NORWEGIAN SOCIETY OF CHARTERED ENGINEERS

NORTH SEA FLOW METERING
WORKSHOP

13 - 15 October 1987

Stavanger Forum, Stavanger

THE EFFECTS OF LIQUIDS ON ORIFICE PLATES
METERING GAS

3·2

Lecturer: Scientific Officer
A. Moore, NEL

DEPARTMENT OF TRADE AND INDUSTRY

NATIONAL ENGINEERING LABORATORY

THE EFFECTS OF LIQUIDS ON ORIFICE PLATES METERING GAS

by

A Moore
(Flow Measurement and Turbomachinery Division)

S U M M A R Y

The influence of relatively small amounts (say up to 5 per cent by mass) of liquid contamination when metering natural gas with orifice plates are examined. It is shown that all the established correlations predict substantially the same minor, but significant, effect.

An approach to correcting (for known gas quality) mass flowrates, determined using the established equations based upon the meter performance with dry gas, is suggested.

The influence of mixture quality has been discussed and some suggestions for the on-line measurement of 'gas quality' are given.

C O N T E N T S

NOTATION

A	Area of flow	m^2
A_2	Area of orifice throat	m^2
C_d	Discharge coefficient	–
C*	Relative capacitance	–
D	Diameter of pipe	m
d	Diameter of orifice bore	m
Fr_m^2	Modified Froude number (defined in equation (2))	–
f(1)	Function defined in equation (12)	–
f(2)	f(1) modified by the inclusion of 0 for constant 1.26	–
g	Gravitational acceleration	m/s^2
h	Height above the datum level	m
K	Mean velocity ratio (U_G/U_L)	–
P	Pressure	Pa
ΔP	Differential pressure at orifice	Pa
Q_m	Mass flowrate of fluid in single-phase flow	kg/s
U	Mean velocity (applicable to two-phase flow)	m/s
W	Mass flow of mixture	kg/s
W_C	Mass flow of condensate	kg/s
W_G	Mass flow of gas in two-phase flow	kg/s
W_G*	Inferred mass flow of gas	kg/s
W_{HC}	Total mass flow of hydrocarbons	kg/s
W_L	Mass flow of liquid in two-phase flow	kg/s
W_W	Mass flow of water	kg/s
X	Lockhart-Martinelli parameter	–
x	Quality (mass dryness fraction) W_G/W	–
y	Liquid fraction (= 1 – x)	–
z	Water cut (z = W_W/W_L)	–
β	Orifice plate diameter ratio	–
ϵ	Expansibility factor (applied to flow through an orifice)	–

θ	Correction factor (function of density ratio)	–
ρ	Density	kg/m³
Φ	Two-phase multiplier	–
Ω	Void fraction ($= A_G/A$)	–

Subscripts

1	Refers to conditions at station upstream of orifice
2	Refers to conditions at the throat measuring position
G	Value of variable for gas
L	Value of variable for liquid
s	Superficial value
t	Value in two-phase flow

1   INTRODUCTION

This paper addresses itself to the potential errors that can be introduced into a measurement of a gas flowrate through an orifice plate by the presence of a small quantity of liquid. This may, in the case of a system distributing natural gas, be condensate or water, or more probably a mixture of both. Our work is at present mainly concerned with systems metering natural gas, since the commercial implications of even quite small errors can be very significant. This allows one to arbitrarily impose limitations on the general topic of two-phase flow through orifice plates and directed my approach to the existing literature, which in general, is quite extensive. Initially the liquid phase was seen as a contaminant and was not treated as a useful commodity. This suggested that the most sensible approach would be to concentrate on the study of work which has used the gas phase as the basis for the correlation between a single-phase measurement and that in the two-phase environment.

It is not intended that this paper shall be a definitive study of the problem, but it is seen rather as a vehicle which may stimulate this forum in a discussion of the current state of the art and help in the identification of those areas into which future investigations might most usefully be directed.

2   STATEMENT OF THE PROBLEM

In the metering of natural gas it is recognised that in order to get an 'accurate' measure of the quantity it is necessary to separate the gas from any associated liquids. Plant to accomplish this is invariably included in any distribution/metering system. It has been suggested that condensate can, even with such plant fitted, be present as a contaminant in metering stations. Additionally operators, faced with the need to apportion – using orifice plates – the flow of mixture from a number of sources, are seeking improved accuracy. The case where a high quality two-phase mixture, rather than pure gas, passes through the meter, has been studied.

The problem is therefore stated: if one infers the gas mass flowrate, based on measurement of pressure difference across the orifice plate (Fig. 1) as W_G^*, where,

$$W_G^* = \frac{C_d \epsilon A_2}{\sqrt{(1 - \beta^4)}} \sqrt{(2 \Delta P \rho_G)} \quad \text{kg/s} \tag{1}$$

what are the likely errors associated with such an estimate for the mass flowrate of gas given that the pressure difference ΔP is due to the passage of a mixture of gas and condensate? It may also be expressed; what level of liquid contamination can be allowed in gas metering systems before one can expect to find significant errors in the assessment of gas mass flowrate through the orifice plate?

In this treatment it has been envisaged that liquid contamination could be as high as 5 per cent by mass.

3   TWO-PHASE FLOW IN PIPES AND THROUGH ORIFICE PLATES

Simultaneous flow of gas and liquid through pipes features a variety of regimes which have been described, typically[1][2]. Attempts have been made to develop maps which encompass most of the variables and typical of these are

the two shown in Figs 2a and 2b, which are derived by Dukler and Taitel[3]. More recently the phenomena of liquid accumulation upstream of orifice plates has been reported by both Norman et al[4] and in the work[5] carried out under Dr Boe's direction here in Norway at the Rogaland Research Institute. The build up of liquid upstream of the plate influences the pressure difference measured at the plate in a manner rather different to that caused by the two-phase flow through the plate and discussed in some detail in paragraph 4 of this paper. It has been shown[5] that liquid accumulation leads to an under-estimation of gas mass flow, while the effect of the liquid passing through the plate leads to an over-estimation of the gas mass flow.

3.1 Liquid Accumulation: When Is It Significant?

The liquid accumulation effect has been reported in work carried out at ambient pressure or relatively moderate air pressures. It has been shown[5] that the build up of liquid in front of the plate can be correlated against modified Froude No Fr_m, ie a Froude number based upon the superficial gas velocity and modified by the density ratio,

ie,
$$Fr_m{}^2 = \frac{\rho_G/\rho_L}{1 - \rho_G - \rho_L} \frac{(U_{GG})^2}{gD}. \tag{2}$$

Examination of the data given in Reference 5 suggests that the effect of liquid accumulation is negligible when the value of $Fr_m{}^2$ exceeds 0.15. We have therefore explored the behaviour of equation (2) for a range of density ratios, pipe sizes and superficial gas velocities. A threshold value (when $Fr_m{}^2 = 0.15$) for superficial gas velocity above which the effect of liquid accumulation is negligible has been calculated for a range of gas/liquid density ratios and is shown plotted in Fig. 3.

One observes from this analysis that it is most unlikely, since the velocities and densities encountered will be high, in practical natural gas metering installations, that one will find liquid accumulating upstream of the orifice plate.

Consequently, in this paper, no further reference is made to the phenomenon.

4 PUBLISHED DATA: MEASUREMENTS OF PRESSURE DIFFERENCE AT THE PLATE IN TWO-PHASE FLOW THROUGH ORIFICE PLATES AND DERIVED CORRELATIONS

A great deal of work has been carried out in this field over the years and much of it has resulted in 'a new correlation'. Surprisingly little of this work has, however, been addressed directly to the problem with which we are concerned although, as it transpires, most of it has some relevance.

4.1 Pressure Difference Measurements and Correlations

In a 1962 paper[6] Murdock presented data which is directly relevant. This was derived from tests carried out by W H Osborne of the Champlin Oil and Refining Company. He had conducted laboratory and field tests on a variety of mixtures, including gas/distillate and gas/water combinations at representative (920 lbf/in²) gas pressures. Data derived from the flow of steam/water mixtures through orifice plates measured in the Naval Boiler and Turbine Laboratory were also used by Murdock in the development of his correlation. He employed the two-phase multiplier

$$\Phi_G{}^2 = \frac{\Delta P_t}{\Delta P_G} \tag{3}$$

and found a linear relationship (reproduced in Fig. 4) between it and the Lockhart-Martinelli[7] parameter X. The best fit line to the data is given by

$$\Phi_G = 1 + 1.26X \qquad (4)$$

with the corresponding expression for the mass flow of the mixture as

$$W = \frac{C_{dG}A_2\epsilon_G}{\sqrt{(1 - \beta^4)}} \frac{\sqrt{(2\Delta P_t \rho_{G1})}}{x + 1.26(1 - x)\epsilon_G(C_{dG}/C_{dL})\sqrt{(\rho_{G1}/\rho_{L1})}} \qquad (5)$$

where x, the quality of the mixture is defined

$$x = W_G/W = 1 - y$$

where y is the liquid fraction and

$$y = W_L/W.$$

The Osborne tests were carried out in reasonably sized pipework, up to 100 mm diameter, with representative plate beta ratios, as detailed in the table in Fig. 4.

Typical of the other data sources is the work[8][9] carried out by Chisholm and his co-workers at the UK National Engineering Laboratory where measurements were made with steam/water mixtures in quite small (50 mm) diameter pipework. A correlation between the two-phase multiplier and the Lockhart-Martinelli parameter

$$\Phi_G^2 = 1 + 2.66X + X^2 \qquad (6)$$

was developed as a result of this work. For high quality flows there is, as shown in Fig. 5, little difference between the results given by the Murdock and Chisholm correlations, for quite wide ranging differences in measurement conditions.

This general approach has been widely followed and more recent work with steam/water and Freon-113 has extended the data to higher $(\rho_G/\rho_L \leq 0.33)$ density ratios. In place of the single equation (4) Lin[10] found that the parameter Φ_G varied with the density ration ρ_G/ρ_L and derived the empirical relationship between his correction factor θ and density ratio shown plotted in Fig. 6. Where his factor θ is given in

$$\Phi_G = 1 + \theta X. \qquad (7)$$

He showed that the distinction between the liquid and vapour phases tends to reduce as the pressure increases. The mixture behaviour clearly approaches that of an homogenous fluid and the value of θ tends to unity as the density ratio is increased.

Lin preferred to use the liquid density as the basis for his correlation, claiming that it gave better results when vapour quality x was greater than 0.1. The preferred correlation due to Lin is

$$W = \frac{C_{dL}A_2}{\sqrt{(1 - \beta^4)}} \frac{\sqrt{(2\Delta P_t \rho_L)}}{\{(1 - x)\theta + x\sqrt{(\rho_L/\rho_G)}\}} \qquad \text{kg/s}. \qquad (8)$$

3

The discharge coefficient is that appropriate to the orifice with liquid flow alone and in the tests referred to it was measured using liquid Freon. The test line was horizontally mounted and 32 mm diameter. A range of orifice diameters were tested, giving diameter ratios β of 0.311, 0.439 and 0.624 respectively. Density ratios of 0.1425, 0.2150, 0.2450 and 0.3280 were used and the highest pressure reached 0.832 of the critical value. Qualities were determined from heat flux measurements and estimated to be accurate to within ±1.0 per cent.

Teigen and his co-workers[11] reached slightly different conclusions from their measurements in high pressure (69-200 bar) steam/water mixtures. They found that their results were best correlated by the simple 'no slip separated flow' model, ie the correction coefficient θ takes the value unity.

4.2 Comparison Between Inferred and True Gas Flowrate

The inferred mass flowrate W_G^* is derived using equation (1). The actual mass flow of the two-phase mixture W may be estimated, if the mixture quality is known, using the expression[5] due to Murdock. This may be expressed in terms of the inferred gas flowrate

ie,
$$W = \frac{W_G^*}{1 + y\left(1.26 \dfrac{C_{dG}\epsilon\sqrt{(\rho_{G1})}}{C_{dL}\sqrt{(\rho_{L1})}} - 1\right)} \quad \text{kg/s} \tag{9}$$

Combining equation (9) with the expression for the liquid fraction y, one obtains

$$\frac{W_G}{W} = \frac{W_G^*}{W} \frac{1}{1 + y\left\{1.26\epsilon\dfrac{C_{dG}}{C_{dL}} \dfrac{\sqrt{(\rho_{G1})}}{\sqrt{(\rho_{L1})}} - 1\right\}} - y \tag{10}$$

$$= 1 - y.$$

The ratio $-\dfrac{\text{true mass flowrate of gas}}{\text{inferred gas flowrate}} = \dfrac{W_G}{W_G^*}$

may be written in the form

$$\frac{W_G}{W_G^*} = \frac{1 - y}{\{1 - f(1)y\}} \tag{11}$$

where the function $f(1) = 1 - 1.26\epsilon \dfrac{C_{dG}}{C_{dL}} \dfrac{\sqrt{(\rho_{G1})}}{\sqrt{(\rho_{L1})}}$ (12)

varies with both gas and liquid Reynolds' numbers and hence with change in quality. The dependence is relatively weak, hence it is meaningful to explore the behaviour of equation (11) with $f(1)$ maintained constant. The assessment is based on the conditions cited in Murdock's paper[6], ie natural gas at 62 bar and with both water and distillate as contaminants.

These relations may be made more generally valid by substituting θ for the constant 1.26 in equations (10) and (12) and using values for θ appropriate to the mixture density ratio.

Contamination has its greatest influence on equation (11) when the density ratio ρ_G/ρ_L is a maximum. The value of $f(1)$ when the mixture is comprised of gas and distillate at a pressure of 62 bar is typically

$$f(1) = 1 - 1.26 \times 0.992 \times (0.603/0.66) \times \sqrt{(50.18)}/\sqrt{(758)}$$

$$= 0.706.$$

The ratio (for natural gas) of true flowrate/inferred flowrate has been plotted in Fig. 7. Also shown in this figure are corresponding ratios derived for two models, viz. air/water at ambient pressure and air/oil at 8 bar; both of which could be fairly readily studied in the laboratory. The input data used in their derivation is summarised in Table 1.

It is evident that at practical density ratios a limited amount of liquid contamination may be allowed before one needs to take account of its direct effect on the orifice plate readings. It is also evident that one should beware of drawing conclusions about the accurate measurement of flowrate in natural gas two-phase mixtures based upon results measured in the laboratory with quite unrealistic mixture density ratios.

4.3 Allocation and the Effect of Another Liquid Component

In the discussion so far the liquid has been seen as a contaminant, however in most cases the liquid passing through the meter is either recovered or evaporated downstream. Then it is assumed that the mass flow of the mixture is of primary interest. The mass flow of the mixture can be related to the inferred flowrate of the gas using

$$\frac{W_G{}^\star}{W} = 1 - f(2)y \tag{13}$$

where the coefficient $f(2)$ (ie the more general form of $f(1)$ with θ used in place of Murdock's constant) has now been adopted. The ratio mixture mass flow to inferred mass flow of gas $W/W_g{}^\star$ has been plotted against liquid fraction in Fig. 8a for the case of natural gas at 200 bar. The case where the gas is at 62 bar has been plotted in Fig. 8b.

It is significant and obvious that the correction is now in the opposite sense. The mass flowrate of hydrocarbons, which is the commodity of interest, has been under-registered by taking an inferred value for the mass flowrate of gas.

The mixture which is passed through an orifice plate downstream of a wellhead separator is comprised of at least three components, wet, gas, water and condensate. If we assume that the commercial values (by mass) of the condensate and gas are equal and take that of the water as zero then we will have a mixture of hydrocarbons, the mass flowrate (W_{HC}) of which is the commodity which we wish to know or allocate.

Writing,

$$W_L = W_W + W_C$$

5

and defining a water 'cut' as $z = W_W/W_L$, then the mass W of gas/liquid mixture passing through the orifice plate is now given by

$$W = (W_W + W_C) + W_G$$

and the valuable commodity, the mass of hydrocarbons W_{HC} is given by

$$W_{HC} = W_G + W_C.$$

Using the relations for $W_G/W_G{}^*$ and $W/W_G{}^*$ previously determined one arrives at an expression for the valuable hydrocarbon mixture

$$\frac{W_{HC}}{W_G{}^*} = \frac{1 - zy}{\{1 - f(2)y\}}. \tag{14}$$

The ratio $W_{HC}/W_G{}^*$ takes the value 1 if the water 'cut' $z = f(2)$. In this case no correction to the value given by the inferred gas flowrate need be made. This condition varies with pressure and vapour composition, ie density ratio. The ratio $W_{HC}/W_G{}^*$ has been plotted against liquid fraction y for a range of water 'cuts' z in Figs 9a and 9b. With natural gas at 200 bar the zero correction water 'cut' is between 50 and 60 per cent. In the case of natural gas at 62 bar it is nearer 80 per cent.

It must be stressed at this stage that the analysis is approximate and that the plotted characteristics will have to be modified to take account of the variation in the parameter f(2) with density ratio and the variation in density of the liquid fraction with water 'cut'. The analysis does however give a good indication of the scale of any correction needed.

5   MIXTURE PROPERTIES

In the treatment so far two fundamental issues have been avoided.

a   A correction to the gas mass flowrate, inferred from the measurement of pressure difference at the plate, can only be made if the mixture quality x is known.

b   The inferred flowrate can only be arrived at if the mixture density is known, or if the gas density can be determined from a knowledge of its equation of state.

Rather than attempt to offer specific solutions, a few notes on each topic shall be put forward for discussion

5.1   Sampling for Mixture Quality

In many cases the mixture quality will remain relatively stable for long periods of time. In such circumstances it is feasible for information on the liquid mixture and the gas properties to be determined by analysis of samples collected on a regular basis. These data taken with measurements of pressure and temperature at the meter will allow, with the aid of an equation of state, an estimate of component densities. One will then be in a position to correct an inferred gas flowrate, using the relations given above. The question that remains to be answered is – how well founded is one's knowledge of the equation of state?

6

5.2 On-line Determination of Quality

The continuous measurement of electrical capacity can be used[12] to provide a measurement of void fraction. In order to calibrate such an instrument the dielectric properties of the liquid mixture and the gas need to be known and remain sensibly stable with time. This approach will not be practical in three component flows, ie when the liquid phase is a mixture of condensate and water. Measurement of capacitance is feasible when it is clearly two-phase flow and is currently being employed[13] in the North Sea for assessing water content in oil streams.

The use of this method at the high quality end of the gas/liquid two-phase flow spectrum appears to be eminently feasible. Fig. 10, reproduced from the static model experiments described[14], shows that capacitance change is relatively sensitive to change in void fraction Ω in this flow regime.

The quality of the mixture is then inferred from a relationship of the type

$$1/\Omega = 1 + K \frac{\rho_G}{\rho_L} \frac{1-x}{x} \tag{15}$$

where $K = U_G/U_L$, the mean velocity ratio, is a function of the flow pattern and geometry of the capacitance meter. It will be noted that the density ratio is included in this expression.

It must be said that, while such an approach offers a sound basis for determining quality in association with an orifice plate, the combination will require considerable development before being useable as a reliable two-phase flow meter.

5.3 Simultaneous Determination of Quality and Mixture Flowrate

Wong, Rhodes and Scott[15] showed that simultaneous measurement of frictional pressure drop and that due to momentum change in an accelerating flow could be correlated to yield mass flowrate in two-phase flow. They used a section of pipework with a twisted tape swirl generator for the frictional loss section and a Venturi meter downstream for the accelerating flow element. Fig. 11 (a and b) are reproduced from their paper and clearly show how the two distinct correlations intersect to yield a solution for each component of the mixture.

With high pressure two-phase flow of natural gas mixtures the frictional pressure drop in the pipe lines is measurable[16] over quite short lengths. Such measurements taken with the pressure drop at the orifice plate will allow the derivation of liquid and gas flowrates. This approach would allow one to validate the technique for correcting inferred gas flowrate with a minimum of development, since the frictional pressure loss correlations[16] are relatively well founded.

If one were to associate such instrumentation with an on-line flow computer then one has in prospect a 'smart orifice plate', with the ability to correct for liquid contamination.

6   IN CONCLUSION

The influence of relatively small amounts (say up to 5 per cent by mass) of liquid contamination when metering natural gas with orifice plates has been

examined. It has been shown that all the established correlations predict substantially the same minor, but significant, effect. Considering the effect of the liquid contamination as an error at the meter, then the actual gas flow will be about 1.5 per cent less than the value registered, with 5 per cent of the total mass flow present as liquid. Alternatively if the whole mixture is deemed to be commercially valuable then the meter will under register the total flowrate of hydrocarbons by about 3.5 per cent, under the same conditions.

An approach to correcting (for known gas quality) mass flowrate determined using the established equations based upon the meter performance with dry gas, has been suggested.

The influence of mixture quality has been discussed and some suggestions for the on-line measurement of 'gas-quality' have been presented.

ACKNOWLEDGEMENT

REFERENCES

1   BAKER, O. Simultaneous flow of oil and gas. The Oil and Gas Journal, 26 July, 1954, pp 185-195.

2   MANDHANE, J. M., GREGORY, G. A. and AZIZ, K. A flow pattern map for gas-liquid flow in horizontal pipes. Int. J. Multiphase Flow, 1974, Vol. 1, pp 537-553.

3   DUKLER, A. E. and TAITEL, Y. A model for predicting flow regime transitions in horizontal and near horizontal gas-liquid flow. AIChE. Journal, January 1976, 22(1), 47-55.

4   NORMAN, R. Private communication, 1987.

5   AGUTA, R. M., OLSEN, K. E. and BOE, A. Investigation of liquid accumulation effects during orifice gas metering. Rogaland Research Institute Report No T16/82, February 1982.

6   MURDOCK, J. W. Two-phase flow measurement with orifices. J. of Basic Engineering, Trans. of ASME., December 1962, pp 419-433.

7   LOCKHART, R. W. and MARTINELLI, R. C. Proposed correlations of data for isothermal two-phase two-component flow in pipes. Chem. Engng Prog., 1949, 45(1), 39-48.

8   CHISHOLM, D. Two-phase flow through sharp-edged orifices. J. Mech. Engng Sci., 1977, 19(3), 128-130.

9   WATSON, G. G., VAUGHAN, V. E., McFARLANE, M. W. Two-phase pressure drop with a sharp-edged orifice. NEL Report No 290. East Kilbride, Glasgow: National Engineering Laboratory, 1967.

10 LIN, Z. H. Measurements of vapour quality and flowrate in two-phase flow with sharp-edged circular orifices. Conf. on Flow its Measurement in Science and Industry. Inst. Socy. of America, 1981, pp 493-504.

11   TEIGEN, B. C., XU, R. D. and WANG, J. Z. High-pressure two-phase flow measurement by a thin plate orifice. Paper No 83-JPGC-PTC-6, ASME 1983.

12   LESKOVAR, B., SUN, R. K., KOLBE, W. F. and TURKO, B. Measurement of the thickness of liquid film by means of the capacitance method. Electric Power Research Institute, Report No NP-1212, Palo Alto, Ca.

13   SHIRRAN, G. Offshore experience with the Endress and Hauser water in hydrocarbons monitor. Paper 1.3, North Sea Flow Metering Workshop, October 1986.

14   MOON-HYUN CHUN and CHANG-KYUNG SUNG. Parametric effects on the void fraction measurement by capacitance transducers. Int. J. Multi- phase Flow, 1986, $\underline{12}$(4), 627-640.

15   WONG, H. A., RHODES, E. and SCOTT, D. S. Flow metering in horizontal adiabatic two-phase flow. Conf. Flow its Measurement and Control in Science and Industry, 1981, Vol. 2.

16   FERSCHNEIDER, G., LAGIERE, M., BOURGEOIS, T. and FITREMANN, J. M. How to calculate two-phase flow of gas and oil in pipelines. Pipe Line Industry, August 1985, pp 33-39.

LIST OF TABLES

LIST OF FIGURES

INPUT DATA FOR THE EXAMPLES CITED IN FIGS 5 AND 7

Mixture	Gas/distillate	Air/water	Air/oil
Pressure bar	62	1.0	8.0
Temperature °C	99	16	90
Gas density kg/m³	50.18	1.20	7.64
Liquid density kg/m³	758	1000	760
(density ratio)$^{\frac{1}{2}}$	0.257	0.035	0.100
Function $\dfrac{C_{dG}}{C_{dL}} \epsilon_G$	0.907	0.980	0.900
Function f(1)	0.706	0.957	0.886

Direction
of flow →

Vena Contracta

Constriction

Station 1
(upstream)

Station 2
(downstream)
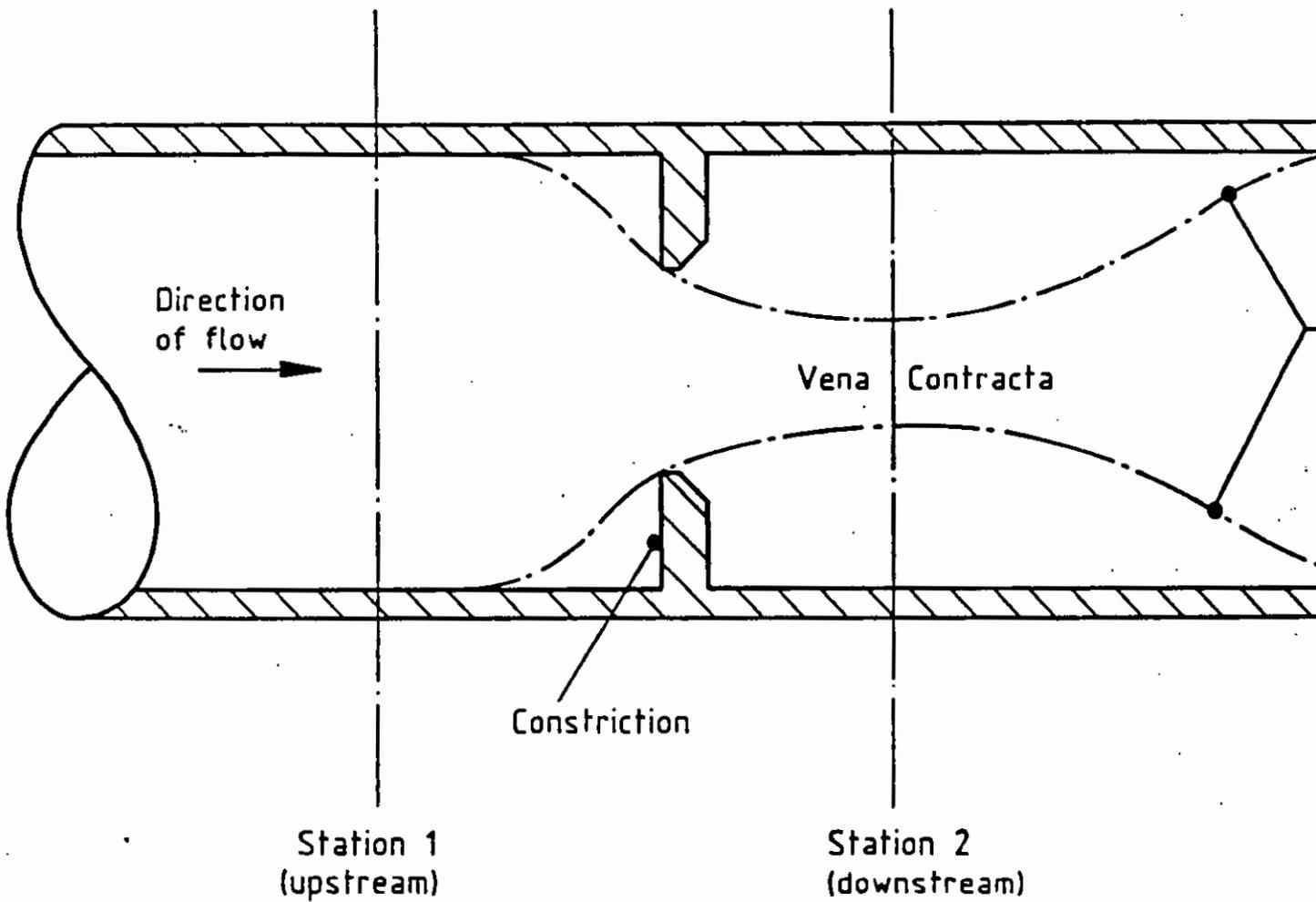
Fig 1   One Dimensional Flow Through a Pipe with a Constriction
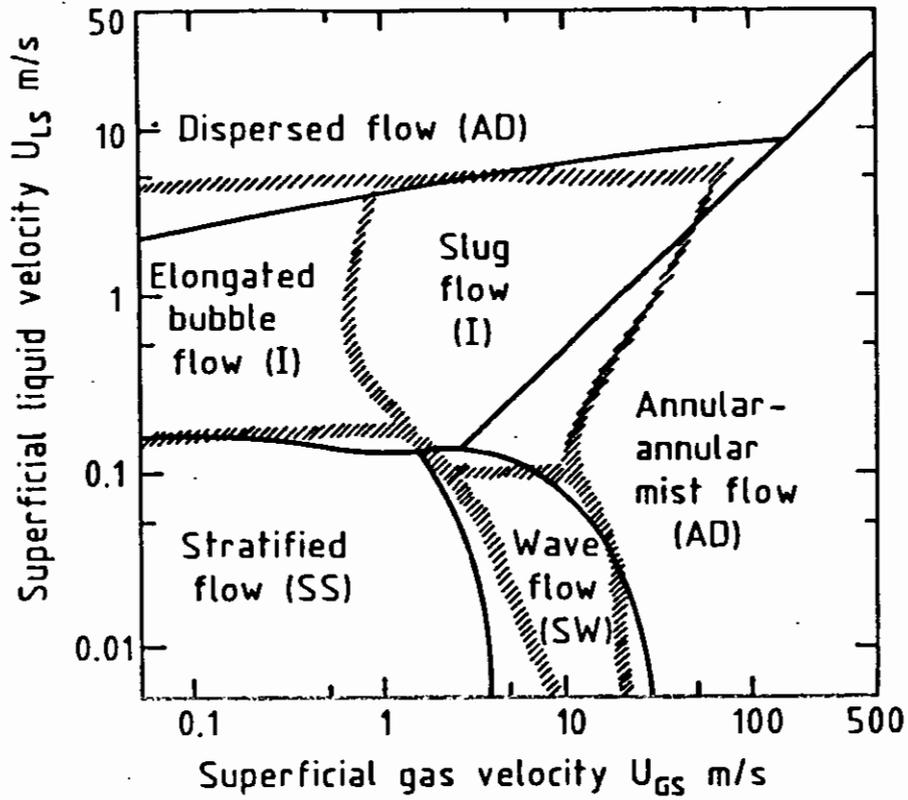
Fig 2a   Flow Regime Map for Natural Gas/Oil
         (68bar) Ref [3]
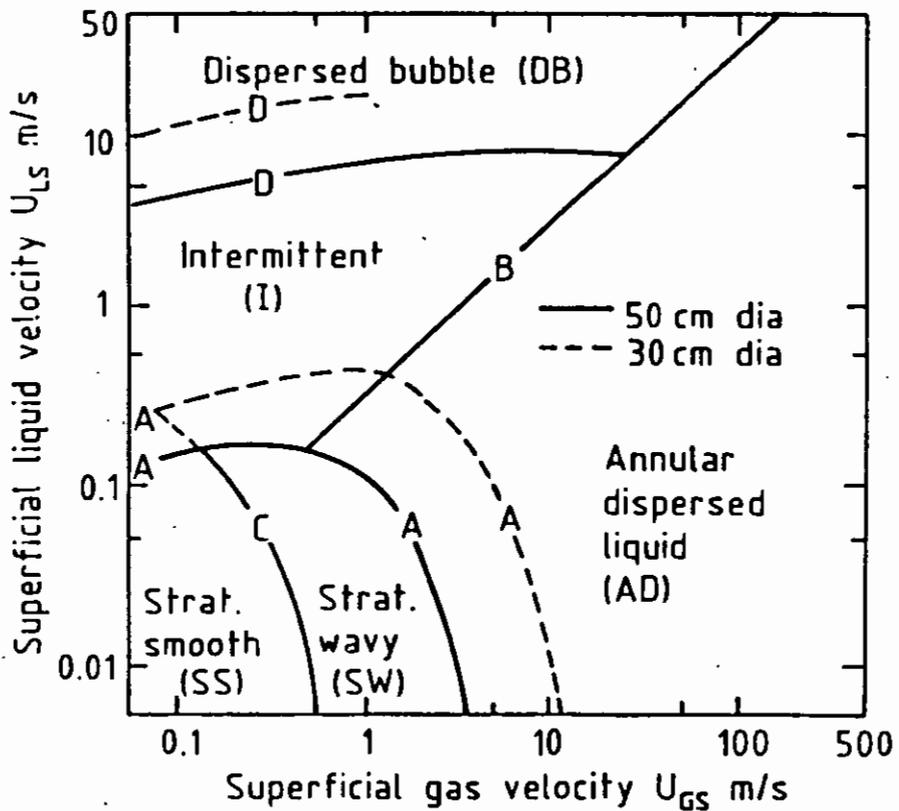
Fig 2b   Flow Regime Map for Air/Water (Ambient
         pressure) Ref.[3]

Fig. 3. Threshold : liquid accumulati

(Gas/liquid density ratio 0.001 − 0.35)
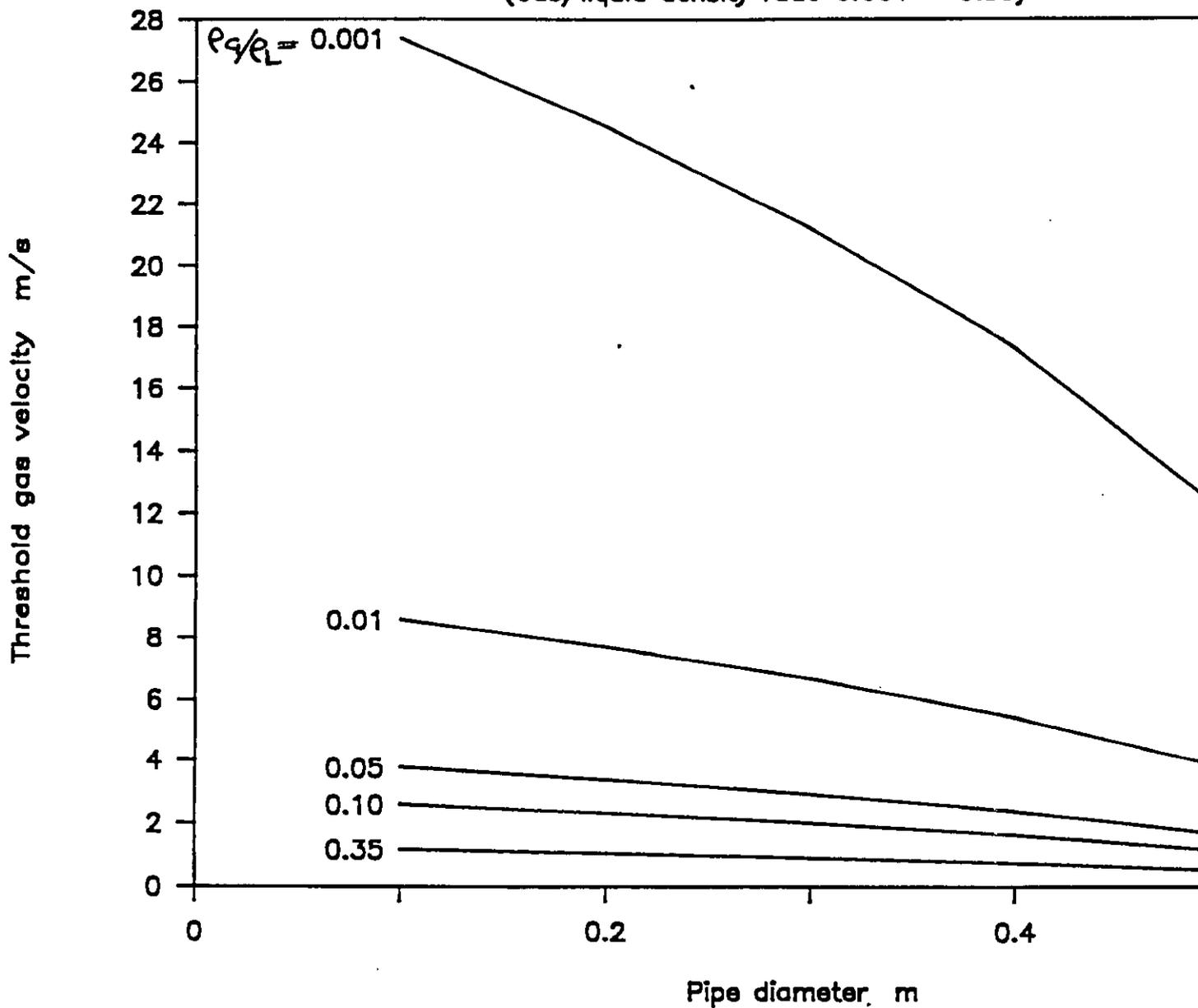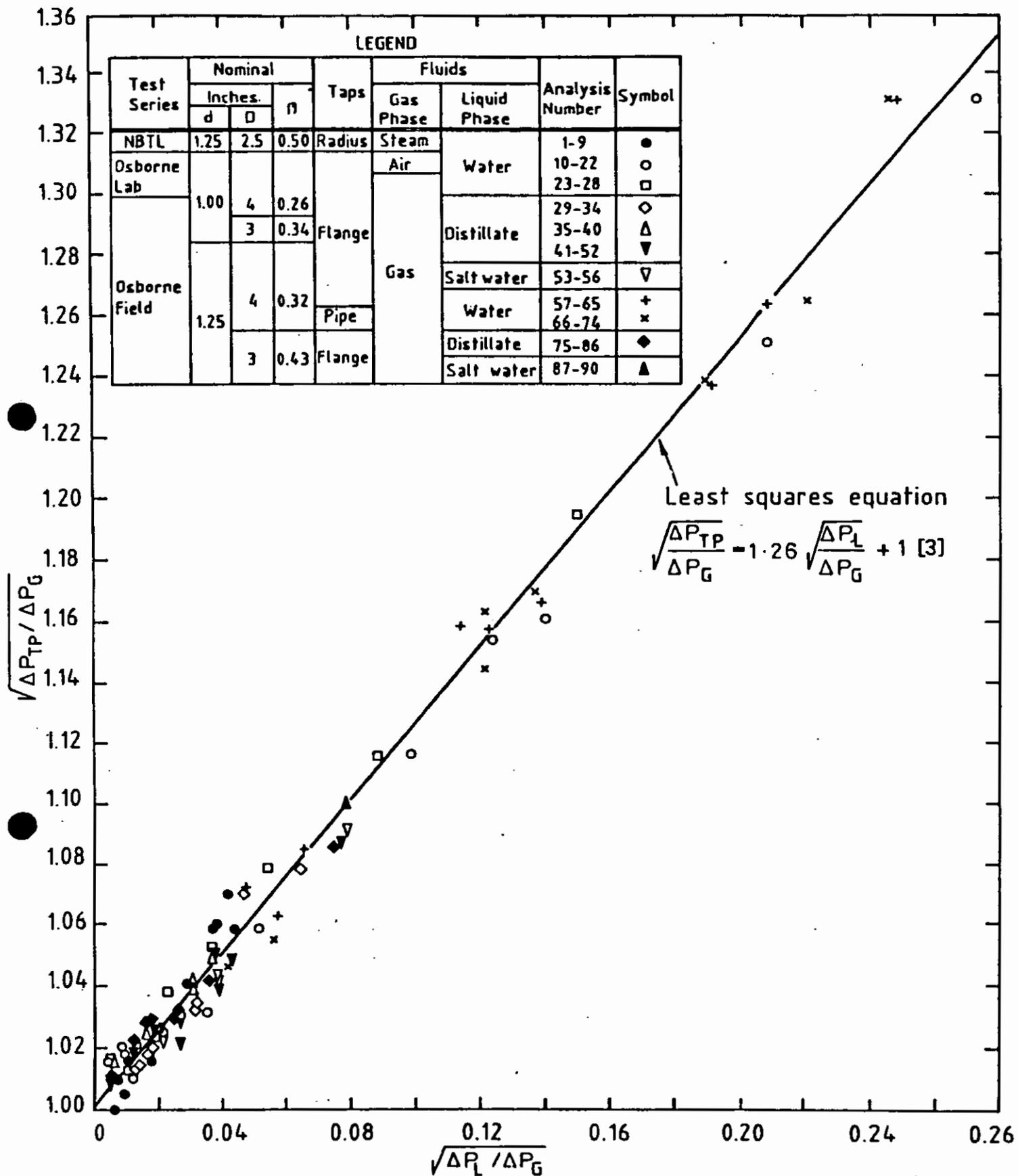
Fig 4   Correlation of Murdock's [10] Data

Fig. 5. Two-phase multiplier variati
(cf Murdock, Chisholm & Lin at 62 BAR)
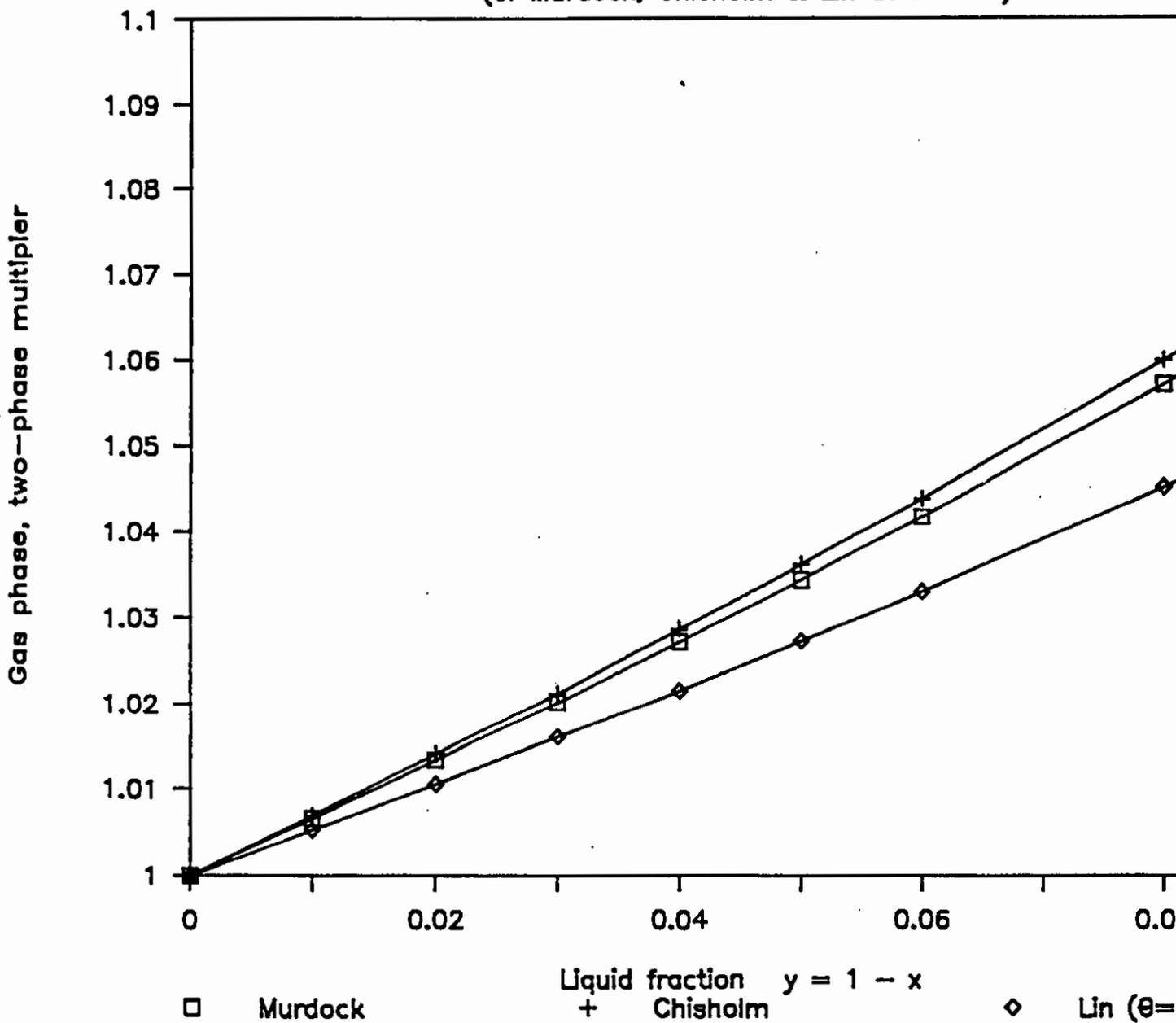
Fig. 6. Two—phase orifice plate corr'ns
(cf Lin's corr'n with Murdock & Teigen)

Value of coefficient θ

Gas/liquid density ratio

—— LIN   + MURDOCK   ◇ TEIGEN
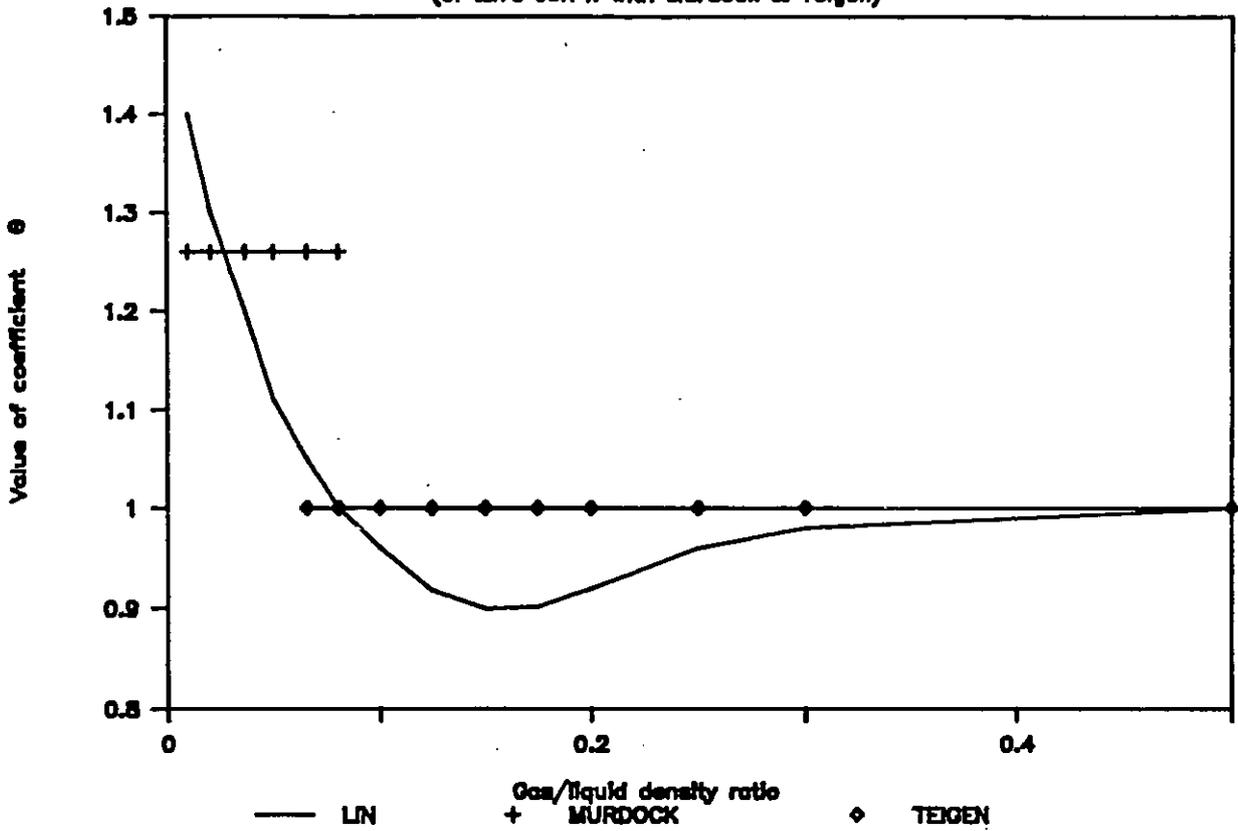
Fig. 7. Two—phase actual gas flowrate
(Full scale compared with two models)
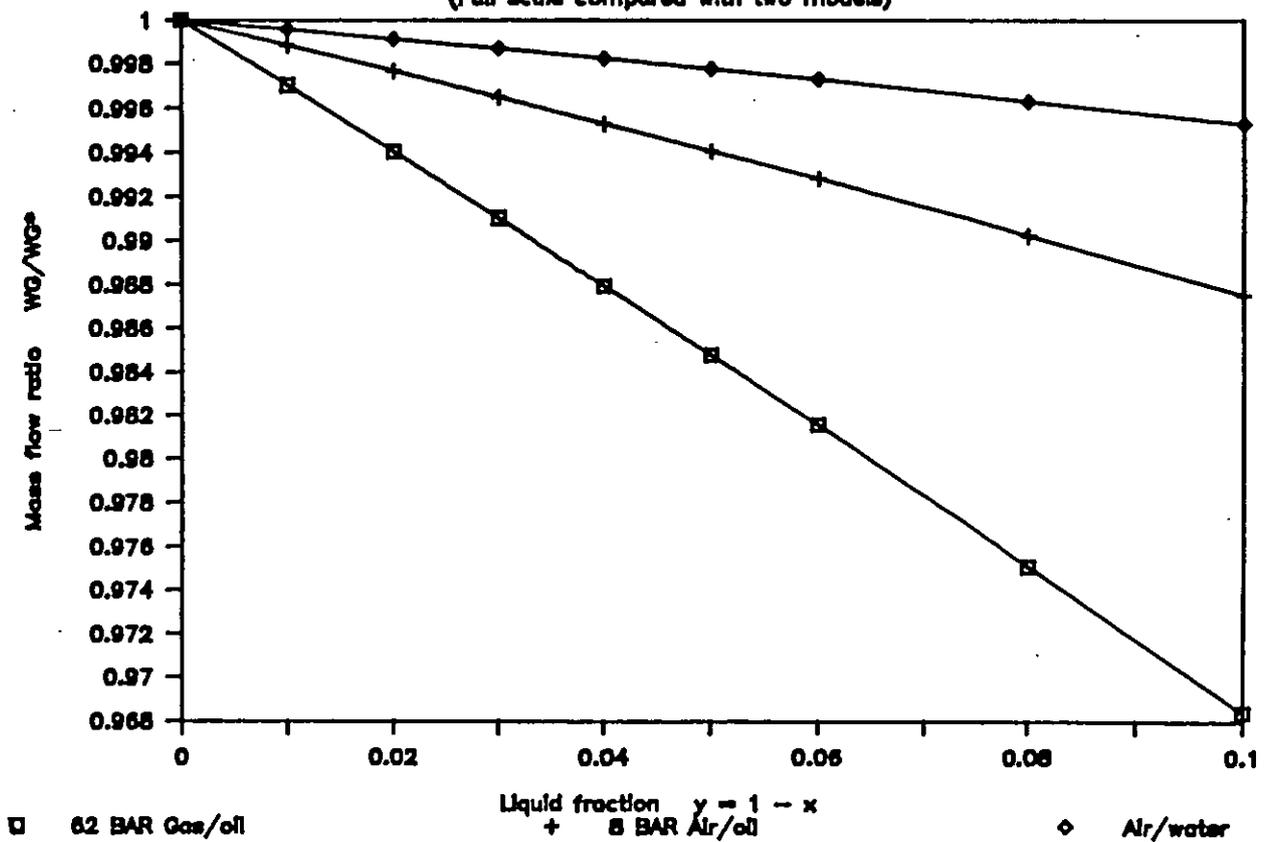
Mass flow ratio WG/WG*

Liquid fraction y = 1 - x

□ 62 BAR Gas/oil   + 8 BAR Air/oil   ◇ Air/water

Fig. 8a. Two—phase flowrate of mixture
(Comparison of Murdock & Lin corr'ns.)

Mass flow ratio W/WG*

Liquid fraction y = 1 - x

□ 200 BAR (Murdock)   + 200 BAR (Lin θ=1)

Fig. 8b. Two—phase flowrate of mixture
(Comparison of Murdock & Lin corr'ns.)

Mass flow ratio W/WG*

Liquid fraction y = 1 - x

□ 62 BAR (Murdock)   + 62 BAR (Lin θ=1)
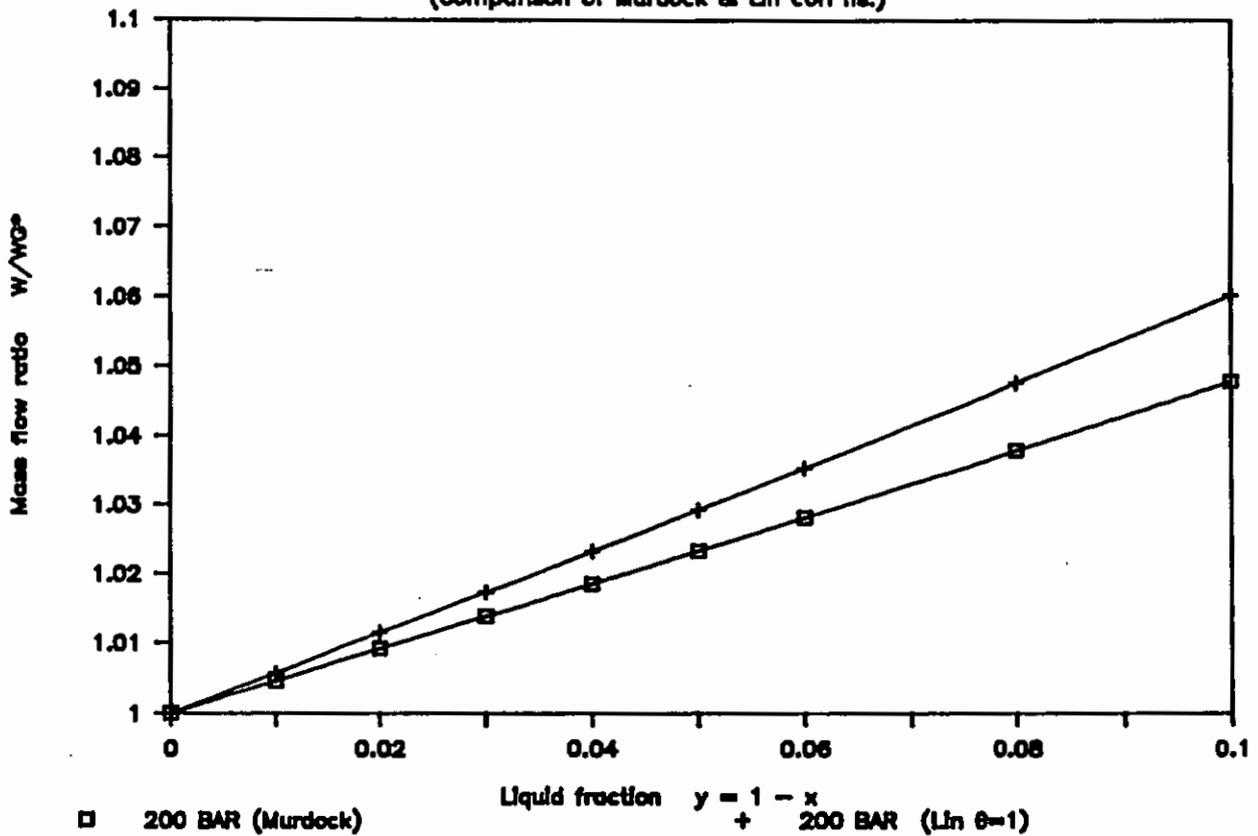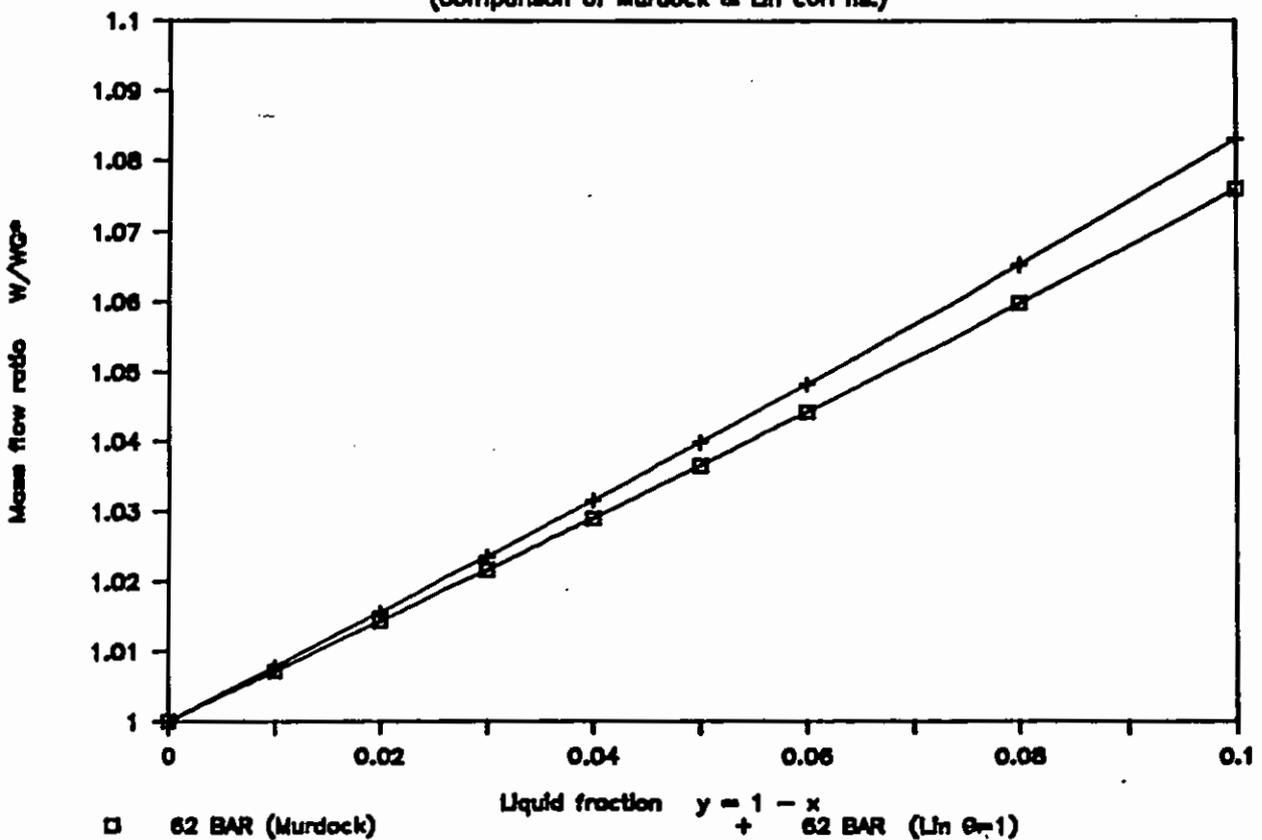
Fig. 9a. Total flowrate of hydrocarbons
(Water, condensate and gas at 200 bar)

Mass flow ratio WHC/WG°

Liquid fraction y = 1 - x

□   z=0   △   0.6   ▽   1.0
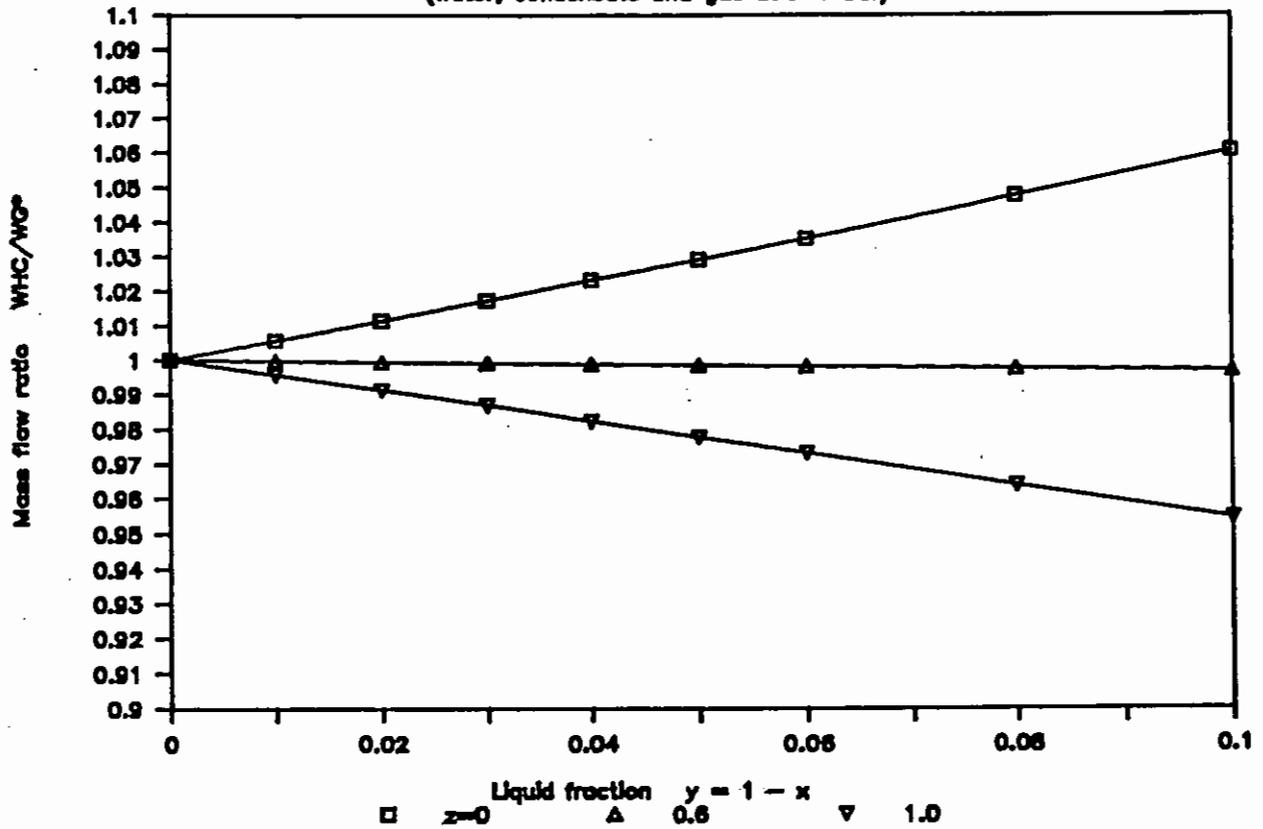
Fig. 9b. Total flowrate of hydrocarbons
(Water, condensate and gas at 62 bar)

Mass flow ratio WHC/WG°

Liquid fraction y = 1 - x

□   z=0   X   0.6   ▽   1.0
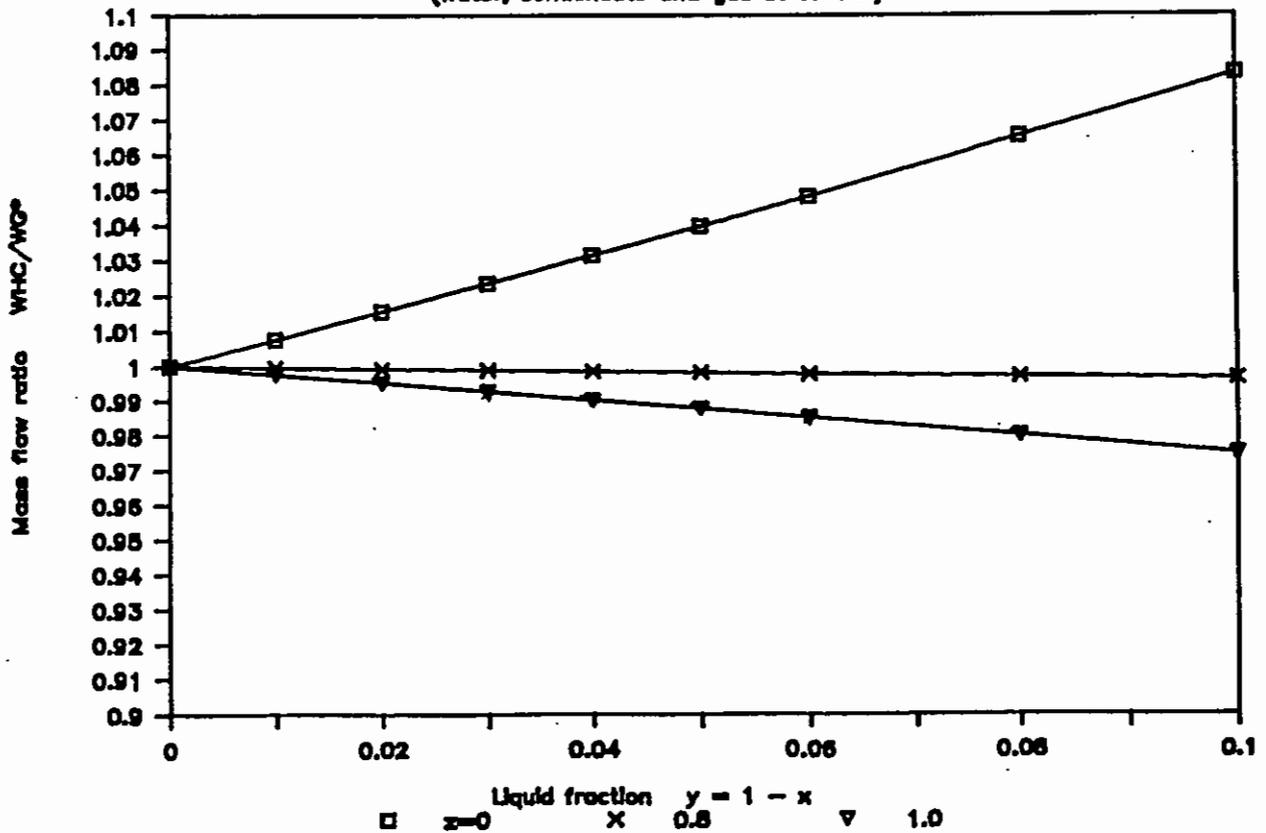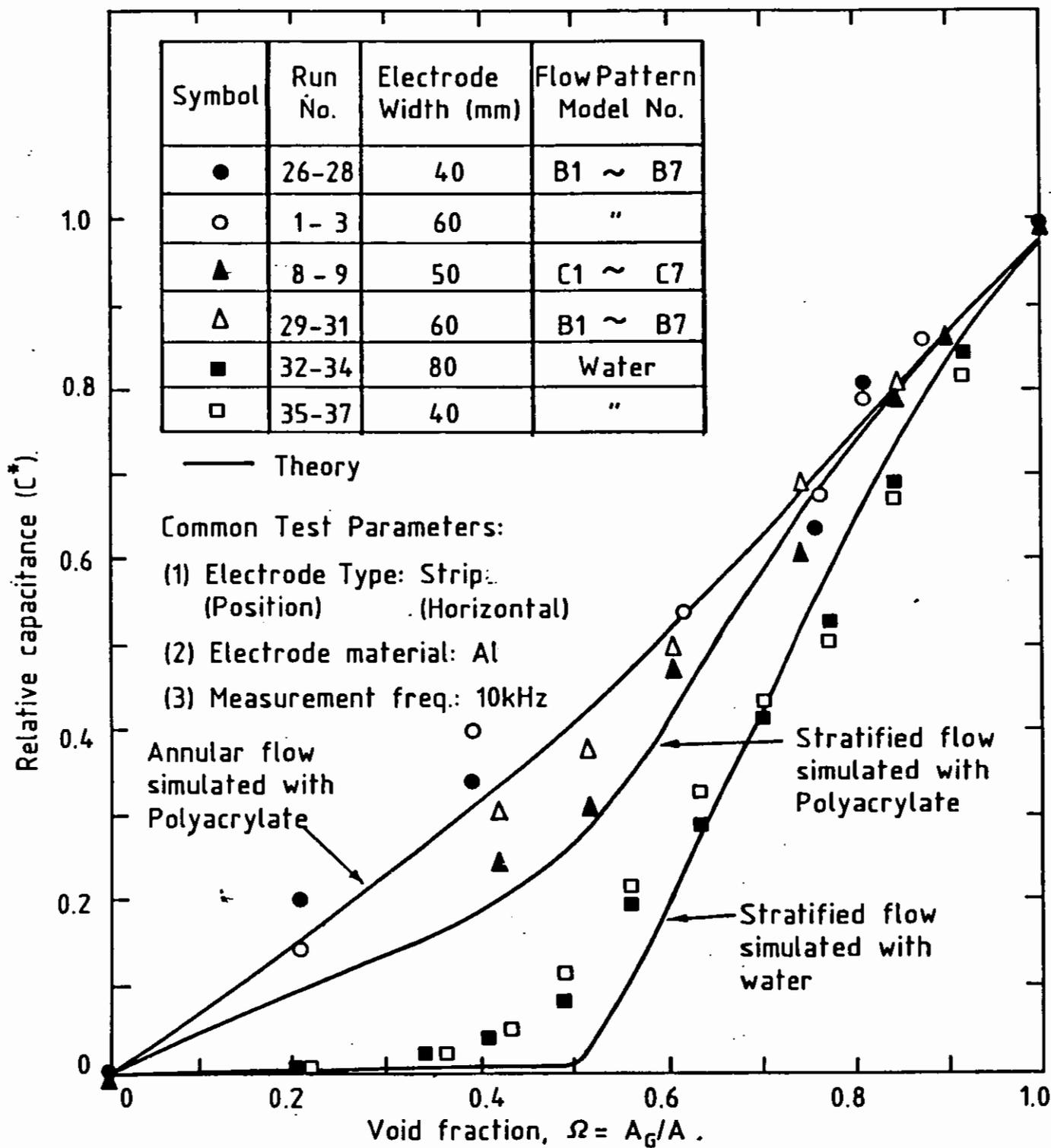
Fig 10 Effect of Geometry and Material on Relative
Capacitance (Static Model Tests Ref [14])
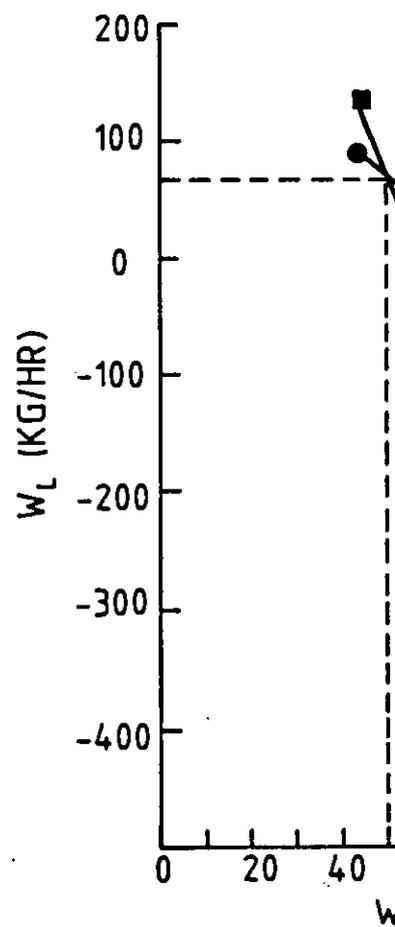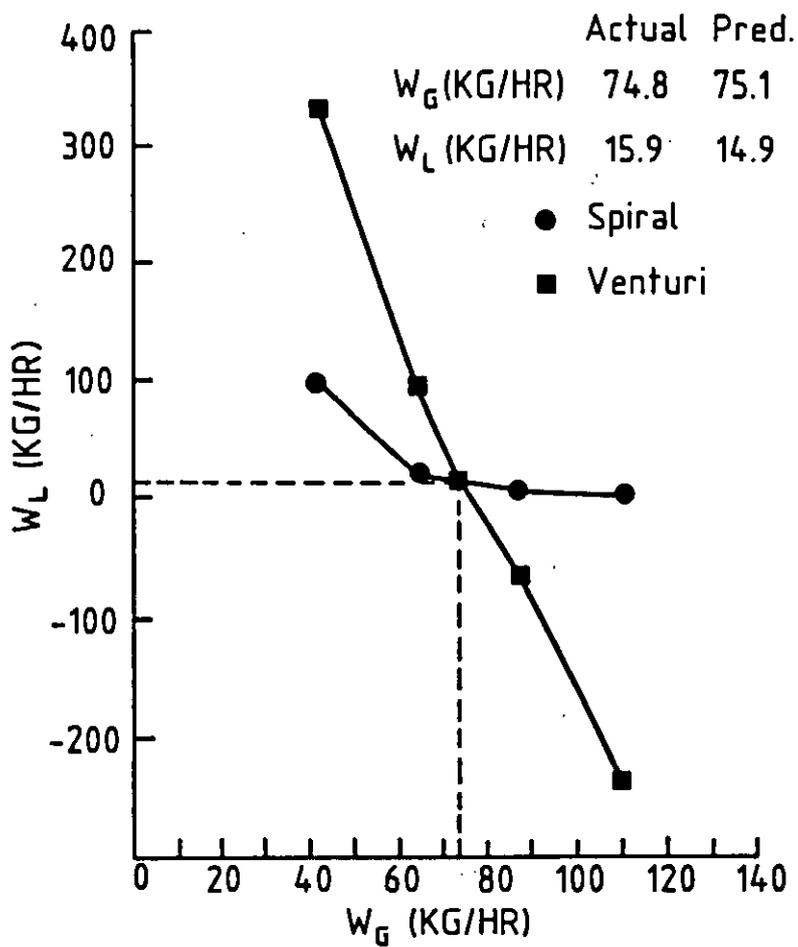
Figs. 11a and 11b   Two Typical W_L Versus W_G Plots from (

(Twisted Tape with Venturi Meter Ref [15])