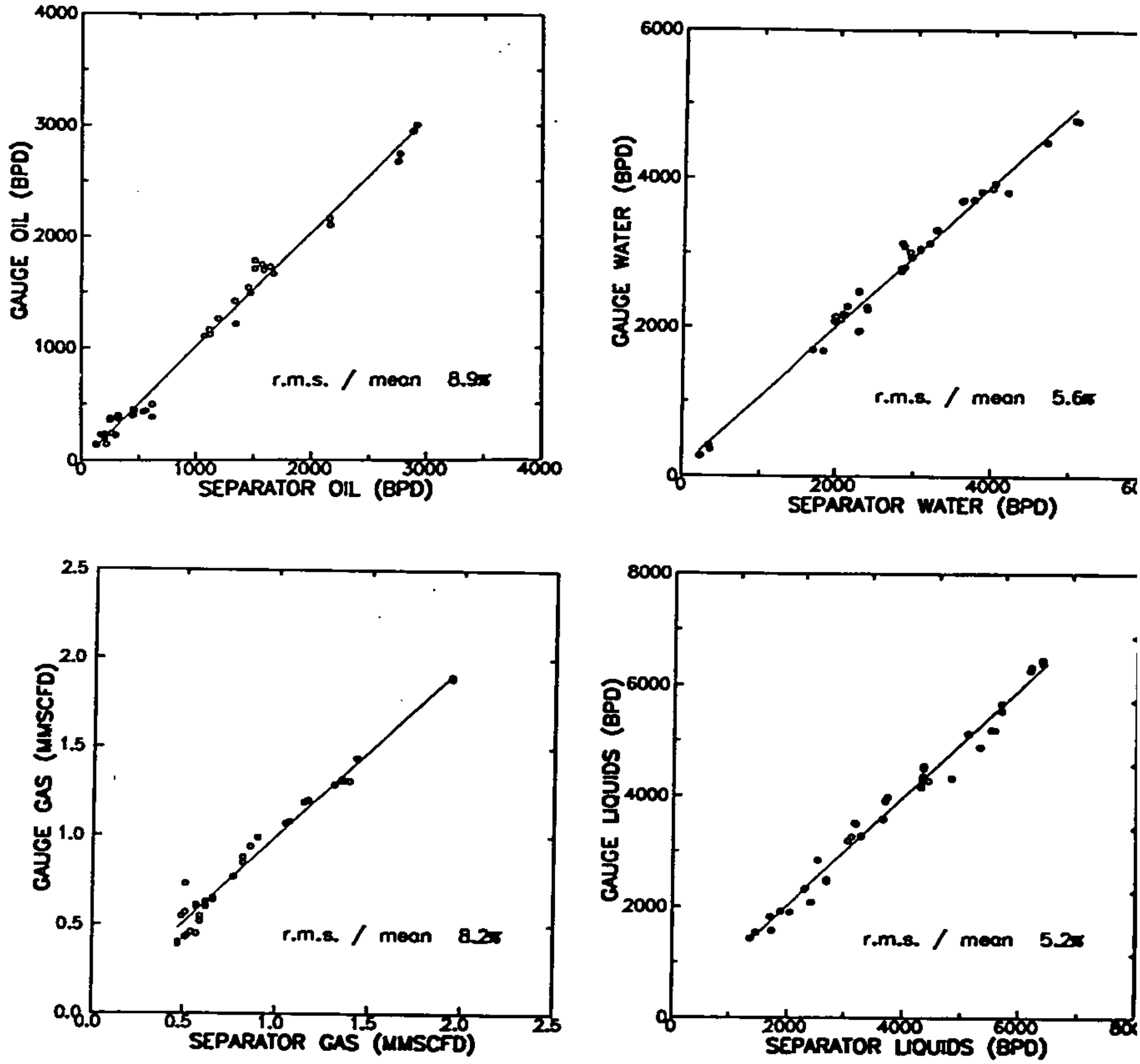


Figure 7. Gauge and separator output determinations of the volume flow rates of oil, water, gas and total liquids.