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Well testing using Multiphase Meters

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Introduction

- Well Testing Background
- Technology Selection
- Principles of Operation
- Learnings From Commissioning & Operation
- Achievements

This paper describes one of the first major roll-outs of multiphase meters in the Middle East area. The project started in 1998 and after trial installations and technology evaluation it was decided to install a series of multiphase meters on unmanned wellhead platforms. A total of 9 meters have been installed and has presently been in service for up to 2 years. Another 7 meters will be put in service on new-built platforms.

The background for considering multiphase meters as an alternative to well testing by traditional methods is

The selected technology and measurement principles is described.

The main experiences for the project is presented and discussed. Of particular interest is the collaboration model applied for the commissioning phase and the continuous follow-up of well test results by use of a field wide model of the production system.

The most important achievements in the project has been that the frequency of well testing has been dramatically increased and the amount of oil lost due to well testing is greatly reduced.

The Middle East

The field is located offshore in the Middle East area.

Offshore complex

The water depth is shallow compared to European standards, typically 10 – 40 meters. The field is developed by small satellite platforms with 1 to 9 wellheads on each. Platforms are generally minimum facilities, with limited power and normally unmanned. The platforms are linked via a network of flowlines to a central processing facility.

Remote jacket

Remote Platform,
Single Well

Why Well Test?

Well testing data is required for a number of reasons:

- Contractual obligations with partners and authorities.
- Well and reservoir performance monitoring and optimization
- Identification of mechanical integrity issues
- Assessment of near well-bore damage on combination with shut in data

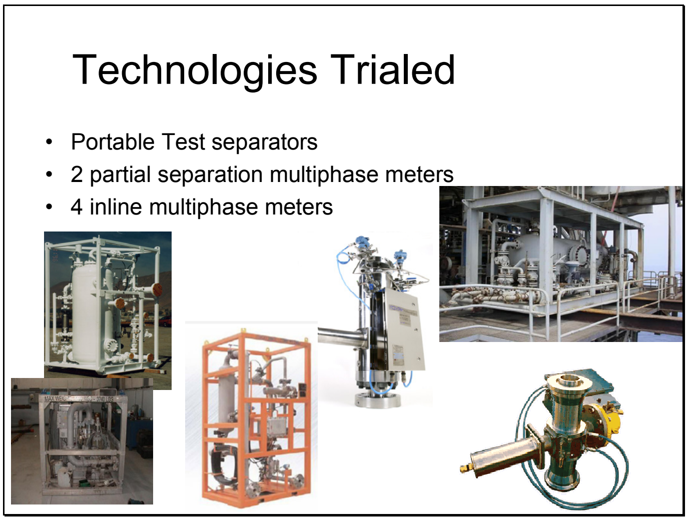
Well Testing; Pre 1995

- Test Separators x 1.
- Could only test up to 50% of producing wells per month
- Lost production
- High OPEX
- Intermediate results for short periods, require stability in flow.

One centrally located test separator served the complete field. Not all platforms have test lines. In case a test line is not available, wells has to be shut in for the well to be tested.

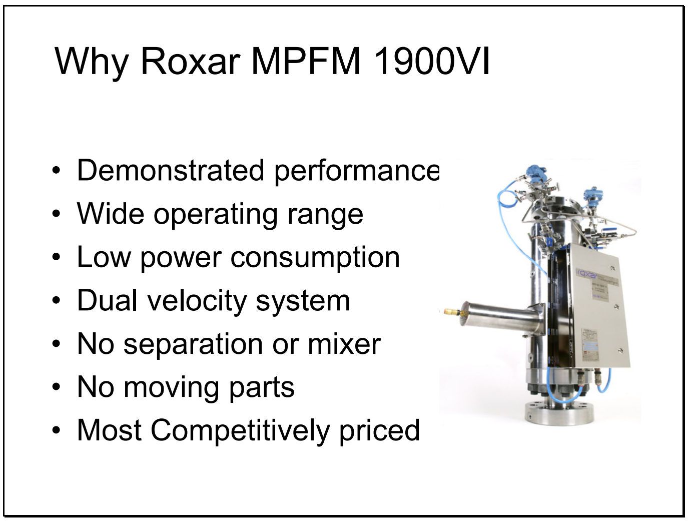
A long distance between wellhead and test separator causes long stabilisation time. The test time selected is therefore a compromise between lost production costs and accuracy of well test results. Additional sources of errors are the differences in hydraulic propeties in test lines and production flow lines.

Selection of wells are done manually on wellhead platforms, hence the operation has high costs and is very weather dependent.

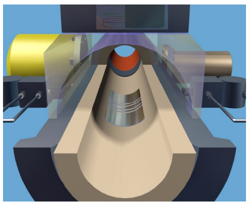


In a trial phase in 1999 – 2000 a total of 6 different multiphase meters were installed offshore in separate periods of time. Each meter was tested over a period of 1 - 3 months. During this time, the meters were tested over a selection of wells and compared with the test separator.

As a result of testing and evaluation, Roxar MPFM 1900VI was selected for field-wide implementation.



Principles of Operation
The ROXAR 1900VI



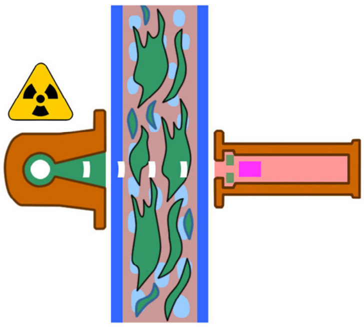
Overview

Two separate principles of measurements are used:

1. Fraction measurement (Gas/water/oil)
   - Gamma densitometer
   - Capacitance sensor
   - Inductive sensor
2. Velocity measurement (flow)
   - Venturi sensor
   - Dual Cross Correlation

1. **Fraction Measurement**

A) Gamma densitometer

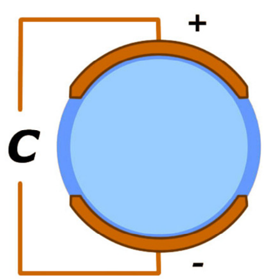


The purpose of the gamma densitometer is to measure the total density of the mixture flowing in the pipe. Because of the significant difference in the densities of the liquid and gas of an oil/gas/water mixture, the rate of the absorption gives an accurate measurement of the liquid and gas fractions of the mixture. The absorption of gamma radiation in a medium is a function of the mean density along the path of the gamma particle beam. Since the Cs beam penetrates steel, no windows or ports to the flow section is required.

The gamma detector used is a Tracerco PRI116 detector clamped on to the outside of the capacitance sensor. The radioactive source used is Cesium 137 (Cs 137). Service life for this system is 15 years. Provided instructions and regulations are followed, the gamma densitometer is totally safe, and does not constitute any source of danger.

B) Capacitance

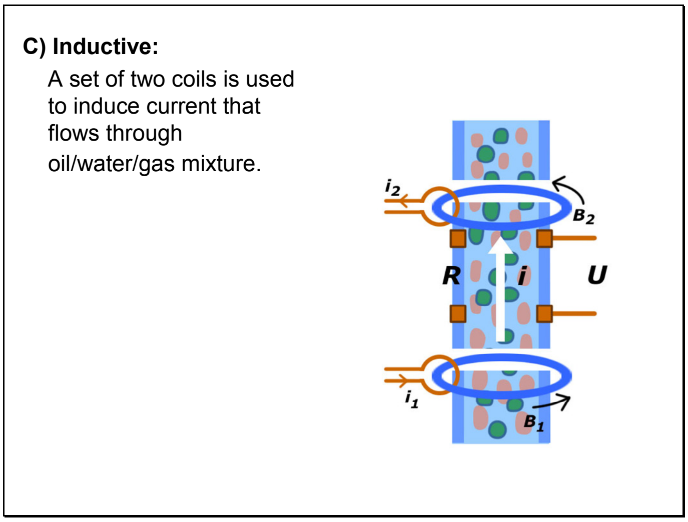
This sensor measures fractions of oil/water/gas by measuring the permittivity' of the mixture.



Functioning as a capacitor, the MPFM 1900VI measures the permittivity (dielectric constant) of the oil/gas/water mixture. The permittivity is different for each of the three components in an oil/gas/water mixture, and the permittivity of the mixture is therefore a measure of the fractions of the different components.

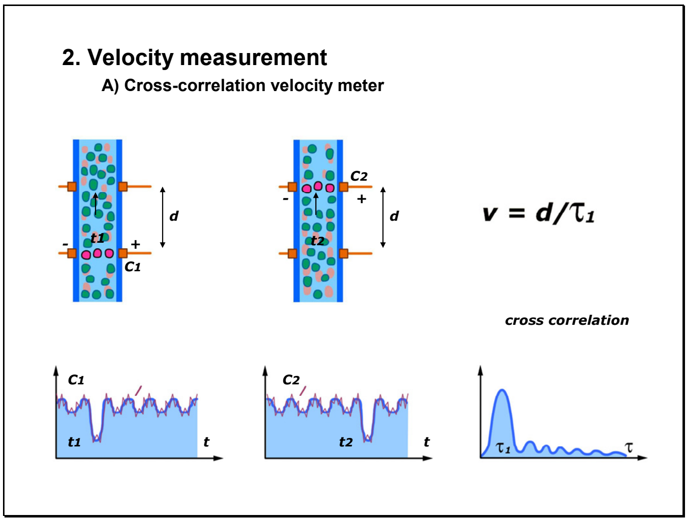
The function is achieved by locating electrodes on each side of the spool. The electrodes are isolated from the metal in the spool using a polymer plastic material (PEEK). By placing an electrode on each side on the inside of the spool, and allowing the mixture to flow through the pipe, the electrical field generated between the electrodes will be affected by the permittivity of the oil/gas/water mixture. The electrodes will act as a capacitance detector and the resulting capacitance can be measured between the electrodes. This capacitance will therefore vary when the permittivity changes, i.e. according to the amount of oil, gas and water in the mixture.

This capacitance measurement works as long as the flow is oil continuous, i.e. as long as water is dispersed in the oil and does not form a continuous path of water between the electrodes. Normally, the flow is oil continuous as long as the water cut is below approximately 60 – 70%. For higher water cuts the flow will become water continuous. For these situations the inductive sensor is used.



When the liquid is water-continuous, the mixture conductivity of the oil/water/gas flow is measured by an inductive sensor. Magnetic coils are used to induce a current through the liquid inside the sensor

The inductive sensor is integrated into the same sensor unit as the capacitance sensor and comprises a set of coils (B1 & B2) and also a set of electrodes. The coils are used to set up an electrical field which induces a current that flows through the oil, water and gas mixture. As long as the flow is water continuous, the water will act as a conductor and the current will flow from one side of the meter to the other side. The potential detector electrodes, also shown in the figure, will pick up the differential voltage created by the induced current. The measured signal depends on the fractions of gas and oil in the water. This information is then fed to the flow computer for calculation of oil, water and gas fractions.



Cross correlation velocity measurement

The sensor consists of pairs of capacitance/conductance measurement electrodes, each pair of electrodes spaced a known distance apart along the direction of flow. The electrodes perform continuous measurements of the flow, utilizing the variations both in velocity and composition inherent in a multiphase flow. The sensor electronics collects data at a a high rate. The collected data forms a time serial signal, and contains information about the flow pattern inside the sensor.

The flow pattern will continuously change as the flow passes through the meter. Thus the time series signal from the two electrodes in a pair will look similar in form, and it is possible to recognize the flow pattern at the next electrode by studying the two time series.

The statistical method cross-correlation, which compares the similarities between the signals picked up by the electrode pair, are used to find the time shift. The cross correlation function plotted versus time returns its first and highest maximum at a time representing the time shift between the signals.

Two electrode sets

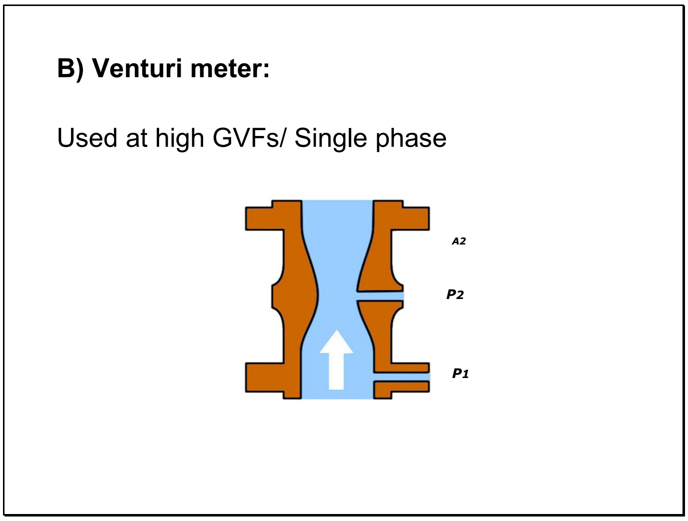
The sensor contains two different shaped sets of electrodes, large and small. The large pair of electrodes will be most sensitive to variations generated by large gas bubbles, whereas the small pair of electrodes will be most sensitive to variations generated by the small gas bubbles. Hence, the velocity of the gas can be determined by cross correlating signals from the large electrodes and the liquid velocity can be determined by cross correlating signals from the small electrodes

Slip flow

In multiphase flow, almost all combinations of liquid and gas fractions results in a flow pattern where the liquid and gas phases travel at different velocities, with the gas traveling with the higher velocity. This phenomenon is called slip flow (the gas phase slips by the liquid phase). The Roxar MPFM 1900VI uses different methods for flow velocity measurement:

- Differential pressure measurement over a Venturi meter
- Cross correlation of time series signals from the capacitance and inductance sensor

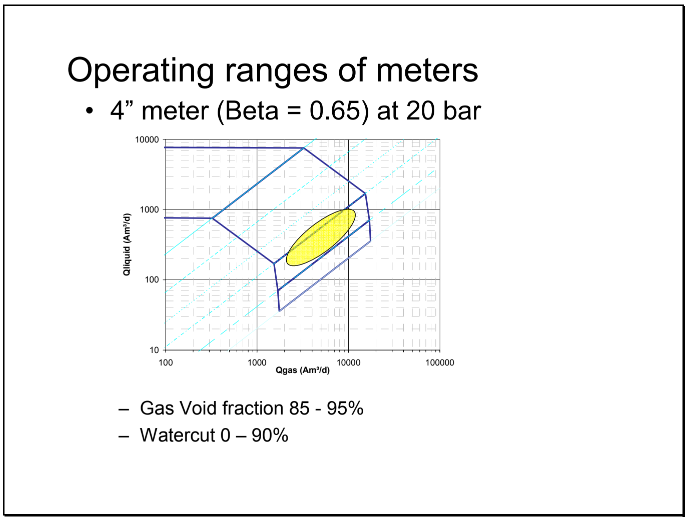
The cross-correlation technique and the Venturi measurement combined constitute a very robust method of finding both the gas velocity and the liquid velocity.



In many applications, the combination of a mass based Venturi meter and a volume based cross-correlation is beneficial. At very high GVF's (typical around 95-99%) the cross correlation technique may not work accurately due to lack of dynamics in the measurement signals from the capacitance/inductive sensor. A typical example would be annular flow where the gas mainly travels in the center of the MPFM sensor with the liquid concentrated along the walls of the sensor.

For these situations a Venturi-based flow meter will still work. Also, including a Venturi meter to the MPFM gives redundancy in velocity measurement. If one unit fails the flow computer will automatically start to use the other unit.

The standard Venturi equation is modified for use in three-phase flow. The modified equation takes into account the gas volume fraction (GVF) of the flow. Since the mixture density is measured with the composition meter, the mean liquid velocity and gas velocity can be determined from the measured differential pressure.



The meters where installed close to wellhead, and saw direct well stream. The wells are gas-lifted, which causes a very high GVF. The typical gas void fraction is 85 – 95%. In addition many wells were had heavy slugging, as normally occurring in gas lift wells.

Meter installation

The picture shows one of the meters installed on a 9-well platform. The platform does not have safe area or control room. Therefore the flow computer is installed in a field enclosure close to the meter. The local display allows operators to directly read the flow rates, perform well tests and set up the meter in a simple way.

The installation is highly exposed to saline atmosphere and high temperatures. Special sun shades are installed on flow computer and meter electronics to protect from direct sun-exposure during the hottest periods of the day.

The meters are installed as in-lie meters rather than in a skid. The piping could then be laid more optimally, and the solution also saves valuable deck space.

Commissioning phase

- Integrated team
- Roxar services included:
  - Training courses
  - Data analysis of well tests
  - Establish filed specific procedures for maintenance, personnel training, operation, data retrieval
  - Presentation of data and integration of data into supervisery systems

Rather than a traditional installation/ commissioning exercise, an integrated team approach was selected for this project. The Roxar service engineers formed part of the operator and engineering team whoich worked cloesly together.

By this approach supplier carries out duties which normally is done by consultants or operator personnel in addition to what is normally defined as supplier scope of work.

Among the tasks carried out by supplier personnel were:
Installation supervision, setup and commissioning offshore
Well testing offshore
Supervision of well testing from onshore.
Training of personnel at various levels and at the time of need.
Data analysis
Establish filed specific procedures for operation, training, maintenance
Presentation and quality assurance of data
Integration of data into operation reporting systems.

The collaboration proved to be very fruitful. It gave an improved understanding by the operator personnel of how to optimally integrate the technology. At the same time, the supplier personnel has a much better understanding of operator priorities and needs. It is quite clear that the approach selected here reduced the time of establishing fully verified measurements and reliable integration into production reporting system.

Lessons Learned During Commissioning

- **Gas rate measurement differences due to phase slip, software rectified**
- **Temperature measurement differences noted due to non-intrusive device used, software fix**
- **Software error interpolation of resolution data in PVT tables resulted in high gas difference**
- **Slugging well test results were not used for validation purposes.**
- **MPFMs proved reliable in service, few failures.**
- **Project delays due to radioactive source import issues**

The commissioning and startup phase for the project has been performed over a period of 6 months.

The main experiences during this period are listed above.

A software adjustment of the gas flowrate calculation had to be don after first time commissioning. The exact reason for this is not clear, although it seems to be related to the high degree of slugging.

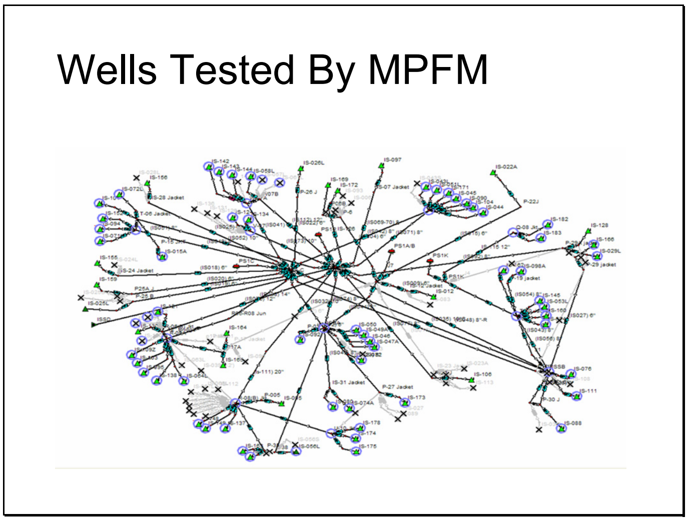
The temperature measurement showed a slow response and sometimes a lower temperature reading than correct. The reason for this was found to be in the design of the thermowell, as it was sensitive to ambient temperature. A software compensation solution solved the issue for the meters already in operation. Manufacturer has later modified the design, and then eliminated the problem for future meters.

All measurements were reported in standard conditions. Calculations from line conditions to standard conditions are based on PVT models established on black-oil composition data. The method the model initially was set up caused interpolation problems in certain conditions. By reducing the possible operating range to the expected range of pressures and temperatures, smaller steps in interpolation is required and the problems disappeared.

Slugging wells proved to be very difficult to compare with test separator. It was believed that the meter behaves better than the test lines and test separator under these conditions.

After installation of the meters, there has been very few failures, and the few which occurred were fixed quickly with a minimum of down-time.

During the project phase, a change in legislation for nucleonic source handling was introduced. Due to that supplier had to re-certify to import sources, and also get approval of working procedures, personnel training etc. It also took more time than expected to get installation licence in place. The delays are mostly contributable to introduction of new legislation, and is not expected for future installations.

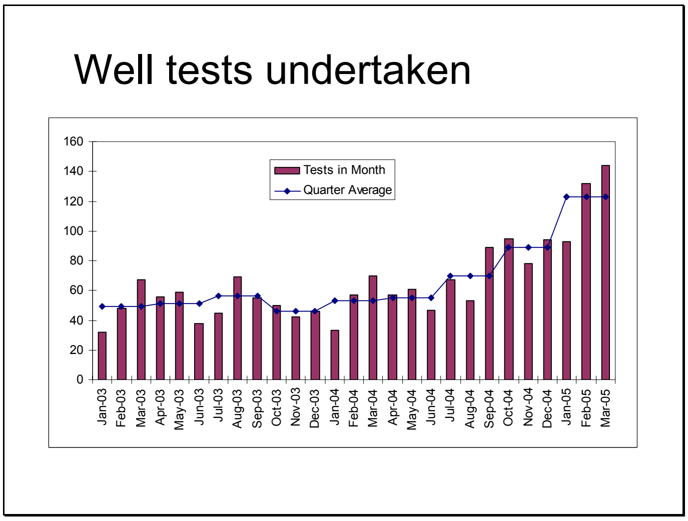


The MPFMs are installed on wellhead platforms, each with 1 – 9 wells. Most of the wells are equipped with downhole pressure and temperature sensors.

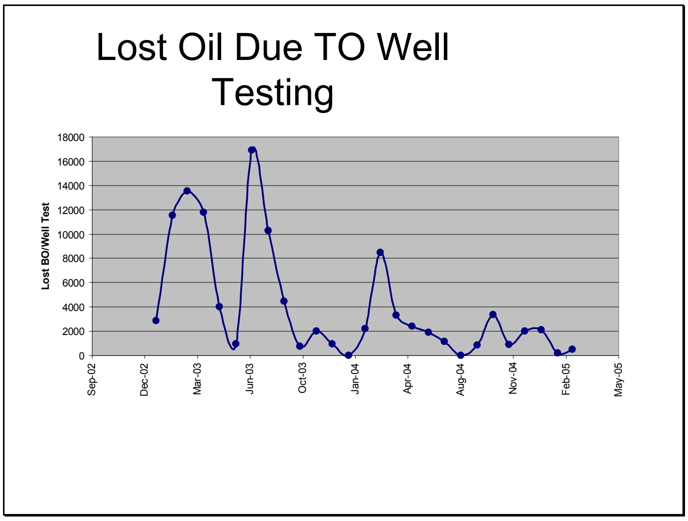
A comprehensive field wide model of the production system is established. The model simulates and correlates all available measurements on the production route, downhole, wellhead, manifold, transport lines and processing system. The welltest results are integrated and validated by this model once new data become available. Based on that, the model is corrected and optimised interactively. The tool provides an excellent way to monitor and validate all well tests and production data across the field.

It proved that comparison of well-head installed multiphase meters with test separator installed at central platform was very difficult. Long stabilisation time, operational issues with separator and slugging flow are the most likely reasons for this.

The sum of all welltest data is continuously compared with the total production as measured in the processing complex. The liquid measurements compares within typically 3% which is very satisfying, and far better than the earlier applied methods.

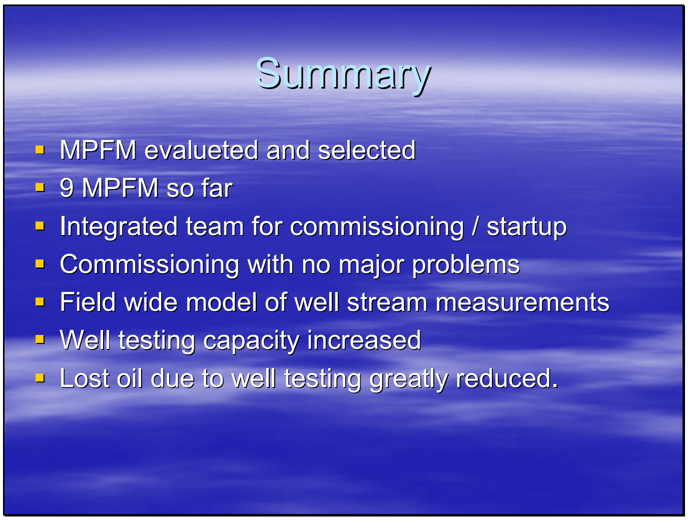


The quarterly average number of well tests taken per month has since MPFM been installed increased from average of 50 to 120.



The amount of lost oil due to well testing has been greatly reduced since well testing by MPFM has been introduced. Typical figure of lost oil per month of 12 000 has been reduced to 20 – 50 barrels of oil per month.

Assuming an oil value of 40 USD/bbl the corresponding value of oil lost due to well testing has been reduced from 500 000 USD per month to a figure close to 0.


Summary
MPFM evalueted and selected
9 MPFM so far
Integrated team for commissioning / startup
Commissioning with no major problems
Field wide model of well stream measurements
Well testing capacity increased
Lost oil due to well testing greatly reduced.