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Paper 9:

METERING OF SATELLITE FIELD PRODUCTION WITHIN THE ALWYN AREA

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**METERING OF SATELLITE FIELD
PRODUCTION WITHIN THE ALWYN AREA**

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Summary

The economic development of the Alwyn South fields called for an unconventional metering approach. The metering options studied resulted in the flow sampling technique being adopted. The innovative method of implementation provides the level of performance required within the constraints of a minimum facilities project philosophy.

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Introduction

The Alwyn Area fields are operated by Total Oil Marine Plc which is the British Exploration and Production subsidiary of the worldwide Total Group. The Alwyn North field situated primarily in block 3/9A in the UK Northern North Sea has been producing since November 1987. Oil / condensate is exported via the Ninian Pipeline to Sullom Voe, gas is exported via the Frigg Transportation System to St. Fergus. Gas export rates have typically been 9 million standard m^3 per day during winter months but oil production has declined in recent years from 11000 tonnes / day (100,000 bbls / day) to approximately 3600 tonnes / day (30000 bbls / day).

The Alwyn North Extension (ANE) comprising 3 subsea wells was brought on stream during 1992 and boosted liquid export. This development was within the original Alwyn North development and Petroleum Revenue Tax (PRT) boundary. For this reason no additional metering was required, hydrocarbons being allocated by volume to each producing well.

The forecast decline in Alwyn North export liquids resulted in spare processing capacity on the platform.

To the South of Alwyn North are three fields collectively termed Alwyn South (see Fig. 1).

Alwyn South reserves are comprised of three distinct areas:

The Western area is largely oil / associated gas and is named Dunbar.

The Eastern area has two gas / condensate fields named Ellon and Grant.

The development plan for Dunbar, Ellon and Grant called for these marginal fields to be produced as satellites of Alwyn North. Fluids from these satellites would be processed on Alwyn North, injection water and power would be supplied from the main installation.

The economic constraints within the development plan only allowed for a minimum facilities platform at Dunbar with subsea wells for Ellon and Grant tied into the Dunbar platform. Permanent facilities on Dunbar are minimised by the use of a Tender Support Vessel during the drilling phase. Export to Alwyn North is via an insulated multiphase pipeline (see Figs 2 & 3).

Although the Alwyn South fields have the same ownership as Alwyn North - 1/3 Total Oil Marine (Operator) and 2/3 Elf UK, they fall in different PRT zones and are subject to different transportation and sales agreements.

Metering Study

In order to fulfil metering requirements within the economic constraints of Alwyn South, three main approaches were studied:

a) Full Fiscal Standard Scheme

Install additional process streams to separate and dry the gaseous hydrocarbons prior to additional compression and export metering. Install additional produced water handling and liquid pumps / export metering.

b) First Stage Separator Metering Scheme

The existing export gas and export liquid metering systems on Alwyn North would measure the commingled Alwyn South / Alwyn North hydrocarbons. The allocation of production to each of the four PRT zones would be based on the continuous metering of effluent from dedicated first stage separators.

Three first stage separators would be required on the Dunbar platform each with gas, oil and water metering / analysis. The two first stage separators on Alwyn North would require upgraded metering / analysis.

In addition a test separator would be required on the Dunbar platform for well testing of the Dunbar, Ellon and Grant wells. A further separator is required on NAB to allow Alwyn South fluids to be fed into the Alwyn North process due to the distinct oil and gas trains and recycle loops.

c) Flow Sampling Scheme

The existing export gas and export liquid metering systems on Alwyn North would measure the commingled Alwyn South / Alwyn North hydrocarbons.

Each well in the Alwyn area would in turn flow through a test separator in order to determine the well production rate at a particular well head flowing pressure measured upstream of the production choke. Continuous measurement of well head flowing pressure would allow each wells production to be calculated on a daily basis. Allocating metered export to each well in proportion to its production would allow field production to be calculated.

One test separator on the Dunbar platform would allow each of the Dunbar, Ellon and Grant wells to be tested monthly. The two existing test separators on the Alwyn North Process Platform (NAB) would continue to test Alwyn North wells monthly.

Selection of Scheme

The full Fiscal standard scheme with large scale associated process plant made the development of Alwyn South fields uneconomic. This scheme was ruled out at an early stage due to negative project economies.

The choice of metering scheme was made from a study of the two main options of 1st stage separator metering and flow sampling.

In order to assess if one scheme could be justified over another the impact on measurement uncertainty was studied by an independent consultancy.

The initial reaction to this problem was to believe that the 1st stage separator method would have a far better measurement uncertainty as it is a continuous metering method. However, the two methods have many similarities which tend to diminish this advantage largely as a result of the Alwyn process plant having many recycle loops.

Hydrocarbons metered either at a 1st stage separator or at a test separator will have to pass through a similar amount of process equipment before it reaches the export metering facilities. There will therefore be a similar level of complexity and uncertainty associated with allocating metered export to each producing field.

The gas or liquid leaving a 1st stage or test separator will be processed to a similar level of efficiency. Oil will be contaminated with water and water contaminated with oil. Assuming 100% separation efficiency or gaining unrepresentative samples will result in additional measurement uncertainty.

An effective simulation of the flow of hydrocarbons through the process for allocation purposes may only be obtained by tracking hydrocarbon and inert components in an accurate manner. This means that the composition of each feed stream must have a representative analysis and the analysis of samples must be sufficiently detailed to identify the presence and properties of the heavier hydrocarbon components.

In addition to the above options, the use of multiphase metering was considered but in 1990 the technology was not considered sufficiently developed to allow reliable measurement to the required level of uncertainty. Multiphase meters could potentially have been used to measure the flows from each PRT zone and for well testing in place of a test separator. In view of the large potential for capital and operating cost savings, TOTAL continues to invest in multiphase metering R & D.

The following table shows a comparison of the uncertainties associated with each metering scheme. Although the values are considered as random and those associated with each element open to some fine tuning a useful trend results as all elements are common except one.

Item of Uncertainty	1st Stage Separator Metering	Flow Sampling
Gas Flow	2.5 %	2.5 %
Liquid Flow	2 %	2 %
Sampling Representivity	5 %	5 %
Sample Analysis	3 %	3 %
Interpolation of Well Test Results	0 %	5 %
Process Simulation	3 %	3 %
Combined	**7.3 %**	**8.8 %**

The difference in measurement uncertainty is due to interpolation of wellhead flowing pressure vs well flow rate from well testing. A figure of 5% is not considered achievable in the first 3 months of production but thereafter well test data should become more consistent as a trend develops.

The Alwyn North 1st stage oil separator (C-101) is injected with liquids separated from the gas process, this recycle loop is connected upstream of C-101. In addition to the difficulty in measuring the recycled fluids metering by difference would have to be performed, further increasing the uncertainty for 1st stage separator metering.

In order to meet the above measurement uncertainties substantial metering upgrades would have to be performed on the Alwyn North 1st stage separator meters where space and access are limited. Furthermore, 3 gas and 3 liquid metering systems would have to be installed, operated and maintained on Dunbar which was planned as a minimum facilities platform with minimum manning.

The outcome of the study was that the 1st stage separator metering scheme and associated additional 3 separators and metering systems could not be justified in terms of the perceived 1.5 % improvement in measurement uncertainty over flow sampling.

It was further considered that by installing well test metering equipment to a near fiscal standard on the 3 Alwyn Area test separators that the above uncertainties could be improved upon.

<u>Method Adopted</u>

The flow sampling scheme chosen allows individual well flow rates to be calculated from a continuous measurement of well head flowing pressure, that is the pressure upstream of the wellhead choke. The relationship between well head flowing pressure and well flow rate is developed by placing the well in series with the test separator. This allows the multiphase well flow to be separated into gas, oil and water, these effluent streams may then be measured using single phase meters. A well test is performed once the effluent flow rates have stabilised. Wellhead flowing pressure and flow rates are averaged over a six hour period, this establishes one point on the curve. Further well test points define the curve of wellhead flowing pressure versus well flowrate (see fig. 4). The points are achieved by adjusting the choke position. Increasing the choke opening increases well flow rate and results in a decrease in well head flowing pressure. Unfortunately this curve is not constant over time due to the gradual fall in reservoir pressure as hydrocarbons are extracted. The tests are repeated at regular intervals (typically monthly).

This process in effect creates a flow calibration curve for the choke dedicated to a particular well. Once well head flowing pressure has been averaged during a production day the corresponding well flow rate is taken from the curve. The most representative numbers are obtained by interpolating between well test curves for a known well head flowing pressure and date.

Samples taken during well testing may be analysed to provide a detailed composition of the well, when combined with the well flow rate hydrocarbon and inert component flowrates may be calculated.

A summation of the daily well flows may be used to estimate the production from a field but some of this flow is used as fuel or flare gas before export from Alwyn North. A more precise method is to calculate the amount of metered export oil or metered export gas from each producing field in proportion to estimated field production. However, this procedure requires careful modelling of the Alwyn process plant due to the interlinking between the oil and gas process equipment (see Fig. 5).

Years of experience in simulating the flow of fluids through the Alwyn North process plant resulted in optimum results from use of component mass flows. Plant feeds are tracked through separation and mixing to flare, fuel and export points.

An extensive study revealed that a method of allocating export, fuel and flare quantities would be effective if the following principles were adopted:

a) Component mass flows used from input to output.

b) A simplified process model used featuring three input feeds plus fuel and flare offtakes plus two export points and a water discharge point. The process model would use daily average pressures and temperatures measured on the plant (see Fig. 6).

c) Allocation coefficients would be calculated from process simulation results and used to allocate inputs in respect of export quantities. Flows would be allocated from a common feed to each well in proportion to the estimated well flow derived from well test curves.

d) Heavy hydrocarbon components would be characterised separately for each reservoir in order to improve the process simulation.

<u>Metering System Design</u>

There was a clear requirement from the allocation method study that mass flow metering was required at the outlets of each test separator. The measurement uncertainty study revealed that metering to near fiscal standards would be justified.

The following constraints were imposed on these goals by the Dunbar project philosophy and existing Alwyn North equipment:

a) Minimum facilities
b) Minimum manning
c) Consistent metering approach across the two Alwyn North test separators and Dunbar test separator.
d) Minimise upgrade work on Alwyn North.
e) Provide well test data that satisfies reservoir management as well as allocation requirements.

A consequence of minimum facilities was that one test separator would be used on Dunbar. This results in a wide range of gas and liquid flows being metered due to the nature of wells tested ranging from gas / condensate to oil / associated gas. Another consequence was that no booster pumps or fast loop pumps would be installed, automatic sampling systems were also ruled out due to their potential for extensive maintenance.

Test Separator Gas Flow Measurement

The gas at the test separator outlet is at saturation conditions. Multipath ultrasonic meters were not considered to be sufficiently developed at the time of the 1990 study. Conventional orifice meters would continue to be used on the Alwyn North test separators and this was the method selected as being appropriate for the Dunbar test separator gas flow.

The presence of liquid traces was accommodated by employing drain holes in the orifice plates and condensate trap pots in the impulse lines. 'Smart' differential pressure, absolute pressure and temperature transmitters are employed for their proven stability. Digital communication with the flow computer system uses the HART protocol to reduce uncertainties from analogue to digital conversion. The risk of liquid contamination prevented conventional density transducers being used. AGA[1] 8 is used to calculate density from the well composition plus measured pressure and compensated temperature. ISO 1567-1[2] is used to calculate mass flow rate. ISO 6976[3] is used to calculate standard density from the well composition.

The wide range of gas flows from the Dunbar test separator required three orifice meter runs of differing sizes. This allows any well to be tested by selecting the appropriate stream, orifice plate size changes are not required.

The two Alwyn North test separators were upgraded by installing the same instrumentation and computational methods as used on Dunbar. Although a smaller range of flow is required to be measured a minimum of two orifice plates are required in the single orifice meter run on each separator.

Test Separator Liquid Flow Measurement

Coriolis meters were selected to meter the mass flow of wet oil and oily water leaving the test separators for the following reasons:

a) The liquid leaving the separator is near to its bubble point. Even when 10 metres of liquid head are created between the separator and the flow meter any pressure drop downstream of the flow meter would result in gas breakout, the effectively rules out an in-situ proving device associated with turbine meters.

b) Mass flow measurement using conventional turbine meters would require density meters for mass measurement. The proximity to the bubble point would make density measurement difficult without a pumped arrangement. The requirement for minimum facilities would make this additional equipment difficult to justify.

c) Total Oil Marine have used coriolis meters for Fiscal metering since 1989 and also for well testing purposes. During this period the coriolis meters (Micromotion D100) have proven to be reliable and to have excellent long term stability. This has been established through in-situ proving and recalibration tests at the factory. Thorough independent testing has also verified an insensitivity to the density and viscosity of oil / condensate / water used.

d) Coriolis meters measure both mass flow and the density of liquid passing through the meter. This allows actual volume to be calculated. Another benefit is that a measurement of oil / water emulsion density also allows water content to be derived providing the dry oil density and produced water density may be calculated at meter conditions.

e) There are no moving parts in a coriolis meter that can over-speed, wear or become damaged. No protection strainers are required upstream which would result in undesirable pressure drop providing erosion constraints are not exceeded.

In order to cover the range of liquid flows, coriolis meter sizes of 3", 1" and 1/2" were required. This was largely a result of the requirements for a working pressure of over 120 barg and a wetted part material of Hastelloy C due to the presence of chlorides in the produced water. The pressure drop limitation also restricted the upper flow limit of individual meters.

A rigorous test programme was undertaken to ensure the coriolis meters met the manufacturers claims for mass flow and density uncertainty on a range of fluids, temperatures and pressures chosen to represent the test separator conditions.

During the course of these tests, considerable difficulties were experienced with the original 3" meters. At the time of order placement these high pressure meters were the only type available to meet the pressure and material requirements. Testing indicated that the meters lacked structural rigidity and would only perform when solidly clamped to a high mass support structure. This could not be reproduced in service due to the need for pipework expansion under process temperature changes.

Replacement units in the form of 3" Micromotion 'Elite' meters became available which provided the required performance over a wider than anticipated flow range.

Temperature and pressure transmitters were mounted at the upstream meter manifold in order to provide measurements for density calculation and volume referral.

Digital communication with the coriolis meter transmitters gave mass flow rate and density values. Pressure and temperature values were again acquired digitally using HART protocol.

System Layout

A major consideration when planning the layout of the Dunbar platform was to ensure that sufficient pressure margins existed in the coriolis meters to prevent gas breakout. This is most likely to occur at maximum flowrate when static pressure at the meter will be lowered by pipe friction, fittings losses and meter pressure drop. The test separator was positioned as high in the platform process area as possible while the coriolis meters were positioned on a lower deck to generate the maximum available liquid head in order to avoid gas break out in the meters. Any check meters or proving device could not be positioned downstream as gas breakout would occur at these points.

The position of the existing two test separators on Alwyn North could not be changed. The new coriolis meters were positioned to generate the maximum available liquid head. This resulted in new pipes being run down through additional deck levels to the new meters.

Well Test Computer System

In the past, well test reports have been generated by a supervisory computer (SVC) on Alwyn North with meter data provided by the Process Control System (PCS). The supervisory computer was coming to the end of its useful life and a replacement was planned. However, it became clear that the replacement SVC could not be procured to include the well test functions required to the Dunbar project timescale. It was also determined that front end flow calculations could not be performed in the Process Control System to the degree of measurement uncertainty required.

A standard Fiscal metering approach was adopted in that computer functions were split into a stream computer plus database architecture. Field measurements of the following parameters are transmitted digitally into the stream computers (see Fig. 7).

Gas	:	Differential pressure Absolute pressure Downstream temperature
Wet Oil	:	Emulsion mass flow rate Emulsion density Temperature Pressure
Oily Water	:	Emulsion mass flow rate Emulsion density Temperature Pressure

Each gas stream computer calculates mass, actual volume and standard volume flowrate using a gas composition specific to the well under test. Each liquid stream computer calculates the flow for two meter runs. The mass, actual volume and standard volume flow rate of dry oil and produced water passing through each meter is calculated in the following manner:

The dry oil density at meter temperature and pressure is calculated using standard API equations and oil properties of the well under test. Produced water density at meter temperature and pressure is calculated from an equation fitted to data variables of salinity, temperature and pressure. The water salinity of the well under test is used.

The following equation is used to calculate the mass % water in the oil / water mixture passing through the coriolis meter:

$$\text{mass \% water} = \frac{\rho\,\text{water}.\ \rho\,\text{em} - \rho\,\text{water}\ .\ \rho\,\text{oil}}{\rho\,\text{water}.\ \rho\,\text{em} - \rho\,\text{em}.\ \rho\,\text{oil}} \times 100$$

where ρ em = coriolis meter measured emulsion density
ρ oil = calculated density of dry oil at meter conditions
ρ water = calculated density of produced water at meter conditions

This result may then be used to calculate the mass flow rate of dry oil and mass flow rate of produced water flowing through the coriolis meter.

A similar approach is used to calculate the oil and water actual volume and standard volume flow rate.

All flow computer constants are held in the database computer and may be updated under appropriate security protection.

Each well has its own set of parameters such as gas composition, isentropic exponent, dynamic viscosity and gas expansion coefficient. The liquid properties of oil K0, K1, oil standard density, water standard density and water salinity are also held for each well. Once a well is lined up to the test separator a command is sent from the Process Control System and the appropriate constants for the well under test are automatically downloaded to the flow computers. In this way flow calculations are performed with the minimum of uncertainty.

The database computer sums gas, dry oil and produced water flow rates from the stream computers to form a total well oil, water and gas mass flow rate for allocation purposes. This is repeated for actual volume and standard volume flow rates for reservoir management purposes.

Once the well flow has stabilised the well test recording may commence and cover a period of up to 12 hours. During each hourly period the average flow rates, temperatures and pressures are calculated, displayed and stored. A continuous period of 6 hours stable flow is required for a successful well test. The standard deviation of flow rate and pressure values are calculated from samples of instantaneous values during each hour. The standard deviation indicates the stability of measured / calculated parameters in order to determine which average flow rates are to be selected to form the final average.

Dunbar has one well test system for the Alwyn South test separator, three gas meters and six liquid meters are interfaced to the computer system. Alwyn North also has one well test system but this serves two test separators, although the combined number of flow meters is similar to Dunbar at two gas and six liquid.

A compromise was necessary with the number of well test points due to the large amount of wells to be tested on a monthly basis. It was agreed that two well test points would be sufficient to describe the relationship between well head flowing pressure and well flow rate providing one test point would be close to the normal operating well head flowing pressure.

Computer Network

Two new computer systems have been installed in order to acquire data and then to process it in accordance with commercial procedures.

Data is acquired by the Networked Information Management System (NIMS) which has effectively replaced the SVC on Alwyn North. NIMS is interfaced to both well test computers, Alwyn North and Dunbar process control systems plus the two export metering systems. Data such as well tests are automatically transferred to NIMS where they are examined and validated prior to transfer to the Hydrocarbon Accounting System (HAS) computer located onshore. This operation ensures that as much data as possible is captured automatically but that only authorised data is used in the allocation. Well tests may then be linked in order to allow interpolation of well flow rate from well head flowing pressure (see Fig. 8).

An important feature of the well test information is that raw data such as gas differential pressure is transferred with calculated flow rates. This allows flow rates to be recalculated once more representative analysis data becomes available. The well test is always performed with the previous months analysis.

The daily average process data acquired by NIMS is used by HAS to perform the process simulation in order to determine representative allocation coefficients. Metered export and fuel / flare quantities are then allocated to each production manifold and then to each well. The Alwyn Area sub-allocation is run daily in order to determine well and field production (see Fig. 9).

Coriolis Meter Zeroing

An important part in the operation of coriolis meters is to establish a representative zero. The meter will not perform to its normal specification with a significant zero instability or offset.

For optimum operation it was decided to check the zero of the in use meters prior to each well test. This involves bringing the meter up to operating pressure and temperature, ensuring there is no vapour present and then closing the meter outlet valve with flow redirected. The unmasked flow rate should be zero ± the manufacturers zero instability, if this is not the case the meter should be rezeroed.

On Dunbar this operation could impose a significant workload on the technician responsible due to the distance between meter valving (operated manually) and panel mounted flow transmitter.

A remote zeroing facility was adopted which allows the technician to remain in the process area while the meter is being automatically checked for a correct zero and then automatically rezeroed if necessary.

In order to perform this function the well test computer system recognises when a meter is brought on-line and then closed in. Once a field mounted push button is hit by the technician the computer system checks the unmasked flow rate measured by the coriolis meter against set tolerances. If the zero flow is within tolerance the technician receives a green light and can place the meter online. Otherwise there is a delay while the meter is automatically rezeroed prior to the Technician being ok'd to place the meter on-line. The measured zero instability and time of any rezeroing are displayed and printed.

Sampling

Three distinct types of samples are required to be taken, analysed and reported to the Hydrocarbon Accounting System (HAS).

a) Gas composition to C7+ for gas density calculation purposes (each well test pair).

b) Water in wet oil and oil in oily water to amend liquid effluent flow rates (each well test).

c) Liquid and gas detailed composition to C11+ to determine well compositions (performed on each well every six months).

The minimum facilities philosophy for Dunbar dictated that manual sampling was performed in preference to automatic sampling.

Sampling points on Dunbar and Alwyn North test separator outlets were installed to a similar standard. These points featured sample probes in well mixed areas, facilities to purge the sample line to flare or closed drain in a controlled manner and to capture a representative sample in a safe manner.

The detailed compositions to C11+ are analysed onshore from high pressure gas and liquid sample cylinders.

The remaining analyses are performed offshore in local laboratories to standard procedures.

HAS combines the detailed compositional analysis with the corresponding well test flow rates to arrive at the well composition.

The analysed level of contaminants in wet oil and oily water are compared in HAS to the online calculated values and the most representative value selected. It is planned that the on line calculated valves may be tuned to allow sampling and analysis of contaminants to cease, thus reducing operating costs.

System Commissioning

Thorough testing was performed at each stage of procurement of the new well test systems and computer systems. Wherever possible tests were performed to check the interface from one system to another to ensure reliable communication.

The new Alwyn North systems were installed some months prior to the Dunbar start-up with the minimum of disruption to the running of the platform. Commissioning the Alwyn North systems well in advance of Dunbar start up and using them for well testing purposes and trial allocation gave time for debugging and improving procedures prior to the date of full implementation.

Commissioning of the Alwyn North well test system proceeded without any major problems. However, it was considered that the zero instability of the coriolis meters was too high.

Detailed investigations with the assistance of Rosemount revealed that the meter drive voltage was varying more than normal. Drive voltage can be measured at the panel mounted flow transmitter and is an excellent indicator of the 'health' of the meter. A variable voltage shows that the meter is not fully 'locked on' to the mass flow rate and density values. A saturated value shows that the meter has lost control of flow and density measurement, usually as a result of severe vapour entrainment or slug flow. Causes of the instability were considered to be electrical interference, lack of rigidity in the meter supports or possible vibration crosstalk with parallel meters. Electrical connections and cable type and routing between the flow sensor and flow transmitter were found to be correct but there were some unnecessary lengths of unscreened cable at the panel terminal blocks. This was resolved but did remove the instability.

Attention was focused on the meter supports and any lack of rigidity that would result in the meter drive being used to vibrate the surrounding pipework. It is vital for successful operation that the meter body is clamped firmly to a solid base in order that only the flow tubes are vibrated with the minimum amount of drive necessary. The manufacturer recommended arrangement is shown in Fig. 10.

The meter supports in use had been designed to accommodate pipe expansion due to process temperature changes. A sliding joint was used on one support to allow pipe movement, both supports used 'I' section mounts. This combination resulted in an unsufficiently rigid system.

The supports were modified by fitting polyurethane "Stauff" clamps on either side of the meters. This modification improved the zero stability of the meters and gave a less variable drive voltage. It also allowed for temperature expansion. The question of vibrational crosstalk between parallel meters was examined by turning off the power to one meter while monitoring the output of the other meter, no change was observed. This indicated that there was not a significant level of crosstalk present.

Another area examined was how the density derived values of water in wet oil and oil in oily water compare to sample / analysis values. At first there was a considerable difference but once detailed well compositions became available and new parameters calculated the discrepancies were reduced. However, the test separators in the Alwyn Area provide good separation and little contamination is found in the liquid flows. The density derived water cut is not reliable below approximately 2% water in oil and is not suitable for calculating the present ppm levels found by sampling / analysis. If poorer separation occurs it should be possible to replace sampling / analysis with density derived water in oil measurement and provide useful savings in operating costs.

System Performance

The well test metering system has performed reliably during its operation since Dunbar start up in December 1994. Regular calibration testing on the instrumentation has not identified any drift problems.

Figures 11, 12 & 13 show the deviation between well flow estimation and hydrocarbons allocated to a group of wells from Export oil and gas plus fuel and flare. Well flow is estimated from interpolations of well tests. The main points to note from the graphs are the similarities in trend across well groups, this indicates that allocation is being performed fairly. There is an improvement during the month as more well test data is gathered. The two upsets observed are due to production shutdowns which result in an imbalance between well production and export.

Figure 14 shows the difference between all well production estimated from well test interpolation and export / fuel / flare quantities. The majority of results lie within the estimated uncertainties with the exception of the upsets caused by shutdowns. Later months show trends similar to the end of March.

These results demonstrate that the forecast levels of uncertainty have been achieved. Furthermore, the investment in a high standard of well test equipment and careful modelling of the processing of well fluid through the Alwyn North plant to export points has reduced any systematic uncertainties to an acceptable level. In addition to a fair allocation of production within the Alwyn Area the improved quality of data has provided improvements in reservoir management.

Conclusions

The development of the Alwyn South fields imposed tight economic and operational constraints on the method of metering field production.

The choice of a metering system based on the flow sampling technique has proven to be an important part of this successful marginal field development.

References

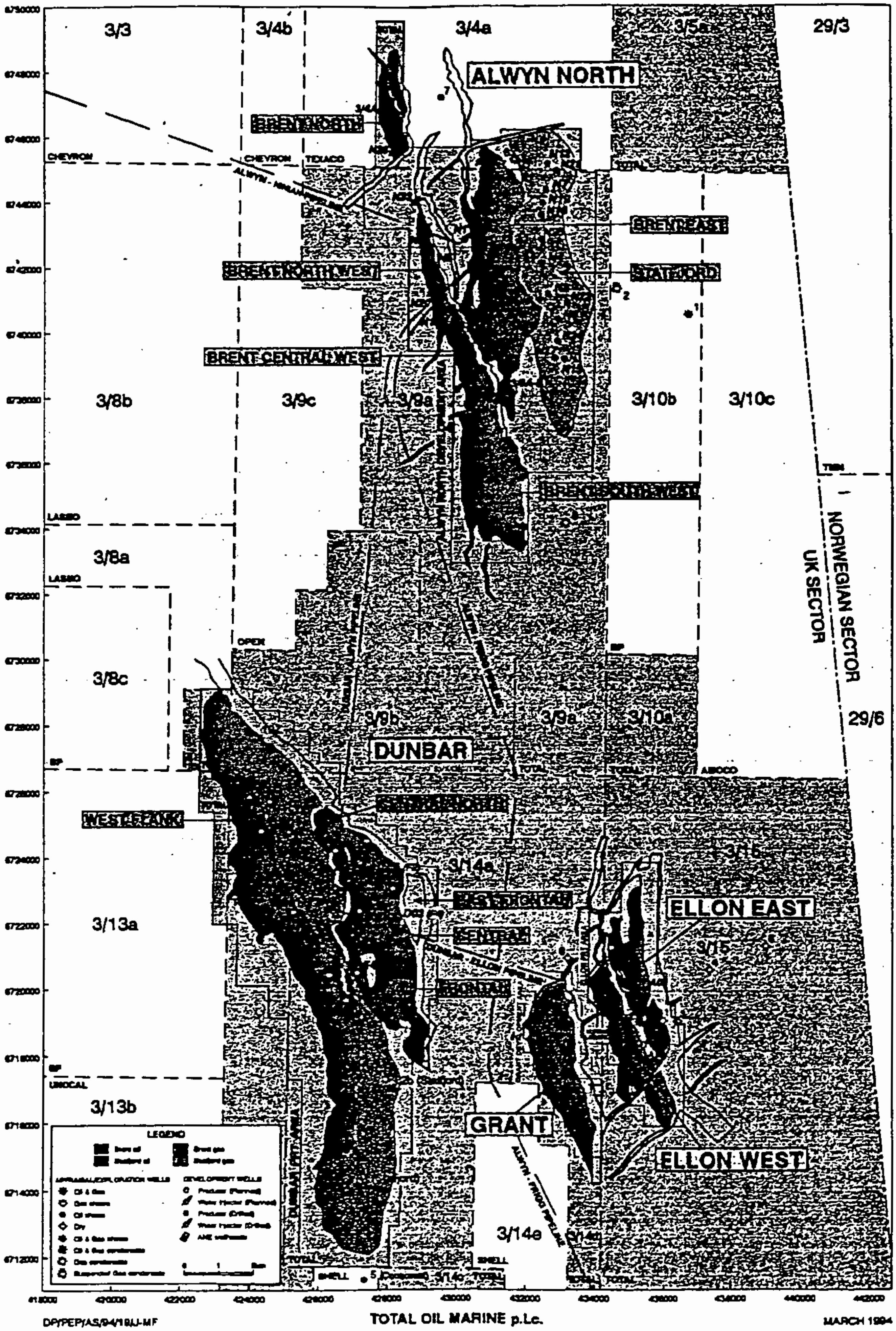
1) Compressibility and super compressibility for Natural Gas and other Hydrocarbon Gases A.G.A. Transmission measurement committee report No. 8 (December 1985).

2) ISO 5167-1:1991 Measurement of fluid flow by means of pressure differential devices - Part 1: Orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full.

3) ISO 6976:1983 Natural Gas - calculation of calorific value, density and relative density.

FIGURE 1

GREATER ALWYN AREA
Field Location Map



DP/PEP/AS/94/19JJ-MF

TOTAL OIL MARINE p.l.c.

MARCH 1994

FIGURE 2

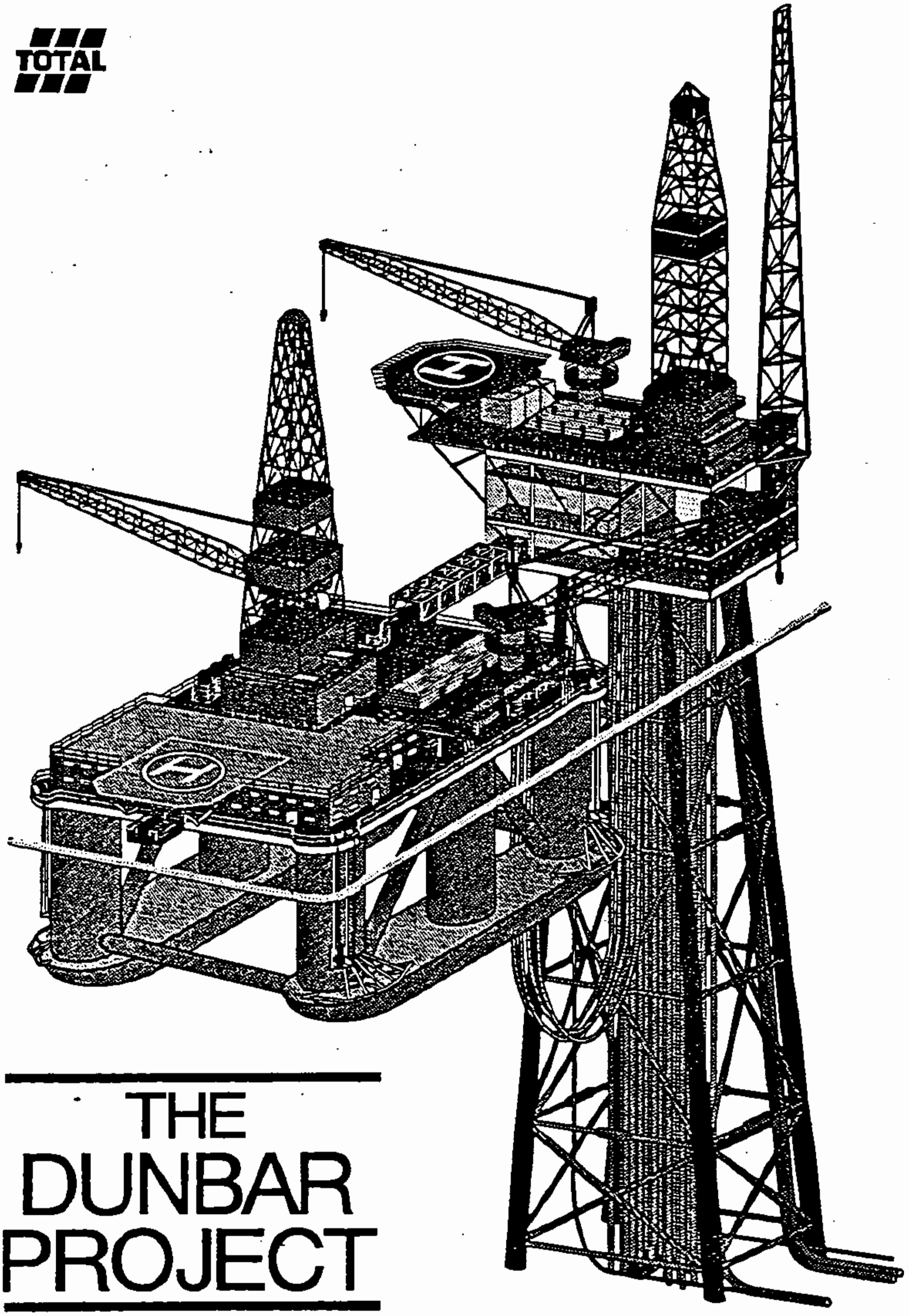


FIGURE 3

**THE DUNBAR PROJECT (Phase 1) +
PROPOSED ADDITIONAL PHASES 2**

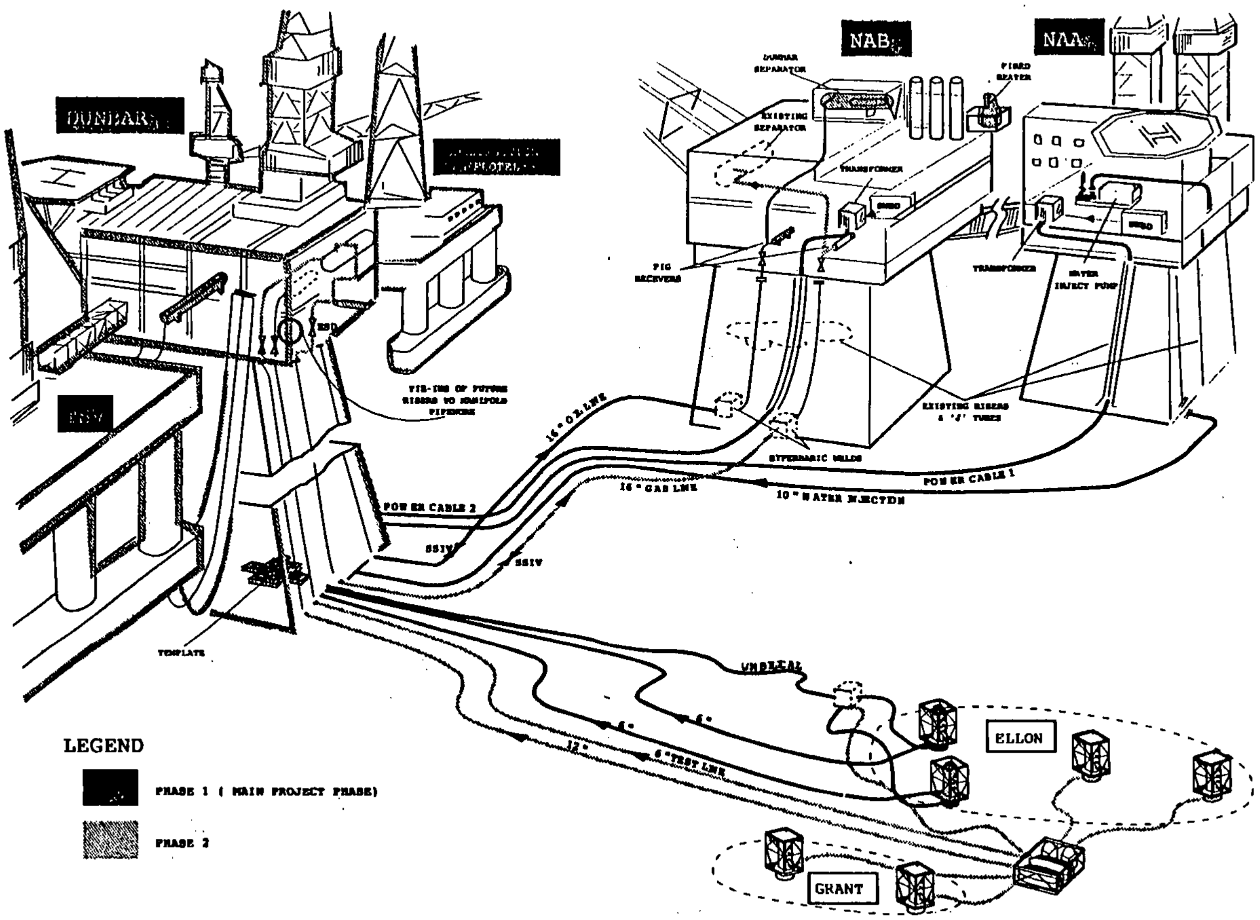


FIGURE 4

WELL MASS FLOWRATE CALCULATION FROM WELLTESTS

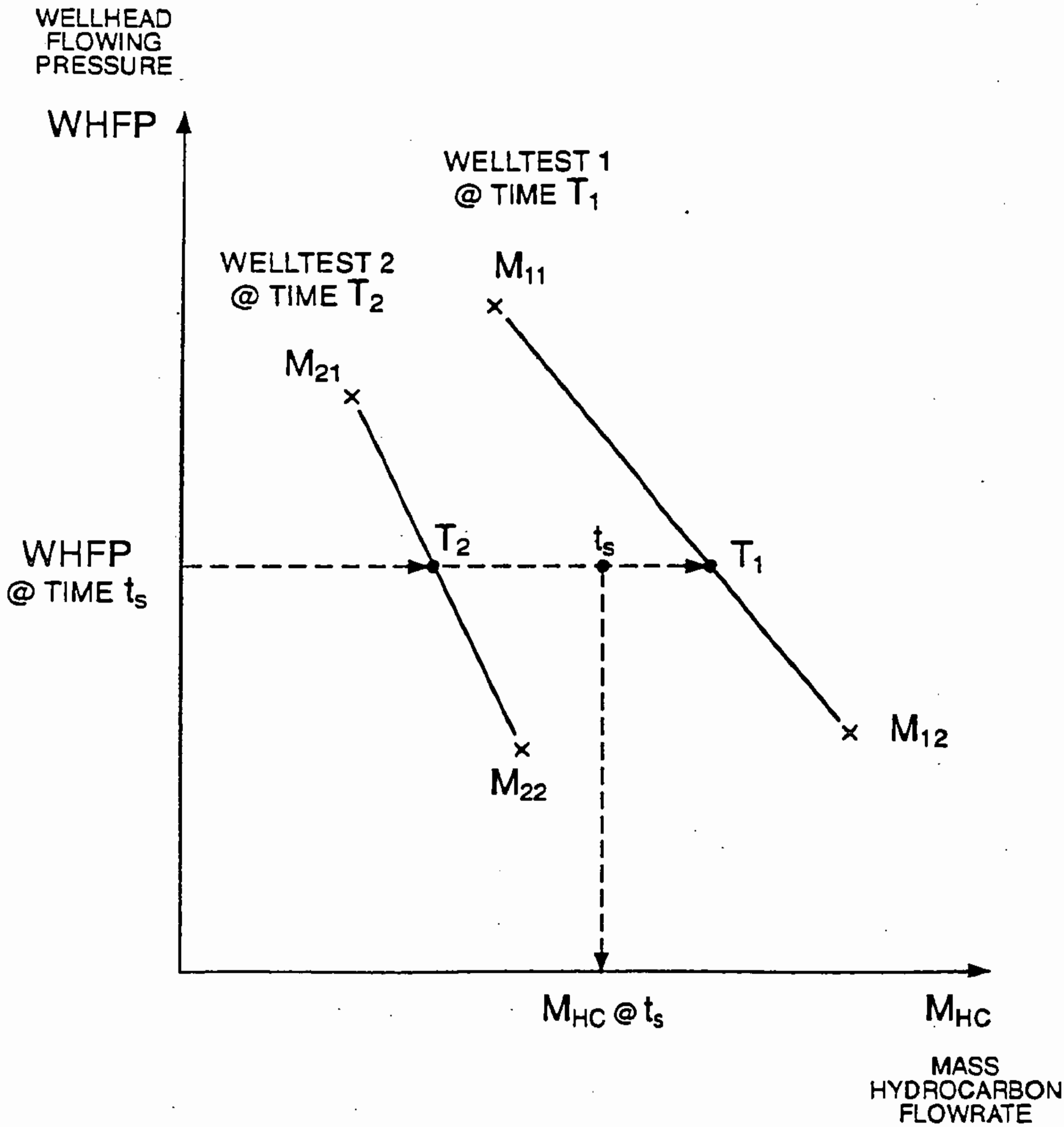
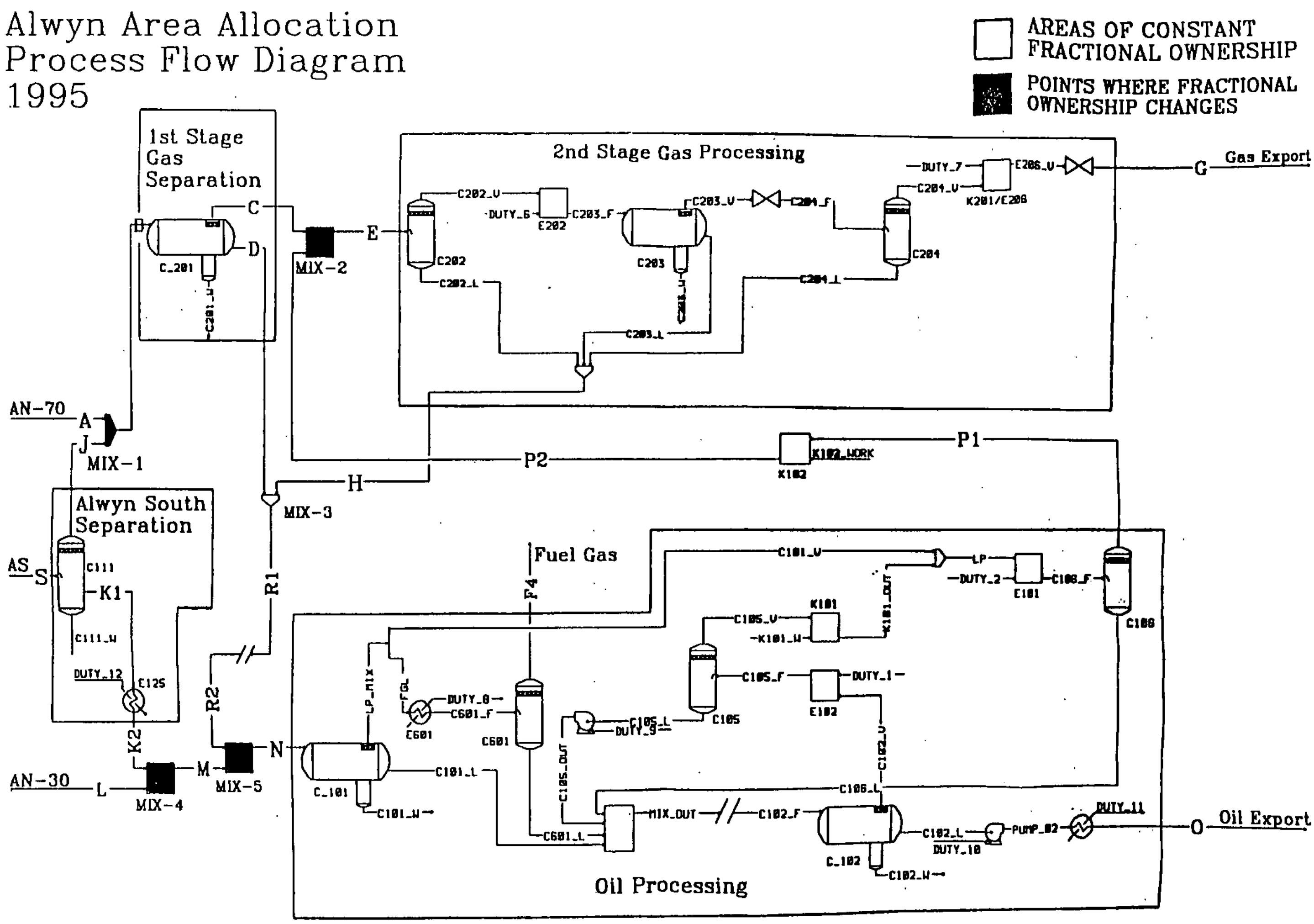
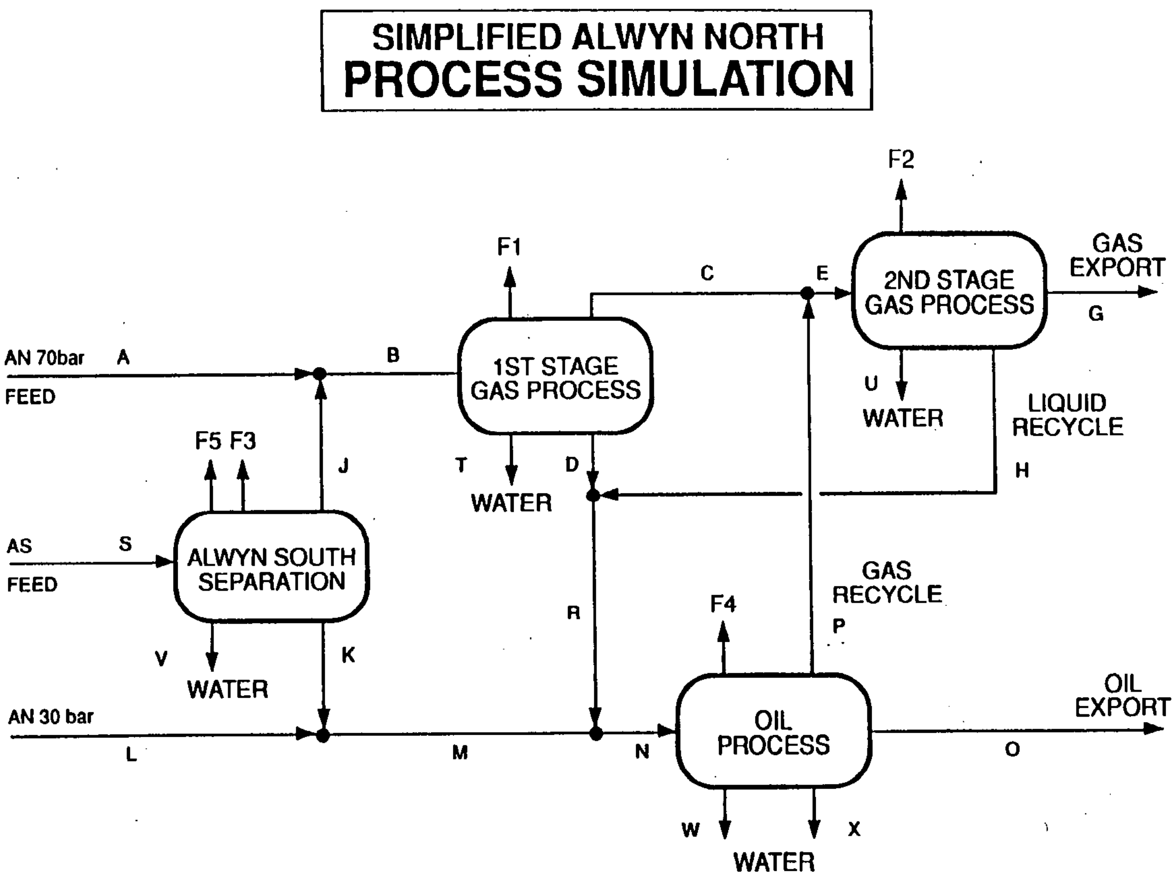


FIGURE 5



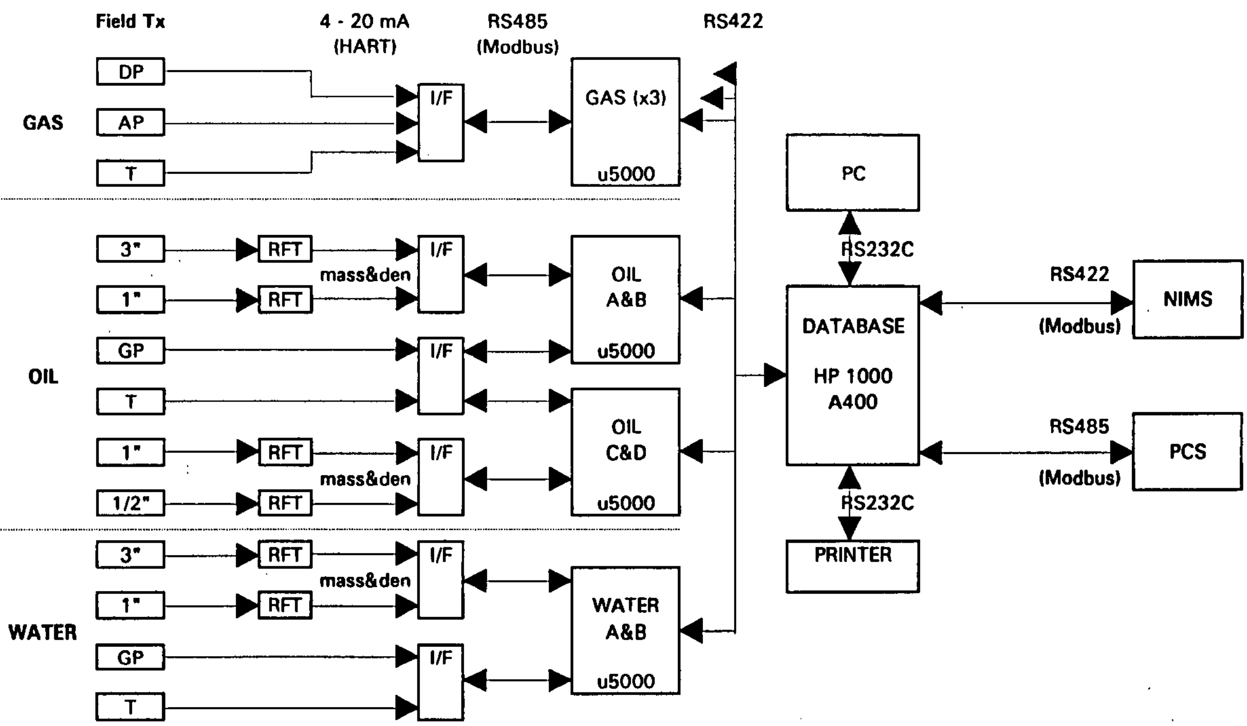
Alwyn Area Allocation
Process Flow Diagram
1995
AREAS OF CONSTANT FRACTIONAL OWNERSHIP
POINTS WHERE FRACTIONAL OWNERSHIP CHANGES
1st Stage Gas Separation
2nd Stage Gas Processing
Gas Export
AN-70
MIX-1
MIX-2
MIX-3
MIX-4
MIX-5
Alwyn South Separation
AS
AN-30
Fuel Gas
Oil Processing
Oil Export
K102
K102_WORK
C_201
C202
C203
C204
E202
K201/E206
DUTY_6
DUTY_7
C_101
C_102
C601
C105
C106
E101
E102
K101
E601
E125
C111
DUTY_12
PUMP_02
DUTY_10
DUTY_11
MIX_OUT

FIGURE 6



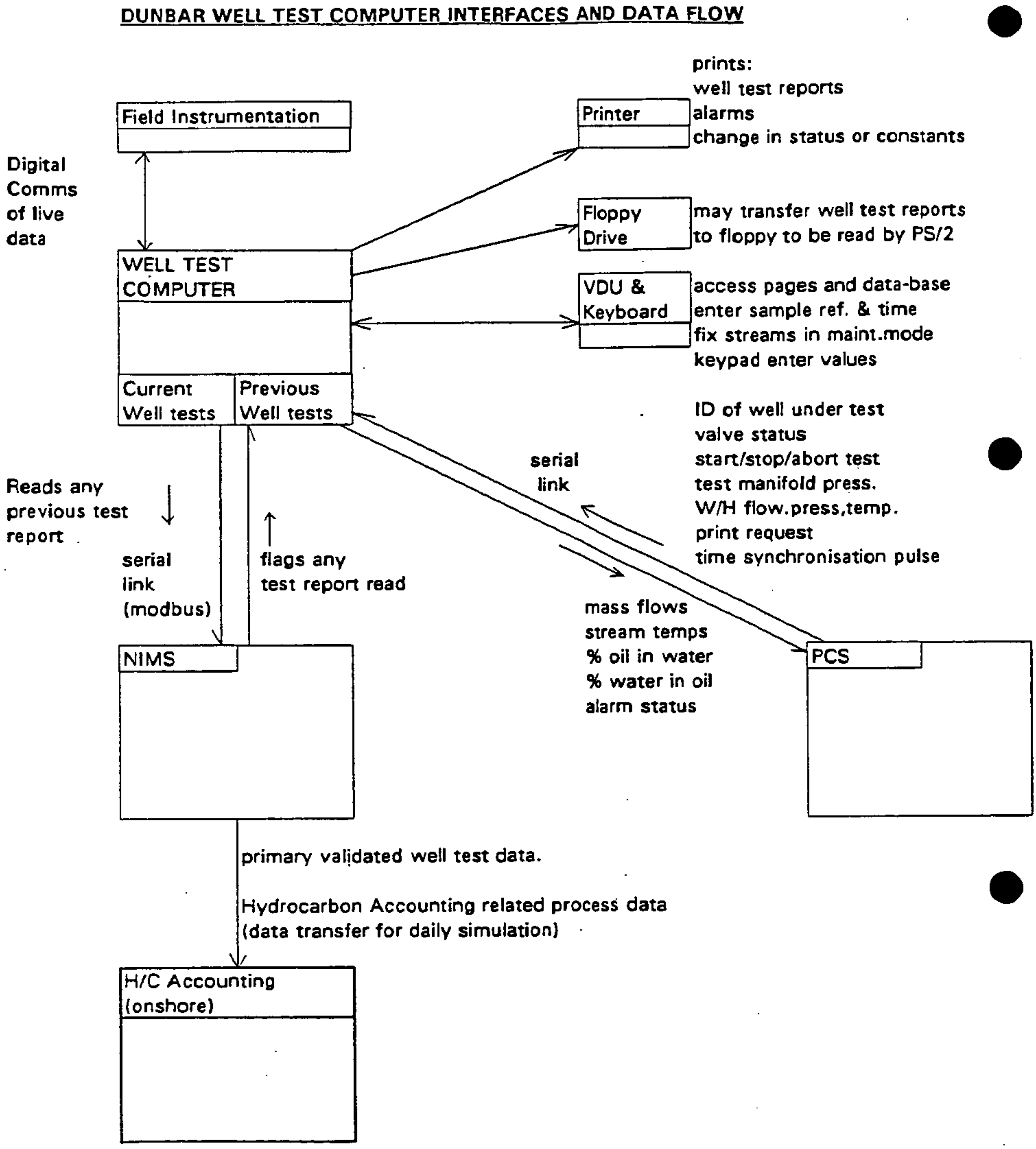
NOTE : Letters signify key streams used in the fractional ownership coefficients

FIGURE 7



DUNBAR WELL TEST SYSTEM ARCHITECTURE

FIGURE 8



DUNBAR WELL TEST COMPUTER INTERFACES AND DATA FLOW
Field Instrumentation
Digital Comms of live data
WELL TEST COMPUTER
Current Well tests
Previous Well tests
Printer
prints:
well test reports
alarms
change in status or constants
Floppy Drive
may transfer well test reports to floppy to be read by PS/2
VDU & Keyboard
access pages and data-base
enter sample ref. & time
fix streams in maint.mode
keypad enter values
ID of well under test
valve status
start/stop/abort test
test manifold press.
W/H flow.press,temp.
print request
time synchronisation pulse
serial link
mass flows
stream temps
% oil in water
% water in oil
alarm status
PCS
Reads any previous test report
serial link (modbus)
flags any test report read
NIMS
primary validated well test data.
Hydrocarbon Accounting related process data
(data transfer for daily simulation)
H/C Accounting (onshore)

FIGURE 9

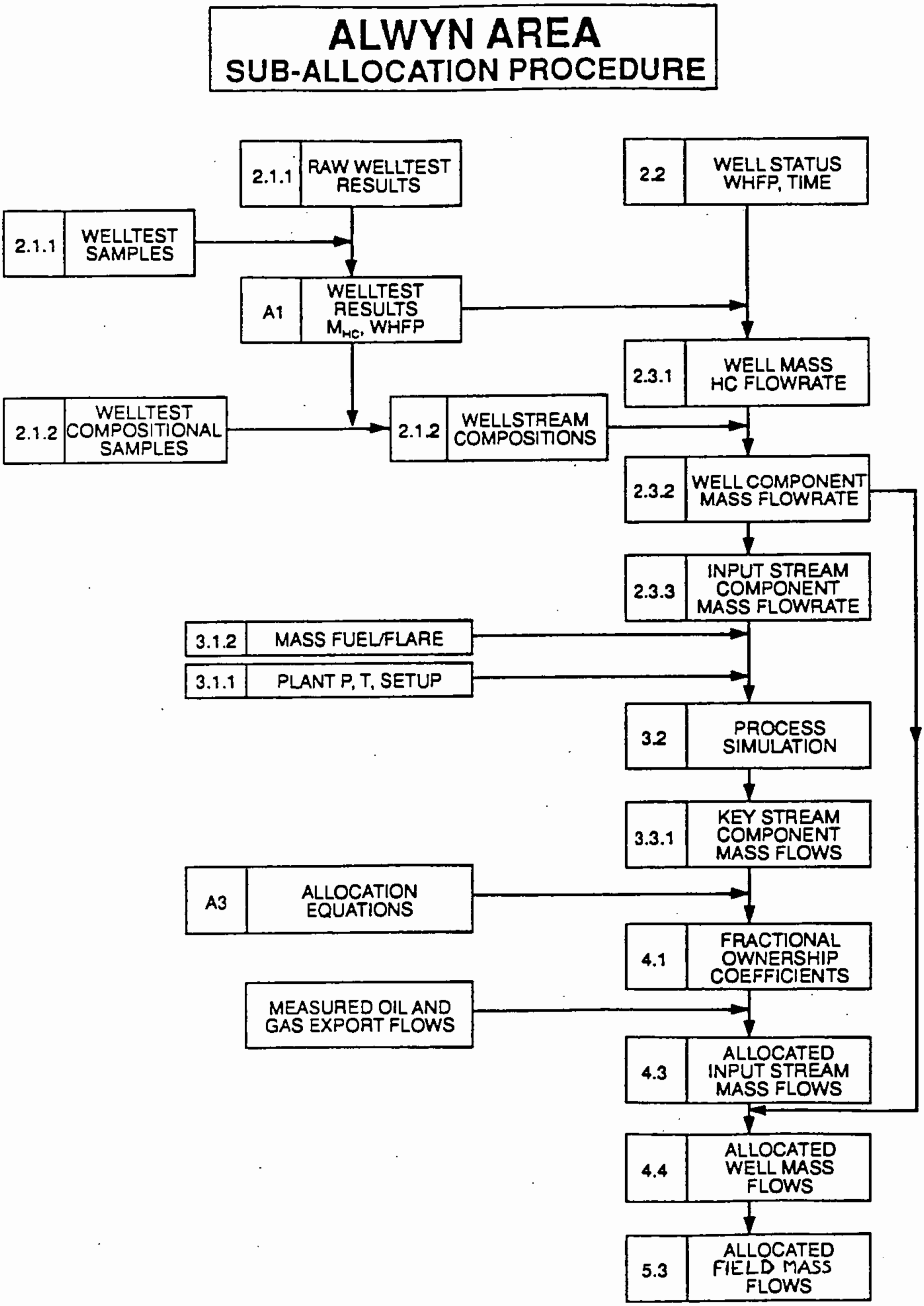

ALWYN AREA
SUB-ALLOCATION PROCEDURE
2.1.1 RAW WELLTEST RESULTS
2.2 WELL STATUS WHFP, TIME
2.1.1 WELLTEST SAMPLES
A1 WELLTEST RESULTS M_{HC}, WHFP
2.3.1 WELL MASS HC FLOWRATE
2.1.2 WELLTEST COMPOSITIONAL SAMPLES
2.1.2 WELLSTREAM COMPOSITIONS
2.3.2 WELL COMPONENT MASS FLOWRATE
2.3.3 INPUT STREAM COMPONENT MASS FLOWRATE
3.1.2 MASS FUEL/FLARE
3.1.1 PLANT P, T, SETUP
3.2 PROCESS SIMULATION
3.3.1 KEY STREAM COMPONENT MASS FLOWS
A3 ALLOCATION EQUATIONS
4.1 FRACTIONAL OWNERSHIP COEFFICIENTS
MEASURED OIL AND GAS EXPORT FLOWS
4.3 ALLOCATED INPUT STREAM MASS FLOWS
4.4 ALLOCATED WELL MASS FLOWS
5.3 ALLOCATED FIELD MASS FLOWS

FIGURE 10

Typical Installation of an ELITE™ Sensor

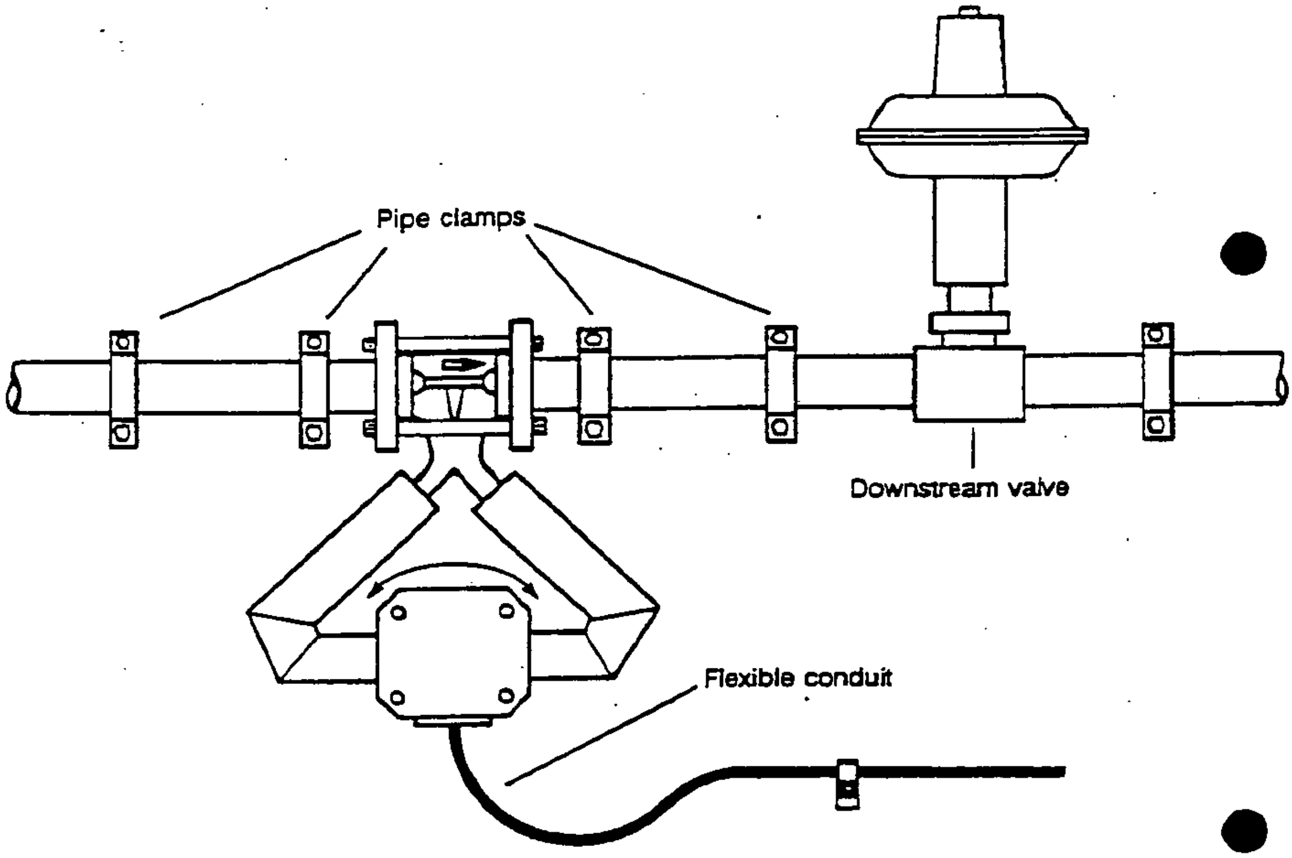
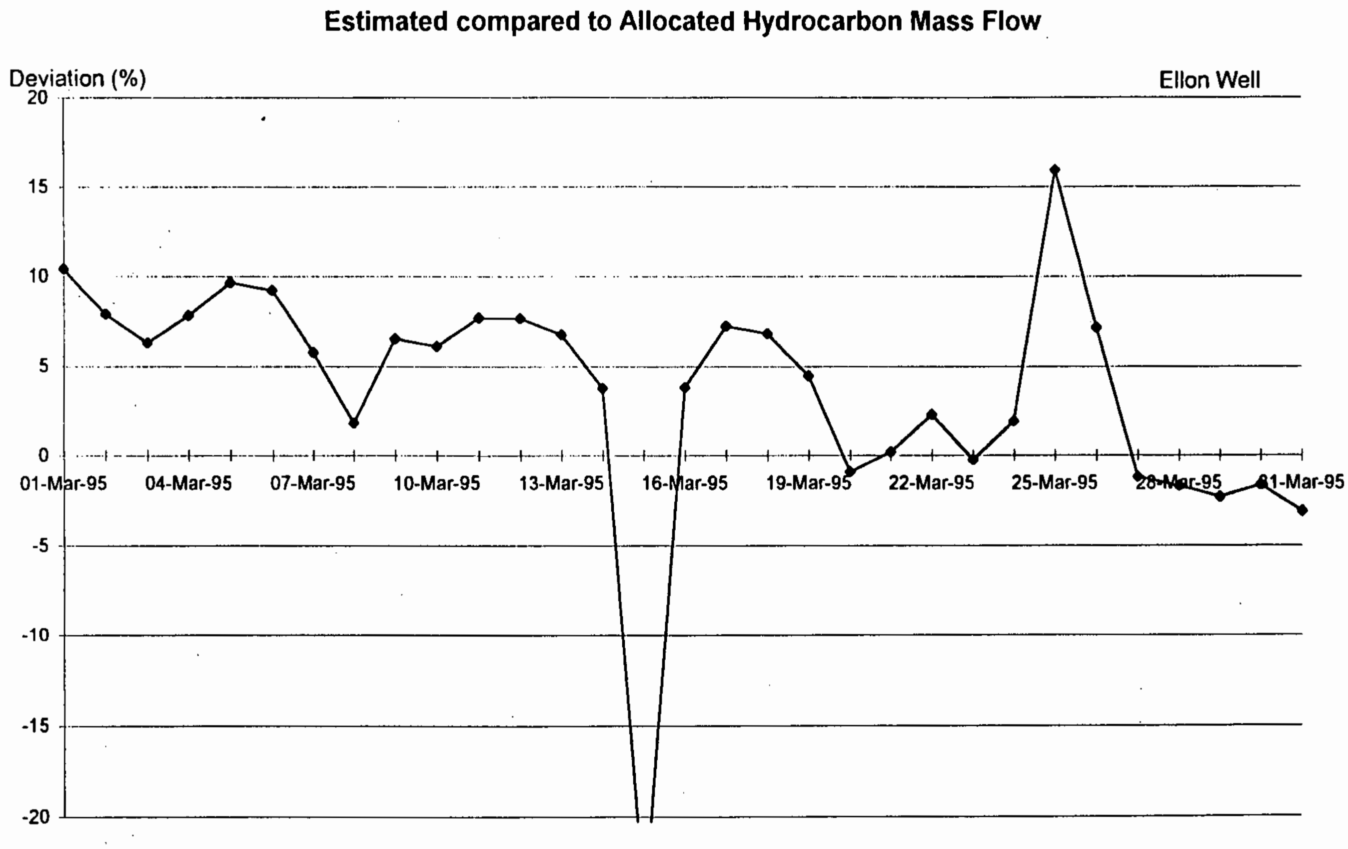
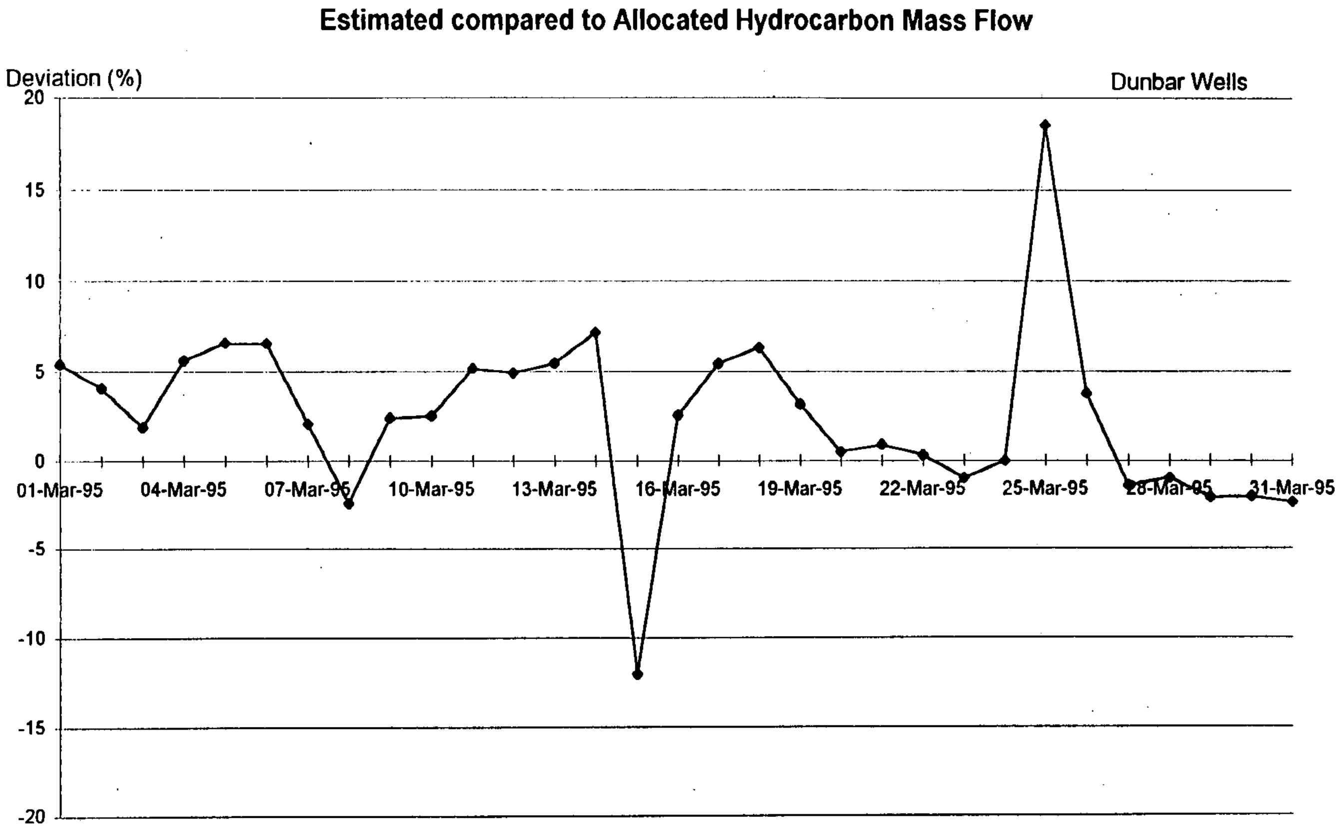


FIGURE 11



Estimated compared to Allocated Hydrocarbon Mass Flow
Deviation (%)
Ellon Well
20
15
10
5
0
-5
-10
-15
-20
01-Mar-95
04-Mar-95
07-Mar-95
10-Mar-95
13-Mar-95
16-Mar-95
19-Mar-95
22-Mar-95
25-Mar-95
28-Mar-95
31-Mar-95

FIGURE 12



Estimated compared to Allocated Hydrocarbon Mass Flow
Deviation (%)
Dunbar Wells
20
15
10
5
0
-5
-10
-15
-20
01-Mar-95
04-Mar-95
07-Mar-95
10-Mar-95
13-Mar-95
16-Mar-95
19-Mar-95
22-Mar-95
25-Mar-95
28-Mar-95
31-Mar-95

FIGURE 13

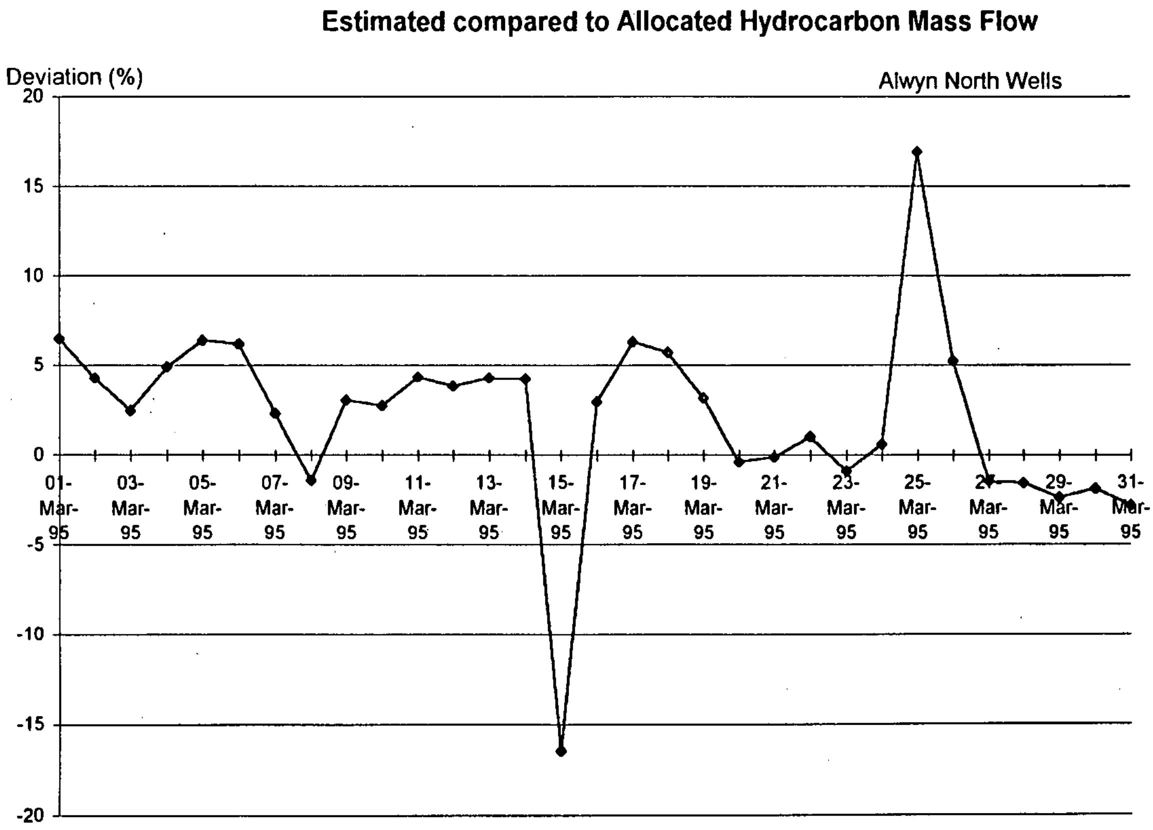
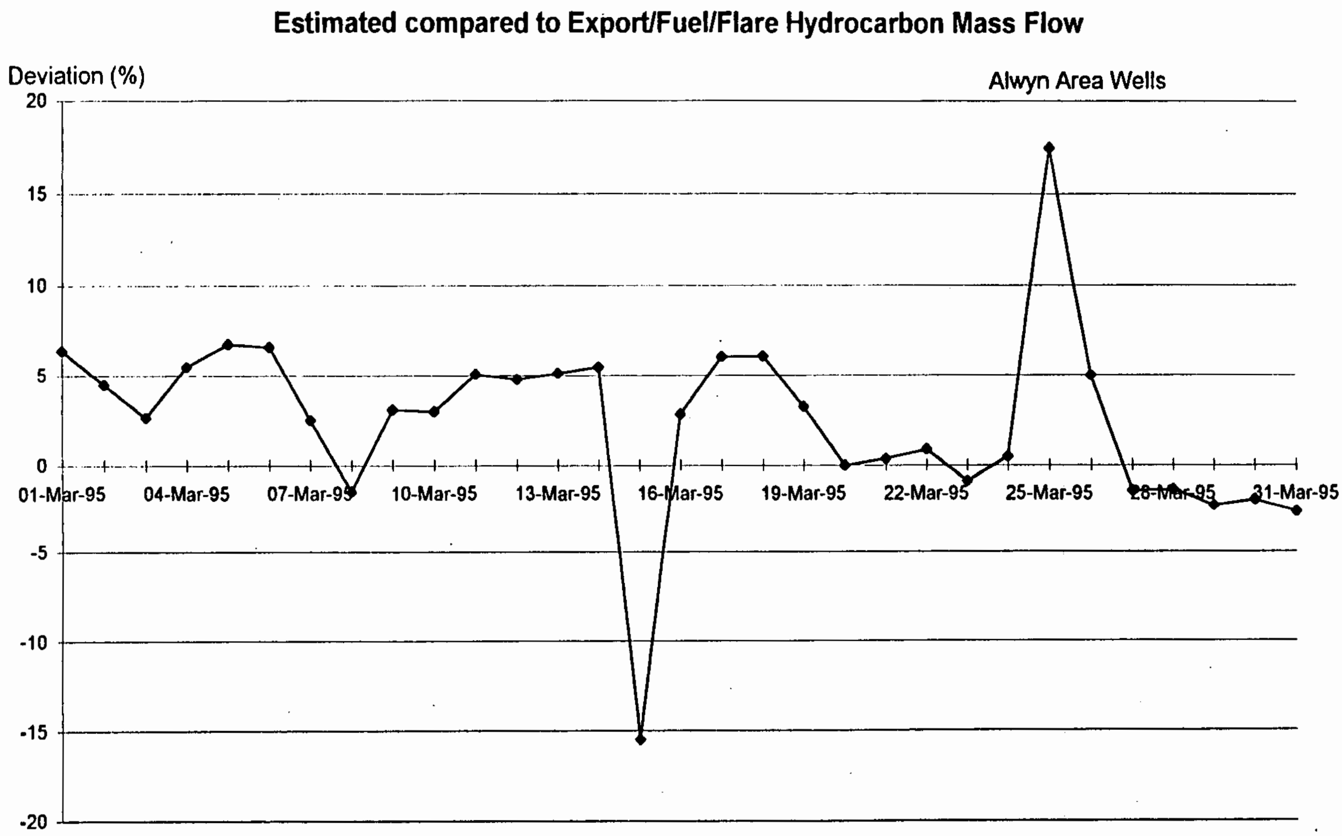

Estimated compared to Allocated Hydrocarbon Mass Flow
Deviation (%)
Alwyn North Wells
20
15
10
5
0
-5
-10
-15
-20
01-Mar-95
03-Mar-95
05-Mar-95
07-Mar-95
09-Mar-95
11-Mar-95
13-Mar-95
15-Mar-95
17-Mar-95
19-Mar-95
21-Mar-95
23-Mar-95
25-Mar-95
27-Mar-95
29-Mar-95
31-Mar-95

FIGURE 14



Estimated compared to Export/Fuel/Flare Hydrocarbon Mass Flow
Deviation (%)
Alwyn Area Wells
20
15
10
5
0
-5
-10
-15
-20
01-Mar-95
04-Mar-95
07-Mar-95
10-Mar-95
13-Mar-95
16-Mar-95
19-Mar-95
22-Mar-95
25-Mar-95
28-Mar-95
31-Mar-95