KRNACRI100085

A Report to

MMS

for

Downhole Commingling Research

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September 30, 2010

Knowledge Reservoir
Document Control Sheet

Document Title:

MMS – DOWNHOLE COMMINGLING RESEARCH

Document and Revision Number:	Total Number of Pages:
KRNACRI100085-004FR_REV1	**52**

Comments: Issuance of Final Report

1	09/30/2010	Final Report Incorporating Feedback from Client	R. Sankar 9/24/10	S. Knabe 9/28/10	S. Knabe 9/30/10
N.A.	09/10/2010	Draft Final Report to Client	R. Sankar 8/20/10	S. Knabe 9/7/10	S. Knabe 9/10/10
Revision	**Date**	**Reason For Issue**	**Prepared**	**Checked**	**Approved**

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1 Management Summary

This report covers the results of the “Downhole Commingling Research Project” conducted for the Minerals Management Survey by Knowledge Reservoir.

Commingling in oil and gas wells refers to the simultaneous production of hydrocarbon from multiple reservoirs through a single production conduit.

The traditional methods of exploiting multiple reservoirs from one wellbore are to either:

- Develop the reservoirs sequentially from the bottom up (Figure 1), or
- Use multi-string completions to maintain segregation

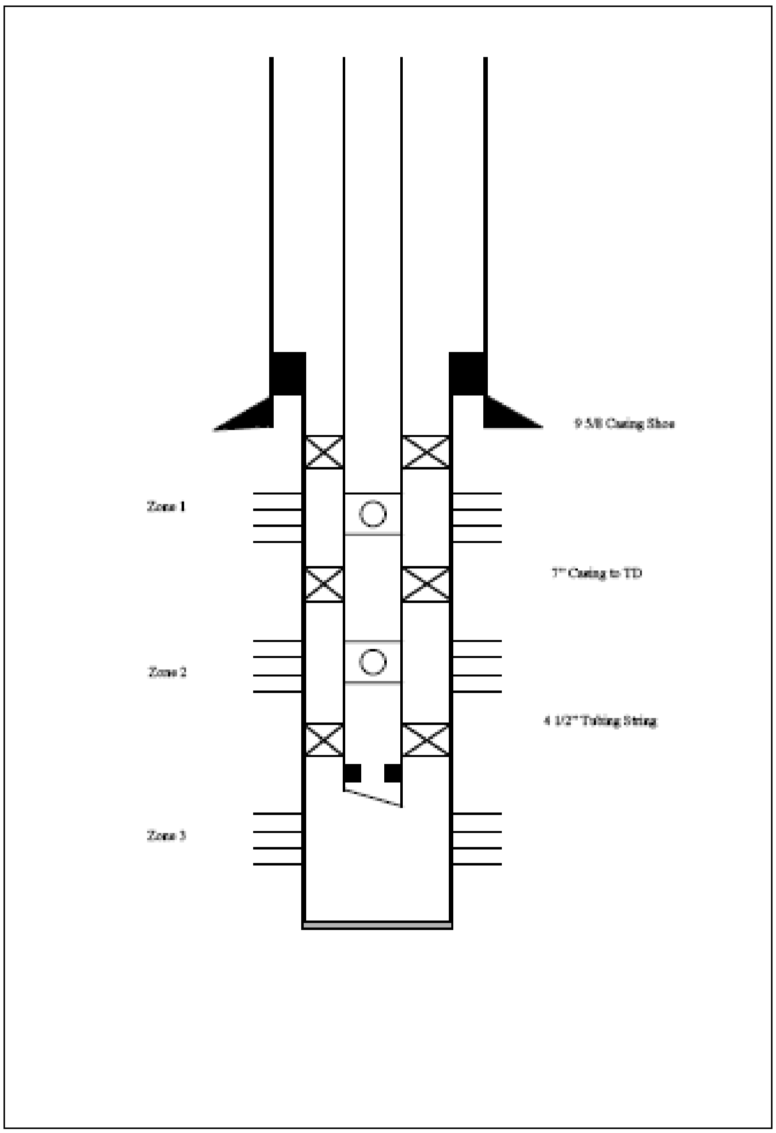

Figure 1: 3-reservoir conventional well completion with mechanically operated sliding sleeves (SPE 85677 figure 3B)

The disadvantages of the first method, sequential development of reservoirs from the bottom up, are:

- The long time needed to exploit all the reservoirs and the resulting negative impact on peak production and economics
- The sequencing of production and cementing off of lower reservoirs to tap into virgin upper reservoir may complicate or preclude use of secondary or tertiary recovery methods with the potential to improve ultimate recovery.

The disadvantage of the second method (multi-string completions) is that productivity from the individual reservoirs and from the well in total can be restricted because the size of the tubing is limited by the size of the casing. In principle casing size can be increased to accommodate the larger tubing required for optimum production, but this is costly in deeper wells.

When two reservoirs are commingled in an uncontrolled fashion, the reservoirs are likely to produce in a sub-optimum manner due to differences in pressure, productivity index (PI), gas-oil-ratio (GOR), and water production. One reservoir may crossflow into another, and gas or water breakthrough in one reservoir may limit the oil production in the other, reducing ultimate recoveries. These concerns are documented in Section 3 of this report.

Notwithstanding these concerns, commingling multiple reservoirs using conventional technology has been successful in largely depleted, closely adjacent reservoirs of similar fluid compositions, drive mechanisms and depth-adjusted pressure, e.g. in later stages of production in Lake Maracaibo in Venezuela and the Austin Chalk, Buda and Georgetown formations in Southeast Texas. In Lake Maracaibo, production of the combined reservoirs appeared to approximate the sum of the individual production of each reservoir based on comparison of commingled and non-commingled wells[1].

The situations noted above where commingling can be carried out without control (reservoirs in the decline stage with similar fluid compositions, drive mechanisms and depth-adjusted pressures) are not very common in new field developments in the Gulf of Mexico. In wells tapping into virgin reservoirs where fluid compositions, drive mechanisms and depth-adjusted pressures vary significantly or where only limited reservoir data are available, controlled commingling using intelligent completions (Figure 2) is recommended as discussed in detail in this report.

Knowledge Reservoir would like to thank the Minerals Management Service for the opportunity to carry out this study.

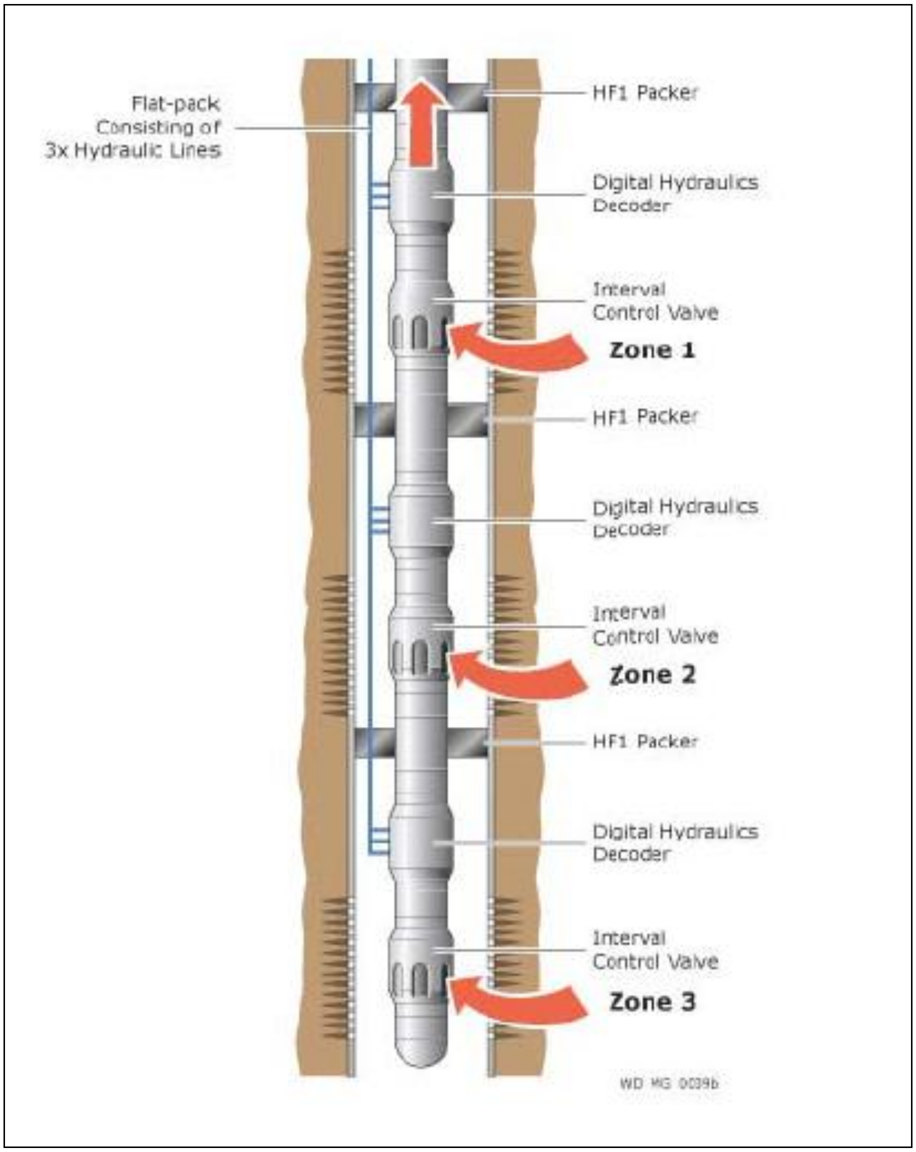

Figure 2: 3-reservoir intelligent well completion schematic (SPE 85677 figure 3A)

2 Overview of Historical Commingling Practices

In many hydrocarbon basins, multiple reservoirs are encountered stacked one above the other. Government regulations and good petroleum practice have traditionally prescribed that the production of conventional oil and gas from distinct reservoirs or pools remain segregated in the wellbore despite the economic impact of deferring production of one or more intervals. The purposes of maintaining segregation of oil and/or gas in the wellbore include:

1. Avoid the potential for wellbore and reservoir conditions that may adversely affect ultimate recovery, e.g. crossflow of reservoir fluids
2. Facilitate effective management of rate and pressure drawdown on a reservoir-by-reservoir basis
3. Enable reservoir-specific enhanced oil recovery (EOR) operations such as water flooding or gas injection
4. Maintain the ability to gather data on individual reservoir production as the basis for royalty determination as well as reservoir management
5. Eliminate problems stemming from fluid incompatibility
6. Minimize workovers

On the other hand, commingling in principle can provide very large increases in net present value for the following reasons:

1. A higher production plateau and faster cash flow
2. Ability to produce hydrocarbons from reservoirs that may be uneconomic to produce on their own, thus potentially increasing total production
3. Fewer wells, less infrastructure and lower capital costs
4. Lower operating expenses
5. A smaller environmental “footprint” due to fewer locations

The economic benefits to the operator and, in the case of Points 2 and 5 above, to the regulatory authorities of commingling are clear, especially in high cost field development applications. However, several practical inter-related issues must be considered before approving uncontrolled commingling:

1. Allocation of production to different reservoirs, which can affect reservoir management decisions and, in some cases, royalties.
2. Prevention of crossflow between reservoirs
3. Ability to exclude production of unwanted water or gas
4. Well integrity and flow assurance
5. Ensuring the compatibility of reservoir fluids

These important factors beg the question of how to better define the circumstances under which commingling can be permitted without a loss of reserves as discussed in the next two sections.

3 Reservoir Constraints on Uncontrolled Commingling

To understand reservoir constraints on uncontrolled commingling, this section considers two common commingling scenarios in the Gulf of Mexico.

3.1 *Commingling Depletion Drive Oil and Gas Reservoirs with Varying Permeabilities*

We begin by considering three oil reservoirs with different permeabilities (5, 50 and 500 md) but similar initial depth-adjusted reservoir pressures as depicted in Figure 3. If the reservoirs are commingled, production will occur mainly from the high permeability 500 md reservoir, all other things being equal. As a result, the static reservoir pressure in the 500 md reservoir will drop below the pressures in the other two reservoirs, with the static reservoir pressure in the 5 md reservoir being the highest.

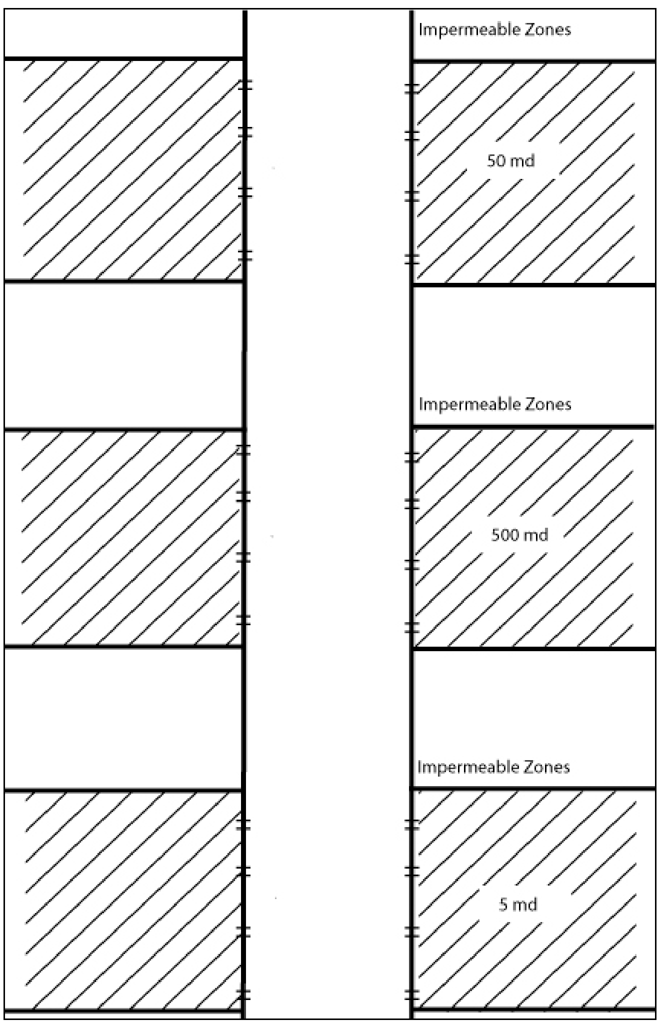

Figure 3: Three oil reservoirs with different permeabilities

Suppose that commingling has reached the point where the pressures in the three reservoirs are as follows:

- 500 md reservoir: 4,000 psig
- 50 md reservoir: 4,400 psig
- 5 md reservoir: 4,800 psig

If the well is now tested at various rates, an inflow performance relationship (IPR) curve, similar to Figure 4, will result[22]. This curve will exhibit the following characteristics:

- An increasing PI at lower production rates (i.e. at low pressure drawdowns), as first the 5 md reservoir, then the 50 md and finally the 500 md begin to flow.
- A decreasing PI at higher production rates (i.e. at higher pressure drawdowns).

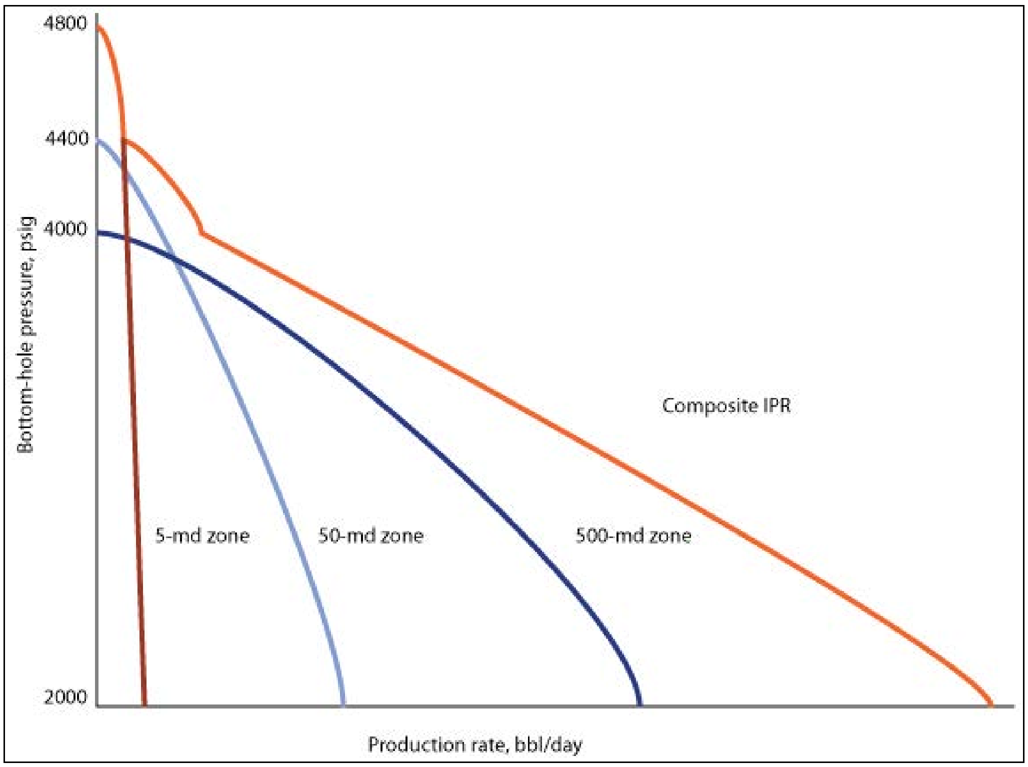

Figure 4: Composite IPR curve for three commingled reservoirs

From a regulatory standpoint, the question now is: what potential problems may occur from uncontrolled commingling of the three reservoirs?

One issue with uncontrolled commingling in this scenario is that the producing gas-oil ratio, an important factor in both maximizing recovery and ensuring effective lift from the wellbore to the surface, cannot be closely manage unless the production from each reservoir can be individually controlled. In our example, where initial depletion has already caused differences in static reservoir pressures as depicted in Figure 4, at low production rates and low pressure drawdowns, only the higher pressure, lower permeability 5 and 50 md reservoirs will produce. Generally, these lower permeability reservoirs exhibit greater degrees of consolidation and cementation, which in turn typically correlate with higher relative gas-to-oil permeabilities (k_g/k_o) and, therefore, higher gas/oil production ratios.

As drawdown pressures and production rates are gradually increased, the higher permeability 500 md formation, which presumably is less consolidated and therefore has lower relative gas-to-oil permeability, will probably produce at a lower gas/oil ratio. As a result, the overall gas/oil production ratio for the well, will fall[22]; however, as the pressure drawdown continues and free gas saturations in the 500 md formation develop, the gas/oil ratio will typically increase again. This common progression in gas/oil ratio with production is depicted in Figure 5.

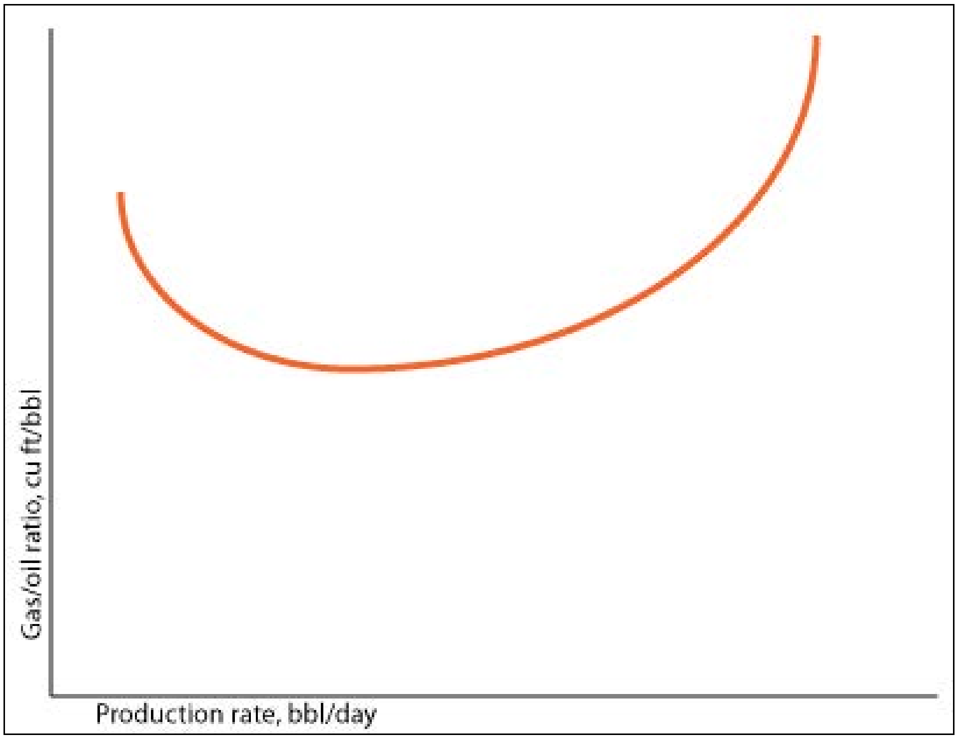

Figure 5: Indicative gas/oil ratio versus production rate for a commingled well

As each reservoir proceeds through the depletion phase, its surface gas/oil ratio (GOR) can be expressed in Equation 1 below.

Equation 1:

$$\text{Surface GOR} = R_s + \frac{B_o}{B_g}\,\frac{\mu_o}{\mu_g}\,\frac{k_g}{k_o}$$

Where:

R_s = solution gas/oil ratio (i.e. the gas solubility in oil)

B_o = oil formation volume factor

B_g = gas formation volume factor

μ_o = oil viscosity

μ_g = gas viscosity

k_g = effective permeability to gas

k_o = effective permeability to oil

When the pressure in a reservoir is slightly below the bubble point, but critical gas saturation (i.e. the saturation at which natural gas flows as a separate phase) has not been reached, the gas/oil ratio should be close to the initial gas saturation in the reservoir, i.e. Rsi. If the pressure is drawn down further to the point where critical gas saturation occurs, the term:

$$\frac{B_o}{B_g} \frac{\mu_o}{\mu_g} \frac{k_g}{k_o}$$

becomes relative to Rs and the producing gas/oil ratio increases, due largely to the increase in kg/ko.

If the pressure in a reservoir is decreased sufficiently, e.g. in the case of a depletion drive reservoir, the gas/oil ratio begins to drop again. This can be explained by examining the behavior of the gas formation volume factor, B_g.

Equation 2:

$$B_g = \frac{14.7}{5.614 \times 520} \frac{ZT}{p}$$

Where:

Z = gas compressibility factor

T = reservoir temperature

p = reservoir pressure

14.7 = standard surface atmospheric pressure in psia

520 = standard temperature in degrees Rankin, equivalent to 60 degrees Fahrenheit

5.614 = the number of cubic feet per barrel

Assuming that the gas compressibility factor Z and the reservoir temperature T remain constant, one can define a constant A where:

Equation 3:

$$A = \frac{14.7}{5.614 \times 520} \times ZT$$

Using this constant A in Equation 1, Equation 1 becomes:

Equation 4:

$$\text{Instantaneous Surface Gas/Oil Ratio (GOR)} = R_s + \frac{p}{A} B_o \frac{\mu_o}{\mu_g} \frac{k_g}{k_o}$$

At high pressure drawdowns (i.e. at lower p) in a depletion drive reservoir, the term p/A will begin to dominate the right-hand side of Equation 4, and the gas/oil ratio will drop with increasing cumulative production[22].

This common gas/oil ratio behavior in a depletion drive reservoir is depicted in Figure 6 and Figure 7.

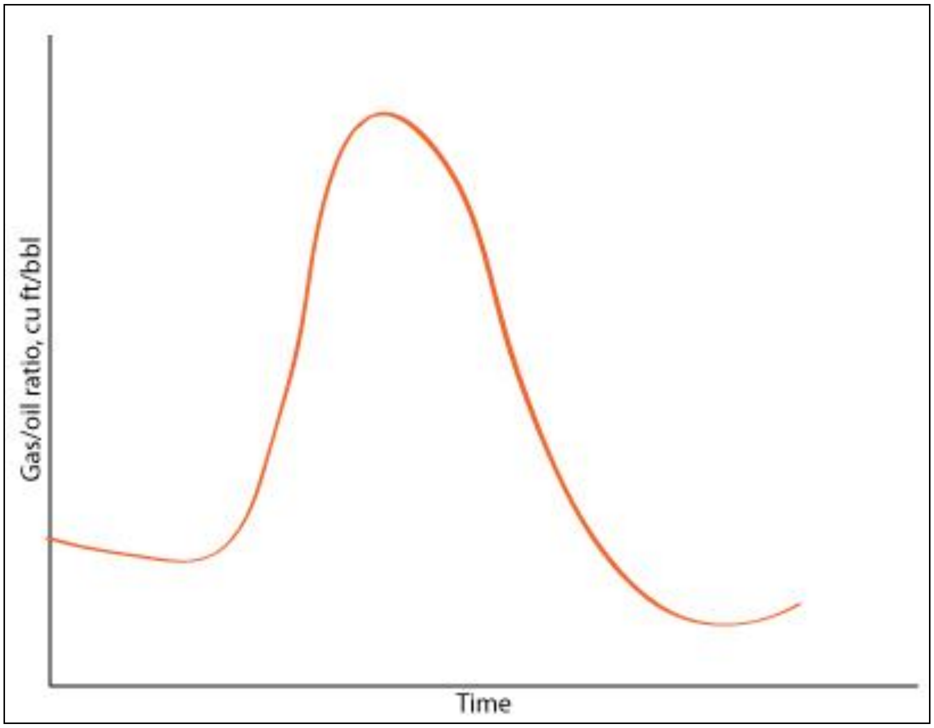

Figure 6: Indicative trend of gas/oil ratio versus time in a depletion drive reservoir

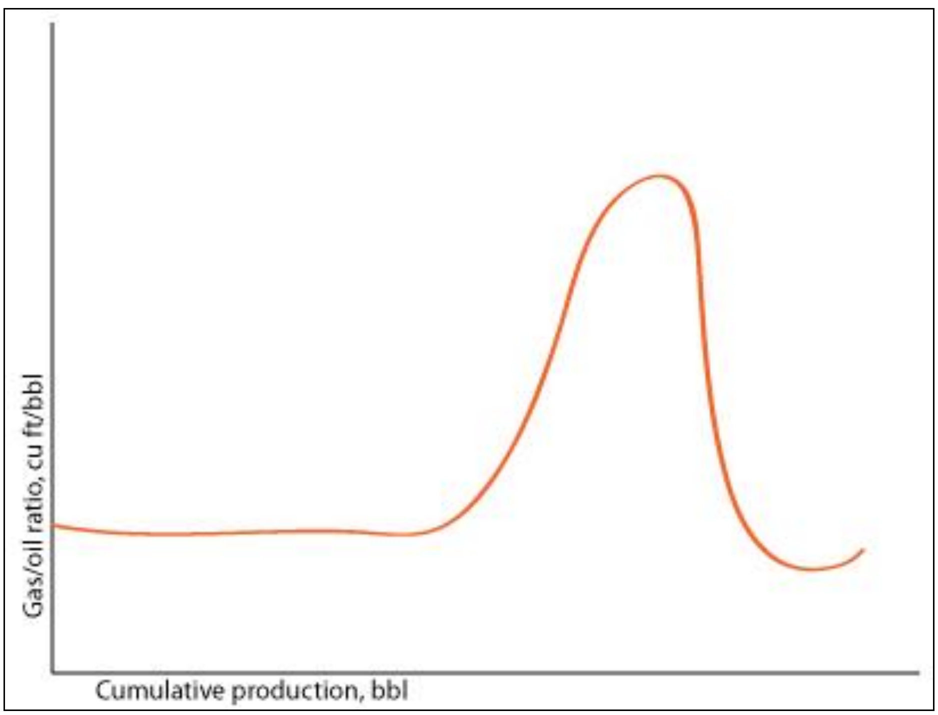

Figure 7: Indicative trend of gas/oil ratio versus cumulative production in a depletion drive reservoir

In gas reservoirs containing liquids, an opposite effect can occur: over-rapid drawdown can result in liquid dropout in the reservoir near the wellbore (condensate banking), which can markedly reduce relative permeability to gas, the overall energy output of the reservoir, and well productivity and recovery[23].

Several key conclusions can be drawn from the factors discussed in this section relative to the importance of managing production rates and pressure drawdowns on a reservoir-by-reservoir (as opposed to commingled) basis to achieve the goal of maximizing ultimate recoveries:

- An over-rapid drawdown of a reservoir can create high gas saturations near the wellbore. This can reduce relative permeability to oil, particularly as further reservoir compaction occurs, thus reducing reservoir productivity and largely depriving the oil phase of the reservoir of the benefits of solution gas drive.
- In gas reservoirs containing liquids, a controlled drawdown is often necessary to avoid premature liquid dropout in the reservoir near the wellbore (condensate banking), which can reduce relative permeability to gas, well productivity and recovery factors.
- Managing the producing gas/oil ratio over time is critical in effectively utilizing reservoir energy to maximize recovery and ensure effective lift from the wellbore to the surface.
- Managing the producing gas/oil ratio for an individual reservoir requires monitoring and, if necessary, altering drawdown pressure at the reservoir, which is effectively impossible unless the production from each reservoir can be individually monitored and controlled.

The question may be raised whether the relative size of the reservoirs being commingled is relevant to the discussion of whether uncontrolled commingling should be allowed. To effectively demonstrate that no negative effects from uncontrolled commingling will occur, future reservoir performance, which in part is a function of reservoir size, should be predictable. However, as the debate over the flow rate from the Macondo well demonstrates, operators in the Gulf of Mexico usually have very limited reservoir data available early in the development cycle when operators typically apply for commingling permits. Thus, the range of uncertainty in likely reservoir size and performance as pressure declines is so high as to make predictions of likely reservoir behavior and recovery very subjective.

As discussed later in this report, these concerns and uncertainties point to intelligent completions as a method to safeguard reserves in common commingling scenarios in the Gulf of Mexico.

3.2 *Effects of Reservoir Drawdown on Water/Oil Ratios*

Suppose that one or more reservoirs in a commingled well have water influx. As discussed in the example in the previous section, in principle the gross IPR can be estimated through well testing to determine the water cuts at different flow rates. Of course, in practice operators often do not have this information at the time of applying to commingle, but we use this example to demonstrate the importance of monitoring and managing pressure drawdown when a reservoir is in proximity to a water stringer or aquifer, a common occurrence in the Gulf of Mexico. Table 1 depicts oil and water rates and pressures for three hypothetical well tests.

Table 1: Oil and water rates and pressures for hypothetical well tests

Gross Rate (bbl/day)	Water Cut (%)	Water Rate (bbl/day)	Oil Rate (bbl/day)	Bottomhole Flowing Pressure p_{wf} (psig)
260	58%	150	110	2350
350	51%	180	170	1900
410	49%	200	210	1600
470	47%	220	250	1300

Figure 8 plots these results to show gross, oil and water IPR curves based on the hypothetical well tests[22].

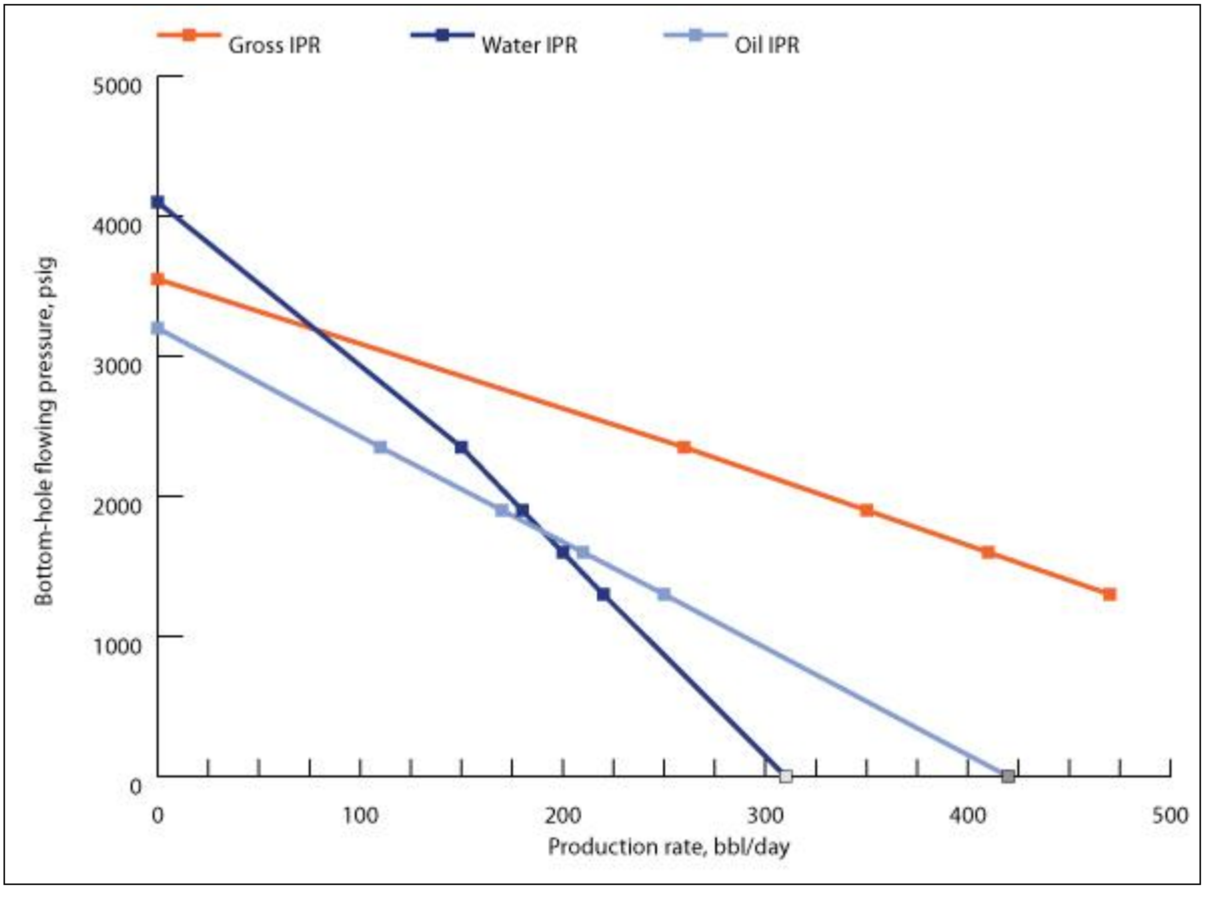

Figure 8: IPR and water cut curves for an oil reservoir in proximity to an aquifer based on data in Table 1

From Figure 8:

- Static pressure of the oil reservoir = ~3,200 psig
- PI of the oil reservoir = ~420/3,200 = 0.13 barrels/day/psi
- Static pressure of the water reservoir = ~4,100 psig
- PI of the water reservoir = ~310/4,100 = 0.076 barrels/day/psi

The water cut curve behavior shown in the table demonstrates a common occurrence in reservoirs in proximity to an active aquifer:

- A high water cut at low production rates, i.e. at low pressure drawdowns
- Increasing oil cuts at higher production rates, i.e. at higher pressure drawdowns.

As production from the oil reservoir in proximity to an active aquifer continues over time, water saturation in the reservoir is likely to rise, which in turn increases the relative permeability to water (k_w/k_o) and the water cut. The rate at which water cut increases depends on such factors as:

- The shape of the relative permeability curves
- The in situ viscosity of the oil compared to the formation water, with more viscous oil reservoirs typically exhibiting higher water cuts[22]
- The thickness of any "water stringers" relative to the total reservoir
- The pressure drawdown on the reservoir; too high a drawdown can encourage water coning around the wellbore as well as water fingering higher into the oil reservoir.

Over the long term, even in the presence of an active aquifer, the water/oil ratio often begins to flatten out again, since encroaching water will tend to travel through established water channels in the reservoir rather than flood additional oil-saturated reservoirs[22].

Figure 9 illustrates the common progression of water/oil ratios during the producing life of a reservoir in proximity to an active aquifer.

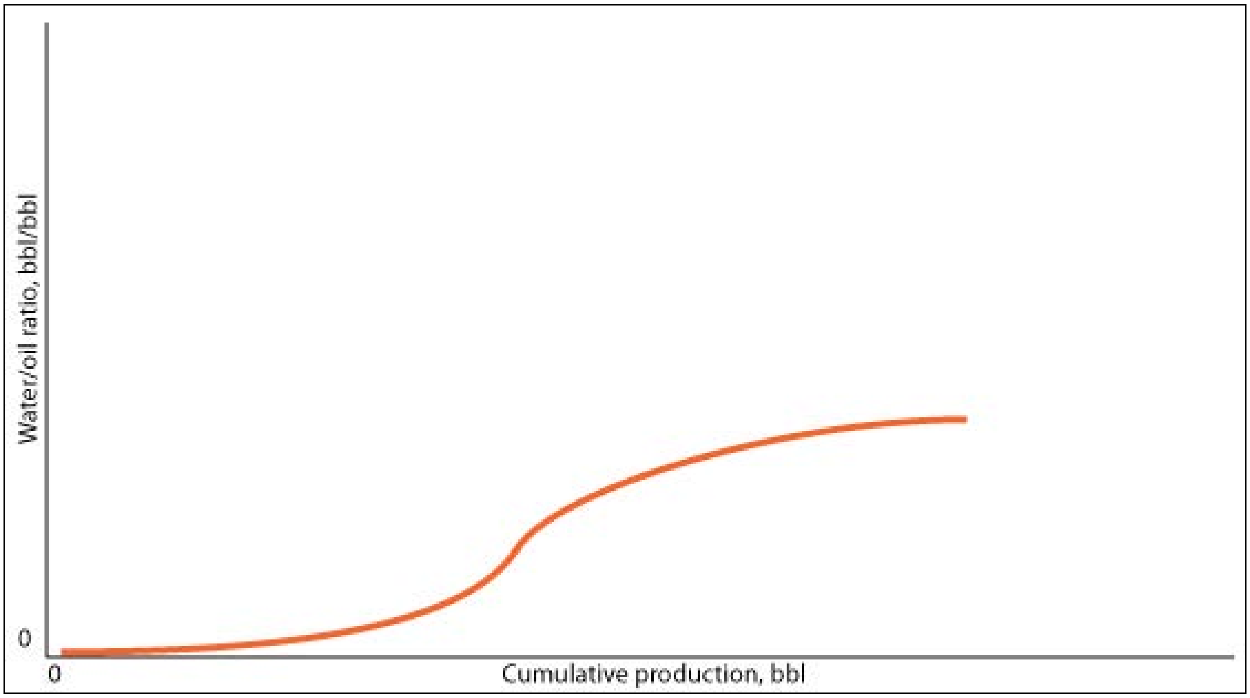

Figure 9: Common progression of water/oil ratios in an oil reservoir in proximity to an active aquifer

In the case of an oil reservoir containing water that is not associated with an active aquiver, water cut behavior would typically behave in the opposite fashion, i.e.:

- The water cut would be low at low production rates, i.e. low pressure drawdowns
- Water cut would rise as total production and drawdown pressures increase[22].

Figure 10 illustrates these effects.

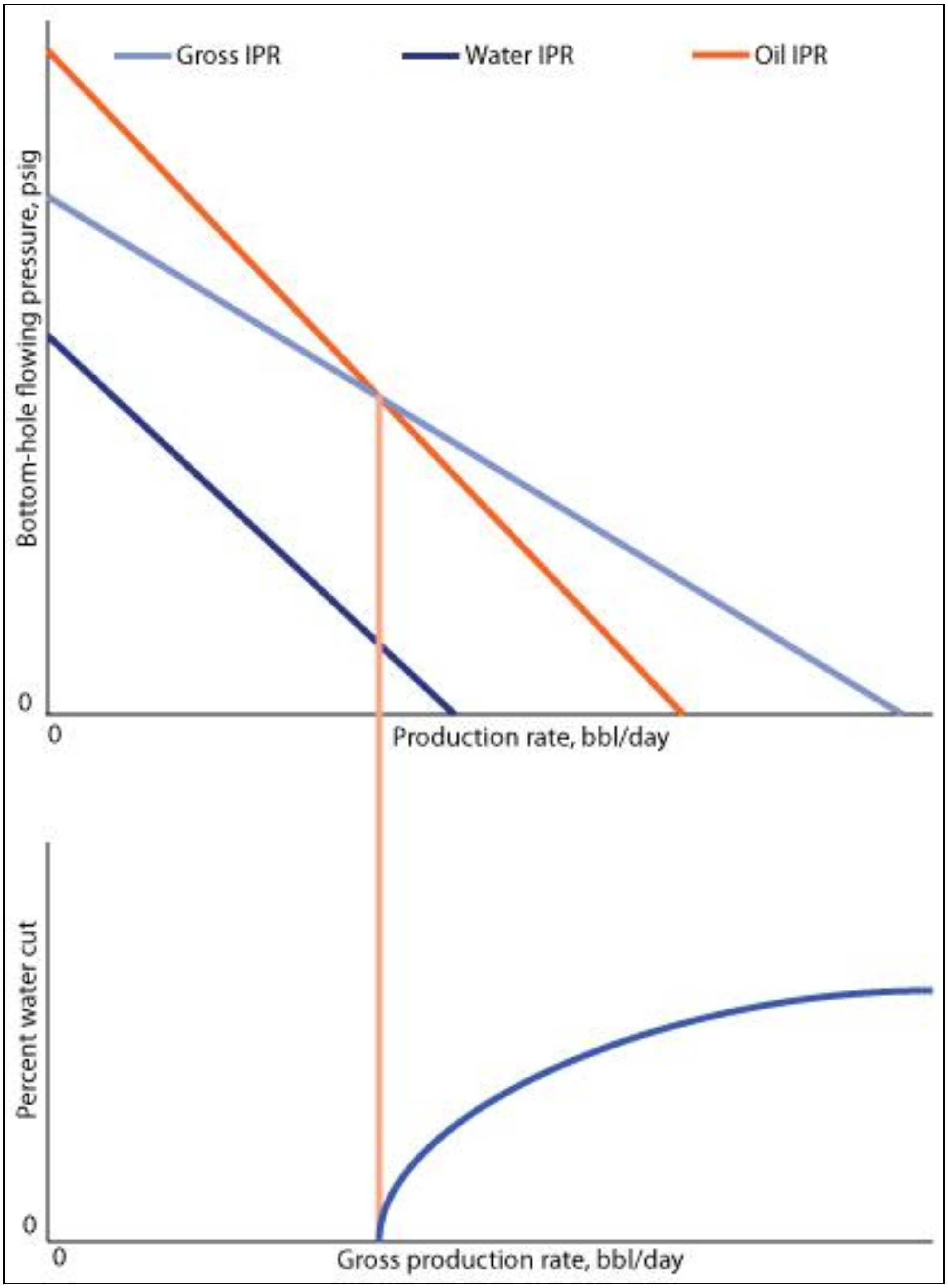

Figure 10: Sample IPR and water cut curves for an oil reservoir not associated with an active aquifer

As these examples of oil reservoirs both with and without active aquifers illustrate, the most effective way to produce a reservoir containing free water in terms of managing production rates and pressure drawdowns is a function of such factors as:

- Whether the oil reservoir is associated with an active aquifer and, if so, the strength of this aquifer
- The thickness of any "water stringers" relative to the reservoir as a whole
- The in situ viscosity of the oil relative to the formation water
- The shape of the relative permeability curves
- The stage in the reservoir's production life cycle

This information is often not available early in the field development cycle when applications for commingling are made. In any case, once the information is available, individual reservoirs are likely to require different drawdown strategies to optimize production over time. This concern points to the importance of monitoring and managing production rates and pressure drawdowns on a reservoir-by-reservoir basis. As discussed later in the report, intelligent completions are a means to achieve this objective and help safeguard ultimate recoveries in common commingling scenarios in the Gulf of Mexico.

One further issue merits mention in this section: if multiple reservoirs are commingled without controls, and one of these reservoirs has a high-pressure water source fed by an aquifer, a high risk exists of high pressure water entering the lower pressure oil and gas reservoirs, causing potentially permanent formation damage in the lower pressure reservoirs[22]. This damage can occur through such mechanisms as:

- Reduction in the permeability of the invaded formation due to changes in relative permeability around the wellbore as hydrocarbon-filled pores are displaced by the invading water. In the most serious cases, water block can occur, particularly with lower pressure gas sands with permeabilities of less than about100 md and small pore throats (less than about 10 microns)
- Clay swelling, where formation permeability is reduced by invading fluids with a different salinity and composition from the original connate water in the formation.

Intelligent completions can be designed to prevent fluid invasion and potential formation damage from occurring.

In the next section, we consider cases in which uncontrolled commingling can be allowed without major harm to ultimate recoveries.

4 Case Study of Successful Uncontrolled Commingling

Before giving the impression that intelligent completions are required for every commingling scenario in the Gulf of Mexico, we turn to an example of successful commingling to draw lessons on when uncontrolled commingling may be allowed. During the 1960's and 1970's, when many reservoirs in Lake Maracaibo, Venezuela producing medium crudes were in decline, a drive to commingle multiple reservoirs was undertaken to improve aggregate production profiles and to increase reserves.

Before commingling was approved, production logs (PLT), capillary gas chromatography (CGC), and separator testing were used to quantify the production of the individual reservoirs related to total production. The CGC confirmed the similar compositions of the different crudes being produced. Similar to the methods described above, the composite IPR of the commingled reservoirs was calculated (Figure 11, Figure 12 and Figure 13) taking the following factors into account:

- The IPR curves of individual reservoirs
- The mechanical configuration of the well
- The separation (distance) between the producing reservoirs and the associated fluid gradient between them
- The distinct fluid properties of each reservoir

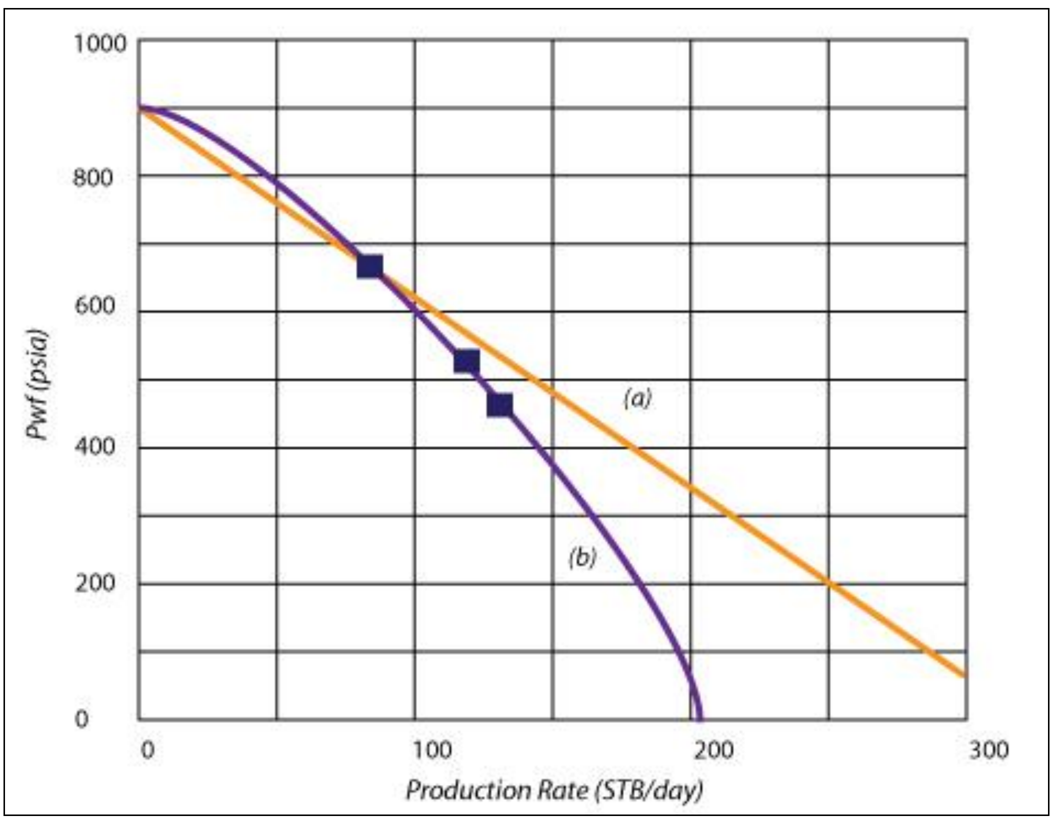

Figure 11: IPR represented as a straight line (a) and typical curved trajectory (b)

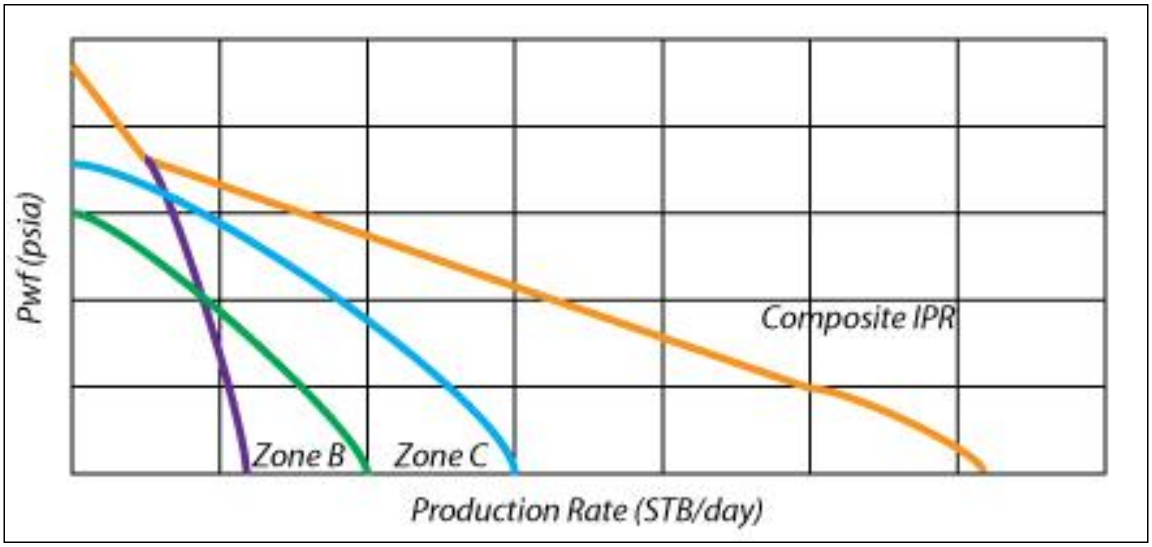

Figure 12: Composite IPR curve exhibits higher productivity index with increasing production rate at lower rates, but a productivity index at higher rates

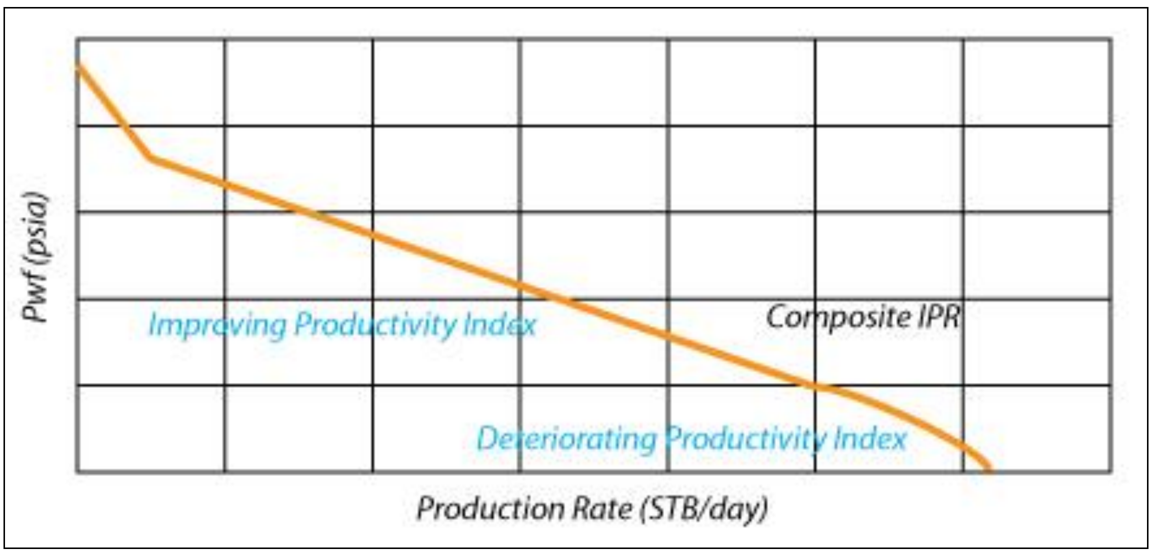

Figure 13: Composite IPR curve exhibits a higher productivity index with increasing production rate at lower rates, but a lower productivity index at higher rates

This method was effective in estimating the composite IPR based on the IPR curves of individual reservoirs to predict the performance of a commingled well. The calculation procedure used can generally show the possibility of crossflow among reservoirs by determining the likelihood of a reservoir depleting faster than its neighbors.

After accumulating and comparing data to identify reservoirs with oil and gas of similar compositions, each reservoir was separated by a casing packer and a sliding sleeve in the tubing. In an attempt to create similar flow conditions from each reservoir into the tubing, a calibrated pre-set downhole regulator was placed in the sliding sleeve in front of the reservoir with the highest pressure so that the downstream pressure of the regulator was the same as the depth-adjusted pressure in the tubing producing from the reservoir with the lowest pressure.

The procedure demonstrated that the right selection of partially depleted reservoirs with somewhat similar characteristics (specifically fluid compositions, drive mechanisms and depth-adjusted pressure over time) can be commingled, but the method and procedure required constant monitoring of:

- Surface pressures and flow rates to ensure that the production rate almost equaled the combined individual rates of the commingled reservoirs.
- Approximate material balance by reservoir, in part to estimate water breakthrough.
- Estimated fluid velocities to control reservoirs with sand production and coning problems.

The best results of commingling were found to occur when:

- Similar static pressure reservoirs were combined, or when a lower static pressure reservoir had a higher PI.
- Wells were in decline but still producing between 600 to 1,000 bopd.
- Each reservoir had similar general characteristics such as oil gravity and gas-oil-ratios within 15% of one another.[1]

Additional commingling projects were run with reservoirs with higher rates of production; however, commingling efforts were not successful when the high rates were very different from one other. No attempts were made to commingle reservoirs of wells that had a mixture of high pressure/high production rates and low pressure/low production rates to avoid the possibility of crossflow.

Despite the overall success of commingling in this example, including producing from reservoirs that may otherwise have been bypassed, clear operational and reservoir management problems exist when downhole regulators with fixed differential settings are placed in sliding sleeves to manage flow:

- In a declining reservoir, dynamic change in the PI and water cut make a fixed setting in the downhole regulator inefficient.
- To adjust the regulator to evolving flow and pressure conditions in a reservoir, the regulator (and tubing) must be physically retrieved and reset, an expensive proposition.
- Over the course of years, changing pressure and flow parameters of the reservoirs in a commingled well may limit the ability of mechanical downhole regulators to effectively manage commingling.

From a regulatory standpoint, the key lesson from this case study is that uncontrolled commingling (i.e. commingling without use of intelligent completions) can work for:

- Reservoirs in the declining stage of production with fairly low production rates
- Wells penetrating closely adjacent reservoirs of similar fluid compositions, drive mechanisms and depth-adjusted pressure over time.

The situations noted above where commingling can be carried out without control are not very common in new field developments in the Gulf of Mexico. In reservoirs where fluid compositions, drive mechanisms and depth-adjusted pressures vary significantly or where only limited reservoir data are available, controlled commingling using Intelligent Completions is recommended. Wherever using uncontrolled commingling or intelligent completions, operators must be willing to commit to regular monitoring and analysis of pressure and flow conditions in the well.

5 Elements of an Intelligent Completion

The petroleum industry defines an intelligent completion as a completion in which control of inflow or injection takes place downhole at the reservoir, with no physical intervention, and usually with active monitoring (2001 SPE Forum in St. Maxine, France).

The advent of intelligent completions offers the promise of independently monitoring and controlling production from each reservoir to optimize a well's flowing parameters. Intelligent completions technology, also known as intelligent well systems (IWS), is now being widely implemented worldwide and has started to deliver on the promise of enabling effective reservoir management in commingled wells. In some cases, production rates have doubled after implementing intelligent completions as documented below. In other cases, intelligent completions have enabled operators to develop reserves that otherwise would have been overlooked.

At a high level, intelligent completions consist of:

- Remotely controlled downhole flow control devices
- Feed-through isolation packers (Figure 14)
- Downhole tubing and annulus pressure gauges, and, in some cases, downhole flowmeters and temperature gauges, that can be remotely monitored from the surface.

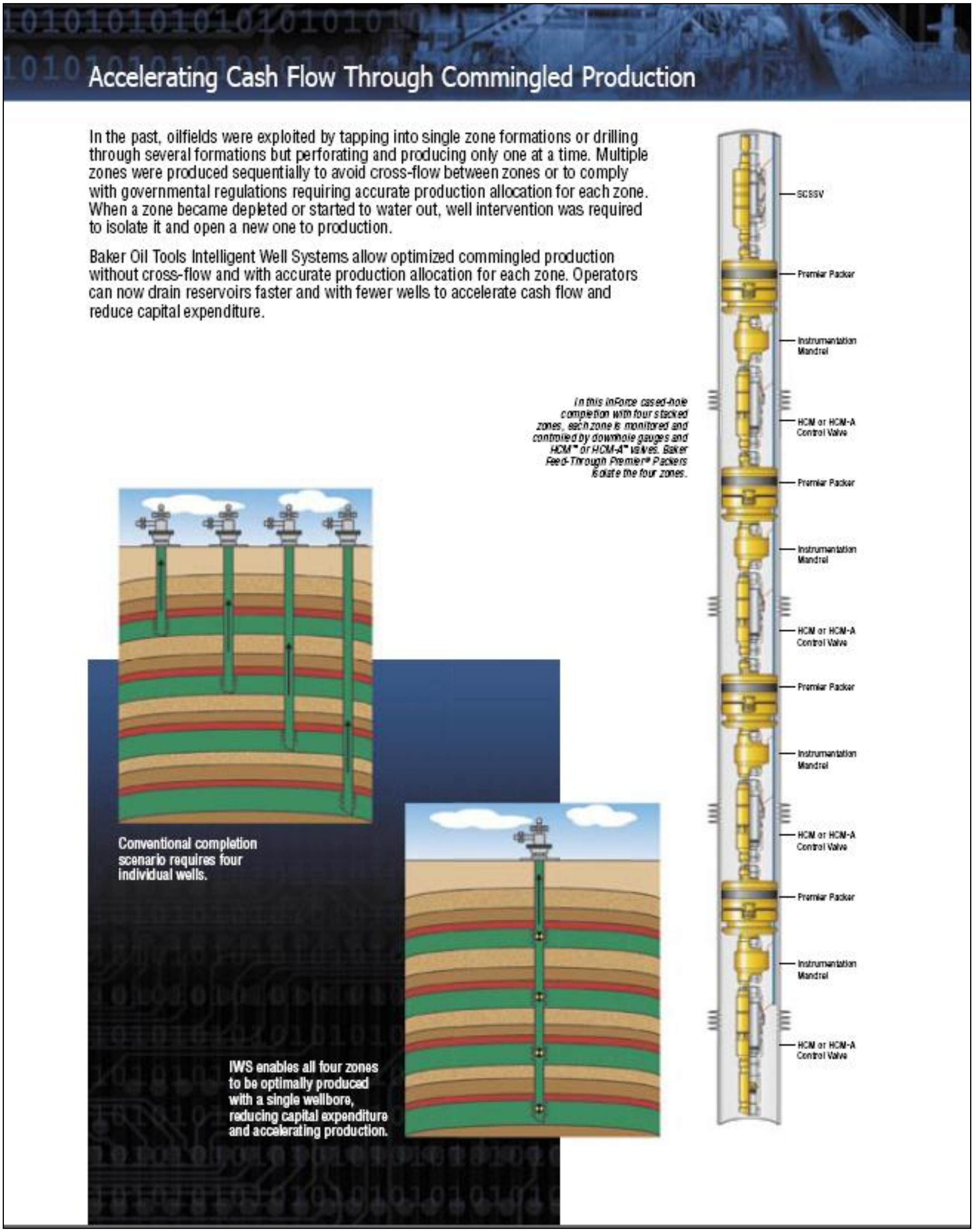

Figure 14: Major components of an intelligent completion (courtesy of Baker Hughes)

An intelligent completion enables:

- Collecting, transmitting and analyzing completion, production, and reservoir data through the use of the downhole sensors noted above
- Separating reservoirs using seal-bore packers with pass-through connections for control lines.
- Taking action such as adjusting downhole sliding sleeve openings to control production rates and pressures at the reservoir face.

At a more detailed level, an intelligent completion requires the following elements:

5.1 *Downhole Flow Control Devices*

Also known as inflow control valves, most downhole flow control devices are based on sliding sleeves (Figure 15) or, for bottom reservoir application, ball-valve technologies (Figure 9). These devices are driven by hydraulic, electro-hydraulic or electric systems and can:

- Be binary, i.e. just have on or off positions (not recommended in complex commingling situations)
- Have multiple degrees of opening ("multiple positions")
- Be infinitely variable

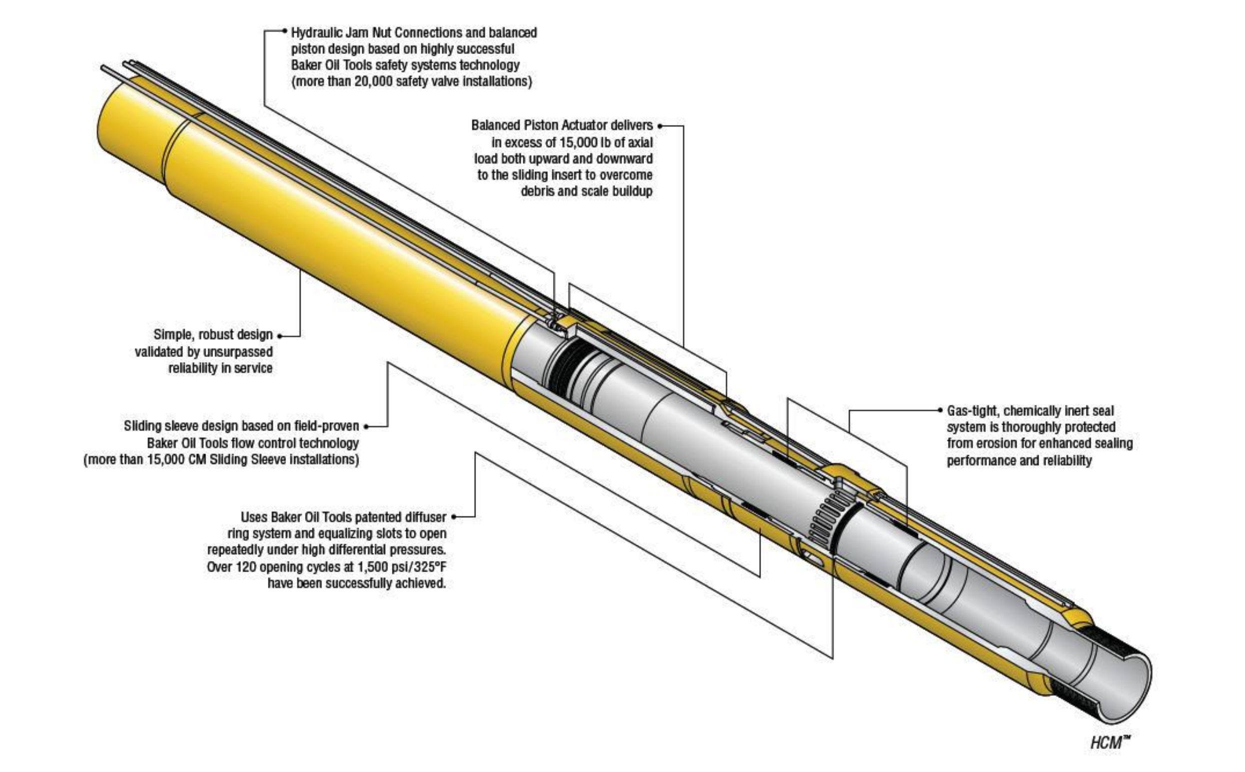

Figure 15: HCM™ and HCM-Plus™ remote-controlled hydraulic valves (courtesy of Baker Hughes)

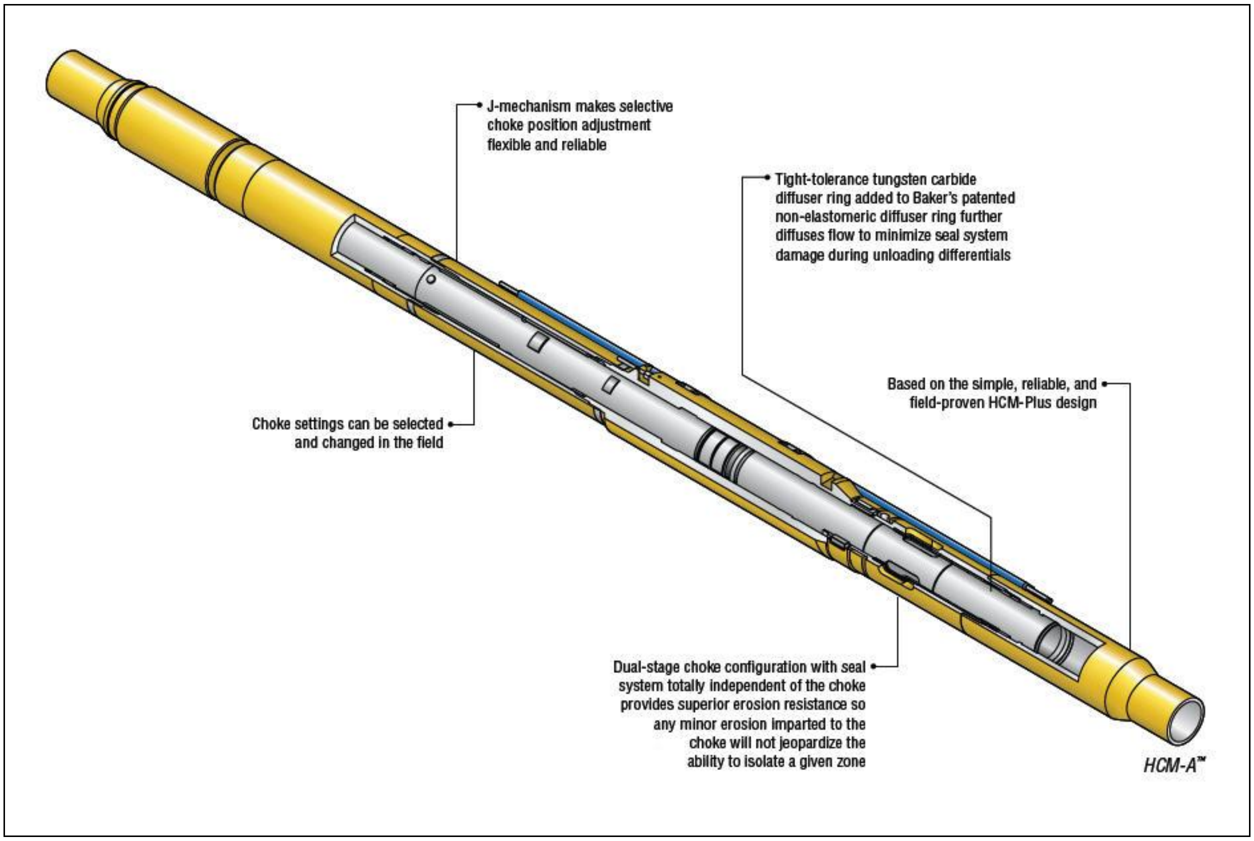

Figure 16: HCM-A™ multi-position hydraulic choke (courtesy of Baker Hughes)

Please note that this report, like much of the industry, often uses the terms inflow control valves, downhole flow control devices and sliding sleeves interchangeably.

5.2 *Feed-through Isolation Packers*

To ensure individual reservoir control and segregation of reservoirs, each reservoir must be isolated from each other by packers that incorporate feed-through facility for control, communication and power cables (Figure 17).

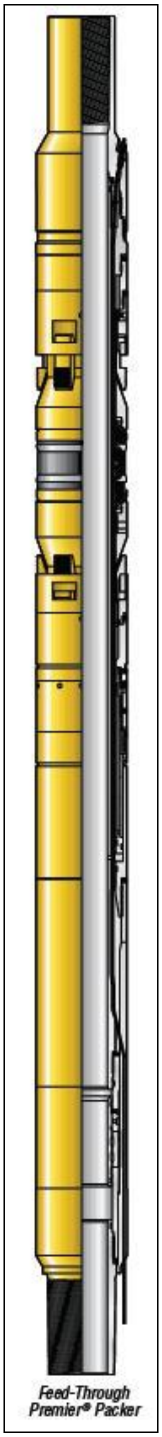

Figure 17: Feed-through Premier® Packer (courtesy of Baker Hughes)

5.3 *Control Cables*

Current well technology requires one or more conduits to transmit power and data to downhole monitoring and control devices (Figure 18). These may be hydraulic control lines, electric power and data conductors, or fiber optic lines.

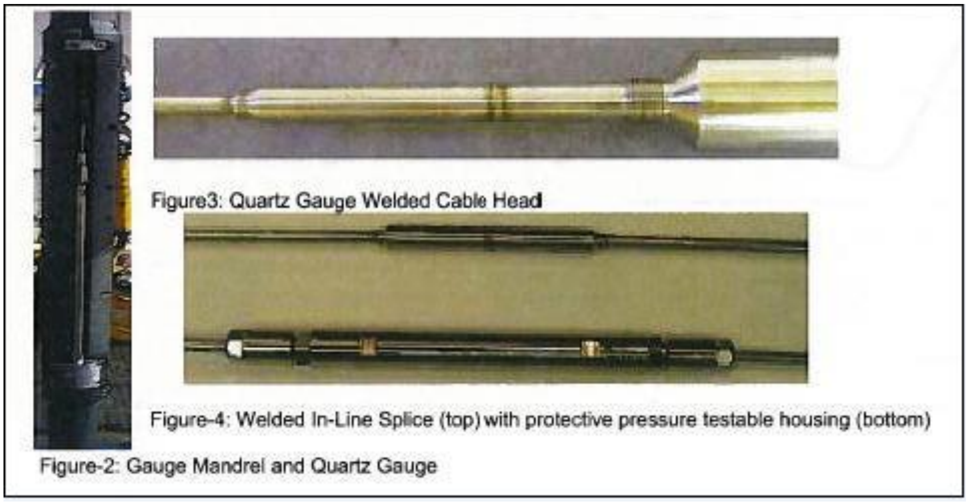

Figure 18: Quartz gauge and gauge mandrel (SPE 126158)

5.4 *Downhole Sensors*

A variety of downhole sensors, including quartz crystal pressure and temperature sensors, optical fibers, and downhole flow meters to monitor flow from each reservoir of interest, are available and are becoming increasingly reliable. Operators can use redundant systems to increase reliability even further.

5.5 *Data Acquisition and Control*

Surface acquisition systems are required to acquire, validate and store the large volumes of data provided by downhole sensors. Processing systems are also required to examine and analyze the data to gain insight into the performance of the well and its reservoirs. Predictive models can assist in the generation of process-control decisions to optimize production from a well and its individual reservoirs.

5.6 *Flow Estimation and Flow Allocation*

Flow estimation is the quantification of the mass or volume of fluids from each reservoir in an intelligent well. This is different from flow allocation, which is the division of a total mass or volume measurement of fluids based on the estimated contribution of each reservoir. Given the limited accuracy of multi-phase flow meters, both flow estimation and flow allocation are important in an intelligent commingled well for reservoir management and production accounting. Sound reservoir management requires that every well with two or more commingled reservoirs have production allocated by reservoir, which begins by collecting reservoir and tubing pressures and, in some cases, downhole flow rates and temperatures.

6 Case Studies of Intelligent Completions to Manage Commingling

The case studies in this section demonstrate the key points raised in Section 3 about the importance of managing production rates and pressures on a reservoir-by-reservoir basis to achieve the goal of maximizing ultimate recoveries. Specifically, these case studies illustrate the capabilities of intelligent completions to:

- Manage drawdown of an oil reservoir to prevent high gas saturations near the well bore, which can reduce relative permeability to oil and impair ultimate oil recovery.
- Control drawdowns in gas condensate reservoirs to avoid premature liquid dropout near the wellbore, which can reduce relative permeability to gas and harm well productivity and recovery factors.
- Manage the producing gas/oil ratio over time to effectively utilize reservoir energy to improve recovery and ensure effective lift from the wellbore to the surface.
- Manage water influx from active aquifers
- Eliminate cross-flow between reservoirs.
- Respond effectively to evolving reservoir behavior over the reservoir's production life cycle.
- Target injection water to specific reservoirs to enable effective management of enhanced oil recovery projects.

On a quantitative level, the examples below indicate the ability of well-designed intelligent completions to:

- Increase ultimate recovery by up to 20% compared to a conventional completion
- Develop reservoirs that would otherwise by overlooked, which conceivably could add 5% or more to reserves in some Gulf of Mexico fields.
- Increase the production plateau from a well by up to 100% by enabling controlled commingling

Clearly, effective surveillance and monitoring by the operator are necessary to take full advantage of intelligent completions and achieve high recovery factors.

6.1 *Na Kika Complex, Gulf of Mexico*

Intelligent well completions are very expensive due to the high cost of inflow control devices, isolation feed-through packers, control cables and lines, and the surface control data gathering systems. The cost of each well completion obviously increases when the well is deeper and has more reservoirs. A current rule of thumb is that each reservoir being isolated requires about half a million dollars in hardware. Rig charges can easily exceed hardware costs, so an intelligent well completion can cost millions of dollars.

However, particularly in deeper waters of the Gulf of Mexico, where wells often produce at high oil and gas rates, installing and monitoring intelligent well completions is highly economic. The Na Kika complex provides an interesting case study of how intelligent completions can be driven by economic considerations in the Gulf of Mexico.

The core Na Kika development comprises five moderately sized (20 to 100 MMBoe) fields containing both oil and gas reservoirs. Individual reservoirs in each of the fields contained recoverable reserves as small as 10% of the field totals. Two of the five fields at Na Kika, Ariel and Fourier, feature multiple pay sequences, requiring stacked completions to enable an economic development concept (Figure 19). As discussed in Section 3, uncontrolled commingling of stacked reservoirs in a single wellbore carries risks such as differential depletion, crossflow or early water breakthrough requiring costly well intervention. Moreover, as is common in Gulf of Mexico fields, reservoir uncertainties existed in terms of compartmentalization, proximity and connectivity between gas and oil-bearing reservoirs, and aquifer size.[19]

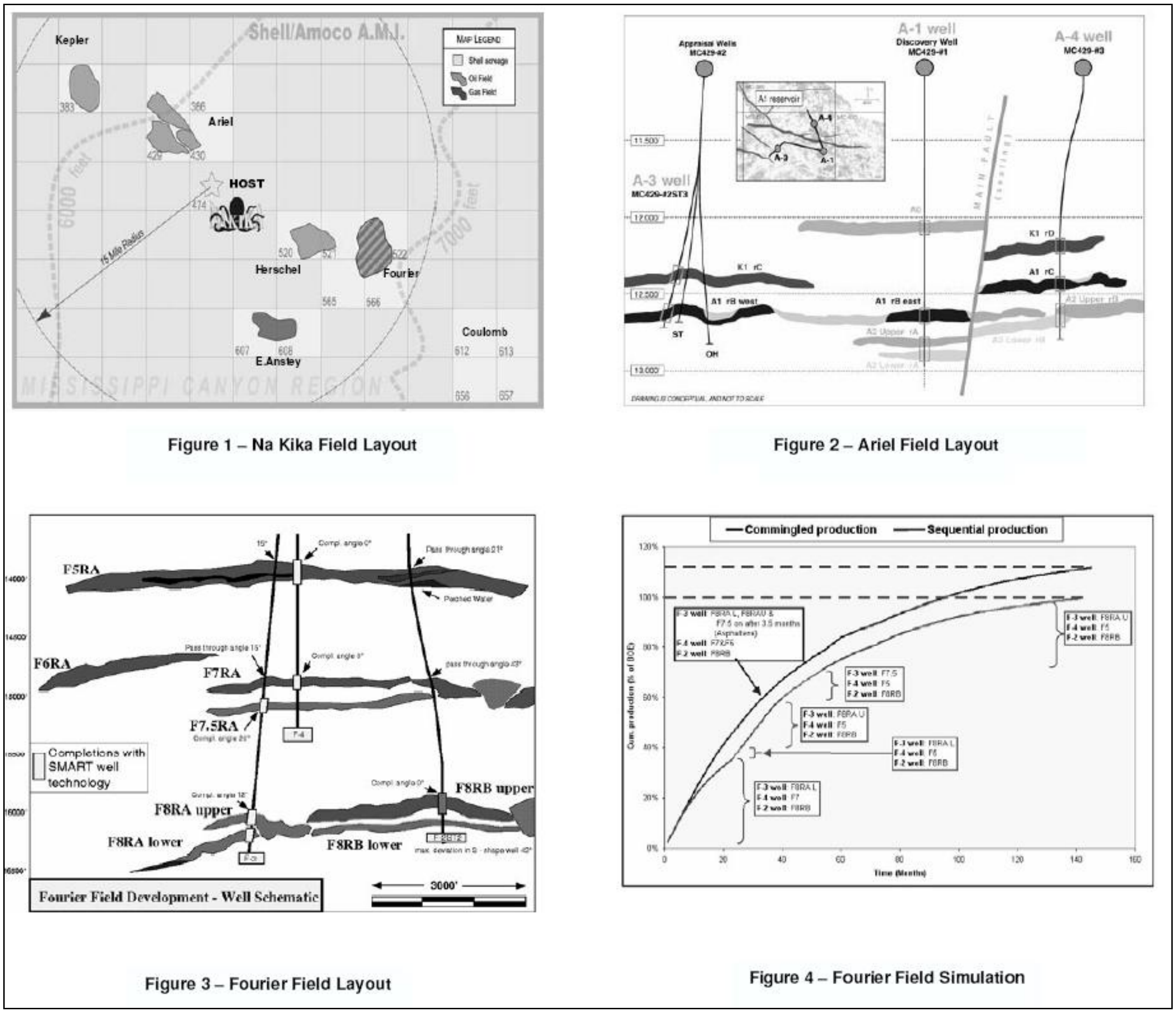

Figure 19: SPE 90215 figures 1 through 4

The generally accepted means to produce multiple pay sections in a single wellbore are listed below in order of decreasing capital investment over the well life:

- Single-reservoir completion with future up-hole recompletions
- Multi-reservoir "selective" completion, requiring future through-tubing intervention
- Multi-reservoir intelligent well completion

- Uncontrolled commingled completion of multiple reservoirs

While uncontrolled commingling requires the lowest investments over time, a single intervention to isolate one of the producing intervals increases the well cost beyond that of an intelligent completion. In addition, completions for uncontrolled commingled wells usually lack the pressure/temperature monitoring capability of individual reservoirs and thus cannot detect cross-flow between reservoirs.

After analysis of these factors and the ~$50 million per well drilling and completion costs for a single-reservoir completion, intelligent well technology was employed in four of the ten Na Kika wells to manage the production uncertainties associated with commingling and to avoid well intervention[17]. Required functionality of these wells included competent sand control with low completion skin, remote zonal control, and continuous pressure/temperature monitoring capability for each reservoir. In the Ariel and Fourier fields, subsurface studies indicated other potential issues, such as differential depletion between reservoirs, fluid incompatibilities, and timing of water breakthrough from uncontrolled commingling. Naturally, uncertainty exists in depletion and water forecasting. The capability to remotely monitor and shut in individual producing intervals alleviates these concerns, adds to ultimate recovery and improves economic returns[19] through:

- Optimal depletion management
- “Managed” commingling of multiple reservoirs in a well-bore while preventing cross-flow on shut-ins
- A lower producing stability threshold through commingling of two or more reservoirs
- The capability for pressure build-up tests on one reservoir to be conducted while producing the remaining reservoirs

Simulations on the Fourier field indicated that the capability to commingle reservoirs in a controlled manner will yield an increase in ultimate recovery of approximately 12% besides improving economics and eliminating the cost and risks associated with well interventions[19].

6.2 *Aconcagua, Camden Hills, and King’s Peak Complex, Gulf of Mexico*

Three deep water gas fields in the Gulf of Mexico, Aconcagua, Camden Hills, and King’s Peak, use intelligent completion technology to optimize commingled subsea development of a marginal reserve base and make the fields economic[2]. The fields are located in Mississippi Canyon and Desoto Canyon blocks in from 6,200 to 7,200 feet of water. Eight of the nine producing are completed as intelligent wells, enabling:

- Commingled gas production from multiple reservoirs
- Adjusting inflow control valves to shut-off water production from individual reservoirs and prevent cross-flow that could damage ultimate recovery without conducting a workover.

6.3 *Agbami Field, Offshore Nigeria*

In the large Agbami field offshore Nigeria, intelligent completions using downhole control valves and interval control valves (ICVs) enable control of production from, and injection into, multiple sub-reservoirs. Reservoir modeling indicates most wells will achieve incremental recovery by use of ICVs because of the ability to manage individual reservoirs, which is to be expected based on the discussion in Section 3. Collecting information on zonal drawdown, PI, and production data helps to sustain plateau production and minimize decline rates[3].

6.4 *Glitne Field, Offshore Norway*

In dual or multilateral wells where the laterals contact different portions of the same reservoir, gas or water breakthrough in a lateral can negatively affect oil production. The Norwegian state oil company Statoil chose to use intelligent completions in the Glitne A-H6 well to remotely control flow from either of two laterals without rig intervention in anticipation of eventual water breakthrough. Additionally, Statoil hoped to gain valuable reservoir and production data from the downhole sensors. Statoil selected hydraulically actuated sliding sleeves using two control lines based on a balanced piston concept to help ensure reliable operation at actuation forces of up to 17,000 pounds. This section of the reservoir would have been uneconomical to drill and complete using a conventional configuration of two single lateral wells, thus adding net reserves. The well continues to produce, and the sliding sleeve has been operated successfully numerous times.[4]

It should be noted that, in about 50 installations worldwide, no field failure has been reported to date of the type of sliding sleeve used in this well.

6.5 *Usari Field, Offshore Nigeria*

Mobil Producing Nigeria Limited (MPN) completed a long-reach producing well in the Usari field and commingled three of the seven discovered reservoirs using an intelligent completion. Each of the three reservoirs was equipped with downhole gauges, which provide the capability to manage the recovery of reserves from each individual reservoir (Figure 20). The average first-year rate was approximately 11,000 BOPD, whereas a single producer would have only produced about 7,000 BOPD.[5]

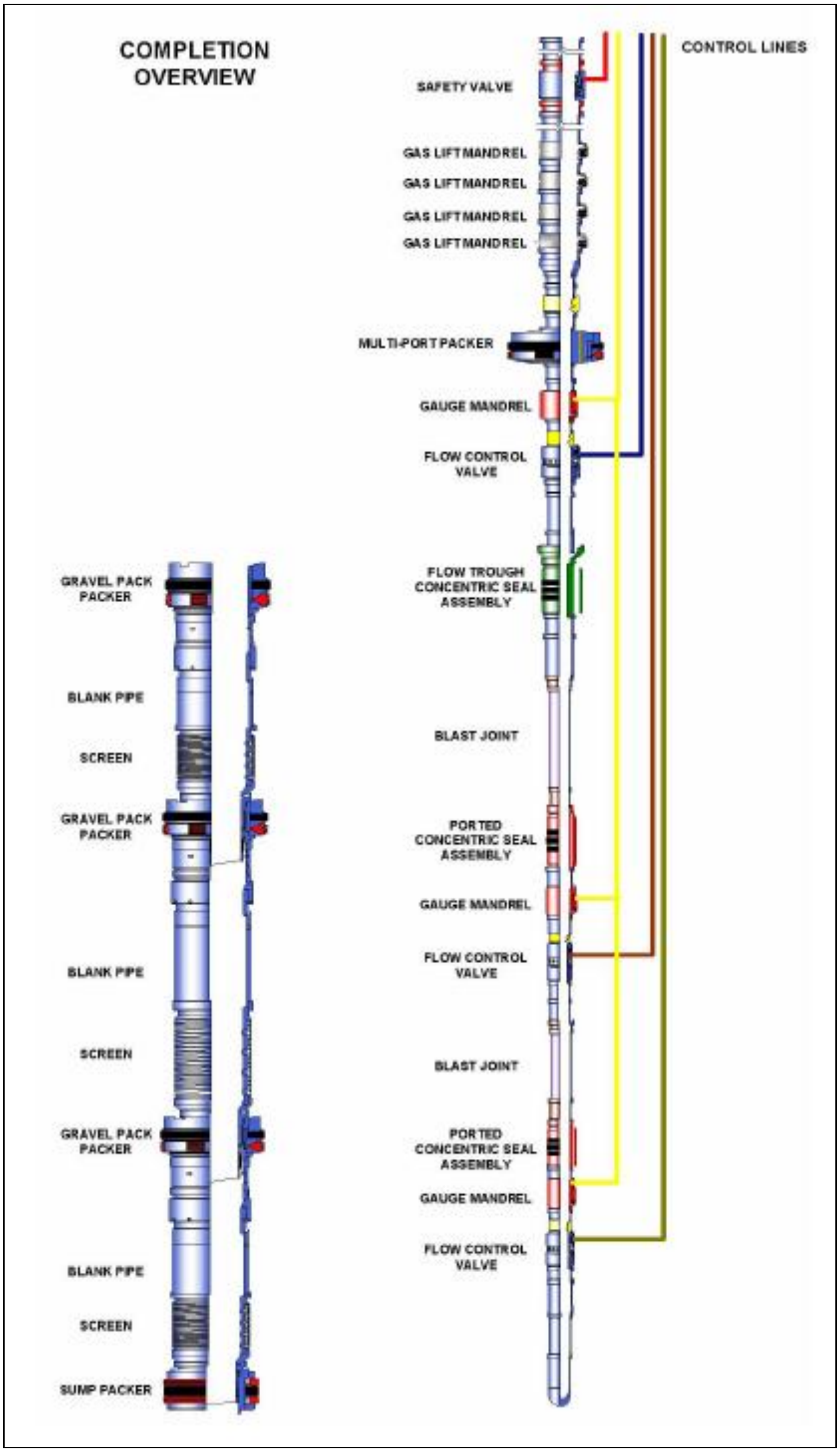

Figure 20: Completion schematic (SPE 101021 figure 5)

6.6 *Marlim Field, Offshore Brazil*

In addition to optimizing production from multiple reservoirs, intelligent completions enable operators to monitor and remotely adjust the injection rate into multiple reservoirs, thus helping to manage water breakthrough and increasing oil recovery. Intelligent completions can also reduce two major common cost items in deep water injection wells:

- Costs associated with workovers to change formations being injected, which can cost millions of dollars.
- Sand control; in injector wells, sand control can be critical during shut-in periods, which can occur frequently, to minimize sand production and potential formation plugging.

The Marlim Sul field in the Campos basin offshore Brazil, which has been producing oil and gas since 1994, is one of the world's largest discoveries in the past 20 years and is part of an enormous offshore industrial complex operated by Petrobras. The reservoirs of the Marlim and Marlim Sul fields are described as sandstone without water influx, and thus require substantial water injection for pressure maintenance. The reservoirs are unconsolidated and require sand control for both injectors and producers. Standard methodology for the field would have been to complete the reservoir as an open-hole gravel pack and inject into all reservoirs uncontrolled from the surface. Intelligent completions technology provided the ability to monitor in real time, the injection rate into each interval and then make changes to the injection rates to optimize production, thus:

- Mitigating water breakthrough
- Managing reservoir sweep and pressure support
- Avoiding production rates that could create excessive sand production.

The intelligent completion selected provides integrated pressure, temperature and flow rate monitoring with remote downhole control of each interval. A system using a single control line per sliding sleeve plus a joint return line was selected to minimize the subsea integration required to install the intelligent completion[4].

6.7 *Tern Field, UK Sector of the North Sea*

In the North Sea, Shell U.K. applied intelligent wells in its Tern field to control commingling of the Lower Ness/Etive and the Triassic Broom/Rannoch/Upper Ness formations. Previous development of these reserves was by sequential development of the more prolific Lower Ness/Etive followed by the Triassic Broom/Rannoch/Upper Ness, while intelligent well technology enabled production from the wellbore to be switched between the Lower Ness/Broom and the Triassic formations (Figure 21). Selective testing of the two formations allowed production splits and water cuts to be obtained without production logging. Estimated accelerated oil production of some 430,000 bbl and estimated incremental oil production of 85,000 bbl are expected using the intelligent well completion[2].

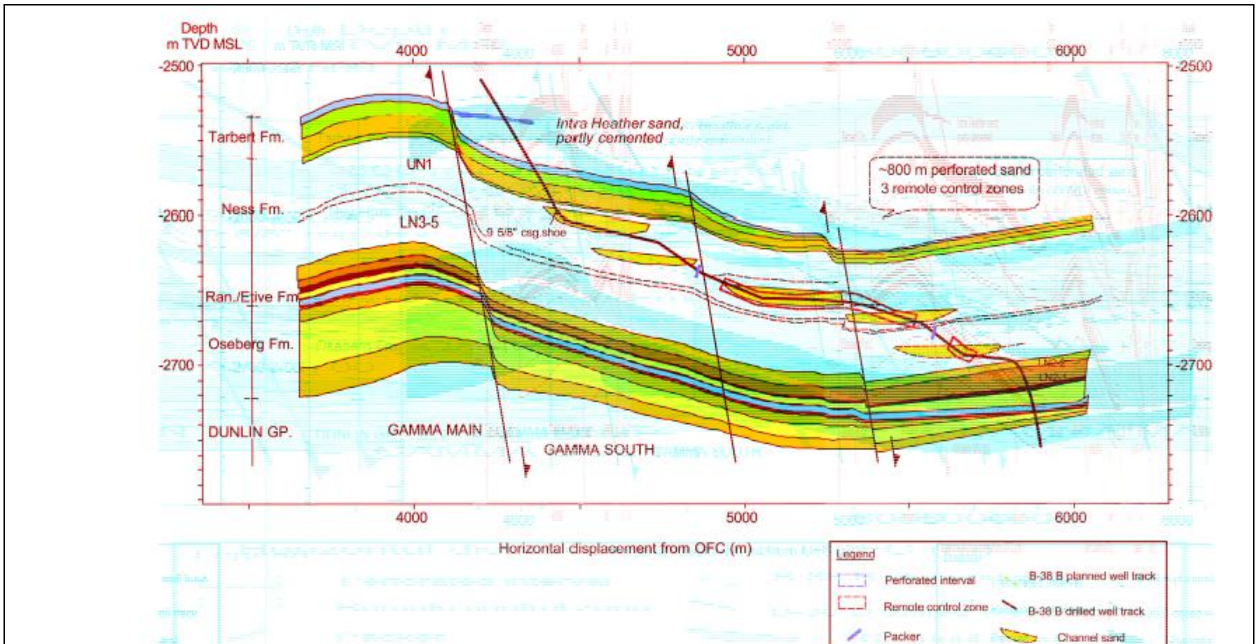

Fig. 3 - Schematic geological cross-section of the Brent Group along perforated well 30/9-B-38 B

Figure 21: Intelligent well trajectory in the Tern field

6.8 *Ghawar Field, Saudi Arabia*

Analytical methods such as nodal analysis are standard techniques to optimize the production of a well at a given point in time. However, techniques such as nodel analysis cannot predict the dynamic behavior that occurs in a well-bore when, for example, a second phase such as gas or water breaks through at one of the completions, changing the mobility from the reservoir into the well-bore and the flow regime in the well. As discussed in Section 3:

- Detecting and quickly reacting to the moment when a change in the production regime occurs is important, as this is the time to adjust the well production strategy to maximize oil production, minimize gas or water production, and manage reservoir depletion.
- In-flow control valves and downhole sensors in intelligent completions enable detecting and managing changes in the dynamics of the well without well intervention.

Well HRDH-A12 in the Ghawar field in Saudi Arabia is a Maximum Reservoir Contact (MRC) multilateral (ML) well equipped with an intelligent completion. It was drilled and completed as a trilateral selective producer with a surface-controlled variable multi-positional inflow control system (Figure 22).

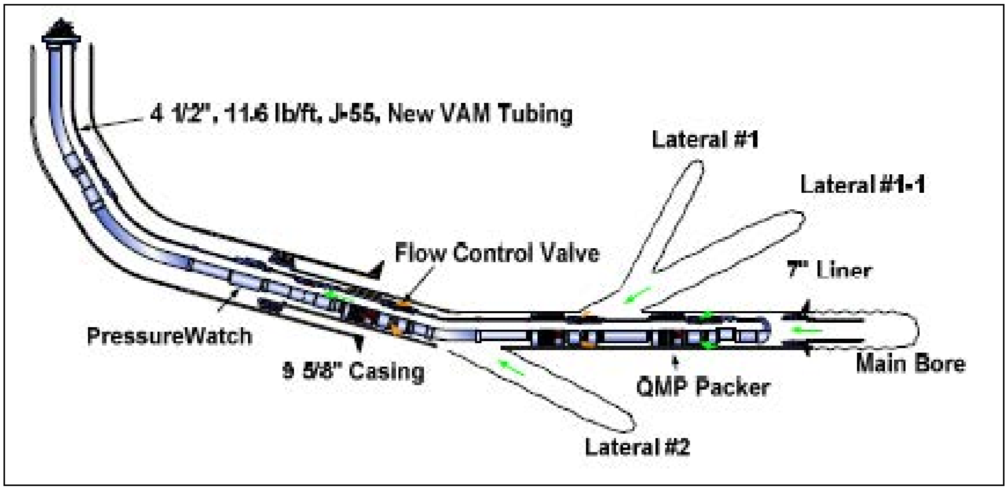

Figure 22: Haradh-A12 smart completion schematic (IPTC 11630 figure 3)

The intelligent completion used three variable downhole flow control valves designed to provide control of the inflow from each open-hole section of the well These valves operate as downhole chokes to restrict or completely shut off production from any interval with increasing water cut over time, thus enabling management of sweep efficiency. The completion also obtains real time reservoir pressure and temperature data, and ensures zonal isolation between the three laterals.

The well began producing water after two months of production, but the intelligent completion enabled a comprehensive rate test to be performed on the well using several downhole choke setting combinations. Once rate test data were analyzed, the well's downhole choke settings were optimized, resulting in a significant improvement in well performance[21].

Similarly, many horizontal wells are candidates for inflow remote control valves and isolation packers strategically placed to:

- Detect and shut off breakthrough of water or gas in a particular segment of the horizontal well.
- Distribute production evenly along the lateral to help provide uniform drainage and recovery.

6.9 *Dual Lateral Well, Saudi Arabia*

Similar to the Gulf of Mexico, where well production is often enhanced with the installation of an electrical submersible pump (ESP), a dual-reservoir completion using an intelligent completion and an ESP in a high-rate well was deployed in one of the large carbonate fields in Saudi Arabia. The ESP pumped the oil to a centralized processing facility far away from the well through a two-reservoir smart well completion that remotely controls fluid inflow from each of the two laterals. This completion enables commingled production from two reservoirs while balancing flow contribution from each reservoir and avoiding cross-flow (Figure 23). This completion uses a downhole hydraulic disconnect tool with an integral anchor assembly to connect the upper completion incorporating the ESP system with the lower completion (Figure 24). This integrated system provides the flexibility to control inflow from each reservoir in the future as the flow regimes change.[6]

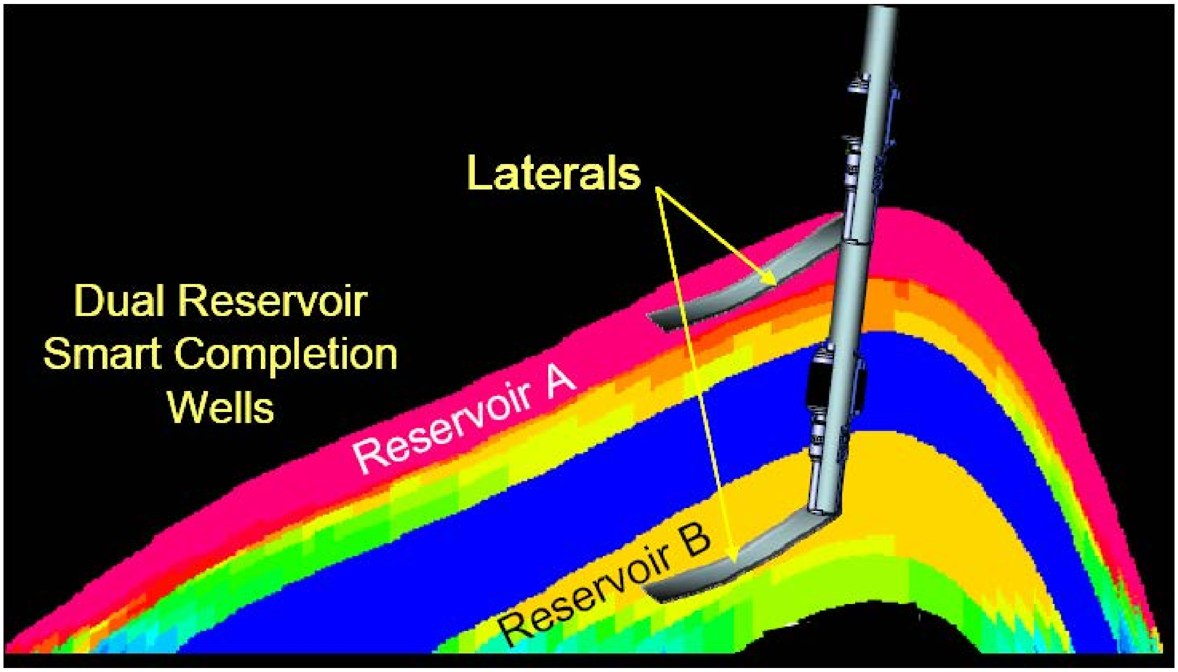

Figure 23: Dual-reservoir commingled production schematic (SPE 120303 figure 1)

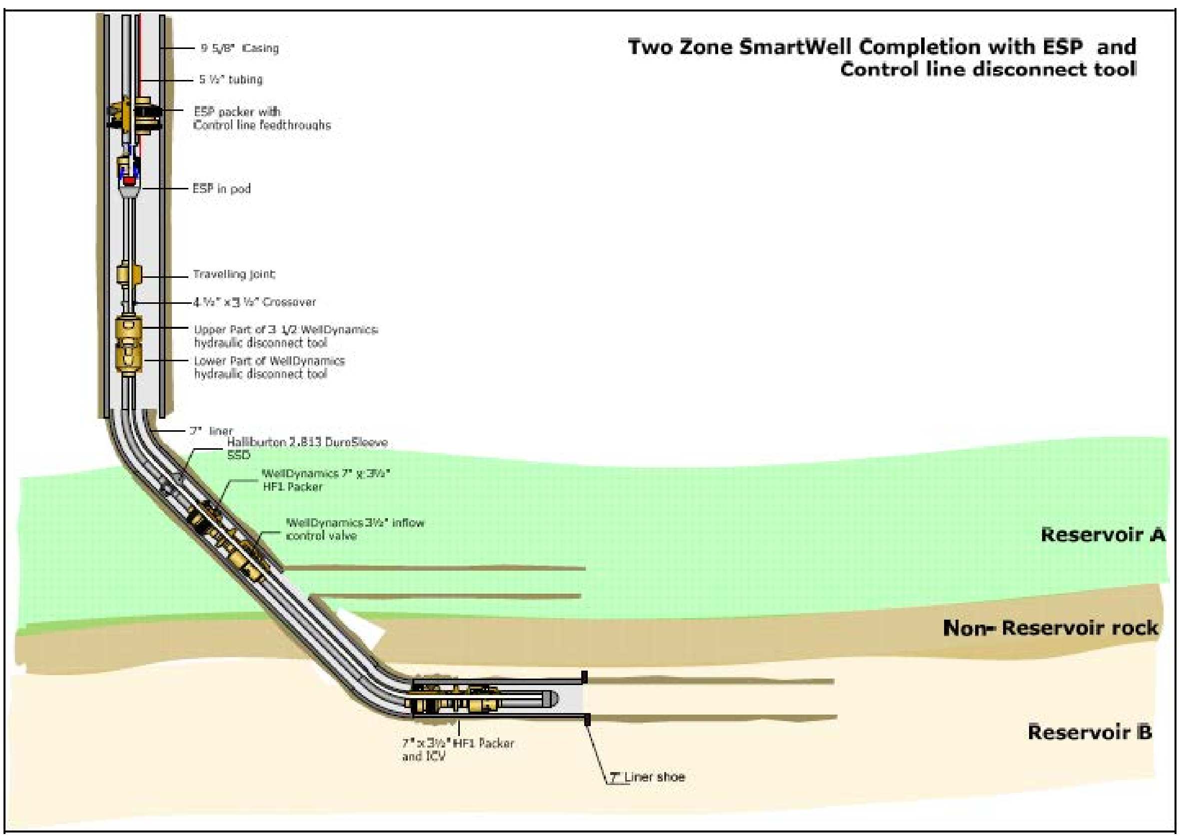

Figure 24: Intelligent completion schematic (SPE 120303 figure 2)

6.10 *Eastern Ecuador*

Producing wells in eastern Ecuador usually contact two to four productive reservoirs. The Government regulatory body historically restricted commingled production from these reservoirs due to concerns that commingled production will lead to loss of hydrocarbon resources by cross-flow, excessive draw-down and inefficient production allocation to reservoirs. The installation of an intelligent completion addressed these concerns by providing real time monitoring of each reservoir along with surface-controlled sliding sleeves across each reservoir. The monitoring system provides bottomhole pressure and temperature of each reservoir as well as the flow rate and water cut of the lowest reservoir. Combining the bottomhole flowing data with three-phase flow measurement at the surface, the operator is able to accurately allocate well production to each of the producing intervals and adjust flowing parameters from each reservoir to eliminate cross-flow, thus satisfying regulatory concerns.[4]

7 Reliability of Intelligent Completions

Today approximately 1000 intelligent well completions worldwide located primarily in the deep waters of the Gulf of Mexico, North Sea, and west coast of Africa. During the last few years, Statoil alone has installed more than 25 intelligent well completions with over 70 inflow control devices on the Norwegian Continental Shelf.

The reliability of intelligent completions, including key components such as downhole sensors and the hydraulic controls associated with intelligent completions, is key to achieving the promise of higher ultimate recoveries from intelligent completions. Based on available data, the major service companies that manufacture and service intelligent well equipment have achieved an average intelligent completion system reliability of about ninety percent through such design techniques as:

- Use of field-tested high-strength non-elastomeric seals.
- Flow slot and port configurations designed to be resistant to erosion
- Use of tougher compounds for hydraulic lines.

The population of intelligent completions this 90% reliability figure is based on comprises:

- Halliburton: 480 installations
- Baker Hughes: 190 installations
- Schlumberger: 400 installations

7.1 *Inflow Control Valves*

In many applications, intelligent completions must be actuated repeatedly under severe well conditions; hence, ensuring sliding sleeve reliability is an important part of the reliability equation. A remotely actuated inflow control valve (ICV), also known as a sliding sleeve or a choke, is driven by hydraulic, electro-hydraulic or electric systems, and can be binary (i.e. be either open or closed), have multiple degrees of opening, or be infinitely variable. Remotely actuated sliding sleeves were derived from the mechanical sliding sleeve, which has accompanied casing packers for decades to enable circulation from the casing annulus to the tubing and to produce multiple reservoirs sequentially.

Sliding sleeves are reliable tools when used with the care required of any equipment exposed to oil, gas and water. In many completions where wells are produced sequentially, sliding sleeves are left for months or years without being activated, with drilling fluid in the annulus behind the sleeve. Good practices to help ensure reliable operation are to:

- Flow every reservoir after the well is completed to test the sleeve and to ensure that the outside of the sleeve does not become caked with mud
- Have lubricating fluid (e.g. oil) behind the sleeve so that later activation is facilitated.

7.2 *Feed-through Isolation Casing Packers*

Feed-through isolation casing packers ensure individual reservoir control and segregation of reservoirs, and incorporate feed-through facility for control, communication and power cables.

Casing packers have been used for decades with a basic sealing principle which has not changed, although material standards for packers have evolved to meet varying production characteristics in terms of fluid composition, temperature and pressure. Whether permanent or retrievable, packers have a reliability factor of some 99%.

7.3 *Permanent Downhole Sensors, Connectors, Control Lines and Hydraulic Lines*

During the relatively early period of permanent monitoring installations in the mid-1990s, only 80% of permanent gauge systems were still operational after 2 years. From 1995 to 2000 reliability improved significantly, with 90% of installations still operating after 2 years (Figure 25).

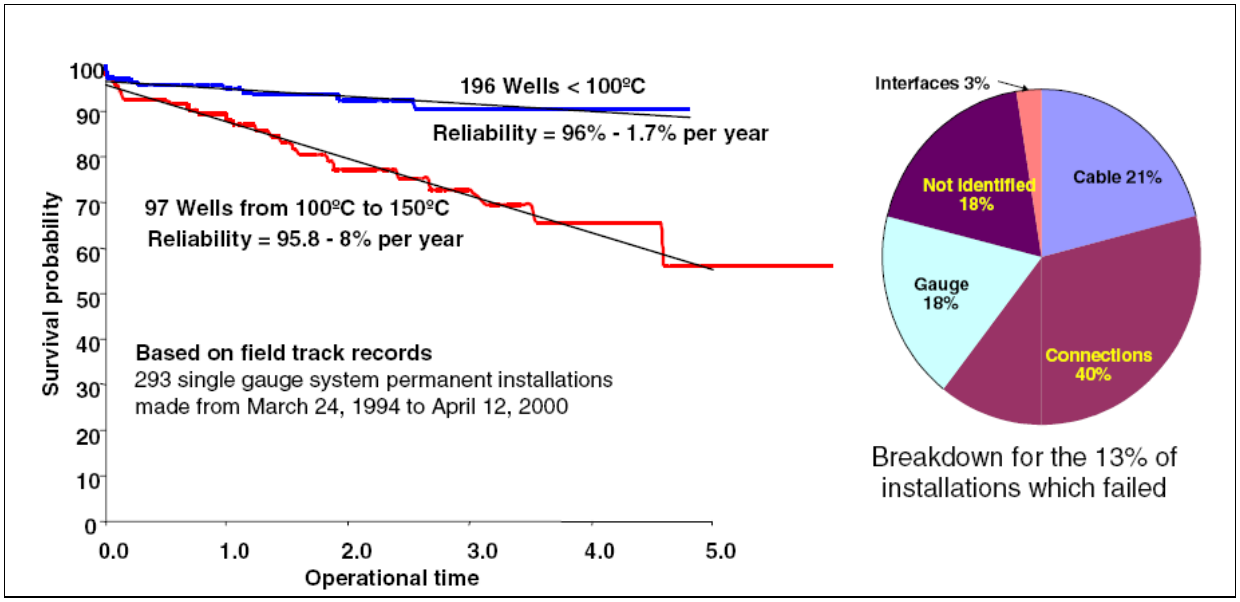

Figure 25: Reliability analysis for permanent gauge installations (OTC 13031)

The challenge is to achieve and to confirm the high reliability of intelligent completions, particularly in the harsh environments in which they are frequently installed. The industry has made extensive studies of the design improvements required for reliable intelligent completions. Much of this work is focused on the design phase, using tools such as failure mode and effects analysis (FMEA) and reliability qualification testing (RQT)[14] including failure mode testing (FMT) and accelerated lifetime testing (ALT).[15] The implementation of these techniques in the 1980s and 1990s led to improvements in system longevity, but there still remained room for improvement[16].

The rapid uptake of intelligent completions since 2000 increased efforts to improve reliability, and a holistic approach was often used to realize further improvements. A traditional product design approach considers intelligent well system delivery in three discrete steps: design, manufacture and installation. A more effective product line management system considers the product life cycle as an iterative process with formal management systems that link each stage.[16] Central to these systems is methodical record-keeping and comprehensive analysis of system operation and any failures on every installation. By applying this holistic approach to the permanent monitoring product line, the latest generation of systems has shown an impressive improvement in reliability.

As an example, Figure 26 shows a survival plot for different permanent gauge systems installed between 1996 and 2005, in part due to deployment of a new dry-mate sealing technology, which has resulted in over 150 permanent gauge installations without a single failure. This new connector technology was developed after analysis identified connectors as a major cause of failure in permanent gauge systems[18]. Under the project lifecycle management process (PLMP), the engineering teams at major service companies instituted better training programs before completing a client installation. Without this complete system approach to introducing this new technology, this track record would not have been achieved.[16]

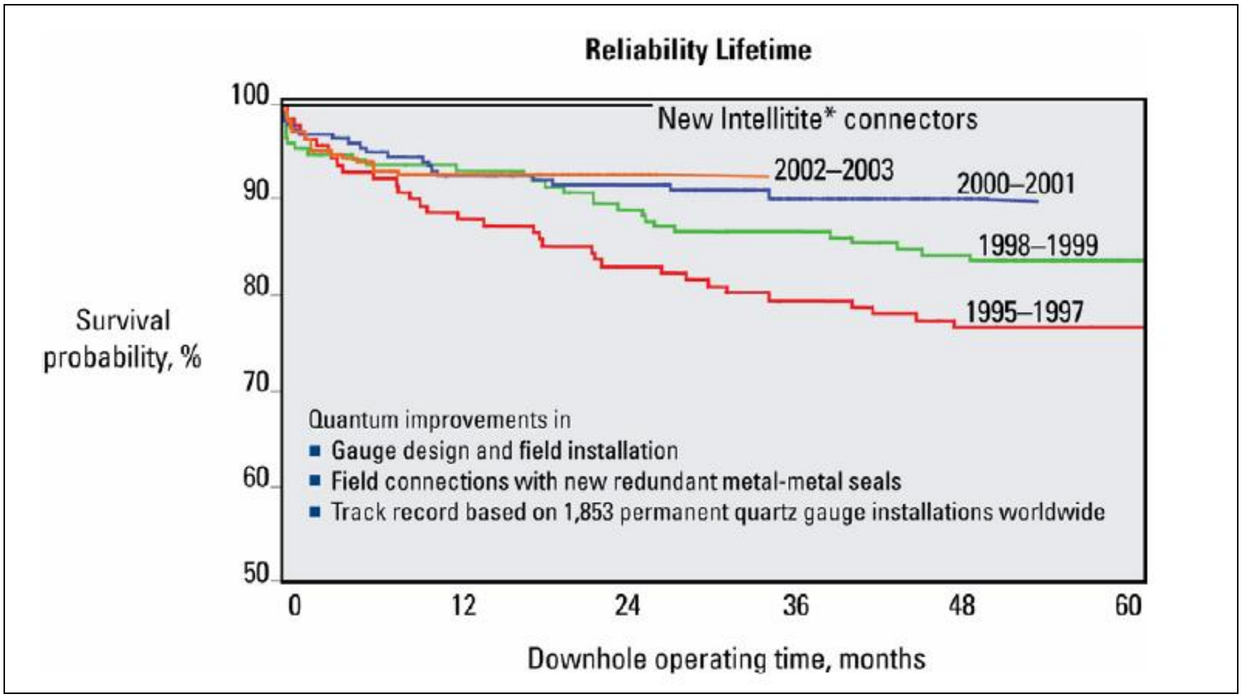

Figure 26: Survival probability of successive generations of permanent downhole gauges (OTC 17999)

While it is impractical to run long-duration laboratory and field tests to qualify the systems for longevity before installation, the industry has set a high reliability target: a 90% probability to survive 10 years for actuators on sliding sleeves and a 90% probability to survive 5 years for monitoring systems.

We checked with the American Petroleum Institute (API) and the Gulf of Mexico Offshore Operators Committee and learned that neither organization keeps comprehensive records of failures of intelligent completion components in the Gulf of Mexico or the USA. We also checked with multiple offshore operators, only one of whom offered hard data on component reliability. This operator indicated that, out of the operator's 28 intelligent completions around the world, three completions had valves that were inoperable due to suspected plugged control lines. This implies system reliability just under 90% over a three year period; a creditable performance.

8 Potential Regulation for Intelligent Completions

The relatively rapid natural decline and relatively low primary recovery factors of many reservoirs in the Gulf of Mexico is leading companies to consider both Improved Oil Recovery (IOR) techniques such as artificial lift and further opportunities for commingling. At present, there are roughly twelve major producing horizons in the GOM. Current wells tend to produce the more prolific reservoirs, leaving behind for the time being those of lesser volumes and pressures. While in principle these deferred reservoirs can be produced later, some can end up not being produced. Drilling wells to produce individual reservoirs in the GOM is expensive, as are dual tubing completions, and companies are not inclined to develop their fields using these techniques given the investment required. As discussed above, using intelligent completions combined with careful monitoring offers an effective approach to commingle multiple reservoirs.

Even using intelligent completion technology, regulations cannot go away[2], since designing and operating an intelligent completion to produce multiple reservoirs requires complex engineering and continuous monitoring to ensure ultimate recovery of as much oil as possible.

Practical issues associated with commingling regulators must consider include:

- Reservoir management and flow control
- Well integrity, i.e. prevention of cross-flow between reservoirs
- Compatibility of reservoir fluids

These are described in more detail in the next section.

8.1 *Reservoir Management*

Reservoir drive mechanisms in the Gulf of Mexico include:

- Depletion drive/solution gas drive
- Gas cap drive
- Aquifer (water) drive
- Water and/or gas injection
- Rock compaction

In deeper formations of the Gulf of Mexico, rock compaction is a more important drive mechanism than at shallower depths, although all drive mechanisms exist. As discussed in Section 3, designing an intelligent well completion considers the drive mechanism, flowing bottomhole pressure (Pwf) and static pressure of each reservoir as well as the composite IPR curve of all the reservoirs. The optimum pressure into the well-bore from each producing reservoir can then be set and managed using the inflow control valve in the intelligent completion[2].

Reservoir management and flow control include:

- Ensuring that intelligent completions can manage production and formation tests from each reservoir independently an unlimited number of times without intervention using packers and remotely-operated sliding sleeves.

- The ability to monitor pressure at each formation face as well as at the entry to the tubing at each sliding sleeve. Pressure monitoring will enable estimation of production and royalties from each reservoir and indicate if sliding sleeves adjustments need to be made to improve reservoir management. Downhole temperature and flow gauges, while usually not essential, can be useful in augmenting the capability to manage the reservoir.
- The ability to open or shut off a reservoir in a commingled well at will. The possibility of shutting off reservoirs is important to prevent cross-flow between reservoirs and to exclude production of unwanted effluent (water, gas).
- The capability to actively modify flow from each reservoir through inflow control valves to maximize recovery from the reservoirs.

8.2 *Well Integrity*

Well integrity refers to reservoir segregation, which is a function of the integrity and reliability of the well mechanical completion. Although intelligent completion technology has a good track record of reliability, the operator should present a clear plan to regulators for what to do if one of the critical elements of the completion fails.

Clearly, a production system with a dry tree will facilitate operator intervention if a workover is required to repair a component of an intelligent completion.

8.3 *Compatibility of Reservoir Fluids*

Compatibility of reservoir fluids refers to the ability of fluids to mix without causing problems such as precipitates or emulsions that will negatively affect the production system.

8.4 *Necessary Information for Commingling Applications*

Applications for commingling should address the above issues before approval is granted. An operator should thus provide the following information when applying to commingle:

- A detailed well completion design, including inflow control valves and gauges to be used
- The well completion installation procedure
- Number and description of reservoirs to be produced and commingled, including the depth and thickness of each reservoir
- The prospective production rate of each reservoir
- Data for each reservoir, including where known rock and fluid characteristics, reservoir drive mechanism, bottomhole pressure, PI, IPR graph and OOIP. While much of this information will be limited for new discoveries, requiring operators to identify what information they have is important to help ensure effective long-term reservoir management in the Gulf of Mexico.
- How the operator will routinely evaluate pressure, production and related data from each reservoir to help optimize oil and gas recovery.
- How the operator will allocate production to individual reservoirs for reservoir management and reserves booking purposes[17]

- Well management plan, including procedures to handle events such as cross-flow and water and gas influx
- Procedures for testing the inflow control valves
- Reliability information for inflow control valves and gauges to be used
- Contingency plans in case intelligent completion components fail

9 Alternatives to Intelligent Completions in Reservoirs in the Decline Phase

Uncontrolled commingling (i.e. commingling without use of intelligent completions) may work successfully in reservoirs:

- In the decline stage with fairly low production rates
- With similar fluid compositions, drive mechanisms and depth-adjusted pressures (within 200 psi)
- Located in the same reservoir complex within 200' of one another.

A question then arises: what techniques regulators should consider requiring in an uncontrolled commingling situation? Two potential options are oil and gas fingerprinting and production logging.

9.1 *Oil and Gas Fingerprinting through Geochemistry*

Oil and gas "fingerprinting" enables allocation of oil and gas production to individual reservoirs by tracking the geochemical composition of the produced fluid. Produced oil and gas from a particular reservoir bear distinct fingerprints[8]. Variations in oil and gas composition are the product of selective biodegradation of different hydrocarbons based on such variables as temperature, pressure and presence of oxygen, giving oil and gas from each reservoir distinct molecular signatures or "fingerprints" and enabling allocating of commingled oil and gas production to different reservoirs in a commingled well or, in some cases, to different sections of a horizontal well (Larter, et al., 2008)[9]. Geochemical procedures such as gas chromatography needed to allocate commingled production have been well documented (Kaufman et al,. 1990)[10]. Of course, fluid samples must be available from each reservoir. Figure 27 provides a graphical example of a geochemical fingerprint.

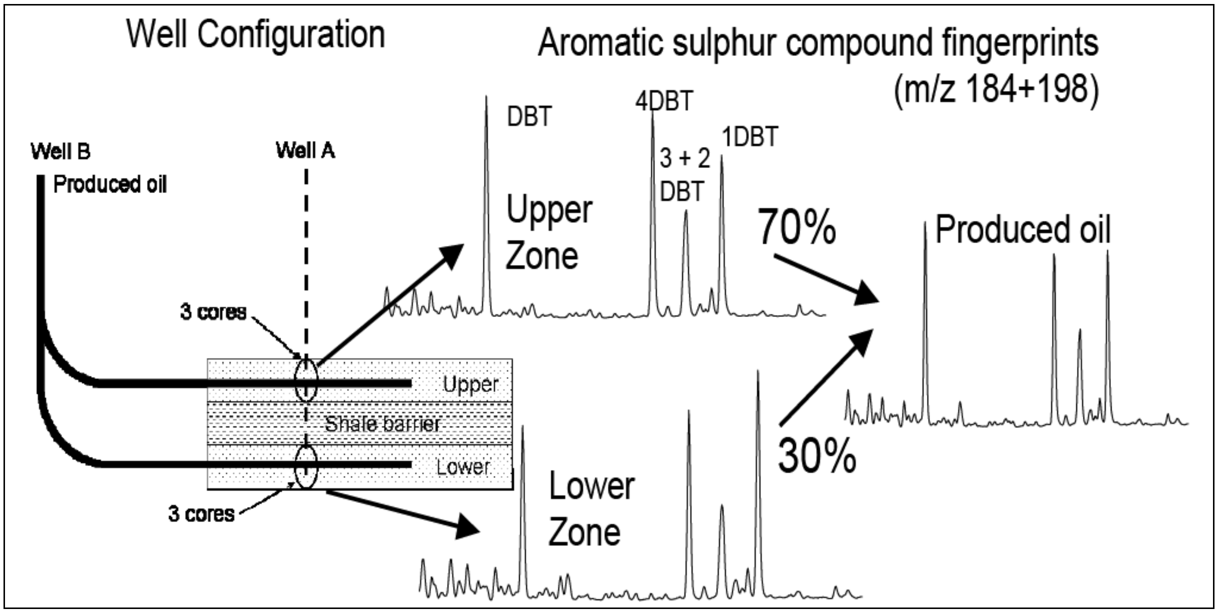

Figure 27: Production allocation based on aromatic sulphur compounds (courtesy of Petroleum Reservoir Group, University of Calgary, 2009)

Geochemical techniques for allocating commingled production from multiple reservoirs in a single well are accurate, rapid, relatively inexpensive, non-disruptive to production, and applicable to both naturally flowing wells and wells.

9.2 *Case Studies*

A gas field in Oman produces from three rich gas-condensate bearing sandstone reservoirs via twenty-three development wells, of which eleven are on production. Three wells commingle from the three reservoirs, and one well commingles only from the upper two reservoirs. The common allocation methods previously used involved zonal isolation and were limited because the commingled flow rates obtained on the surface were not necessarily representative of isolated formation flow rates. Geochemical techniques using gas chromatography and isotope analysis enabled properly allocating gas production from commingled reservoirs.[12]

In the super-giant Burgan field in Kuwait, approximately fifty oils were analyzed to enable application of reservoir geochemistry in the field to help address the following reservoir characterization and management issues:

9.2.1 **Reservoir Continuity**

The Burgan field contains five major reservoirs. Each of these is further subdivided into several reservoir layers. Oil fingerprinting along with other oil field data are used to evaluate vertical and lateral compartmentalization in the field.

9.2.2 **Production Allocation and Well Diagnostics**

The relative proportions of individual oils in an oil mixture can be determined with gas chromatography (GC), providing a rapid means of production allocation in Burgan without taking wells off production. This method is also applied to evaluate the extent of oil mixing:

- In the well-bore due to mechanical problems, or

- In the reservoir because of cross-flow from deeper, higher-pressure reservoirs.

Although the oils in the Burgan field are compositionally very similar, minor differences are sufficient to monitor oil from different reservoirs and field compartments.

9.3 *Production Logging*

Production logging helps measure the quantity of oil and gas being produced from a specific reservoir using such techniques as wireline spinner surveys; however, production logging has accuracy limitations and can only indicate relative flow at the point in time when the survey is run. Reservoir testing and other analytical work are often needed to support the results of production logging and enable reasonable production allocations between reservoirs.

In a subsea (wet tree) completion, running production logs can be a highly expensive proposition in that a mobile rig would be required.

9.4 *Regulatory Applications of Oil and Gas Fingerprinting and Production Logging to Commingling*

In a well with a properly functioning intelligent completion, oil and gas fingerprinting and production logging are generally unnecessary; however, situations may arise in depleted offshore fields where an operator believes that the cost of an intelligent completion renders commingling uneconomic. In these situations, regulators may wish to consider the following stipulations before approving commingling:

- The operator demonstrate that the cost of an intelligent completion would render production uneconomic
- The operator provide evidence that the reservoirs to be commingled:
  - Are in the decline phase
  - Have compatible fluid properties and drive mechanisms
  - Have depth-adjusted static pressures within 200 psi of each other.
- The operator carry out hydrocarbon fingerprinting or production logging once every three to six months.

If hydrocarbon fingerprinting or production logging provides evidence of cross-flow or other downhole problems, the operator should be required to take steps to expeditiously work over the well to remedy the problem.

10 Conclusions

When reservoirs are commingled in an uncontrolled fashion, the reservoirs are likely to produce in a sub-optimum manner due to the differences in pressure, productivity index (PI), gas-oil-ratio (GOR), and water production. One reservoir may cross-flow into another, and gas or water breakthrough in one reservoir may limit the oil production in the other, reducing ultimate recoveries.

Traditional methods of exploiting multiple reservoirs without commingling are to either:

- Develop the reservoirs sequentially from the bottom up
- Use multi-string completions to maintain segregation.

Both of these methods present economic drawbacks, such as the long time needed to exploit all the reservoirs in the case of sequential production and the limited tubing sizes and high cost of multi-string completions.

An alternative technique to produce from multiple reservoirs is to use intelligent completions to manage commingling and avoid cross-flow between reservoirs. While intelligent completions pose incremental capital and operating costs, they enable greater flexibility in producing multiple reservoirs simultaneously or sequentially without risk of cross-flow. This report recommends using intelligent completions as the standard requirement when operators request to produce in a commingled fashion.

In fields where the operator believes that the cost of an intelligent completion would render commingling uneconomic, regulators may wish to consider approving commingling under the following stipulations:

- The operator demonstrate that the cost of an intelligent completion would make commingling uneconomic
- The operator provide evidence that the reservoirs to be commingled:
  - Are in the decline phase with fairly low production rates
  - Have compatible fluid properties and drive mechanisms
  - Are located in the same reservoir complex within 200' of one another.
  - Have depth-adjusted static pressures within 200 psi of one other.
- The operator carry out hydrocarbon fingerprinting or production logging every three to six months to enable detection of cross-flow.

If hydrocarbon fingerprinting or production logging provides evidence of cross-flow or other downhole problems, the operator should be required to take steps to expeditiously work over the well to remedy the problem.

Knowledge Reservoir would like to thank the Minerals Management Service for the opportunity to carry out this study.

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