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WELL TESTING ISSUES AND A NEW COMPACT CYCLONE SYSTEM

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ABSTRACT

Well testing is the basis for reservoir management, allocation of production from various wells, and a key tool to quantify investments. In the past, well testing has been seen by many operators more as a requirement for obtaining numbers for management instead of use as a tool for planning and management of resources.

New technologies from computing power, integration of command and control into basic measurement instruments, and mathematical modeling of the fluid dynamics of complex systems has opened up new opportunities to improve management of fields. A few of these changes and their impact on well testing will be covered in this paper. The challenge for the future will be for reservoir and production engineers to utilize the data which these systems will provide. This information can then be presented to management with the chance to greatly improve the decision process about field upgrades, tertiary recovery opportunities, and improvements in manpower utilization.

Examples of relationships between data and the production of oil will be discussed. Equipment, which has been designed to incorporate technologies to enhance data obtained will also be described. A fundamental change in the methods and perspectives of personnel about well testing data is required to maximize the use of the new technologies.

1 INTRODUCTION

In the past, geological and reservoir engineers have focused on interpretation of data obtained by wirelines and other bore hole techniques along with summary production numbers to determine and optimize well production. Most of this information is obtained at a very high cost and can change overnight due to many factors beyond the engineer's control. Data such as water or miscible injection rates and production pressures, temperatures, flow rates of oil, water and gas are obtained on a regular basis and are shared among the various engineering groups. This latter data is the day-to-day operational information for evaluation of the production from a given field. The most fundamental information is contained in the well test data. This well test data is typically taken once or twice a month in most fields in the Americas.

It is interesting to look at some expectations of prior periods in time. In 1964, the following was stated by George Kite [1]:

> "Various arrangements for three-phase separators are in wide use but are often unnecessarily expensive and complicated; frequently they leave much to be desired insofar as accuracy, operator convenience and adaptability to automation are concerned.
>
> The instrumentation system discussed automatically and continuously meters and monitors an oil water stream containing ... or any combination thereof, and, without physical treating or separation, provides an accurate digital readout of net clean oil volume, directly in barrels.

No calculations, conversion factors, or interpretations are required; data are presented instantly, continuously and cumulatively in the most usable form. In addition, electrical digital signals for remote counting and an electrical analog signal for remote percentage water indication or recording are available at the computer terminal block."

Today, the industry is still stating that the current systems are expensive, operator intensive, inaccurate, and difficult to maintain. The proliferation of Seminars, Joint Projects, Conferences and Workshops concentrating on "Multiphase Measurement" emphasizes the industry is looking for better technology. The perfect solution would be compact, non-intrusive, low pressure drop, accurate, inexpensive and simple to use. This is a good description of what "Multiphase Measurement" is trying to accomplish. The question is how long will it take to get there and to what specifications and price can each of the markets requiring this withstand. In the meantime, the industry has not yet solved the basic problems which have been plaguing them for 30 years.

2 WELL TESTING ISSUES

There have been many forms of well testing, from tank strapping to three phase separators, two phase separators and now to three phase meters. The "ideal" well test system would be one that could be put anywhere and give accurate, repeatable results for oil, water and gas measurement with no additional back pressure on the well. This system would be flexible enough to be put in any kind of service and be portable enough to be moved from location to location.

Traditionally, the well test designs have been done by various groups throughout the industry sizing and specifying various components of a testing system. The vessel itself may be purchased from a separator design company with the remainder specified by an engineering company. In too many instances, the designer is twice or further removed from the person specifying the field parameters and needs. In many instances the company designing the equipment will never actually visit the field or talk to the end users of the equipment that he is designing. This makes this effort very dependent on the communications between the various operating groups and leads to many problems once the equipment is on site. Unfortunately, the well testing system is only too often considered secondary to the rest of the engineering efforts. Once the equipment arrives on the site and commissioned by a third party the operation is turned over to the field production groups. The result is that the end user must make it work. The burden is then on the field technical support groups.

Different segments of the market require different solutions depending on whether the customer is in the Arctic, South America, or the North Sea. The difference may not necessarily be in the technology but, more in the application of technology to the field. Heavy oil vs light oil applications require very different approaches to well test skids. Another difference could be in the method of presenting the data to the end user. In many cases in the Americas, the data is taken by operators writing down the various numbers at the site. The equipment may need to be designed for simplicity or complexity depending upon the measurement needs, capital money available, and knowledge and sophistication of the operators of the fields. Several other design parameters than can affect well testing include: fluid viscosity, water cut, gas oil ratio, oil density, water salinity, gas composition, distance of test equipment from the well head, flow stability, and reporting requirements of the operation. Asking questions of various operators, field production personnel, and design companies have led to the following comments about well testing:

1. <u>Reliability and Maintenance</u> – Today, fewer technicians are available, higher reliability is required; maintenance must be straight forward and simple to identify the problems. Complex systems must be made understandable.

2. Often there is inadequate understanding of the application at the beginning which then affects design decisions, selection of equipment, their sizes and capabilities.

3. Installation, documentation and support of equipment in the field are insufficient.

4. Presentation of data that is concise and pertinent to the operation.

5. Understanding and evaluation of methods used to validate well testing results which are often not consistent with accuracy or reproducibility.

Until the measurement, research, and engineering community begins to address these basic concerns, the industry solution required 30 years ago will still be a dream for tomorrow. The required outcome of a successful well test is not a measurement system but, instead, is the data obtained. How the data was obtained is not important as long as it meets the requirements of the end user of the data.

One of the most basic problems is that these solutions require very diverse types of professionals to implement a complete design. Contributing professionals to a successful design may include: fluid dynamics engineers, process engineers, instrumentation/electrical engineers, physicists, computer engineers, and involvement with the actual site reservoir, production, and maintenance personnel. When the requirements in a particular field are studied, many cases can be seen where the range of liquid and gas flow turndowns may exceed typical capabilities of a given design. This is because one site may have new wells and very old ones with varying tertiary methods of recovery. Another common concern is when a new facility design is completed which was based upon results from one or two exploratory wells that may not be representative of the range or rates once the field is in production. Oil and gas measurements are primary concerns but the water issues should not be forgotten. Important economic decisions based on the water production can be made about chemicals for corrosion and scale control. If the current and future needs of the same site are considered, the design of one system to address the solution will be unacceptable, yet this is the solution commonly chosen. If the professionals could model the designs and communicate with the field and reservoir engineers, a more flexible design may solve these issues. Too often, well testing is not considered important enough to concentrate the up front efforts required to implement a good system. This is surprising since the petroleum company makes its money on efficient use of its resources for production optimization.

Since each company, and in many cases each field, will have different computing systems and protocols, the data collection and storage is not an easy issue to address. The method of data collection may affect the results to a great extent. The system was designed without giving enough thought to the effects of how the data was gathered and manipulated. An example of this is when data is collected through a PLC to a DCS system. The PLC polls the equipment every 1 second, the results are integrated over a 3-5 minute time frame and then the DCS polls the PLC for the data. The graphs available to the operator are only the integrated data points each point separated by a 3-5 minute period. At the actual equipment it is obvious that the fluids are slugging from 60 m^3 to 600 m^3 over a 30 to 60 second time frame because the separator is out of control. The 3-5 minute integration is long enough that the data does not show the severe problem that actually exists. In another case, the dump/fill cycle of the separator was only 30-45 seconds and the emulsions went from oil continuous to water continuous and then back to oil continuous. This dramatic change in the fluid properties created considerable problems in the measurement equipment, and separator control. Since the data collection was every minute, extremely long well tests were required to obtain reasonable data.

The actual proposed use of the well test data is not always specified in the beginning. Whether for field evaluation, development and allocation of production of a new field, process control, and/or payment of taxes, the manner in which the data was obtained is important to the validity of the use of the data for the stated purpose. Field evaluation may only require a +/- 10% accuracy while fiscal measurement will place much tighter requirements on the design. If the data is obtained by integration over 10 minute intervals, the problems in separator efficiency, slug handling, and level control may not be observable in the data. Conversely, if the data is obtained and displayed on a 5 second interval, most operators would not interpret the data in a favorable light. The perceived operation of a system versus the actual operation is very different in some cases. The rapid changing of data due to fluid characteristics may be interpreted as a problem with the system. Thus, if the same data had been integrated and presented differently, the same operator would believe the system is okay. Although unacceptable to the operator, this "fast" data may be of much interest to the production engineer or the reservoir engineer since it may shed light on the actual performance of the well, separator and the control system. Data for fiscal use may only be the sum total oil/water/gas production per day with all periods less than one day inconsequential. Any other presentation of the data would be a problem to interpret by the actual user of the information.

Although the selection of the measurement instruments is very important to the end accuracy and generation of worthwhile data, the instruments are but one part of the system. The system must work as a whole and the data obtained must be consistent with the end use. The algorithms used to interpret the data collected from the separate instruments are critical to the operation of the whole. This is true whether it is a complex state-of-the-art multiphase analyzer or a two phase vessel with standard instrumentation. The combination and handling of the whole system is critical to performance in the application.

Next, the incorporation of high technology into these systems is both a problem and a blessing. "High tech" is frequently thought to be too complex and hard to understand by operators and technicians alike. Like the first microwave ovens that required an engineering degree to set the clock or to defrost and then cook a meal. Usually the "High tech" industry likes the whistles and bells in lieu of common sense straightforward methods. "High tech" is good in the sense that it gives an opportunity to address problems with solutions that were not possible before. Implementation of new technology typically provides a supply of ideas which will mature into better solutions than the existing technology. Unfortunately, these solutions become usable industry standards only after the technology is given a chance and the analyzer industry corrects the initial problems and redirects some of the methods. The first sales of these complex systems must go through the various stages of acceptance before the need merges with the knowledge and technology.

Finally, some of the greatest difficulties in development of new process technologies lie in understanding which questions to ask and how to obtain valid answers. The operations people may not be able to help since the people that need the technology most don't necessarily understand the problems and questions that are being asked. Therefore, they may not be sure how to answer the question. The technologist asking the questions may totally misunderstand the answers given. Truly, they may not understand the solution proposed because the fundamental issue that they question is why a different approach needs to be taken. In other cases, the new technology may appear as a threat to their existence in a particular job position. This issue alone can completely undermine a valid technology and the use of it in a well suited application. These issues must be carefully addressed during the information gathering process.

3 EXAMPLES OF WELL TESTING SITUATIONS

Since very early in the 1950's the need for well testing and good data from these tests has been pursed. Results have been very good in fields where steady production flow rates with low water cuts exist. Other cases exist where the two or three phase separators have been designed for good control and the oil and water separate readily with standard process methods or due to the properties of the fluids. In many cases, the data taken for well testing has not been analyzed completely and therefore important opportunities for improvement have been hidden. Several interesting cases will be described in the following discussion.

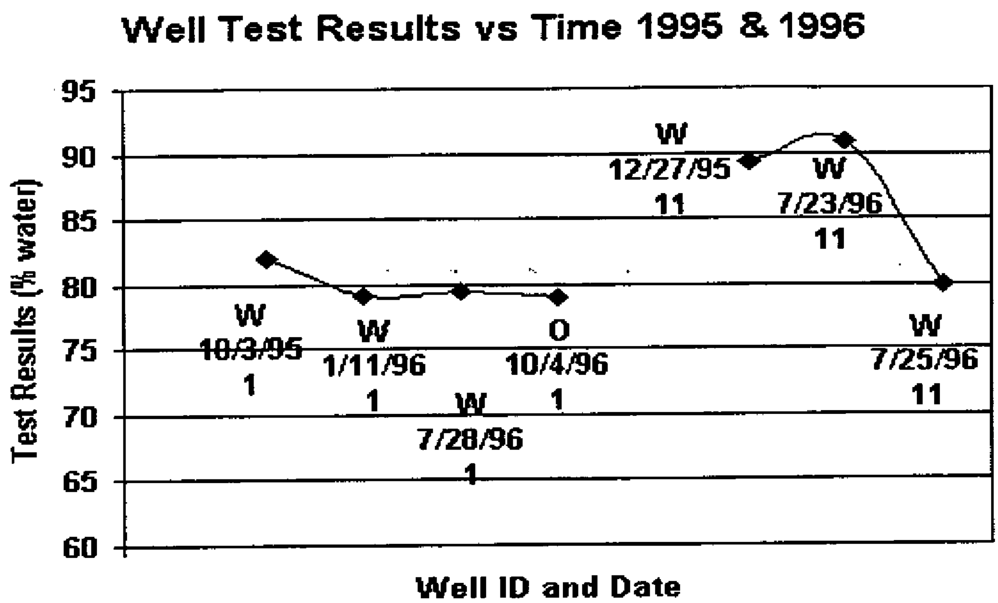

Figure 1 - Well Test Summary Results

Figure 1 shows two wells with results from testing over time. Well #1 shows consistent test results over a one year time frame. The "W" or "O" alongside the data represents the phase of the emulsion; water or oil continuous respectively. Notice the change from water continuous to oil continuous from 7/28/96 to 10/4/96. This change was due to the addition of gas lift to the well. A very tight and viscous emulsion was formed causing high pressure at the wellhead and lower production rates when the gas lift was initiated. The properties of the oil supported a phase inversion from the oil continuous to the water continuous phase at approximately 82% to 84% without other factors being involved such as gas lift injection. The gas lift altered the inversion point and maintained the oil continuous phase. The well was returned to production without gas injections to reduce the wellhead pressures and decrease viscosity which increased flow. Well #2 demonstrates a change in water cut of over 10% over the same time frame but, the emulsion type remained constant. The reason for this increase in oil production was a change in the pumping rate. Results from these tests allowed improvement in production of oil and understanding about production from this reservoir with data supporting the changes. The emulsion phase of the fluids is very important in understanding the behavior of wells. Most sites do not record this phase information as part of the historical well test data.

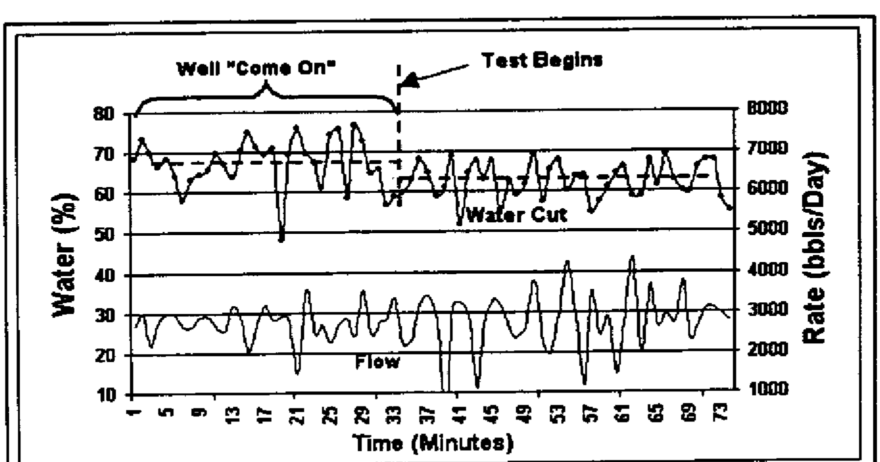

Figure 2 - Throttling Type of Separator Performance

Figure 2 shows real time data for a well to demonstrate that there is a time period for the measurement system to settle out once it is switched into the test separator. The wait of approximately 30 minutes was necessary for the well to "come on" and arrive at a steady rate of production and for the 2 phase separator to arrive at equilibrium. The remaining 12 hours of well test time was similar in nature although only a portion is shown in the graph. This system is a throttling type of two phase separator. This gives a relatively constant flow rate and therefore, eliminates many of the measurement problems seen with the dump-fill type of separators. Problems can occur with throttling types of separators when the design was not made to handle the control problems at very low and high flow rates. Data from throttling type of separators appears to be more consistent and verifiable than others. Pulling a sample when the water cut is maintaining a mean value is less difficult than a dump-fill type of separator where the cycle is changing the water cut rapidly through the dump portion. Therefore, a throttling type of cycle is easier to verify the performance of a system. Both the flow measurement and water cut instrumentation have higher potential of delivering good data due to the more consistent emulsions, flow and water cuts.

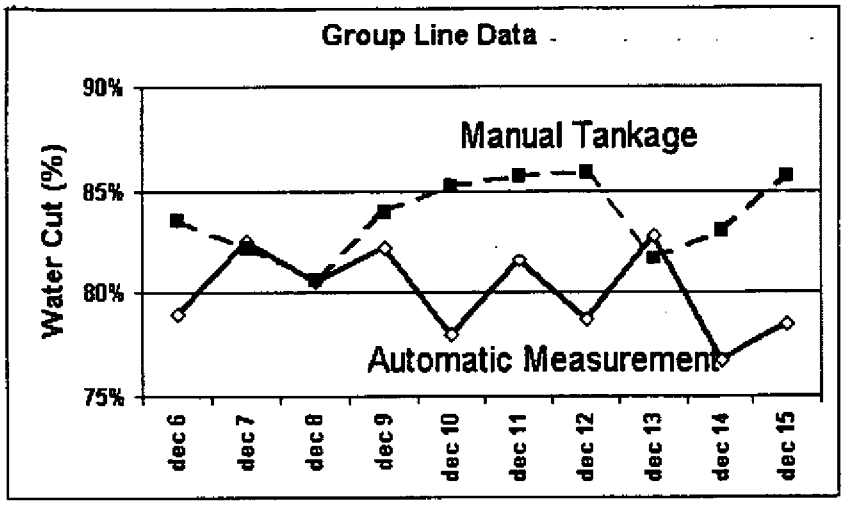

Figure 3 - Group Line Study

Figure 3 shows a common header where approximately 100 wells are merged into a "group line" and the test results from this line. Although not specifically defined as "well testing" this situation is part of the well allocation and production balance accounting. In the normal routine, testing was done by tank strapping each day. A 4" in line water cut analyzer was installed with a flow meter input to obtain net oil and to help in automation of the area. Tank tests results typically gave higher water cuts than the automated system. This problem was partially solved when the operator determined that another line merged with the free water knockout vessel, which was before the main strapping tank. This second line had flow metering problems of its own. Therefore, the second flow line numbers were taken as accurate measurements when they were not. The results proved that the automatic method was more reliable and reproducible than the manual method. In addition, the automatic method provided for better overall accounting of production balance. Installation of the automated system found problems for production, which would have been difficult to spot prior to automation.

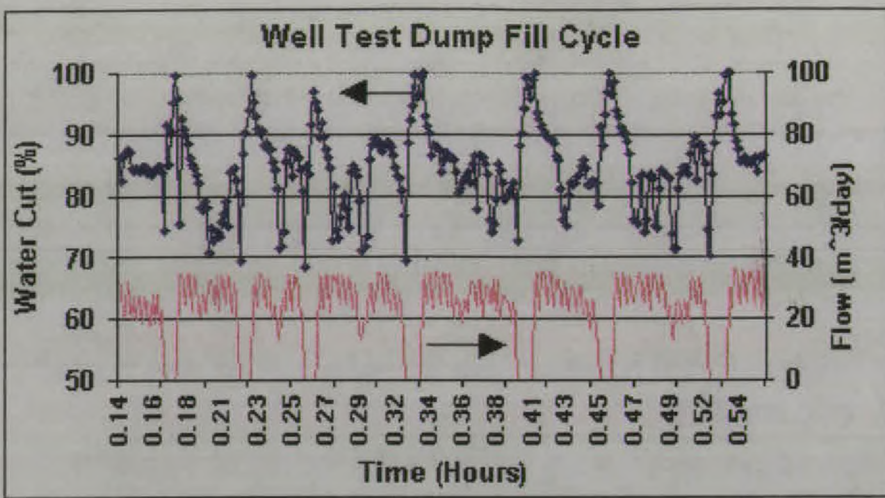

Figure 4 - Dump-Fill Type of Separator Performance

The well test results in Figure 4 are typical of a dump and fill type of two phase separator where the flow rates are relatively constant but not continuous. The flow can be seen to give relatively repeatable dump fill cycles of about 2.5 minutes for each cycle. One of the main difficulties with dump fill separators is that often the flow cycle will be reduced to less than 1 minute. This usually occurs as the well production matures and water flood is begun, or due to undersized vessels. At this point it becomes more difficult to accurately measure water cut and rates since the cycle time is too short to allow everything to come to a state of equilibrium. In addition, both types of emulsions are most likely to appear during this cycle. This creates a great deal of measurement uncertainty due to the great change in viscosity for heavier oils. In these cases a mass type of flow measurement is best.

4 CYCLONE SEPARATORS

Cyclone separators have many advantages other than the economic and facilities issues. Figure 5 demonstrates one advantage that is the very short time required switching over wells and achieving stability. The liquid capacity of the cyclone is typically very small. This small volume coupled with the closeness to the well manifold makes for a very short time to the next test. The typical well test can now be reduced to 2-4 hours instead of the normal 6-24 hours. Decreased time to test means more wells can be tested in a month. This helps in reservoir management and in production control. Wells with problems can be discovered before they become an issue and better allocation of production to wells can be accomplished.

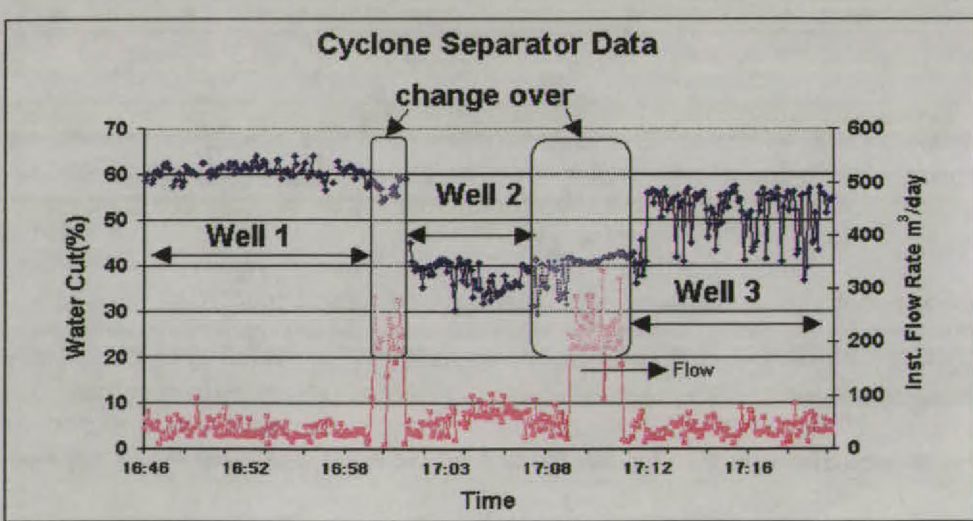

Figure 5 - Cyclone Separator Data

4.1 Compact Cyclone Multiphase System (CCM)

A unique design for a Compact Cyclone Multiphase (CCM) measurement system was designed to provide a very small physical footprint with performance in excess of existing methods of measurement. Field and laboratory data supporting its operation has also been completed with two systems installed in oil fields in North and South America.

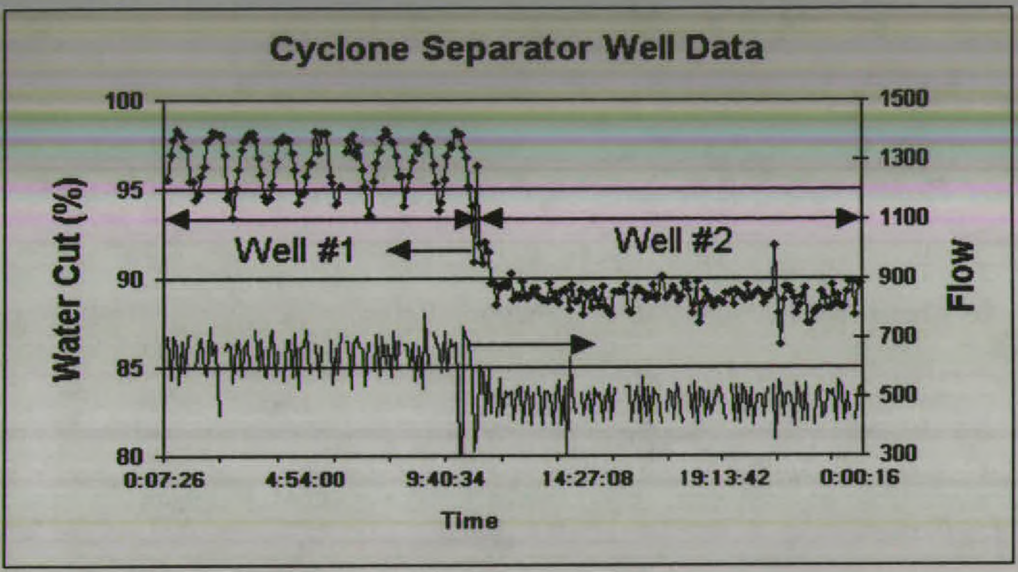

Figure 6 - Compact Cyclone Multiphase Data for 3 Wells

A novel gas blockage arrangement developed and patented by Kvaerner and Statoil a.s., is used which provides high centrifugal forces to be applied to the gas and liquid mixtures. This gives increased gas separation capabilities along with better control of the dynamics of the separator. The resulting design is optimized for the oil fields in which it will be used through modeling of the fluid dynamics within the gas/liquid separator. The concept for this system was invented and proven in use as an inlet device for gravity separators in the North Sea during the past two years. Approximately 20 oil production separators are now operating with this inlet device in the North Sea. The separator package for the CCM uses this unique device to eliminate the gas from the liquids so that conventional instrumentation can be used for the liquid stream.

The Kvaerner cyclone coupled with a Phase Dynamics' microwave water cut measurement, a coriolis flow and density measurement and appropriate gas measurement, provides a complete well testing system. Complete system control is integrated into the water cut measurement electronics to provide for minimum redundancy of electronics and maximum reliability. Integration of the water cut analyzer to the compact cyclone was accomplished as a joint venture between the two companies. The key is to solve the 30 year old problem mentioned in the beginning of this paper, and to provide an industry solution where one vendor is responsible for the entire design, instrumentation and support.

Data obtained from Porsgrunn supports the operational envelope of the CCM. Field data has also demonstrated the ability to remove gas and provide a measurement which conventional separators have had difficulties managing. The ability to look at almost real time well performance provides a unique opportunity to manage fields and wells unlike any point in the past.

Figures 5 and 6 show different wells under test with each having a unique signature of its own. The two wells in Figure 6 were from the same type of formations. The flow data is smooth and regular in both cases. Submersible pumps were the source of the flow. Looking at six different wells at the same site demonstrated that the characteristic of the data was unique to each well. The Well #2 in Figure 5 was later run for a long period of time to verify the data was representative after approximately 5 minutes of settling time. The long switching time between Well #2 and Well #3 was due to engineering curiosity where several wells were switched in at once to see the response. Data for the operator was integrated and displayed in a different format.

Figure 7 shows the basic compact cyclone separator. The cyclone portion is static and it makes use of the centrifugal force as the driving force for separation. Liquid and gas enters the cyclone distribution chamber through a spin section which will set up a rotational velocity. The spin section can be made up of vanes or tangential ports. The swirling flow induces a centrifugal field, typically 50-100 G's, which separates the liquid and the gas with the liquid leaving the separation chamber at the bottom.

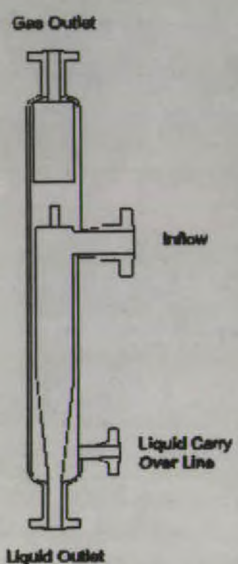

Figure 7 - Basic Cyclone

The cyclone is equipped with a gas blockage arrangement that directs the gas toward the overflow of the cyclone cylinder body. The gas and the remaining entrained liquid leave the first separation stage at the top and enter the second stage polishing unit. This second stage is the scrubber and polishing portion which separates the last of the liquid from the gas and then the gas leaves the top of the cylinder body. The liquid from the gas scrubbing stages is carried over into the annulus between the main cylinder body and the inner cyclone body. The liquid discharges out the liquid carry over line as part of the regulation and pressure balance of the system.

The multiphase meter includes a control system with up to three regulating valves depending upon the turn down ratios and gas oil ratios. The control is automatic and due to the unique design is very robust across the operational envelope

This system including the flow (liquid and gas) measurement, water cut analyzer and system control makes up the CCM. One of the key elements of this system is that every component can be identified and repaired because of the exact similarity to existing two phase separators. Existing personnel will be able to work on each section without additional training except for the control system itself.

The Phase Dynamics, Inc., water cut instrument was originally developed during the 1985-1992 time period with ARCO Oil and Gas and has been in worldwide use for approximately 5 years. Over 1000 systems are installed with the majority being used in well testing situations. The key is a microwave based measurement which provides an accurate measurement from 0% to100% water content in oil. This analyzer provides information about the phase of the emulsions for reservoir management and is very friendly to install, troubleshoot and use.

The water cut analyzer is well known throughout the world but, with the largest concentration in the North and South American Continent. The microwave based measurement is simple in the approach and rugged in real world applications. The unique "Oscillator Load Pull" patented technology provides for the extraordinary sensitivity of up to 3 MHz change in frequency for a 1% change in water cut for low range systems. The full range systems utilizes this sensitivity improvement in order to make a reproducible measurement even in the water phase at salinities up to saturation (27% salt by weight). The sensitivity improvement was brought about simultaneously with a very simple circuit. This combination provides the reproducibility, accuracy and reliability for field use that has been requested by the petroleum industry for many years. The design eliminates the complex microwave sources and down conversion circuitry required on typical microwave systems.

The CCM has been designed with the end user in mind by incorporation of the understanding from many fields and users of such equipment. These issues of reliability and maintenance, understanding of the application by the designer of the equipment, installations and support have been addressed in the design of the CCM system. Additionally, data which can be obtained from the use of this type of continuous flow systems has just begun to be understood.

4.2 Porsgrunn Test Results

A test of the prototype CCM was done at the Norsk Hydro Test facility in Porsgrunn during January, 1998. More than 60 points were tested at 23 and 35 bar pressure. The fluids were Norsk Hydro's Troll Oil, hydrocarbon gas and salt water with following properties:

- Temperature: 60°C
- Pressure: 23 and 35 bar
- Density water: 998.3 kg/m^3 at 60°C
- Density oil: $0.0035P^2 - 0.6879P + 871.22$ kg/m^3 at 60°C (25.7 API)
- Density gas: $0.0002P^2 + 0.6867P + 0.4829$ kg/m^3 at 60°C

Densities of oil and gas are best-fit lines of PVT data at 60°

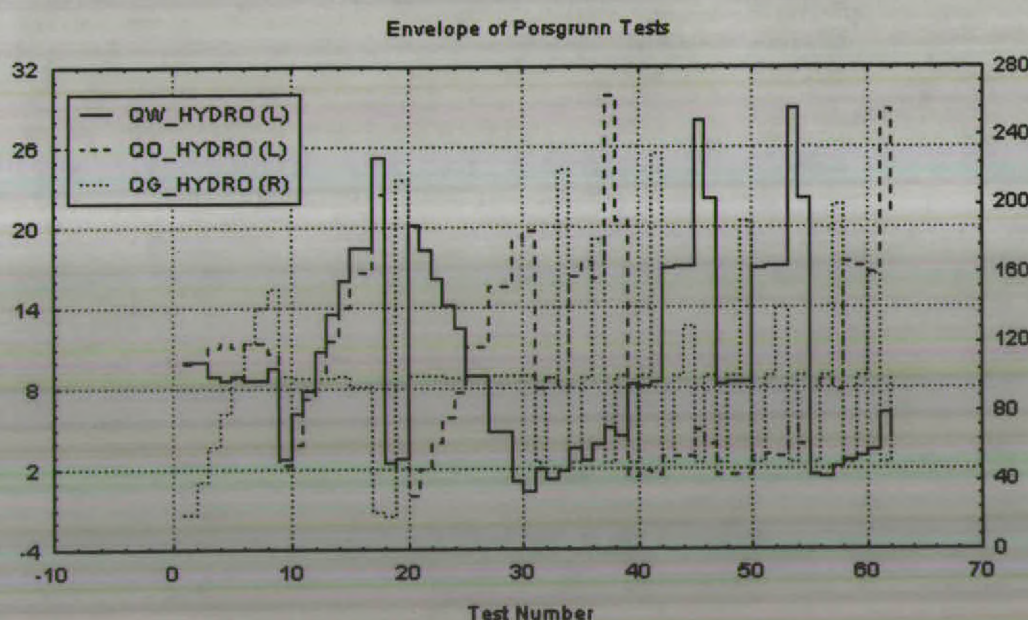

Figure 8 - Test Envelope

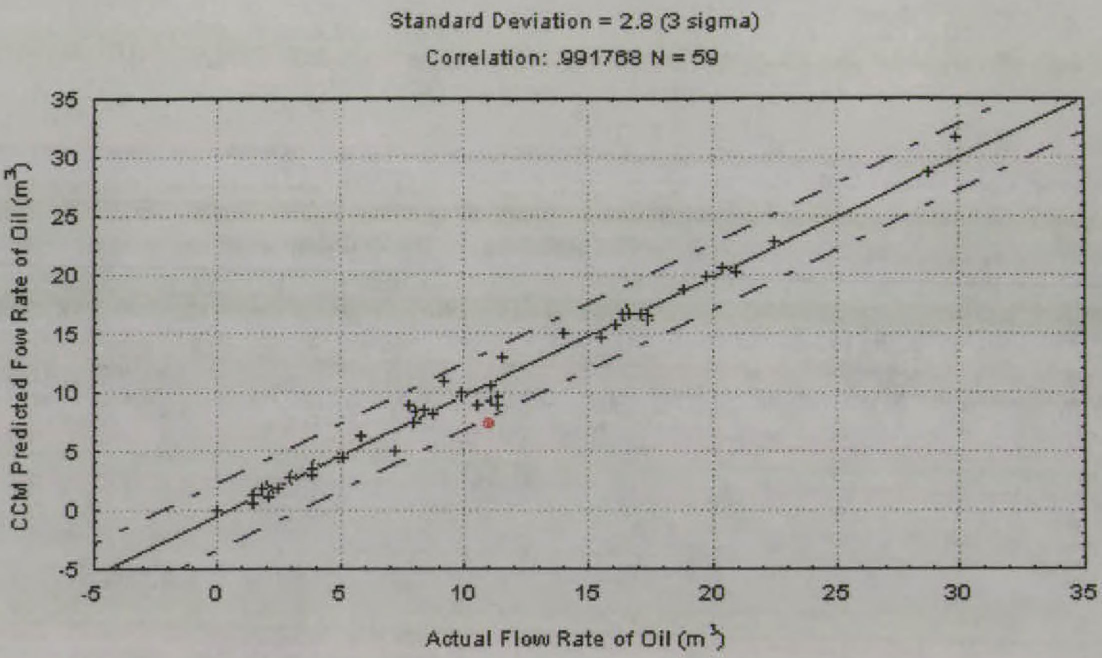

Figure 9 - Test Results for Oil Totals at Various Water Cuts and GVF

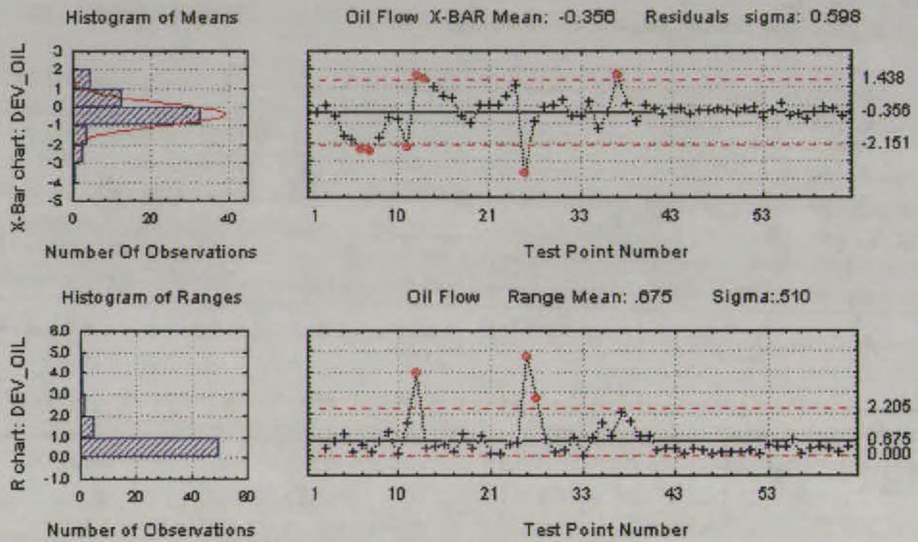

Figure 10 - Statistical Information on Oil Flow Errors

The objectives of the test were to test the new control system enabling the meter to function at GVF range from 0 – 100% at all pressures, and to test some design changes of the internals. Figure shows the gas/oil/water rates for the various test points. The control system worked according to expectations and the accuracy of the meter was increased somewhat compared to previous tests taken during 1997. Figure shows the results from 61 test data points giving flow rates for oil rates for the CCM versus the Hydro standards using a best line fit. The results are statistically very good as shown in Figure which gives the X-bar Chart and Range statistics for the error in Oil Flow. The X-Bar Chart is the result of the distribution of the differences between the two data sets. This distribution is "Normal" and therefore, is more valid than the best fit line data. The mean of the residuals is –0.35 with a standard deviation of 0.6 (3 sigma of 1.8). The second or Range Chart shows that the majority of the data points had less than a 0.67 error.

The internal design changes to the 2^{nd} stage separator were sufficient although they could be improved upon above 100 m^3/hr rates. In Figure gas readings show a standard deviation of 5.1 m3/hr (3 sigma = 15.3) for a best fit line. Figure shows the X_bar and Range Charts for all of the points. The X_bar chart gives the statistics for the distribution of the data and also provides a plot of the differences between the CCM and Porsgrunn gas data, the mean and standard deviation. Again, the distribution of the data for the best fit line is not very "Normal." If the data was processed only for below 100 m^3/h gas flow rates, the Standard Error of Estimate is reduced to 3.6 from the 5.16 for all of the points. The 2^{nd} stage separator is now redesigned through CFD (Computational Fluid Dynamics) calculations and laboratory experiments in order to improve the higher gas ranges.

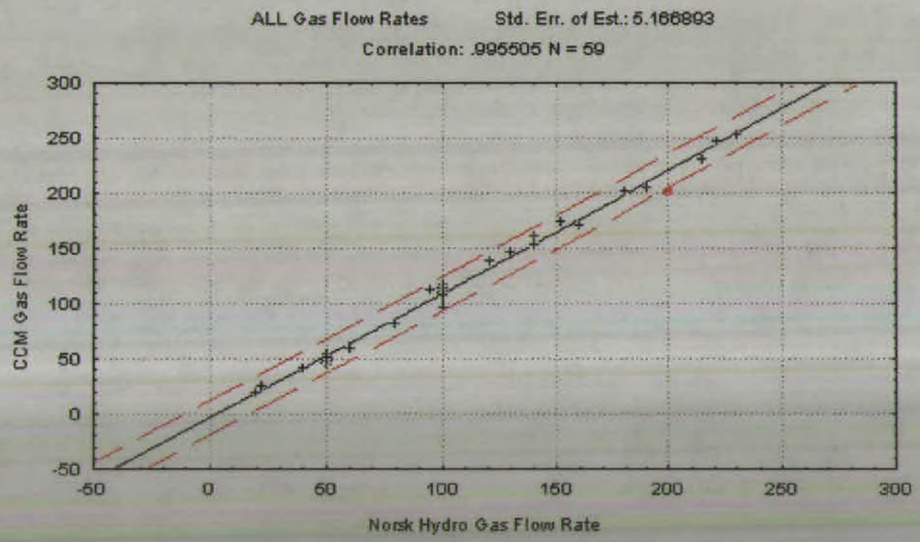

Figure 11 - All Points of Gas Measurement

In theory the accuracy of the CCM should be as good as the individual meters combined. In practice this is not easy to obtain because of the small volumes in the separator, which are comparable to an equivalent length of piping. This is a source of uncertainty in slug flow cases. About 3 – 4% error is added in slug flow. This uncertainty is not because of degraded separation efficiency, but mainly because each meter sees a transient, oscillatory flow.

The separator will work in any given GVF, but the flow and fraction instrumentation installed will restrain the metering due to their unique turn down ratios. If the system was designed for optimal reading at a GVF of 50%, good liquid reading would be obtainable at GVF ranging from 0 and up to approximately 99%, whereas good gas readings would be obtainable at GVF ranging from 5% and up to 100%. This means that the meter can be designed for optimal reading of both gas and liquid at any given GVF. The ability of the meter to function in high GVF flows (>95%) is particularly interesting for fields with high quantities of gas, and where the gas, condensate and water need to be measured. Full range water cut readings are standard.

These tests at Porsgrunn demonstrate that performance can be achieved from a very compact design using standard instrumentation. The accuracy envelope exceeds typical existing installations in the Americas. Improved accuracy can be achieved by designing for the oilfield's particular envelope of operation in an attempt to reach the measurement ccuracy of the various instruments. The real time data achieved through the use of the CCM should benefit management of the fields and accounting methods.

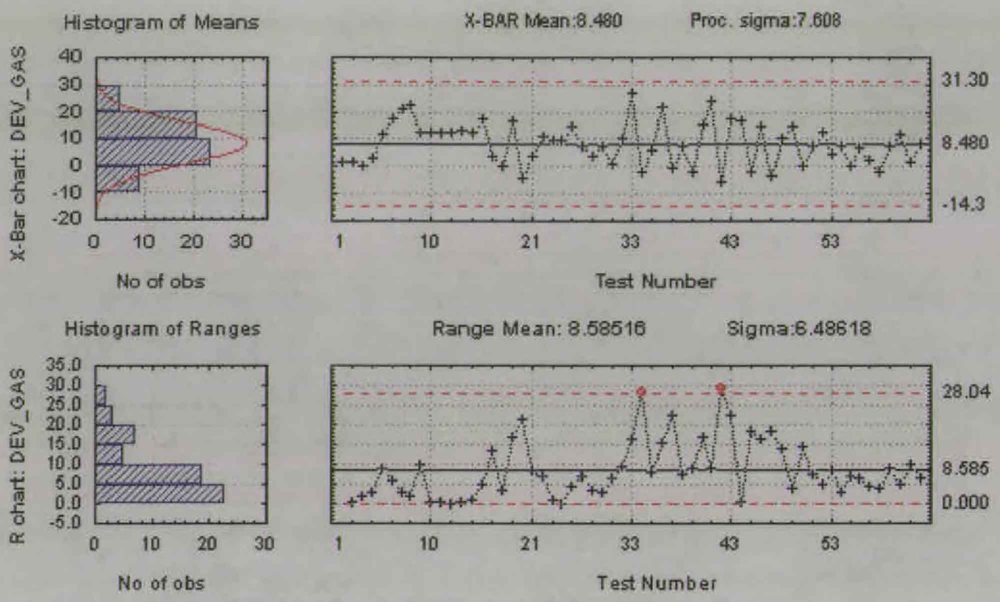

Figure 12 - Statistics for Gas Measurement

5 CONCLUSION

Reliance solely on conventional methods of reservoir management, fiscal accounting, and personnel managing the well test systems, must be changed to meet modern quality control of these processes. Use of real time analysis, expert systems, and statistical process control must be preceded by equipment designed to obtain more consistent information. The CCM is a step into this direction for the future.

What petroleum companies require is data representing the production and optimization of processes. The difficulty will be to balance the system complexity, degree of automation, required accuracy, size and back pressure allowed in order to produce the required data. The measurement industry needs to supply equipment where they have taken on the burden of providing sample system design, applications engineering for the site where it will be used, analyzer selection and engineering including requirements for installation and maintenance. The petroleum industry's prejudices about specific analyzers and methods would be eliminated if good data was supplied. This would help to free up talent in the equipment industry and would help to remove many constrains imposed upon new technology for use in the industry.

Involvement of the measurement industry's personnel in the measurement process will provide the additional insight into the use of the data that will become available as these new technologies unfold. Just obtaining megabytes of data on a well performance will not be sufficient. Information will be lost without proper interpretation and statistical manipulation of the data. With modern data acquisition systems the shear volume of data which can be obtained tends to cloud the solution to problems.

References

[1] Paper presented at the North Sea Flow Measurement Workshop, a workshop arranged by NFOGM & TUV-NEL

Note that this reference was not part of the original paper, but has been added subsequently to make the paper searchable in Google Scholar.