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Technical Paper

Title – Multi Phase Flow Meter on all Wells – an Operator's Perspective

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Installing Multiphase Flow Meters (MPFM) on all oil wells in a given field has potential to radically improve production operations - the purpose of this paper is to outline some significant opportunities for improvement, assuming cost effective and adequate MPFM technology will evolve to fulfill this operational aspiration. The following topics are described and substantiated:

MPFM on all wells can result in increased safety in that operators will make less trips to hazardous locations in hazardous vehicles.

MPFM on all wells can also result in increased well and surface production facility integrity due to improved flow assurance, leak detection, chemical injection and unconventional well start-up efficiencies.

MPFM on all wells can result in increased production/increased ultimate recovery due to:
- early detection of underperforming wells;
- real time production and artificial lift optimization;
- improved analysis/understanding of well-to-well interactions;
- early water/gas/steam breakthrough detection;
- improved reservoir models.

MPFM on all wells can result in decreased OPEX due to:
- for all wells a reduction, or elimination of well test services;
- for all wells reduction in manpower and logistics due to increased remote operations;
- for gas lifted wells a reduction in lift gas flow and corresponding reduction in compression load;
- for ESP/PCP wells, run life extensions, resulting in less rig intervention;
- for heavy oil wells a reduction in expensive steam injection.

MPFM on all green field wells can result in CAPEX reduction due to:
- for all wells, elimination of test separators, manifolds and test lines;
- for offshore wells savings in deck space associated with test separators and associated piping;
- for offshore wells, reduced manning resulting in reduced expensive real estate for people accommodation and sustenance.

MPFM on all wells can significantly improve Hydrocarbon Accounting due to continuous flow measurement, rather than occasional well testing.

Introduction

The purpose of this paper is to document the business case for installing MPFMs on all wells in a given field and is so doing quantify the associated business benefits to justify this approach. A literature search revealed few cases of MPFM application to all wells in a given field. However, there are numerous papers describing all well, real time, Virtual Multiphase Flow estimation (VFM). VFM being achieved using well models based on data driven and/or physical modelling approaches. VFM is not as desirable as MPFM in that flows are continuously estimated using models that are refreshed with occasional well tests, whereas with MPFM, flows are directly and continuously measured. Also, VFM models may be slow to reflect physical process changes (e.g. valve wear, scale/wax deposition etc.) and multiphase fluid changes (e.g. water/gas breakout). However, it is premised that VFM gives an indication of the benefits that could be achieved with all well MPFM which should at least achieve similar, if not improved gains. There are also numerous papers describing benefits stemming from real time reservoir, well and surface monitoring and optimization again indicating potential all well MPFM gains. There are also a number of papers describing benefits accruing from MPFMs installed on a well subset in a given field which have been reviewed to determine associated business gains.

The scope of the exercise is from the reservoir sand face to the surface point of sale, covering many common reservoir, well and production types for oil and gas operations onshore and offshore. However, there are some practical considerations for MPFM application:

- brown field applications will predominate because they by far outnumber green field wells;
- onshore brown fields applications will by far outnumber offshore, because there are many more onshore well candidates and it is more cost effective to install and maintain onshore MPFMs;
- there are applications for brown fields offshore topside MPFMs, but it is small compared to onshore candidates;
- subsea brown field wells are unlikely to be MPFM retrofitted because of the sheer cost and installation difficulty;
- it is unlikely that it would be cost effective to install MPFMs on very small e.g. “stripper” wells.

The presumption that brown field, onshore application will predominate implies the following fundamental “ideal” MPFM design requirements:

- device would be low cost to encourage “all well” installation;
- device would be non-intrusive due to high cost of shutting-in wells and operator reluctance to interrupt production;
- device would be scalable to accurately measure oil, water and gas rates for a wide range of flow regimes and changing fluid conditions;
- device would be self-powered as many onshore wells do not have power supplies;
- device would have a wireless output for low cost rapid installation.

This paper is structured into five individual sections describing safety, technical integrity, productivity, operating/capital cost and hydrocarbon accounting. Each section describes the underlying production problems, how MPFM on all wells can help alleviate these problems and substantiation of the associated benefits based on review of available VFM, optimization and MPFM related papers. The following figure graphically depicts the associated MPFM enabled real time systems applications and data flows which are described in the following text.

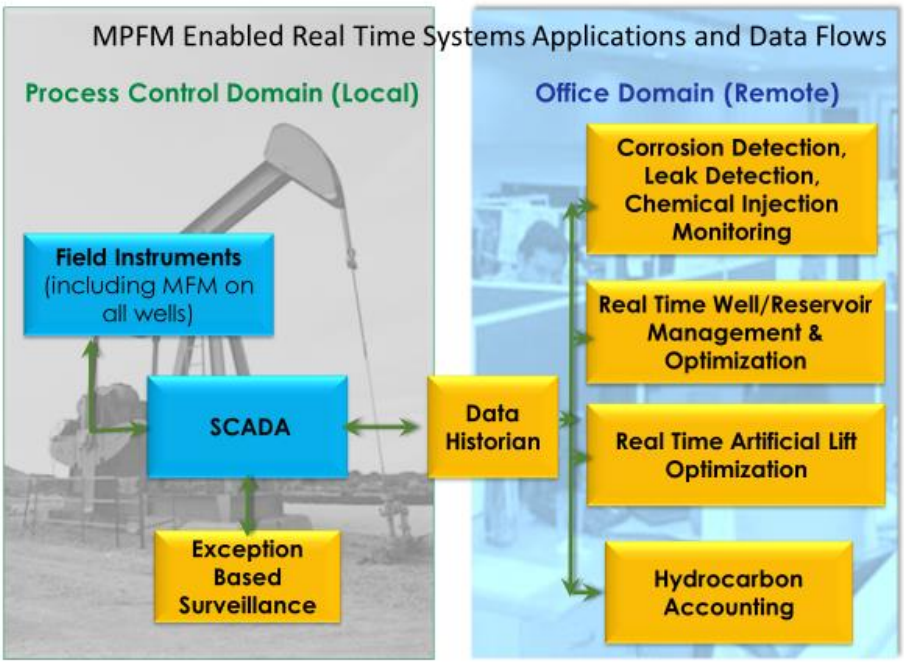

Figure 1, MPFM enabled real time systems applications and data flows

Safety benefits from all well MPFM application

Associated underlying production safety problems:

The traditional means of well surveillance is local, manual and routine – the operator routinely travels to the well e.g. once per day, puts wells on test, checks that wells are running as best they can (touches, feels, listens), takes samples and sends samples to the lab. Ultimately the results reach the office, and it is noted, for example that the water cut has changed. Because water cut sampling can be inaccurate, the office may request re-sampling to confirm. Now, the well water cut may have changed weeks before the first test and it may take further weeks to process and re-confirm with much operator travelling and corresponding exposure to travel and process hazard. With the traditional, manual work process it is difficult to see and understand the changes that are occurring because of the long delays between change detection, which also hampers the understanding of incident cause and effect. Also, because this is a routine process much data is acquired and transferred needlessly as the underlying process may not have changed, or was declining at the expected rates. The net effect is that operators and engineers are swamped with spurious data for processes that have not changed, which makes it harder to detect and understand the items that really have changed and operators are unnecessarily exposed to travel and process hazard.

How MPFM on all wells can alleviate these safety (and surveillance) problems:

MPFM Exception Based Surveillance (EBS) would be much better in that it would be automatically based on acquisition, processing and analysis of the real time process variables, coincident with, or, soon after the changes! MPFM and associated pressure, temperature readings input to SCADA/DCS and changes/trends would be presented to the operator on an exception basis. Hence the operator wellhead visits would be exception-based – no need to go to remote wells that have not changed, no need to put wells on test, no need to take water cut samples, hence less, but, better data, less visits and less exposure to hazard.

Evidence that MPFM can enable safety benefits:
The following paper extracts substantiate the safety case for MPFMs on all wells using VFM as a proxy:
- "VFM enables remote operations with a corresponding travel reduction of up to 20%." (ref 1)
- "Real time remote operations/EBS can lead to a reduction in manpower needed for visiting remote wellhead sites and, with that, much less travelling and exposure to hazards." (Ref 2)
- "In one Shell operation the introduction of VFM has reduced the need for routine operator visits to remote offshore locations in helicopters and/or boats." (Ref 3)
- "Shell operating companies also use VFM to improve safety by providing a continuous indication of liquid flows for all wells. This facilitates well intervention by exception, rather than routine, requiring visits only to those wells that have changed. This process reduces travel and minimizes operator exposure to the hazards of the production process." (Ref 4)
- "Substantial business benefits have been achieved in producing assets by the application of exception based surveillance, collaborative working and integrated operations at onshore and offshore locations. They include increased production, reduced deferment, increased equipment reliability and facility availability, reduced OPEX costs, increased staff work efficiency and reduced HSE exposure." (Ref 5)
- "Enables retaining healthy injection and production rates and helps increase operational safety by minimizing the cases of wrong and dangerous requests caused by human error." (Ref 6)

The following graphic depicts the desired progression to remote operations with correspondingly less operator exposure to hazard.

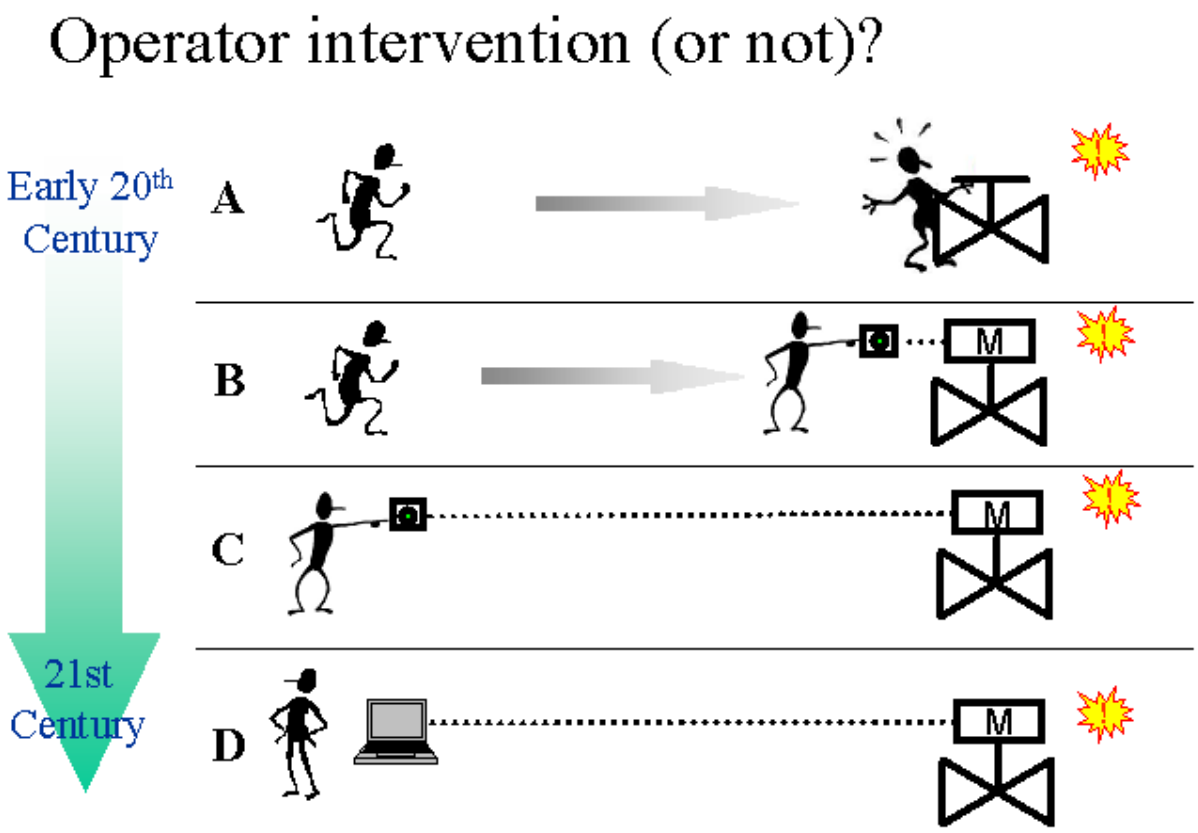

Figure 2 – MPFM enables progression from traditional, routine, manual remote facility visits to safer, more automated remote operations.

Technical Integrity benefits from all well MPFM (and flow line) application

Associated underlying technical integrity problems:

Integrity Problem 1 – proactive corrosion detection
Multiphase flowline fluids may give excessive corrosion/erosion which if undetected can result in loss of containment of flammable fluids and associated hazard to life and property. Corrosion is aggravated by the presence of free water in the multiphase flowing mixture, along with H2S (sulphuric acid and stress corrosion cracking) and CO2 (carbonic acid).

It is crucial that internal line corrosion be detected and remediated prior to containment loss. The presence of internal pipeline corrosion may be detected/estimated by running intelligent pigs through the lines to measure wall thickness loss and the presence of cracks. However, this approach does not work for the myriad of upstream lines that cannot be pigged due to small line size, lack of pig receivers, line impediments, severe line bends, subsea lines etc. Also, pigging is expensive and time consuming and hence is conducted infrequently e.g. once per year – in some cases too late to prevent line leaks. Internal line corrosion also may be detected using periodic (e.g. once per year), ultrasonic testing and/or the use of corrosion coupons. Ultrasonic testing involves the use of an external ultrasonic device to measure the thickness of the pipeline wall — a thinning of the wall indicates the presence of corrosion. A corrosion coupon is a small metal plate placed inside the pipeline and inspected for corrosion say every 6 months. In short, the problem is serious corrosion leading to pipeline failure, which can on occasion occur faster than expected, resulting in catastrophic line ruptures, hence requiring proactive corrosion detection.

Some operators have so many pipelines to monitor that it is difficult to keep the associated corrosion monitoring data up-to-date. Hence, it is desirable to where possible automate the corrosion monitoring process.

Integrity Problem 2 – reactive leak detection
Ideally multiphase flow line corrosion problems are identified prior to leakage, however, if a leak occurs early detection/remediation is highly desirable – the larger the leak the more important it is to detect and remediate as soon as possible to limit environmental and potential fire/explosion damage and/or loss of life.

Integrity Problem 3 – injecting the right amount of flow assurance chemicals
Flow assurance to combat corrosion, scale, wax, ashphaltines, hydrates etc. is achieved by injecting various liquid chemicals into the flow lines. The challenge is to inject the required ppm of chemical into the line when the multiphase line flow rate at a given point in time is unknown. The best that the operator can do is to adjust injection ppm based on the last good well test which may have been months before and in the meantime the multiphase flow and composition may have changed significantly. Ideally the injection rate would change along with changing multiphase flow/composition to maintain the desired chemical ppm.

Integrity Problem 4 – preventing reservoir formation/fracture start up damage for unconventional wells

Ref 7 indicates that an important stage between the end of fracture treatment the start of production is the flowback period. Flowback involves high well drawdown rates to accelerate fracture fluid unloading, sand cleanup and hydrocarbon production. Flawed flowback operation can result in formation and/or fracture damage. Excessive proppant flowback from the fractures is potentially damaging, because it can result in unpropped areas in the near well bore zone. Unpropped areas can subsequently be pinched closed, leading to loss of connection between the well bore and the fracture causing significant production decline, or well failure. The challenge is to optimize flow back operations to mitigate potential fracture connection loss by minimizing the risk of uncontrolled sand flow back and near well bore fracture pinch out.

How MPFM on all wells can alleviate aforementioned well technical integrity problems
MPFM on all wells could result in increased well and surface production facility integrity due to improved flow assurance and leak detection. Real time MPFM flow and composition data could be automatically input to online corrosion models, along with pressure, temperature and H2S/CO2 measurements to alert the onset of corrosion conditions and trigger remedial or inspection actions such as injection of corrosion inhibitors, coupon inspection, ultrasonic wall thickness measurement and flow line pigging. Hence, loss of containment due to corrosion problems may be enabled by automated utilization of real time MPFM multiphase flow and other associated data. Automation of the corrosion monitoring process would also be valuable for operators who are struggling to cope with the avalanche of data and associated data analysis.

If containment is lost, early detection and remediation could limit the loss due to line leaks/ruptures. Fast rupture detection could be achieved by tracking the ratio of MPFM flow and line pressure. On line rupture, the flow will increase due to decrease in back pressure and at the same time the pressure will decrease – this is the “classic” means of single phase rupture detection which could also work for multiphase. Leak detection could also be achieved by tracking the difference between the sum of real time average MPFM well head flow measurements and corresponding bulk flow measurements from the production process (adjusting for shrinkage and pressure differences) – changes in that difference could indicate major leaks. For some vulnerable flowlines it could be expedient to install MPFMs at both ends of the line and track the flow difference – changes in that difference potentially alerting smaller leaks.

More accurate chemical injection could be achieved by tracking the real time ratio of injection chemical flow to MPFM measured fluid flows. Hence, continuously providing the “true” chemical ppm and on MPFM measured multiphase flow changes adjusting injection flows to maintain the required injection rate.

Near well bore fracture during unconventional well start up can be mitigated by utilizing surface real time MPFM readings, along with real time sand and BHP measurements to ensure production within the secure operating-envelope (SOE). Note, the SOE is derived from a combination of data analysis, geo-mechanical modeling and prior experience.

Evidence for MPFM technical integrity enabling – problem 1 proactive corrosion detection:
- Refs 8, 9, 10, 11, 12 indicate potential for upstream, multiphase flow line corrosion model automation to calculate corrosion rate/wall loss and thus assess the corrosion threat in real time. Corrosion models being automatically updated with real time MPFM/VFM and other available real time data such as temperature, pressure etc. The model results could be used for monitoring purposes by providing rapid “traffic light” warnings when a key control variable (such as corrosion rate or wall thickness) breaches

preset limits. This monitoring through corrosion models is particularly useful for assets that may undergo rapid corrosion and/or suffer large changes of corrosion rate due to small changes in operational conditions.

Evidence for MPFM technical integrity enabling – problem 2, reactive leak detection:
Only a little evidence for MPFM/VFM driven multiphase leak detection could be found in the literature, as follows. However, the author has knowledge of a major subsea leak being detected by increasing VFM estimated multiphase flow, coincident with corresponding decrease in line pressure.

- Ref 13 indicates that "a combined leak-detection, gas-composition-tracking system has been developed, installed and operated for two wet-gas pipelines in the North Sea. One system has been operating for almost 3 years with no false leak indications to date. The system is based on a simplified, transient, multi-phase, on-line VFM model. The real time system also estimates the liquid content of the pipeline and informs the operator when the main trunk-line requires pigging to reduce liquid hold-up. The model also provides an estimate of the slug size in front of the pig."

- Ref 14 indicates that "for Gulf of Mexico subsea flowlines theoretically, it is possible to estimate both size and longitudinal location of the leak, by using the two leak detection indicators in the software-based leak-detection method."

- Ref 15 indicates that "in theory for three phase leak detection systems utilizing multiphase flow meters a leak detection threshold of 5% of liquid flow is achievable using a combination of mass balance line pack compensation and pressure point analysis."

- Ref 16 indicates that "Real Time Transient Model (RTTM) performance has been assessed for the Statoil-operated Troll oil pipeline. Leak scenario boundary data sets (pressure, flow and temperature) are calculated by transient simulation of leaks using production data as input. This was accomplished using an Olga pipeline model tuned against production data. RTTM simulations indicate that for the Troll pipeline system with current leak detection thresholds, leaks representing approximately 5 % of the pipeline flow rate are detectable within about two hours of the leak onset. A theoretical assessment based on the API publication 1149 indicates that leaks of this size should be detectable within about 15 minutes."

Evidence for MPFM technical integrity enabling – problem 3, injecting the right amount of corrosion inhibitor:
- Ref 17 indicates that Shell Malaysia Upstream operations offshore have been utilizing a data driven VFM System to support Exception Based Surveillance (EBS) to optimize chemical injection. In the absence of multiphase flow meters, a VFM system is being used for well by well production rate estimation. The VFM System has been extended to provide real time corrosion inhibitor flow monitoring with the aim to track injection rates and keep injection on target, while minimizing excess chemical costs. Within days of the deployment of this real time surveillance tool, high injection rates were detected and adjusted downwards to the correct setting, resulting in significant OPEX savings and the required degree of corrosion protection. Note, elimination of chemical over-injection is also beneficial in that it eliminates the possibility of damage to downstream equipment by harmful chemicals.

Over the same period, detection of low injection has allowed faster adjustments to increase injection and thus minimize corrosion effects to the pipelines. The most significant benefit is injection of

necessary chemical ppm to minimize pipeline corrosion. Over/under injection statistics are shown in the following diagram:

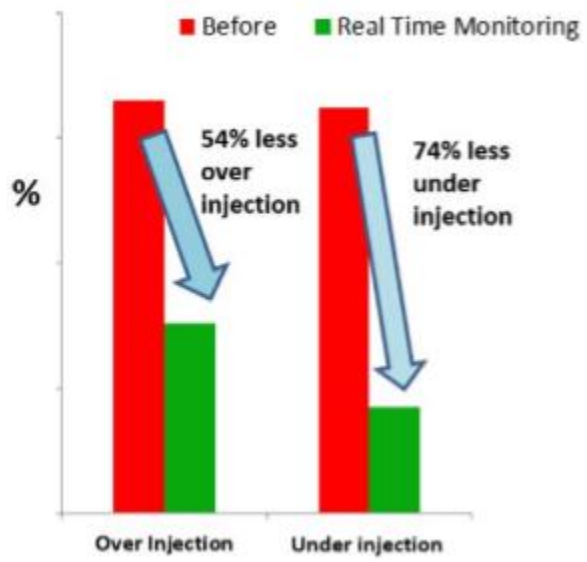

Figure 3 – Reduction in over/under injection of corrosion inhibitor following implementation of a real time VFM based injection monitoring system (ref 17)

Evidence for MPFM technical integrity enabling – problem 4, mitigation of well bore formation/fracture damage in unconventional wells

Ref 7 indicates that during unconventional well start up real time MPFM plus sand and pressure measurements are being effectively utilized to mitigate well bore formation/fracture damage. The following diagram plots BHP vs MPFM and shows that for this unconventional well start-up production was maintained within the required safe operating envelope by adjusting the surface choke.

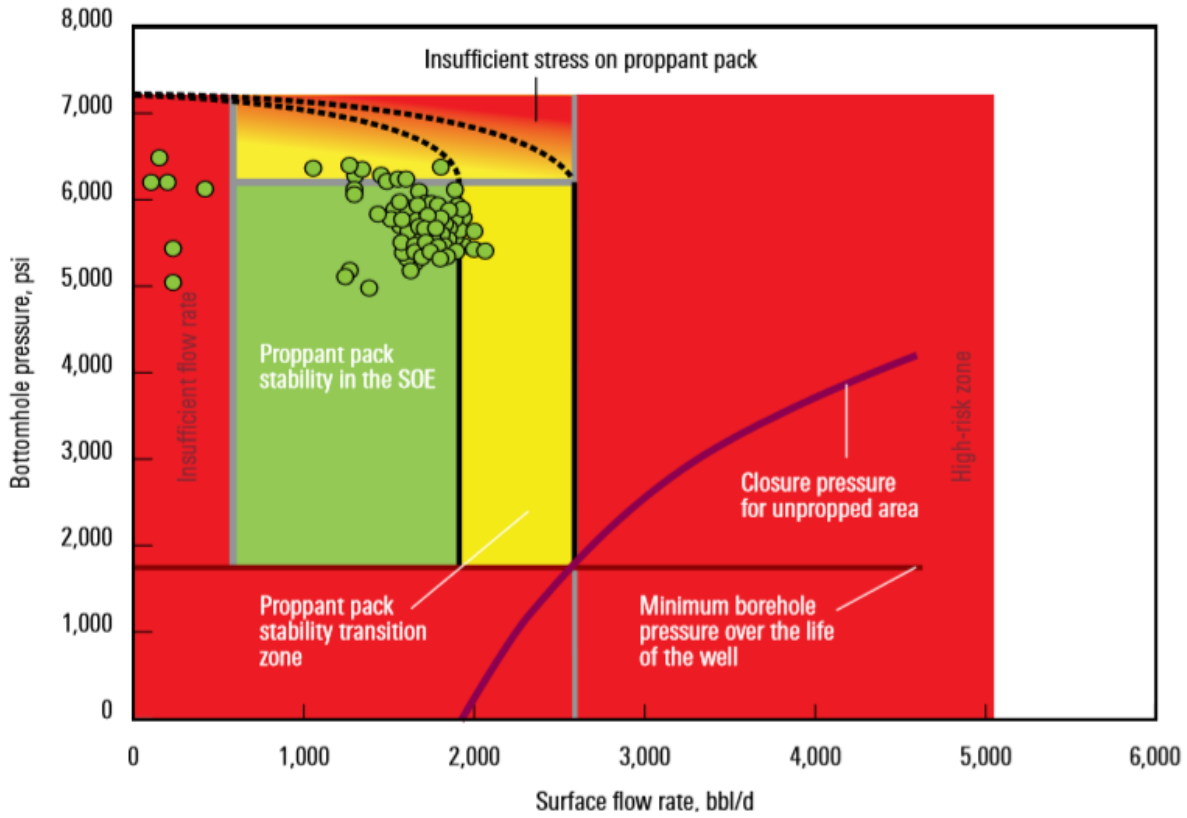

Figure 4 illustrated a well start up safe operating envelope used to ensure performance within that envelope by MPFM rate monitoring and corresponding control of the well head choke (ref 7)

Examples of catastrophic line ruptures – could MPFM have helped?

Example 1 (Ref 18) - Oil had been leaking for five days from a corroded pipeline between facilities at Prudhoe Bay when a worker driving a deserted stretch of road in the oil field noticed a strong petroleum odor and stopped to investigate. Between 1996 and 2004, Prudhoe Bay EP operations suffered 500+ oil spills annually, but this was by far the biggest – 201,000 gallons. The operator had corrosion monitoring/ leak detection barrier systems in-place, but they failed to prevent/mitigate containment loss, resulting in a thick layer of black crude oil that spread covering an area larger than a football field.

The incident investigation (ref 19) revealed that the real time leak detection system was insufficiently sensitive to detect the leak – perhaps the presence of upstream/downstream flow meters would have helped?

The incident investigation also revealed that the corrosion rate had unexpectedly increased, possibly due to increased free water content and decreased throughput – perhaps if an MPFM had been continuously measuring the flow and the water content and automatically sending the results to an online corrosion model an early warning may have been created? Spill photographs follow.

Figure 5 Alaska spill location

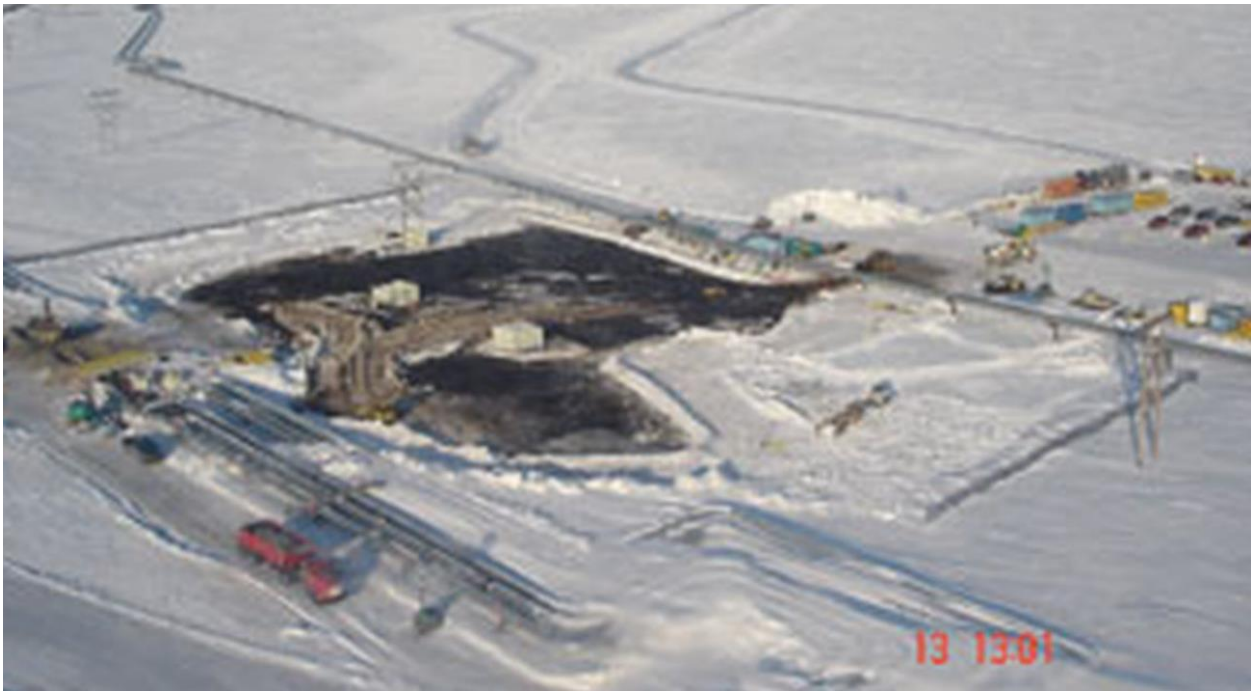

Figure 6 Alaska spill extent

Increased Production/Ultimate Recovery from All Well MPFM Application

The following text describes how all well MPFM can improve real time well surveillance and enable real time well/reservoir optimization. The net effect of sustained improvements will be increased production, decreased decline rate and increased ultimate recovery.

Associated underlying productivity problems:

Problem 1 – Real time surveillance and unscheduled deferments

In the production process work flow each well may have a set target production indicating what the well is expected to produce on a given day. The difference between actual and estimated target production for all wells, corrected for planned outages is known as "unscheduled deferment." In other words, what the operator was targeted to make minus what was actually made.

A critical unscheduled deferment component is earliest possible detection and remediation of wells that stop production and/or are producing less than normal. The traditional way to detect/confirm well problems is by diverting the well flow to a vessel which separates liquid and gas and measures these flows discreetly – so-called "well testing." Wells are normally tested routinely e.g. once per month, or by exception if the operator suspects that a given well looks abnormal. Hence the problem detection time is usually set at the time of the well test – the problem probably started sometime between the latest and the previous well tests leading to unscheduled deferment.

MPFM on all wells would automatically track well oil, gas and water flows, immediately reporting when wells stop, or are producing less than normal allowing the operator to remediate sooner, hence reducing associated unscheduled deferment.

MPFM enabled real time surveillance will also quickly reveal sudden changes in well/reservoir performance such as water/gas breakout and interactive well effects. Faster efforts to mitigate the effects of these “mother nature” incidents, along with decreased unscheduled deferment will result in increased production and increased ultimate recovery.

Problem 2 – real time well/reservoir optimization (RTO)

Prior to real time MPFM data availability, physical well/reservoir models were updated when new well test data became available. However overall optimization did not usually occur until most wells were tested and updated and resulting data entered into models which were run to generate new set points for variables such as well choke settings, ESP speed and gas lift input gas flow– usually once, or twice per annum. Consequently, if there was a significant process change such as a water/gas breakout, well workover, gas lift compressor failure or natural reservoir decline, the production process was inherently sub-optimal. Now, if MPFM data were available for all wells, along with other real time process data (THP, CHP, FLP, bulk flows etc.), it would be possible to adjust the wells much more quickly in response to changing process variables and constraints.

Real time MPFM flow/composition measurements along with other relevant parameters (e.g. pressures, temperatures and single-phase flows) could also be automatically fed to the reservoir simulator by exception and the simulator automatically run on significant changes.

The net effect of this progression towards real time well/reservoir optimization is hypothesized over the life cycle in the following figure. Cumulative “natural” production is shown as the green area. Total production due to periodic optimization is shown as the sum of the green and brown areas. Total production due to real time optimization is shown as the sum of the green, brown and blue areas. The blue shaded area would be the RTO “prize.”

The net RTO effect would be to enable significantly improved well/reservoir management resulting in in reduced reservoir decline and improved ultimate recovery.

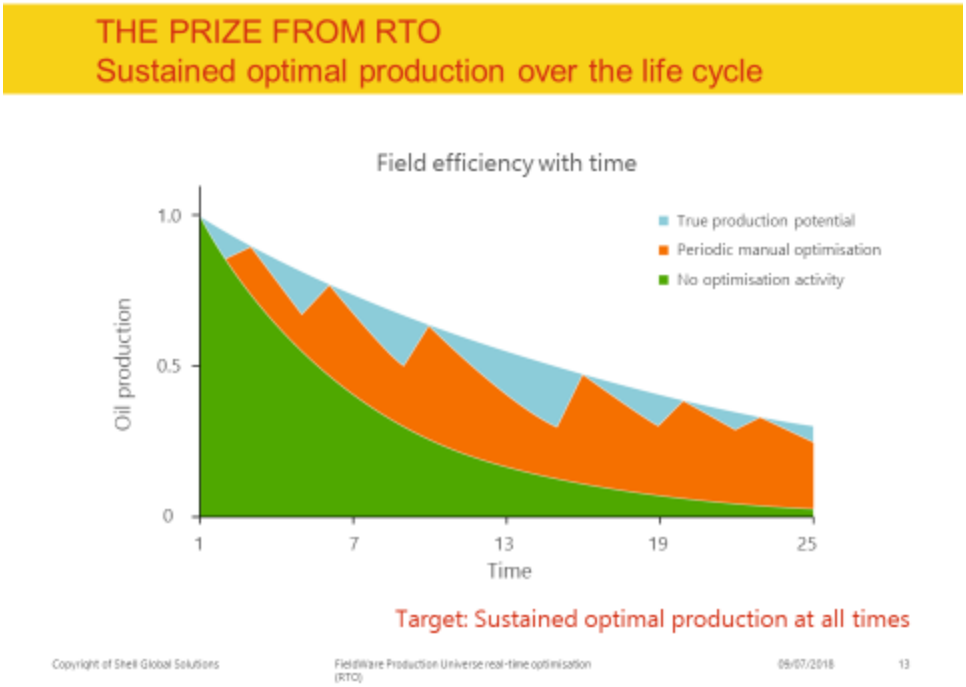

Figure 7 indicating hypothetical field decline with no optimization (shaded green), occasional optimization (shaded brown) and continuous optimization (shaded blue)

Evidence for MPFM/VFM enabled productivity improvement – problem 1 real time surveillance and unscheduled deferment

Ref 20 indicates that VFM models were constructed for all wells in a steam injected field producing 800 m3/d of API 8 bitumen from 100+ beam pumpers. VFM gives real time estimates of oil and water flows for each of the wells during steady state and transient operations. VFM tracks rates when wells are producing steadily, starting-up, closing-in and for transient flow oscillations, resulting in automatic daily reports of total production and unscheduled deferment for each well.

The deferments reports drive an exception-based surveillance (EBS) process by automatically flagging the engineers of the largest production gain opportunities. EBS analysis and associated well remedial actions have resulted in an 8% production gain. The following graphic shows the associated automatic daily report of VFM calculated deferment driving the exception based surveillance process.

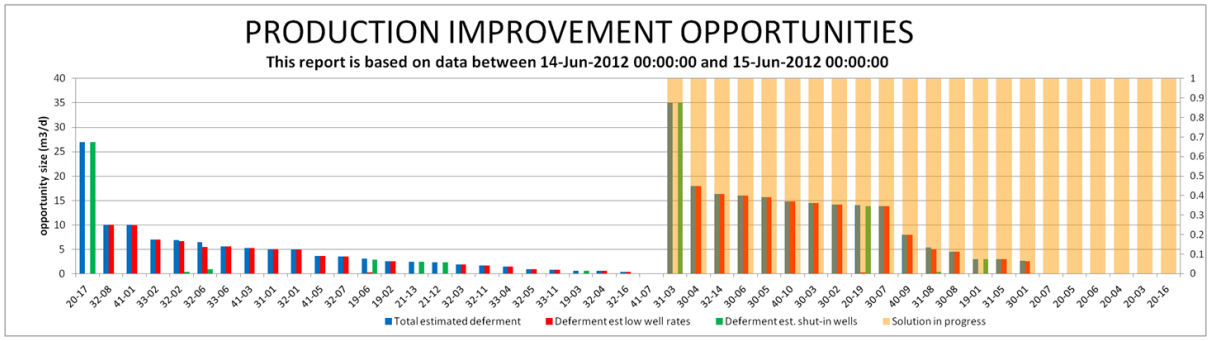

Figure 8 - Example of automatic daily production improvement opportunity chart ranking wells by low and off deferment, and thus flagging largest targets to chase (ref 20)

Ref 1 indicates that improved VFM surveillance could enable up to 5% more production due to early detection of well low and off.

Ref 21 indicates that “MPFM can sound the alarm for early water/gas breakthrough.” Consequently, faster remedial actions can enable reductions in unscheduled deferment.

Evidence for VFM(MPFM) enabled productivity improvement – problem 2 real time optimization

Example 1 Ref 22 indicates that VFM was configured for all gas lifted wells in a South China Sea producing platform. Real time wells flows were automatically input to an online gas lift optimization model which generated optimal set points for gas lift injection to each of the wells for steady state and transient operations. The optimal set points were applied resulting in a 25% reduction is gas lift gas used with no change in oil production as can be seen in figure 9.

Ref 23 indicates that Gas Lift optimization enabled by VFM was sustained over a longer period of time as shown in figure 10. As can be seen subsequent to RTO implementation the field decline rate decreased significantly and was sustained over a number of years.

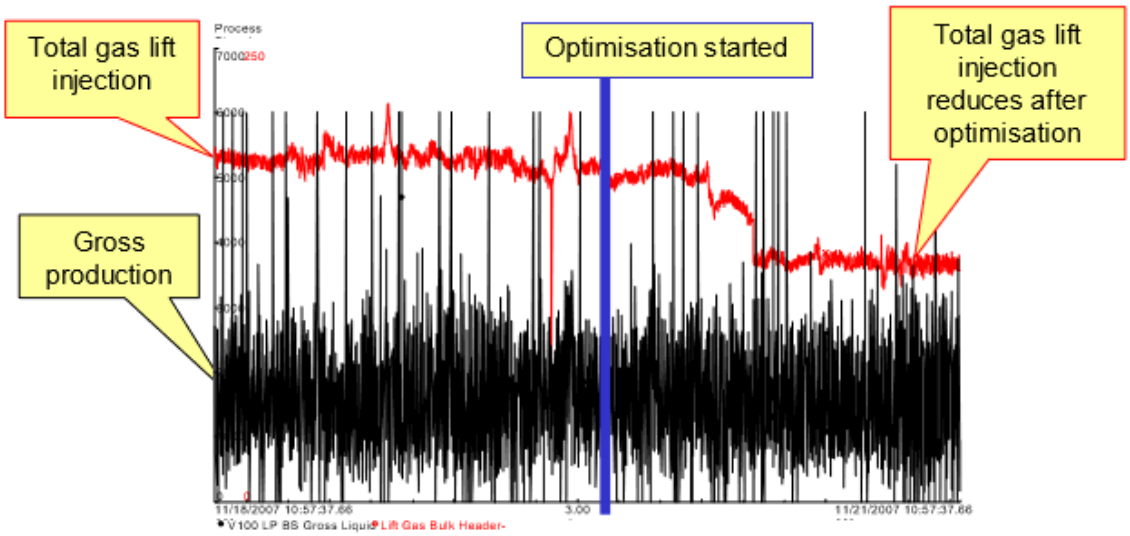

Figure 9 South China Sea gas lifted production platform undergoing VFM driven RTO and showing 25% reduction in gas lift utilization with no change in production (ref 22)

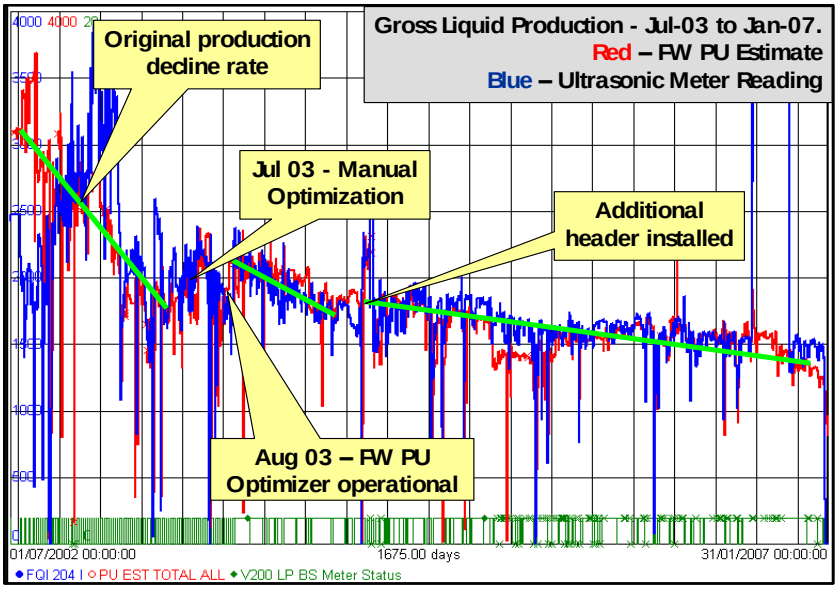

Figure 10 South China Sea gas lifted production platform undergoing VFM driven RTO and showing sustained decrease in production decline (ref 23)

Example 2 Ref 20 indicates that for the aforementioned steam injected field continuous VFM estimation of well bitumen and water flows has allowed real time optimization of the entire field. This is achieved by continuously maximizing production within the plant water handling and economic constraints. The system continuously estimates how much oil and water the wells are producing and recommends rates for each of the wells to maximize production within the water handling capability

Example 3 Ref 24 indicates that "RTO technology as currently applied to an offshore deepwater asset showing early benefits including a 2% production uplift realized from VFM enabled optimizing gas lift allocation and performing a single well routing change recommended by the technology. Furthermore, more reliable rate allocation to wells has improved the quality of subsurface models used for reservoir management."

Example 4 Ref 2 describes improved real time surveillance and RTO in numerous Oman onshore oil fields resulting in Gas-lift operations that are expected to yield up to 5% more oil production, with 10% less lift gas. Beam-pumped production has improved 5% because of faster response time, with a 35% increase in mean time between pump failures. ESP production is expected to increase 3%, with pump life improved.

Decreased OPEX/CAPEX from All Well MPFM Application

All well MPFM OPEX/CAPEX reduction solutions and evidence for these solutions

For all wells a reduction, or elimination of well test services enabled by MPFM
Having an MPFM on all wells in a given field eliminates, or reduces the need for conventional well testing and automates the well test process providing the following OPEX/CAPEX reductions:

- Manpower OPEX savings - no need to travel to remote sites, no need to process/validate well test data, no need to maintain well test equipment;

- Logistics OPEX savings – less helicopters, boats and trucks;
- CAPEX savings - for all green field wells, elimination of test separators, manifolds and test lines;
- CAPEX savings - for offshore green field wells savings in deck space associated with test separators and associated piping;
- CAPEX savings - for offshore wells, reduced manning resulting in reduced expensive real estate for people accommodation and sustenance.

Evidence for savings associated with elimination of well test services
Ref 21 indicates that "Over years prior to 2012 more than 3,000 MPFM rate tests have been conducted yielding significant OPEX savings associated with well testing. MPFMs are also low maintenance cost and that will reduce OPEX. MPFM allows the elimination of test lines to the platform and test separator infrastructure. Adding to the MPFM's advantage is their small offshore footprint, as these meters take up much less space and weight, which is important for offshore environments where space is limited. This is extremely important for economic justification of offshore and marginal projects in that the MPFM's will reduce CAPEX through the elimination of expensive, conventional testing facilities. Also, MPFMs supported the establishment of new and more efficient data acquisition practices including a reduction in samples from 18,000 to 8,000 for 10 offshore/onshore fields with significant OPEX savings."

For all wells reduction in manpower and logistics due to MPFM enabled remote operations
Remote operations is the ability to operate a remote facility from a central control room (CCR) which may be just outside the blast zone, or may be hundreds of miles away from the production site. The main remote operations' objective is to operate the remote production facility unattended, or down-manned, with less staff and associated logistics required for routine operating tasks.

Evidence for savings associated with Remote Operations
Ref. 1 describes a large, 300 gas well, onshore brown field that was refurbished to accommodate remote operations. Benefits achieved included a 60% reduction in field work force due to remote start-up, shut down and adjustment of wells, well testing and process parameters as depicted in the following diagram

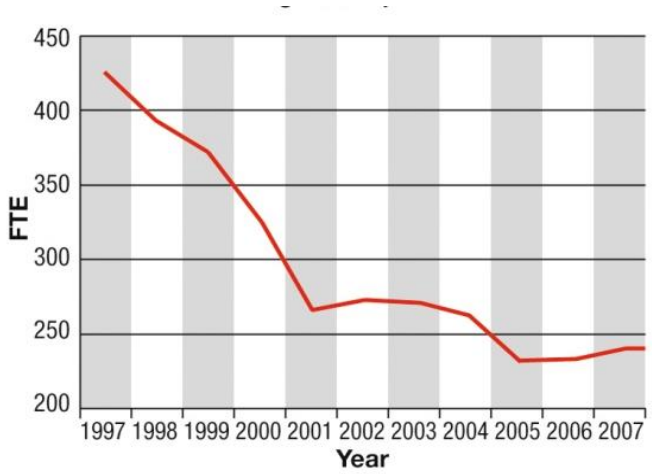

Figure 11 - Staffing Trend vs. Time as the Remote Operations Implementation Progressed and Became Embedded

For gas lifted wells MPFM enables reduction in lift gas flow and corresponding reduction in compression load

For gas lifted wells the shape of production rate vs lift gas flow plot is parabolic with production increasing with increasing lift gas until there is an inflection point and thereafter as lift gas flow is increased production declines. Consequently, in many cases operators inadvertently increase the lift gas flow beyond the inflection point producing less oil with more gas.

Evidence for OPEX savings associated with gas lifted wells

Ref 22 indicates that VFM was configured for all gas lifted wells in a South China Sea producing platform. Real time wells flows were automatically input to an online gas lift optimization model which generated optimal set points for gas lift injection to each wells for steady state and transient operations. The optimal set points were applied resulting in a 25% reduction is gas lift gas used with no change in oil production as can be seen in figure 9. The reduction in lift gas used enables gas compression OPEX savings – where multiple compressors are in use it may be possible to eliminate one.

Ref 23 indicates that Gas Lift optimization enabled by VFM was sustained over a longer period of time as shown in figure 10. The sustained reduction in lift gas implies a corresponding reduction in OPEX associated with gas lift compression costs.

For ESP (PCP) wells, MPFM enabled run life extensions, resulting in less rig intervention

Electrical Submersible Pump (ESP), are multistage, downhole centrifugal pumps used for oil well artificial lift with flow rates ranging from 150 B/D to 150,000 B/D. A major ESP OPEX factor is the cost of rig-pulling operations and lost production that occur when correcting downhole failures, especially in an offshore environment.

Evidence for OPEX savings associated with ESP/PCP wells

Ref 21 indicates that "MPFM enables further optimization of ESP well's performance which in turn improves the sweep efficiency of the reservoir, accelerates production of recoverable reserves and helps improve pump run life."

For thermal heavy oil wells, a reduction in expensive steam injection enabled by MPFM

A major production technique for heavy oil production is Steam Assisted Gravity Drainage. SAGD involves injecting high-temperature steam underground through a horizontal injection well to melt the bitumen, allowing it to flow to an adjacent horizontal production well. SAGD is operating cost intensive with steam cost being more than 60% of the total OPEX.

Accurate MPFM wellhead oil flow measurement is critical for production optimization in terms of producing the maximum quantity of oil while simultaneously injecting the minimum steam flow and also to enable detection of steam breakout in the reservoir from injection to production wells.

Evidence for savings associated with more efficient steam injection

Ref 25 indicates that for thermal operations steam injection could be reduced throughout the field by about 8% with no impact on production, and steam re-distribution from over-injected patterns to under-injected patterns could increase oil production by 10%.

Hydrocarbon Accounting (HAC) Benefits from all well VFM applications

HAC process description and underlying HAC flaws

Hydrocarbon Accounting is a critical business system used to prepare, report and store reconciled/ allocated well production data for fiscal, audit and reporting purposes. HAC also provides volumetric input to reservoir simulators which in turn are used to make decisions regarding future field developments and to track and record reservoir reserves. The concept of adjusting the individual conduit volumes (based on well tests and estimated well uptime) such that their sum equals that of the related fiscal measurements is called allocation. The main Hydrocarbon Accounting KPI is the allocation factor which is the ratio of the sum of individual well test measured (adjusted for estimated uptime) conduit volumes to the associated fiscal volume measurement for a given month.

The main flaw in this "traditional" hydrocarbon accounting process is the assumption that the well flow during well testing (approx. 1% of the time) is identically equal to the well flow when the well is not being tested (approx. 99% of the time). This assumption is questionable for many reasons as described in ref 26. Another source of inaccuracy is the estimated well uptime, as mentioned previously traditionally well stops and low production are detected when the well is tested – the problem may have occurred many days before!

The effects of all of the aforementioned flaws can be mitigated using techniques that provide continuous estimation (VFM), even better continuous measurement (MPFM) of well flow rates.

Evidence for VFM enabled HAC improvement

Example 1 Ref 27 describes a North Sea offshore platform producing 50,000 boe/d per day from 33 wells and two subsea tiebacks. Well three phase flow was traditionally measured via periodic routing of wells to a test separator with well production "interpolated" from test to test. VFM was adopted to give continuous three phase flow estimates for all of the wells all of the time – tantamount to a "virtual" 3 phase MPFM for each well. This data has been used to perform daily allocation in which the sum of the VFM well estimates is divided by the overall platform oil production rate to derive the allocation factor. Allocation factors were also calculated on a daily basis from well tests, adjusted by well uptime and then summed across all wells and divided by overall platform oil production rate. The following figure 12 illustrates a snapshot of the allocation factors as derived by continuous VFM and discontinuous well test methods. As can be seen VFM provides a fairly stable average value of the allocation factor in the region of 1.0, whereas the well test method is relatively unstable and averages about .88 on the low side.

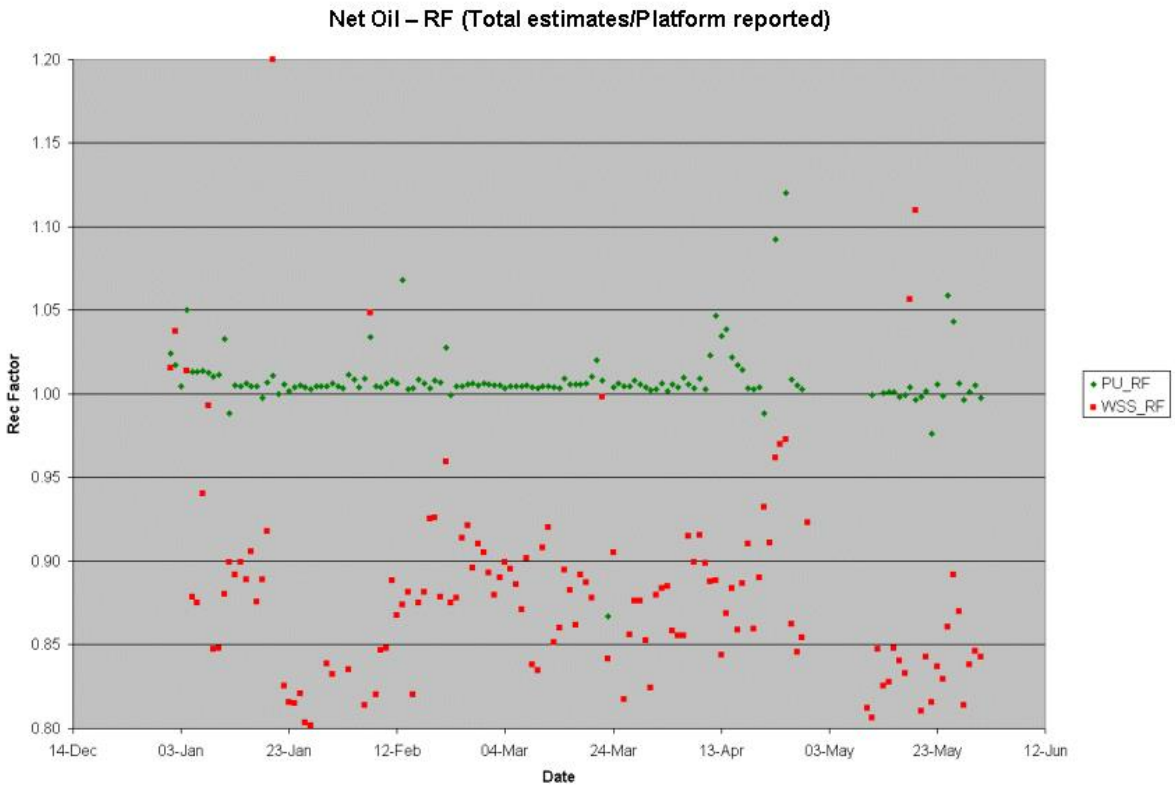

Figure 12 Six month trends of allocation factor computed using discontinuous well tests (red pen) and continuous VFM based well flow estimates (green pen) – Ref 26

Example 2 Ref 27 also describes an FPSO offshore West Africa with daily production rates of 200,000 bopd from 13 subsea wells. Hydrocarbon accounting and allocation was initially achieved using the "traditional" approach – that is monthly, discontinuous and based on well tests and interrupt times. In this case the well interrupt times were determined from real time pressure readings, obtained from the subsea and FPSO DCS control systems and hence reasonably accurate. Continuous allocation based on continuous flow estimation (oil, gas and water) was installed and commissioned. The following figure 13 shows a two-year comparison of allocation performed the "old" way (discontinuous and based on well tests) and the "new" way (continuous, using VFM). As can be seen in this case the "old" method gave allocation factors which erred 4% on the high side, whereas the "new" method averaged .05% on the low side – a considerable improvement

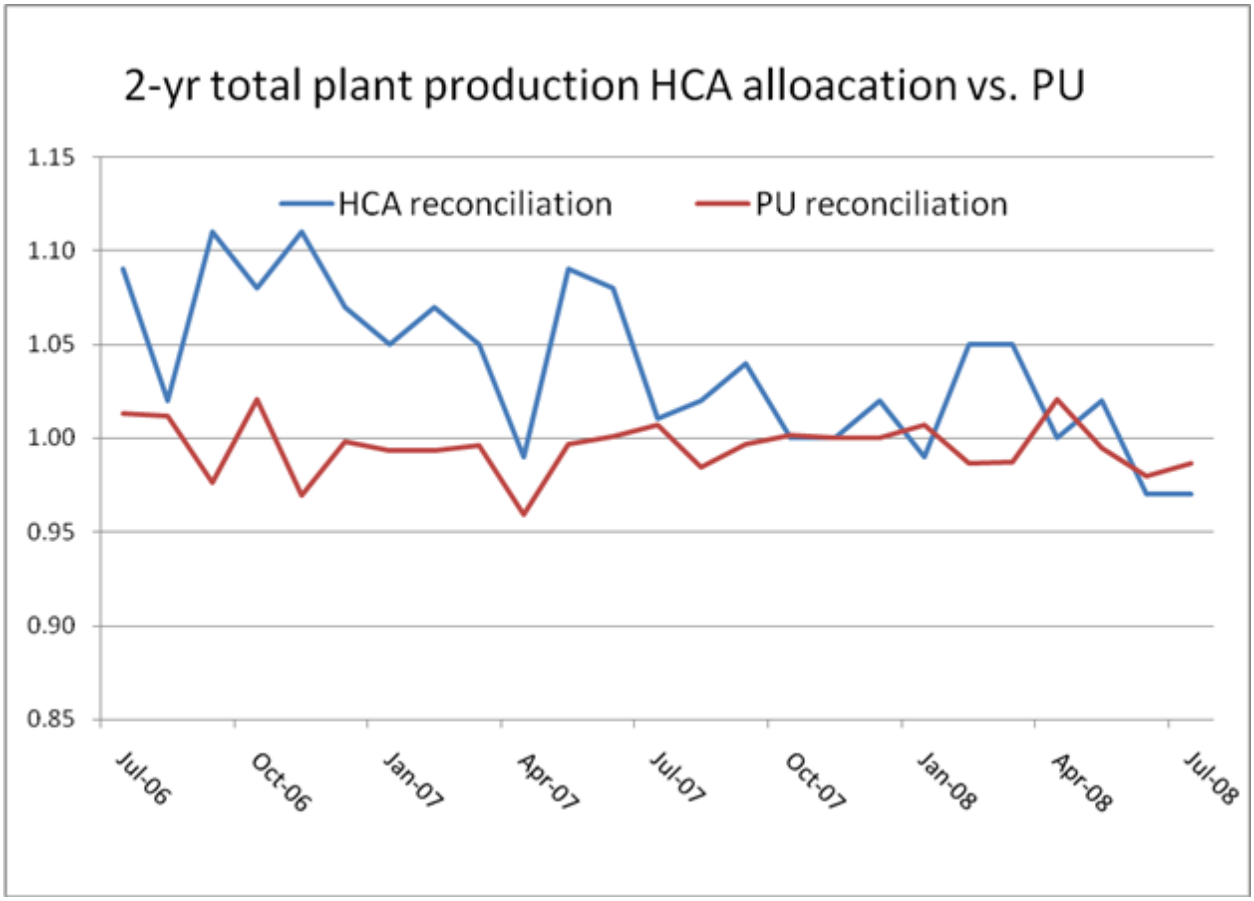

Figure 13 Twelve month trends of allocation factor computed using discontinuous well tests (blue pen) and continuous FW PU based well flow estimates (red pen) – Ref 16

Example 3 Ref 28 describes HAC process for the Atlantis production platform in the Gulf of Mexico. It is reported that the traditional allocation process using well tests and manual determination of downtime led to +/- 10% error. Use of real time VFM to calculate well flows has enabled an allocation improvement with accuracy of +/-3% error using the new method.

Conclusions

There is a compelling business case for installing and sustaining MPFM on all wells in a given field. This paper describes the following significant safety, integrity, productivity, OPEX and accounting benefits:

i) Safety

- MPFM enables remote operations such that operator travel in helicopters, boats and trucks could be reduced by up to 20%.
- Operators would be less exposed to the hazards associated with proximity to surface oil and gas production processes.

ii) Technical integrity

- MPFM enabled, automated, online corrosion monitoring can pre-empte loss of containment and ensure that all critical pipelines are continuously monitored using minimal bureaucracy.

- MPFM enables real time leak detection by tracking pipeline flow/pressure rate of change and flow-in, flow-out differences, changes of which could give early containment loss warnings.
- MPFM enables more efficient pipeline chemical injection by real time tracking and advisory control of injected chemical ppm – one operating company reported 50% less over injection and 70% less under injection.
- MPFM helps prevent reservoir formation/fracture damage during unconventional well start up by real time monitoring and control of operations within the allowable safe production envelope

iii) Increased production/increased ultimate recovery
- MPFM can enable up to 8% decrease in unscheduled deferments due to VFM early detection/ remediation of well stops and low production.
- MPFM can quickly flag early water/gas breakthrough, leading to faster remedial actions and consequent reductions in unscheduled deferment.
- MPFM could also enable RTO and corresponding production increase. For gas lift 5% production increase was reported using up to 10% less gas lift. It was also reported that subsequent to RTO/VFM implementation field decline rate decreased significantly over a number of years.

iv) CAPEX/OPEX savings
- It was reported that MPFM can eliminate the need for well testing and associated separation/ manifold/piping equipment thus enabling significant CAPEX/OPEX savings.
- It was reported that MPFM utilization leads to improved ESP surveillance resulting in increased run life and decreased OPEX due to reduction in rig tube-pulling operations.
- RTO leads to decreased gas lift to lift the same, or more oil resulting in OPEX savings due to decreased gas compression.

v) Hydrocarbon Accounting
It was reported that MPFM enabled Hydrocarbon Accounting could increase the accuracy (allocation factor) by more than 5%.

MPFM enabled automation of the above processes could also lead to "getting the right information to the right people, at the right time, in the right context/format." Thus allowing engineers to spend less time looking and more time analyzing data, with less bureaucracy.

In lieu of available MPFM information, the above multiphase flow tracking benefits are mainly based on VFM as an MPFM proxy, based on a literature search. Note it is possible that benefit from MPFM on all wells could exceed that from VFM which is based on infrequent well tests masking change effects, whereas MPFM should see significant process changes immediately.

Abbreviations
BHP – Bottom Hole Pressure
Bopd – Barrels of oil per day
CCR – Central Control Room
CO2 – Carbon Dioxide
CHP – Casing Head Pressure
DCS – Distributed Control System
EBS – Exception Based Surveillance
FLP – Flow Line Pressure
HAC – Hydrocarbon Accounting

H2S – Hydrogen Sulphide
HSE – Health, Safety, Environment
KPI – Key Performance Indicator
MPFM – Multiphase Flow Meter (on all wells in a given field)
OPEX – Operating Expenditure
PIMS – Production Integrity Management System
PPM – Part Per Million
RTTM - Real Time Transient Model
SAGD – Steam Assisted Gravity Drainage
SCADA – Supervisory Control and Data Acquisition
SOE – Secure Operating Envelope
THP – Tubing Head Pressure
VFM – Virtual Flow Meter

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