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Level measurement and control strategies for subsea separators

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Abstract. *Level monitoring instrumentation is an essential part of hydrocarbon processing facilities, and has, together with separator technology, been widely addressed over the last decade. Key issues are production capacity, product enhancement, and well-flow control. The reliability and accuracy of the level instrumentation, and its ability to monitor all the interface layers of the separator, including the thickness of the foam and the oil–water emulsion, are particularly important when considering the level instrumentation as the main sensing element in the automatic control of the separator vessel. Lately, industry focus has been placed on optimal automatic control to improve the quality of the production output, and to minimize the use of expensive and environmentally undesirable separation enhancing chemicals. Recent developments in hydrocarbon production include subsea separation stations, where the constraints placed on the reliability and accuracy of the level instrumentation are especially demanding. This paper presents level interface monitoring developments based on electrical, ultrasonic, thermal, and nucleonic physical principles for three-phase hydrocarbon separators, and introduces the notion of tomometry, meaning multipoint cross-sectional metering aiming to acquire information on the cross-sectional flow-component distribution in the process vessel intended for control purposes.*
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1 Introduction

In traditional hydrocarbon production systems, the producing wells are connected into a commingling system, i.e., the manifold or the template manifold, which ensures transportation of the multiphase hydrocarbon mixture, consisting of oil, gas, produced water, and suspended solids, to a topside separation and offloading facility. Usually, the separation process is carried out in several subsequent separator stages, characterized by oversized hardware and an excessive consumption of separation enhancing chemicals. The separation process is mainly controlled by fluid quality monitoring at the separator outputs. The separated produced water emerging from the hydrocarbon flow is either reinjected into the reservoir for production enhancement purposes, i.e., to uphold the well formation pressure, or it is cleaned and subsequently dumped into the sea.

1.1 *Subsurface Separation*

In the North Sea oil industry there is a trend towards enhancing the production from existing oilfields, in addition to exploration of the oilfields that have not been profitable using conventional technology. These are fields with complex reservoir structures, inadequate well pressure, high water content, and production at large water depth and offsets, which involves issues such as hydrate formation, i.e., water combining with free gas to form an ice-like solid given certain combinations of pressure and temperature, and wax formation. These are all potentially capable of decreasing the flow transportation rate. Exploration of such fields is associated with technical difficulties and high cost. In order to facilitate exploration of difficult fields, the industry has started to investigate the possibilities of subsurface separation, which includes downhole and seafloor separation. The prospect of the subsurface separation technology is to separate the multiphase hydrocarbon mixture either downhole or at the sea floor, such that only the separated oil and gas constituents are transported to the topside production facility. Improved separation control strategies and instrumentation are required to enable the subsurface separation technology.

This paper applies to the issue of level interface control and monitoring of seafloor separation installations. Seafloor separation is usually denoted *subsea separation*. It should be mentioned that downhole separation, including instru-

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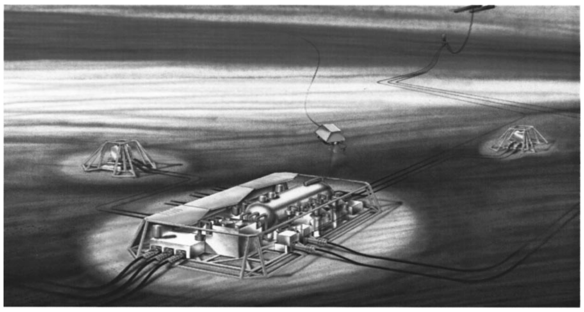


Fig. 1 ABB subsea separation and injection scenario.

mentation, has been investigated by many parties, including Read Well Services[1] and Christian Michelsen Research (CMR).[2]

1.2 *Subsea Separation*

The purpose of subsea separation is to carry out the hydrocarbon separation at an earlier stage in the production chain, thereby obtaining operational and financial benefits:[3,4]

1. The average density of the hydrocarbon production mixture will decrease if the water phase is removed from it. This may increase the amount of recoverable hydrocarbons from the reservoir due to reduced reservoir backpressure by 3%–6%. This effect will increase with water depth.
2. The water component of the hydrocarbon mixture occupies capacity in the downstream production facilities. If the produced water is removed, the spared downstream production capabilities can be used to increase the hydrocarbon production within plateau restrictions.
3. The water phase of the hydrocarbon mixture is the main component in formation of hydrates. By removing the water phase, problems relating to control and removal of hydrates can be minimized, and the pipeline transportation conditions will be improved.
4. Subsea separation can justify hydrocarbon production from marginal fields, since increased liquid takeout rates will result in a shorter production duration when the water phase is removed.

There is a clear indication that there is an economic potential in implementing subsea separation. Calculations carried out for a specific producing field indicate a 15% increase on the net present value.[4] Even though it must be emphasized that this calculation is significantly dependent on the reservoir/field in question, it is evident that subsea separation developments are feasible from an economic point of view.

Since 1995 the ABB corporation has developed a subsea separation facility called the subsea separation and injection system (SUBSIS). Figure 1 shows an artists impression of the ABB subsea separation station.[3]

The hydrocarbon multiphase mixture flows through the well and manifold structures through to the subsea separator, which is located a short distance downstream of the production manifold outlet. The subsea separator vessel performs separation according to gravity, thereby splitting the oil, water, and gas phases into three product streams, i.e., wet gas, unstabilized crude oil, and produced water. In the SUBSIS scenario the sand content in the flow is assumed to be minimized by choking the production wells, and subsequently minimal amounts of sand will be present in the flow while the well is producing in an active steady state. A sand monitor device is installed in order to survey the actual sand production emerging from the reservoir. With reference to Fig. 2, the separated produced water will flow through an outlet at the bottom of the gravity separator in front of the installed weir plate, as seen from the inlet.

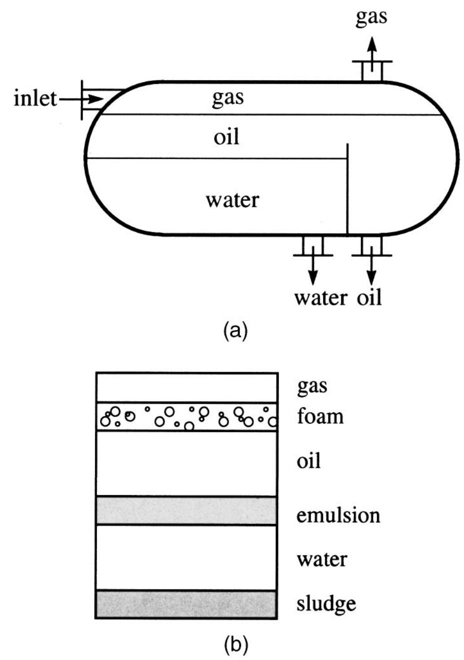


Fig. 2 Schematic illustration of a three-phase hydrocarbon production separator and its phase distribution.

The produced water is intended either to be dumped to ambient sea water or reinjected to the reservoir formation via a predrilled well structure. Typically, the oil content in the produced water out of the separator vessel will be in the range of 1000 ppm. In order for the produced water to be discharged directly to the sea it must be cleaned, e.g., by using hydrocyclones. If the produced water is to be dumped to the sea there is at present, e.g., in Norway and in the U.K., a maximum allowed oil contamination of the produced water of 40 ppm dispersed oil in the produced water, as an average over a one month period. In the U.S. this value is 28 ppm all of hydrocarbon constituents included, i.e., both dissolved and dispersed oil. When the produced water is to be reinjected to the reservoir, reservoir experts suggest that the oil contamination of the produced water must be less than 1000–2000 ppm (dependent on reservoir conditions), in order to avoid clogging of the porous reinjection reservoir rock structure, making further injection of water impossible. It is, however, obviously of interest to keep the oil content in the separated produced water as low as possible due to the fiscal value of the remaining hydrocarbons in the produced water. Some typical subsea sepa-

Table 1 Typical subsea separator design requirements.

Issue	Requirement / Comment
Water depth	$\approx$ 350 m, to be increased to 1500 m
Pressure	Typically 250 bara design pressure
Ambient temperature	Seawater ($\approx$4 °C)
Liquid temperature	Ranging from 50 to 120 °C (Typical design temperature is 100 °C)
Water cut	30%–90%
Flow rate	Typically 10.000–15.000 Sm^3/D (standard m^3 per day) (62.500–93750 bbl/day)
Stepout distance	Typically 10–30 km, i.e., the distance from the subsea separation station to the topside processing and/or offloading facility
Fluid	Hydrocarbon production constituents, including gas, crude oil (dispersed and dissolved), produced water, sand particles, and production chemicals
Flow component properties: density (ρ), relative permittivity (ε_r) and conductivity (σ)[a]	Produced water: $\rho \approx 0.98\,\mathrm{g\,cm^{-3}}$, $\varepsilon_r \approx 70$, $\sigma \approx 5\,\mathrm{S\,m^{-1}}$ Crude oil: $\rho \approx 0.83\,\mathrm{g\,cm^{-3}}$, $\varepsilon_r \approx 2.0$, $\sigma \approx 10^{-6}\,S\,m^{-1}$ Gas: $\rho \approx 0.00\,\mathrm{g\,cm^{-3}}$, $\varepsilon_r \approx 1.0$, $\sigma \approx 0\,\mathrm{S\,m^{-1}}$
Flow component thermal conductivity (λ) and velocity of sound (c)[b]	Produced water: $\lambda \approx 0.68\,\mathrm{W\,K^{-3}}$, $c \approx 1620\,\mathrm{m\,s^{-1}}$ Crude oil: $\lambda \approx 0.12\,\mathrm{W\,K^{-3}}$, $c \approx 1000\,\mathrm{m\,s^{-1}}$ Gas: $\lambda \approx 0.07\,\mathrm{W\,K^{-3}}$, $c \approx 520\,\mathrm{m\,s^{-1}}$
Separator length	Typical 9000 mm
Separator diameter	Typical 3000 mm
Separator wall thickness	Typical 180 mm
Residence time	Approximately 4 min
Typical measurement response time required	20 s, i.e., minimum one measurement every 20 s
Typical level resolution required	100 mm
Electrical interface	To subsea control system. A frequency signal is preferred
Design life	25 years
MTBF	$>$ 100 years (objective)
Maintenance intervals	Minimum 2 years, desirable 4 years

[a]Reference 5.

[b]Reference 6.

ration design requirements and features are as listed in Table 1.[5,6]

Present subsea installations require all interventions to be diverless, and the subsea structure must meet the requirements set for the protection of fishing vessels, i.e., the fishing nets, operating in the area. The subsea separator unit is for all practical purposes not retrievable.

The subsea separation concept places high demand on system performance in comparison to the traditional topside operation. Especially issues relating to system component reliability and mean time between failure (MTBF), maintenance and retrievability/replacement have to be optimized. In addition, a proper redundancy philosophy has to be adopted due to the extremely high cost and long repair time for failing components. The reason behind the extremely high MTBF figures for subsea equipment is due to the fact that subsea system intervention is very complicated, extremely expensive, and at times impossible to perform, e.g., during the winter, due to critical meteorological circumstances.

In 1997 ABB was awarded the first contract for a subsea separator by the Norwegian oil company Norsk Hydro ASA to be installed on the Troll C field. In general, the Troll C Pilot subsea separator design resembles the generic subsea separation station as presented. However, most notably, the Troll C Pilot separator has a common oil/gas outlet, and it features reinjection of produced water to the reservoir via a special water-injection christmas tree mounted on the subsea separator manifold. The Troll C Pilot subsea separation station features two independent-level monitoring systems, a nonintrusive nucleonic-based principle, and an intrusive electrical-based principle using inductive measurements. The subsea separator on the Troll C field was installed in 1999. After a one year test period the experience of the oilfield operator shows that the system is functioning according to specifications with an approximate production of 120 ppm oil in water.[7]

1.3 *Three-Phase Hydrocarbon Separation Process*

Most three-phase separators are based on gravity, relying on the principle that immiscible fluids separate if left to rest with the heaviest fluids collected at the bottom and the lightest fluids at the top of the separator. Figure 2(a) shows an illustration of a generic gravity separator, where the multiphase fluid is injected into the separator to the left, and the three separated phases are taken out at the other end of the separator. Additional to the three main hydrocarbon multiphase mixture constituents, i.e., oil, water, and gas, are unwanted products such as sand or other solids forming a sludge at the bottom of the separator, an emulsion of primarily water and oil, and a foam layer on top of the oil phase, as illustrated in Fig. 2(b).

Due to the diversity and complexity of the hydrocarbon multiphase flow, operational separation problems are common, including formation of foam, emulsion, wax, and scale, in addition to carry-over problems. Presence of foam in the separator can lead to severe operational problems. Since foam has a large volume-to-weight ratio, it can occupy a substantial volume in the separator vessel limiting the space for liquid collecting or gravity settling. In the extreme case it can be impossible to remove the separated gas or degassed oil from the separator without entraining some foam into either the gas or liquid outlets. Foam production can be minimized by injecting an antifoam chemical upstream of the separator inlet. At the interface of the oil phase and produced water phase an accumulation of emulsion usually appears. This accumulation will increase the effective residence time of the hydrocarbon liquid in the separator, and therefore, lead to a lower water–oil separation efficiency. Emulsion-breaking chemicals or heat will minimize this operational problem. Furthermore, accumulation of paraffin on the separator internals can cause severe operational problems inside the separator. In cases where paraffin in known to be a problem, nozzles are installed to allow steam, solvent, or other type of cleaning of the separator internals. To minimize scaling problems in the separator scale-inhibiting chemicals are injected upstream of the separator inlet. Sand production can be very troublesome in some cases, leading to possible cutout of valve trim, plugging of separator internals, and accumulation in the bottom of the separator vessel. Implementation of sand jets and drains are a means to maintain separator operation in a sand-producing scenario. Two other common operating problems are carryover and blowby. In situations where free liquid escapes with the gas phase so-called *carryover* will occur. Usually, it indicates insufficient separator design, damaged separator internals, a high liquid level, presence of foam, plugged separator outlets, and/or exceeded design rate. Likewise, blowby occurs when free gas escapes with the liquid phase. *Blowby* indicates level control failure, a low liquid level, or vortexing in the separator. Another operational problem includes slug flow entering the separator vessel causing wavy liquid interfaces inside the separator. Due to these waves inside the separator the different levels will change continuously and possibly cause the control system to create pulsating flow downstream of the level control valve.

2 Level Control Strategies

The traditional way of operating an oil separator facility has been by detecting the interface levels of produced water and oil, in addition to periodically sampling the produced water output from the separation hardware, in order to determine the oil-in-water fraction. Subsequently, incomplete online process information has resulted in implementation of simple and nonoptimal separator control schemes, providing limited possibilities for accurate real-time separator process optimization. Presently, the oil companies are addressing issues such as increased well-flow liquid rates, mixing of crude oil from different satellite fields, handling of difficult emulsions, limiting consumption of expensive and toxic separation-enhancing production chemicals, production using fewer separation stages, and production directly to transportation and floating production storage and offloading (FPSO) vessels.

There are several ways to improve the efficiency of a hydrocarbon separator, including improved mechanical designs of the separator internals, inlets and outlets, and injection of different hydrocarbon flow-controlling chemicals to minimize the build up of emulsions, foam layers, and scale inside the separator vessel. However, present demands on improving the separator efficiency cannot be fulfilled without also implementing improved control strategies based on representative, reliable, and accurate real-time interface-level instrumentation, providing information on the entire cross section of the separation vessel, i.e., the gas, the foam, the oil, the emulsion, and the produced water levels. In addition, to ensure uninterruptible production, it is important that the implemented instrumentation is easy to install and maintain. Implementation of effective separator-level monitoring instrumentation and process control has the potential of avoiding unnecessary production shutdowns, increasing the production capacity, reducing the consumption of production-enhancing chemicals, e.g., emulsion breakers and foam inhibitors, which are unwanted due to environmental and cost-related issues, and reducing the oil content in the produced water in addition to reducing the water content in the oil.

Figure 3 shows an illustration of the improved control strategy scenario based on implementation of real-time multiphase interface-level information and control.

The separator control system receives information on the interface levels, i.e., the produced water, the emulsion, the oil, the foam, and the gas in the separator, in addition to information on the actual production of sand emerging from the well. Based on control optimization algorithms, the control system sends control signals to the chemical injection unit, the inlet choke valve, the sand flushing

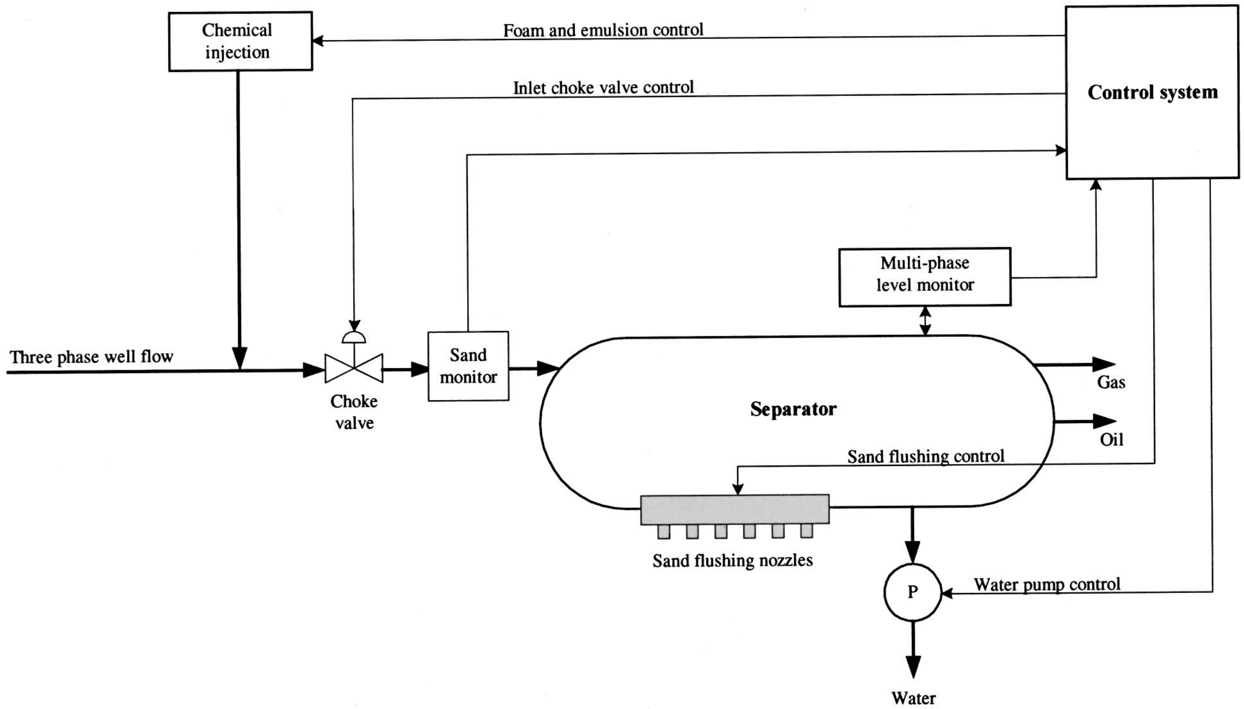


Fig. 3 Improved control strategy using a multiphase-level sensor to enhance separator performance.

nozzles, and the pump at the produced water outlet. The control system is placed either locally at the separator vessel, i.e., subsea, or remotely, i.e., at the production controlling unit, e.g., a platform. Alternatively, the control system can also be divided so that some parts of the control system are placed topside, whereas the remaining parts are placed subsea.

The dynamic response of the control system is a function of the level interface instrumentation response and the computational complexity of the control algorithms. If the control system is placed remotely to the separator vessel the communication delay must also be taken into account concerning the overall system response. The separation process of a hydrocarbon separator operating under normal conditions does not need a fast control system response. Typically, one level interface measurement reading per minute would be sufficient. There are, however, situations which will require a faster dynamic response from the control system, e.g., in situations requiring acid squeeze operations to remove scaling, and cement squeeze operations to seal reservoir formations. Furthermore, during sand-flushing operations, well switching, and appearance of slugs at the separator inlet, a fast response from the control system will be required.

Whereas some of the mentioned operational production situations are planned well in advance, others may emerge unexpectedly. It is, therefore, important that the instrumentation and control system is able to quickly adjust its dynamic response. A dynamic system response ranging from approximately 5 s to 1 min and above is recommended for optimal separator operations.

As an example of the possibilities inherent in improved level interface monitoring and control, Fig. 4 shows level interface data from the Chevron Alba field using the Tracerco Profiler™. The profile of the separator consists of 96 independent measurement channels. The Tracerco Profiler™ is described later in this paper.

- Case A shows separator A on the Chevron Alba field at the time when the Tracerco Profiler™ was first commissioned in September 2000. Significant amounts of produced water are going forward to the coalescers, which are not able to fully handle the situation. There is a significant amount of emulsion above the weir plate.
- Case B shows the result of adding demulsifier chemicals into separator A on the Chevron Alba field at a rate that would cost about £ 500,000 per year per separator. The emulsion layer is visibly smaller, whereas the water level has increased. There is only

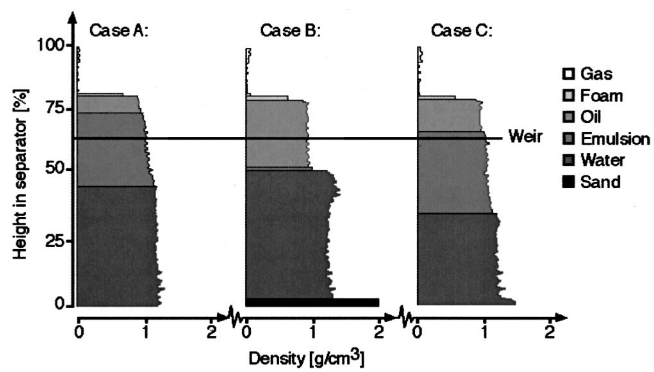


Fig. 4 Case study of level interface monitoring in separator A at the Chevron Alba field using the Tracerco Profiler™.

oil and foam above the weir plate. Since some of the oil is restricted from flowing over the weir plate, the production situation is nonoptimal.

- Case C shows how the information available from the Tracerco Profiler™ made the operators able to control the levels in the separator and pass forward only a small amount of water which could easily be removed by the coalescer, without the need for large amounts of demulsifier chemicals. Note that the emulsion layer is significant, but that only a small portion flows across the weir plate. The entire bulk of separated oil flows across the weir plate.

2.1 *Tomometry*

Implementation of an improved control strategy is fully dependent on representative and accurate level interface measurements. The purpose of the level interface instrumentation is to obtain cross-sectional process information of the separation vessel, where sensitivity is required to all phases, including foam and emulsion.

Cross-sectional monitoring is often associated with *tomography*. A tomography measurement system can be defined as a multipoint cross-sectional imaging measurement principle aiming to acquire cross-sectional information on the distribution of the substances in a measurement volume, e.g., a separation vessel. The output of a tomography measurement system is represented by an image, i.e., *a tomogram*. Although tomographic principles have been investigated for monitoring of separator vessels and found feasible for the purpose, tomography methods are not practically realizable for oilfield operations.[8]

Following the above, even though tomography is not practically applicable concerning level interface instrumentation, it is still of interest to acquire cross-sectional information on the separator process providing process data output. Subsequently, the notion of *tomometry* is introduced. Tomometry is cross-sectional metering of process parameters using multiple measurements. Tomometry covers both intrusive, nonintrusive, and invasive measurements in vessels of any shape and orientation. The notation also includes measurements based on intrusive rods assuming *a priori* information on the process, e.g., the vertical fluid distribution inside a separation vessel. In order to enhance the process information, any combination of cross-sectional measurements can be performed.

3 Recent Level Interface Developments for Subsea Separation

The challenge concerning level interface instrumentation is to develop a robust instrument able to measure all the interface layers, not being disturbed by the rough conditions in the separator vessel, i.e., by formation of scale, wax, sand, etc.

3.1 *Traditional Level Monitoring Instrumentation*

Level monitoring is a classic metering challenge posed to many different industries, and a variety of instruments are available, e.g., for two-phase liquid/vessels ultrasonic level indicators, capacitance level indicators, pressure level indicator, and side-mounting and magnetic float-switch indicators are used.[9,10] However, due to the rough surroundings and high reliability and failure demands, there are presently only a few level-sensing principles in use in the topside oil and gas industry. The two dominating types are displacers and differential pressure sensors, which rely on known densities of the phases. In many cases these principles are sufficient for efficient production. A few other techniques, such as a capacitive rod measuring the dielectric constant of the fluid, microwave radar and ultrasonic techniques measuring the reflection of waves, and gamma-ray attenuation methods measuring the density, are commercially available. The displacer, as well as the differential pressure sensor, is normally located in pipes outside the separator, i.e., in standpipes. To prevent scaling, wax formation, and other clogging, the pipes normally have to be electrically heated, by so-called heat-tracing.

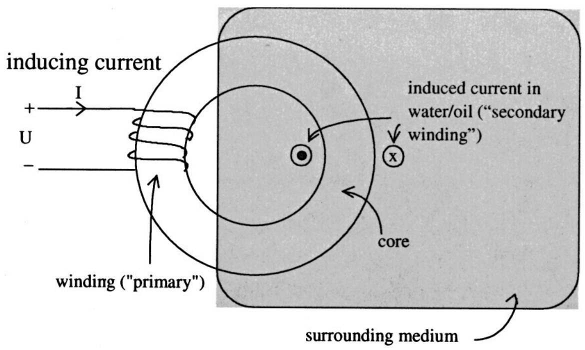
3.2 *Recent Developments in Separator Interface Monitoring*

Alternative measurement principles providing improved level interface information for optimized control purposes include segmented capacitance measurements, inductive measurements, ultrasound measurements, thermal measurements, and nucleonic measurements, as presented next.

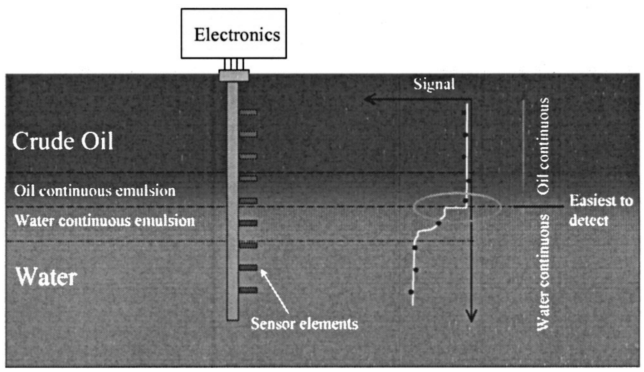
3.2.1 *Segmented capacitance level interface monitoring*

The capacitance measurement principle is based on measurements of the dielectric constant of a medium placed between two capacitive plates. The most common level-monitoring instruments implemented are based on measurements using the separator wall as the reference electrode toward a single sensing electrode vertically placed in the vessel. In order to obtain level interface information in separator vessels, segmented capacitance sensors have been designed and tested.[11–14] In addition, a tomography setup using capacitance sensors has been demonstrated at Christian Michelsen Research.[15] A common problem with capacitance sensors is the presence of water fluids between the electrodes, which will ''short circuit'' the measurement, making the capacitance measurement insensitive to an increased water level between the electrodes.

The most recent development within capacitance level interface monitoring is the advanced profile gauge (APG) by the Norwegian company, Sentech AS.[14] Whereas the conventional segmented capacitance rod monitors are based on measurements between two closely located and well-defined electrodes, the APG is based on only one electrode, i.e., the separator wall is the other electrode. The sensor layout consists of 40 electrodes electrically insulated from the surrounding media positioned vertically along a rod in the separator vessel. Each electrode is equipped with a dedicated integrated oscillator circuit working in the lower 20 MHz range, and the presence of the surrounding fluid causes a change in frequency depending on the dielectric property of the fluid, which is transformed to a volume-averaged value of the dielectric constant of the surrounding fluid.[14] The change in the operating frequency of the oscillator caused by the dielectric constant of the surrounding medium can be measured with a frequency meter. The reported sensitivity of a change in capacitance is in the order of 0.0003 pF with a measuring time of 10 ms.[14]



(a)



(b)

Fig. 5 Schematic illustration of the ILMS sensor principle.

Tests conducted in an atmospheric system at ambient temperature containing salt water, crude oil from the Sleipner field, and air show that the measurement principle can reliably detect the presence of gas, crude oil, and water near the sensor. Formation of emulsion causes the probe to output a measured signal between that of water and crude oil, and the measured signal will vary as a continuous function from the water phase to the crude oil phase, indicating varying water content in the emulsion layer. The measuring system was able to detect the gas/crude oil interface and the crude oil/emulsion interface within ± 20 mm in all the tests. With regard to the emulsion/water interface, this was within ± 20 mm in all but four tests. The accuracy is reported to be within $\pm 10\%$ in all the tests.[14]

The capacitance measurement principle is simple, safe, flexible, and well proven. In addition, the principle is inexpensive. Since the instrument intrudes into the separator vessel, its measurement accuracy will be effected to some degree by wax, scale, etc., forming on the sensor head.

3.2.2 *Inductive level interface monitoring*

An inductive level monitoring principle, the inductive level monitoring system (ILMS), has been developed by ABB based on measurements of electrical conductivity, which is significantly different for oil and produced water. The property of electrical conductivity can be measured in a number of ways. The direct way is to place two electrodes in the medium being measured. This is, however, not feasible due to possible buildup of different kinds of insulating layers in the separator vessel and on the electrodes. An alternative method is to set up an alternating magnetic field which induces a current in the medium as a function of the conductivity of the medium. The operating principle of such an inductive sensor element is shown in Fig. 5(a). In this schematic, a coil wound around a ferrite core has a current I applied to it which sets up a magnetic flux Φ in the core. This flux induces a current in the surrounding medium, the value of which depends on the conductivity of the medium. The induced current causes a counteracting flux in the core, resulting in a lower circuit inductance or, viewed from the source of the current I, in a lower impedance, as shown in Fig. 5(b). Thus, the measurement of the impedance of the sensor element reveals the conductivity of the surrounding medium. The excitation frequency is below 1 MHz.[16]

All the performed experiments and theoretical evaluations consistently prove that the ILMS is capable of measurement in water and water-continuous emulsions. The oil-continuous phase and gas phase, on the other hand, exhibit practically no conductivity. Thus, the ILMS signal does not provide any information on the interfaces in this region, e.g., between oil and gas. Since the ILMS instrument is specifically designed for the Troll C Pilot separator, where the control is designed around the height of the water column in the separator, the ability to measure in the water and water-continuous emulsions is sufficient.

The robustness of the ILMS can be summarized as follows; the sensor elements, i.e., the ferrite cores, of the instrument are in direct contact with the process fluid, and the measurement volumes consist of the volume enclosing each of the ferrite cores. The ferrite core may be covered by relatively thick layers of scale, wax, etc., which may grow over the years of operation, without compromising its ability to detect the level. Even magnetic layers, although very unlikely, would not upset the measurements. This has also been verified experimentally.[16] The instrument tolerates water ingress to some extent even if the stray capacitance does increase due to the high permittivity of water. However, if salt water comes into direct contact with the naked supply wires it will short circuit the entire sensor and ruin the measurements. Providing suitable insulation materials are used, water ingress mechanisms will leave most salt ions outside the barriers and only distilled water will penetrate.

The inductive sensor provides the ability to detect the water phase in both subsea and topside separators. The ultimate goal is, however, to provide a full profile measurement of the separator vessel. This cannot be achieved using the inductive principle alone. Since capacitive principles allow measurement in regions with low conductivity (oil, gas), it is proposed by ABB to develop an instrument combining inductive and capacitive measurements in the same measurement rod layout, providing a possible full separator interface profile readout.[16]

3.2.3 *Level interface monitoring by high-frequency magnetic-field probing*

A novel high-frequency magnetic-field principle is in development at the University of Bergen. The electrical impedance of a coil inserted into a fluid depends on the characteristics of the fluid. If the material is electrically conductive, the impedance of the coil will be reduced due to the eddy currents induced in the material, setting up a

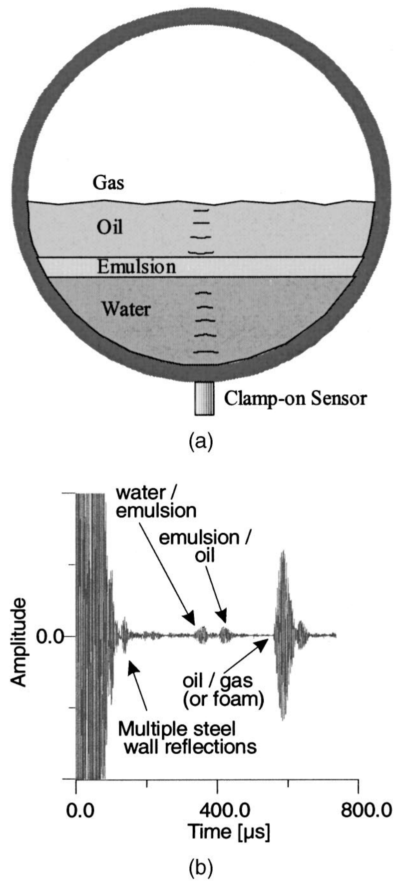


Fig. 6 CMR UID instrument setup with the progress of a typical pulse-echo measurement (see Ref. 18).

magnetic field directed against the field generated by the coil. The impedance will increase but still remain low in the water-continuous water/oil emulsion zone, but will rapidly increase in the oil-continuous oil/water emulsion zone. In pure crude oil the impedance will be high and even higher in gas. Multiple coils are implemented as windings on a ceramic dip pipe, each driven by separate LC oscillators. The exact frequency depends on the exact geometry, but is typically between 8 and 20 MHz. The high frequency is crucial to enable discrimination of oil and gas, and is only obtainable with this coreless coil configuration. The principle has been successfully tested in laboratory experiments with water, oil, and gas. However, it is not yet verified whether the sensitivity of the sensor is sufficient to distinguish foam from gas.[17] The sensor elements of the instrument are in direct contact with the process fluid, and the measurement volume consists of the fluid volume close to the ceramic dip pipe. The instrument is simple, safe, and flexible.

3.2.4 *Ultrasound level detection*

Implementation of ultrasound for detection of interface levels in hydrocarbon separators relies on ultrasonic energy, in the form of mechanical waves or vibrations of frequencies in the range above 20 kHz, being directed into the vessel to be investigated. Due to reflections in the measurement volume, i.e., at the different interface levels of the separator fluid, it is possible to determine the position of the interface levels within the separator vessel based on pulse-echo time-of-flight computations. CMR has developed an ultrasonic level interface monitor based on this principle called ultrasonic interface level detector (UID), where the liquid levels are detected using a single clamp-on sensor attached to the underside of the separator vessel, as shown in Fig. 6(a).[18]

The direction of the UID sensor is perpendicular to the liquid interface, and the unit acts both as transmitter and receiver of acoustic pulses. It is important that there is a good acoustical connection, i.e., a direct mechanical connection, between the UID and the wall of the separator vessel. As mentioned previously, the liquid levels are determined based on *pulse-echo time-of-flight* measurement computations, where the layer thickness l is given by the simple equation

$$l=\frac{ct}{2}. \tag{1}$$

c is the sound velocity of the liquid and t is the measured time of flight of the acoustic pulse traveling back and forth between the boundaries of the liquid.

In a separator vessel there will be multiple ultrasound reflections, i.e., some of the transmitted energy will be reflected back to the receiver at each interface. At the oil/gas interface the remaining ultrasound pulse is almost totally reflected due to the large difference in acoustic impedance between oil and gas, as shown in Fig. 6(b). Since the UID instrument is not in direct contact with the process fluid, problems caused by wax and scale are minimized. Furthermore, the sensor has little sensitivity to changes in the properties of the oil, gas, and produced water, and is relatively simple to install and easy to replace. No calibration is reported necessary.

The disadvantage of the instrument is that it will experience difficulties when monitoring diffuse phase transitions, like that of foam and emulsion. Another critical issue is the fact that ultrasound is attenuated/scattered significantly by gas bubbles in the liquid. In cases when a significant volume of gas is present in the liquid of the separator vessel, e.g., due to pressure relief operations, problems are likely to occur. The gas bubbles have no influence on the monitoring of the water level in the separator, whereas the monitoring of the oil level can be influenced at low pressures. Increased pressure will reduce this effect since the density of the gas bubbles increases with the pressure. Sand buildup will reduce the ultrasound signal amplitude. However, as long as the ultrasound amplitude is sufficient to be detected, the interfaces will be detected with the same sensitivity as prior to the buildup of sand. In cases where the extent of sand build up is significant, the amplitude of the ultrasound wave will be reduced to such an extent that problems in detection of the interfaces will be experienced. The amount of sand that can be tolerated by the sensor functionality is, furthermore, a function of the composition and characteristics of the specific sand deposit.

The UID system has been tested and verified at CMR, Norsk Hydro ASA in Porsgrunn, Norway, Statoil at Kollsnes, Norway, and at the Brage offshore production platform in the North Sea. The test results show that all liquid interfaces can be detected within ± 20–40 mm in a separator vessel with a diameter of 180 cm.[18] During the

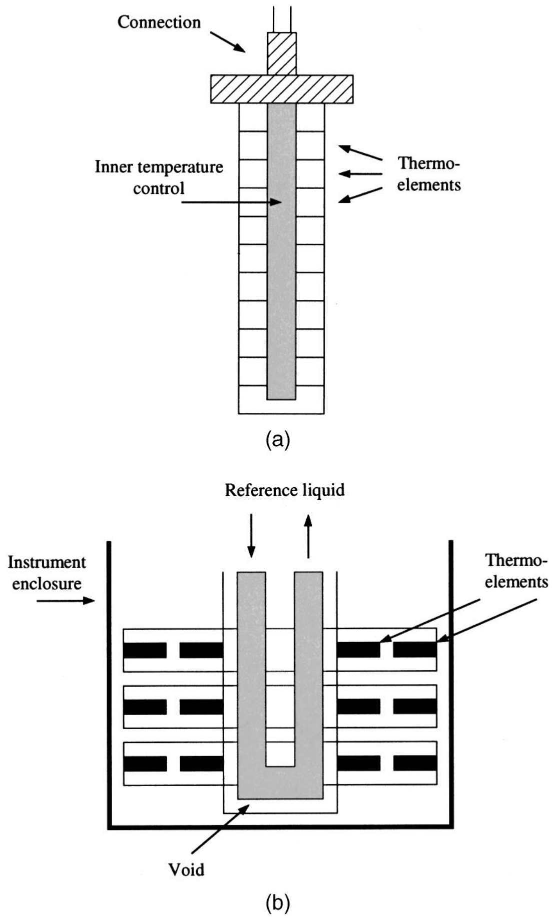


Fig. 7 Tech instrument thermal principle (see Ref. 19).

testing at the Brage field the UID was able to identify the buildup of sand deposits quantitatively by processing the received amplitude of the ultrasound signal. The UID can, therefore, also be used as a sand detector.

3.2.5 *Level detection by thermal measurements*

A thermal level detection principle called the separation profile gauge (SPG) has been under development by Teck Instrument AS in Norway since 1989. The measurement principle is based on measuring the thermal conductivity of the liquid surrounding a thermal sensor installed intrusively into the separator vessel, which is different for oil, water, and gas. The inner part of the instrument assembly, i.e., the dip pipe structure, is kept at a constant temperature by continuously circulating a temperature-controlled reference liquid, as shown in Fig. 7(a). On the outside of the rod there is mounted several thermoelements for measuring the temperature difference between the inner temperature, i.e., the reference temperature, and the temperature at different vertical locations along the rod, i.e., the separator process temperature, as shown in Fig. 7(b). The heat flow from the media in the separator to the reference can be determined either by thermocouples or by fiber-optic temperature measurement, or in order to achieve redundancy, by a combination of both. By stacking several sensor elements together, the different layers within the separator can be determined. The rod will provide protection of the sensing elements, and for heat transfer to the outer element. The rod is made of titanium to sustain the harsh environment within the separator.

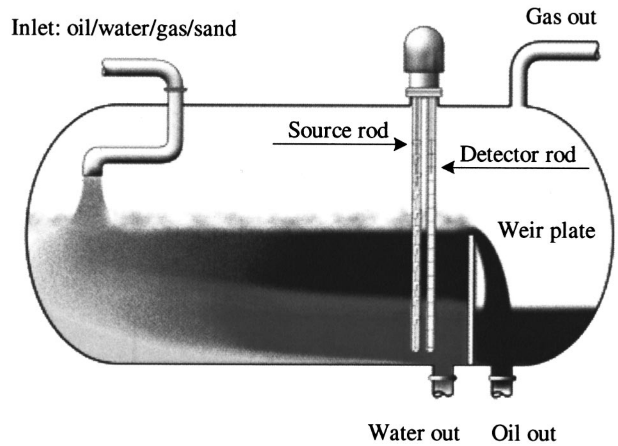


Fig. 8 Tracerco Profiler™ installed in a separator.

The instrument has been tested at the high-pressure facility of Norsk Hydro ASA in Porsgrunn, Norway, and at the Veslefrikk field of Statoil in the North Sea. A commercial version was available in 1997. The instrument can operate in temperatures from −20 to 120 °C, with a maximum design pressure limited by the titanum material of the outer tube to 95 bar. The resolution of the measurement instrument is 20 mm. There is a maximum of 96 separate measurement points over the sensor length, and the measurement response time is less than 10 s. The instrument has a diameter of 50 mm, a length of 4500 mm, weighs approximately 60 kg, and is prepared for subsea installation.[19]

The advantage of the SPG instrument is that it has no moving parts. It is suitable for new and existing separators, and it is relatively simple to install. The disadvantage of the instrument is that, e.g., wax and scale buildup will change the heat-transfer characteristics such that the different phases in the separator will experience a more similar temperature difference between itself and the reference temperature. Also, the instrument is intrusive, expensive, and the issue of a continuously circulating reference liquid is cumbersome. Furthermore, the heat-transfer coefficient will vary with the Reynolds number and the flow rate, i.e., in situations when the residence time for a specific flow component in the separator vessel is shorter than for the others, this will influence the measurement.

3.2.6 *Level interface monitoring by nucleonic density measurements*

ICI Synetix has developed a separator interface instrument based on nucleonic density profiling named the Tracerco Profiler™. A vertical array of low-energy gamma-ray sources emit radiation which is monitored by two vertical arrays of geiger detectors. The process material at each monitoring level attenuates the radiation seen by the detector. The amount of attenuation is approximately related to density. Each detector in the vertical assembly, therefore, provides level interface data which the instrument converts into a density measurement.[20] A schematic illustration of the measurement principle is shown in Fig. 8.

Low-energy gamma-ray ^{241}Am sources are fitted into holes drilled diametrical through a vertical length of steel rod. The rod is fitted into a steel sleeve (collimator) predrilled with two small holes at each source location. These holes give direction to the gamma radiation emitted by each source: one narrow beam of gamma rays is directed upwards at a small positive angle to the horizontal center line through the source; the other narrow beam is directed downwards at a small negative angle to the horizontal. In this way, each source directs radiation to two sensors, one at an elevation immediately above the source and the other at an elevation immediately below the source. The source assembly is secured into a titanium dip pipe that projects into the vessel. An external shutter mechanism allows the collimator to be moved vertically relative to the source rod so that the collimator holes no longer match source elevation when the shutter is moved into the ''closed'' position. With the shutter closed, virtually all the gamma radiation is absorbed by the collimator and the intensity of the radiation penetrating through the titanium dip pipe is below the limit at which access to the dip pipe needs to be controlled.

The interface level instrument can provide a maximum of 96 independent measurement points. For best vertical resolution, 48 sensors are arranged in each of two separate detector assemblies, and each assembly is housed in its own sealed titanium dip pipe. Within each dip pipe, the vertical separation between adjacent geiger sensors is 56 mm, but the column of sensors in one dip pipe is displaced relative to the column of sensors in the other dip pipe so that the dual-dip-pipe assembly provides a separate measurement point every 28 mm. Each radioactive source produces radiation which is directed to a pair of sensors, one immediately above the source elevation, and one (contained in the other dip pipe) immediately below the source elevation.

The geiger detectors are rugged and offer a design life of, typically, 15 years, coupled with high stability and adequate sensitivity. Each detector produces a train of voltage pulses as its output signal. The rate at which these pulses are produced is directly proportional to the intensity of the radiation incident on the sensor, and this is determined by the density of process fluid at the sensor elevation.

The instrument is able to measure the vertical distribution of the various phases in a vessel and provides information on the extent of interphase mixing. Up to 96 individual density measurements are made simultaneously. Accuracy of each density measurement is approximately $\pm 10\ \mathrm{kg\,m^{-3}}$ in the range $0-3000\ \mathrm{kg\,m^{-3}}$. The measurement update period is selectable, typically, 3 s. The vertical resolution is 28 mm minimum. The instrument is easy to install and requires only a single 6 in. vessel nozzle. The instrument has no moving parts, and essentially zero maintenance.[20]

The Tracerco Profiler™ is currently installed at the BP Forties field, the Shell Tern, and at the Chevron Alba field, and has proven to be successful. After a four months testing period at the Chevron Alba field there was no report of maintenance required.[21] The success of the installation has attracted widespread attention in the industry, and a subsea design of the profiler is now being envisaged.

Density profilers have existed in the petrochemical industry for many years, but most of them were unsuitable for offshore use. There were temperature limitations, requirement of cooling fluids, and they were sometimes mechanized, i.e., involving raising and lowering of source and detectors, e.g., the Ohmart system.[22]

Another recent development using nucleonic level monitoring includes the time-of-flight (TOF) instrument by ABB.[3] This system comprises a radioactive source and a detector system based on a scintillator rod having a top- and bottom-mounted tube for detecting the radiation intensity at the different vertical positions on the rod. The density profile inside the separator can be deduced from the time-of-flight information.

Generally, nucleonic level instruments are robust and they measure all the interfaces reliably. They experience low sensitivity to wax and scale deposits due to the large measurement volume, and they can be placed either outside or inside the separator vessel. Due to the presence of potentially hazardous nucleonic radiation, special care must be taken during installation and maintenance. In addition, installation and handling of nucleonic instrumentation is burdened with many regulations and a strict bureaucracy.

4 Conclusions

At present, separator control strategies are extremely simple and based on measurements of a single liquid level. Full production capacity is not utilized, and the quality of the separated phases of the hydrocarbon mixture is nonoptimal. Better understanding of the distribution of the hydrocarbon mixture phases present in the separator using tomometry measurements would allow improved and advanced control strategies for optimal utilization to be adopted, yielding obvious benefits such as:

- more effective utilization of available separator capacity;
- design of smaller, more efficient separators, with lower design safety margins;
- reduced use of chemicals, such as foam-reducing chemicals, which could be injected only when it was evident that foaming was a problem;
- better handling of fluctuations in the inlet flow, e.g., slugging;
- better adaptations to changes in fluid characteristics; and
- better quality of products leaving the separator.

In order to accomplish exploration of oil fields with, e.g., complex reservoir structures, inadequate well pressures, high water contents, and production at large water depths and offsets, the current industry trend is to perform the hydrocarbon separation subsurface, either downhole or at the sea floor, i.e., subsea separation. In order for these installations to be successful the separator control strategy must be significantly improved compared to the present control situation used in topside separators. Improved information on the separator interface layers is needed. Advances in level interface instrumentation must facilitate reliable and accurate monitoring of all the interfaces, including the water, the emulsion, the oil, the foam, and the gas levels, with very high demands set on MTBF and redundancy.

This paper has presented new level interface monitoring developments based on electrical, ultrasonic, thermal, and nucleonic sensing principles. Obviously, there are benefits and limitations of all the presented monitoring principles, and in order to qualitatively compare the presented instruments comparative tests would have to be conducted at a suitable test location, e.g., at the Norsk Hydro ASA test facility in Porsgrunn, Norway. Apart from the UID ultrasound level interface instrument developed by CMR, all the presented level-sensing principles rely on installations in dip pipes intruding into the separator vessel. This is an unwanted, but still acceptable, instrument property for the operators. The nucleonic instrument by ICI Synetix is the only instrument presented in this paper that has demonstrated successful functionality in field tests monitoring the entire cross section of the separator vessel.

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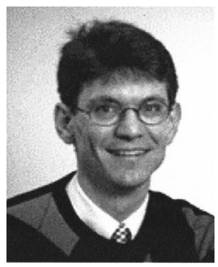

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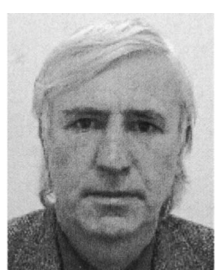

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