Managing uncertainties in reservoirs, particularly in carbonate rocks, is a major challenge. However, intelligent-completion technology gives operators the ability to monitor and control individual zones within wells. Without this control, operators may lose a well when a zone unexpectedly waters out or a well may require mechanical intervention, with its associated risks and costs.

Intelligent-completion technology is enabling operators to optimize production or injection programs, improve reservoir performance, achieve higher extraction ratios, and reduce field-development and intervention costs. The technology’s reliability has been demonstrated in high-productivity wells, and fit-for-purpose intelligent completions are now being installed in wells with lower productivity to help safeguard against reservoir uncertainties and provide incremental production.

In this article, Bernard Montaron and Adam Vasper describe examples for applications ranging from water control to gas lift in which intelligent-completion technology is proving to be the most economic option.
Completions that enable reservoir engineers to monitor and control production or injection in at least one reservoir zone are known as intelligent or smart completions. Such technology is proving to be a reliable and cost-effective way for better reservoir management. It protects operations from the risks associated with early water or gas breakthroughs and from crossflow between producing zones in the same well. The technology also helps operators to increase production rates, extend field life, and reduce the need for well interventions.

Intelligent completions in multilateral wells were reviewed in *Middle East & Asia Reservoir Review* in 2001 (issue 2, pages 24–43). The possible benefits of intelligent completions were described, but at that time there were few examples to consider and none from the Middle East or Asia. Since then, the economic benefits of using this technology have been demonstrated for high-end wells in the region, those typically producing over 1,500 m³/d. Fit-for-purpose intelligent-completion technology is now being successfully applied to lower-productivity wells in a variety of applications. Increasingly, the technology is being used in the Middle East to manage uncertainty in carbonate reservoirs, but other applications for intelligent completions include gas lift optimization and sand management.

Managing uncertainty

Intelligent completions are being used to manage reservoir uncertainties, and the technology has now become well established. Operators such as Statoil, Shell, and Saudi Aramco adopted intelligent-completion technology during the early stages of its development and now expect to use it in any well that is designed to produce from several zones or in which there is a risk of early gas or water breakthrough.

Determining the permeability of a carbonate reservoir before drilling is very challenging. In many wells, a large proportion of the fluid is produced from or injected into a relatively short high-permeability section. The location of this high-permeability streak may be unidentified, even after a thorough formation evaluation. Carbonates tend to fracture more easily than sandstones. Although a carbonate matrix may have a permeability measured in millidarcies, an adjacent fracture is likely to have a permeability above 1 D, which gives a permeability contrast of the order of 1,000 over a very short distance.

Using data from wireline tools such as the FMI* Fullbore Formation MicroImager*, geoscientists and reservoir engineers can identify open and closed fractures but cannot predict which fracture zones will produce water in the future. Likewise, resistivity images can show the location of conductive intervals, but without further investigation, using the MDT* Modular Formation Dynamics Tester tool, for example, it is difficult to know whether the intervals are connected and to establish if they will flow.

So how can this uncertainty be managed? In some circumstances, a reactive well intervention, such as plugging and abandoning a water-producing zone, may be appropriate. However, mechanical intervention can be costly because it may require bringing a rig to the wellsite and there is the consequent loss of production during the workover. There is also a risk that the intervention equipment may become stuck in the well. Simply accessing deepwater and subsea wells can be challenging, and, as well designs with multilateral legs become more complex, well intervention is becoming increasingly difficult.

Gaining access to the well is only part of the challenge. Once this has been achieved, the asset team must then decide what to do. Data for total flow rate, wellhead
pressure, and fluid composition can be acquired at surface, but only downhole static snapshots from well tests and production logging are available with standard completions. Running production-logging tools in wells with complex well configurations can be risky, time-consuming, and expensive, particularly where laterals branch from the underside of the mother bore. Even in wells where the operators conduct periodic logging investigations, a problem such as crossflow between producing zones may go unnoticed for years.

Some operators choose a proactive strategy and use intelligent completions to provide continuous reservoir monitoring and control of production from one well. High-quality reservoir data are available at a cost, but the time, cost, and associated risk increase rapidly as the number of wells increases. Intelligent completions, however, can provide high-quality data at a reasonable cost. The Schlumberger TRFC-HN AP tubing-retrievable flow control valve, for example, is hydraulically actuated and can be used to regulate annular to tubing production. The TRFC-HN LP valve has a shroud across the choke section and can control production from within the same tubing (Fig. 1). The TRFC-E valve is also tubing retrievable, but it has an electromechanical adjustable choke and integrated pressure, temperature, and mass flow sensors. These sensors can measure flow data within the tubing and the annulus.

Reliability is vital for systems that have to operate throughout the life of a well—some Schlumberger flow control valves have now been in continuous operation since 1998.

Intelligent completions use gauges, valves, packers, and other equipment to integrate zonal isolation, flow control, artificial lift, and sand control. However, there is far more to intelligent completions than installing safe and reliable hardware. A cycle of monitoring, simulation, and control is used to optimize production or injection (Fig. 2).

Downhole monitoring and movements

Permanent downhole monitoring began in the 1960s using modified wireline equipment, but the gauges used have come a long way since then and have earned a worldwide reputation for reliability. Today’s intelligent completions use single pressure and temperature gauges to monitor fluids in the tubing and the annulus. Other sensors monitor the performance of ESPs or provide wellbore temperature profiles.

The valves that control fluid flow are among the most important components in any downhole configuration. The original downhole flow control valves were simple devices with two settings: open or closed. Today, engineers can use sophisticated valves with 10 sequential choke positions plus a fully closed position.

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Keeping the reservoir in mind

Interventions in high-angle, multilateral, and subsea wells can be difficult, and some intelligent completions have been designed to make them unnecessary. Reduced need for well intervention is a significant benefit of using intelligent completions, but it is important to design the completion systematically and from the perspective of the reservoir.

Reservoir and production engineers optimize an intelligent completion at the design stage using reservoir models or nodal analysis to tailor it to a particular well. Economic considerations play an important part in this design process, and the completion’s functionality is a trade-off between the costs, the risks associated with reservoir uncertainties, and the benefits that increased monitoring and control can bring.

For example, monitoring and controlling every 10-m well section may be economically unrealistic, but without any control an entire well might be lost through premature waterfacing out in just one producing zone. In this situation, the operator might calculate that an intelligent completion that isolated and controlled the main producing zones would provide useful protection against reservoir uncertainties.

In the absence of monitoring and control, water cut in a single producing zone could force an operator to abandon an entire well, even if the other zones were still producing oil without significant water cut. However, if the calculations indicated that an intelligent completion would deliver optimized production, higher extraction ratios, and lower intervention costs, the commercial reasons for choosing this approach could be overwhelming. The number and the location of the flow control valves are usually determined by the number of lateral legs, or the number of major producing zones within these legs, and by the economic factors.

When the asset team has a good reservoir model, it will be used to optimize the design of the intelligent completion. Modern reservoir models divide the reservoir into a discrete finite-difference grid that can be used to solve fluid flow equations in the formation. The well is segmented in the same way so that the asset team can solve fluid flow equations for the tubing. Alternatively, when only basic reservoir parameters such as pressure and productivity indices are known, nodal analysis can be applied. These parameters are used to build nodal analysis models, which ultimately identify the required choke areas.

Since the early intelligent completions were installed, the design process has been made more systematic, which has helped to reduce the lead time required. A strong team approach between the operating company and the service provider is required during the design phase to ensure that the completion is fit for purpose and optimizes production or injection.

Balanced production

Many brownfield development wells have multiple targets. Minor pays may not produce in the presence of uncontrolled prolific zones, and crossflow from a prolific zone into a minor zone may develop. In the past, minor pays may have been bypassed to protect prolific zones from this crossflow, a condition that occurs when two production zones with dissimilar pressures are allowed to communicate.

Intelligent-completion technology now enables operators to take incremental production from zones that would have been bypassed, without creating crossflow conditions or having to recomplete the well. This is achieved either by balancing production from each zone using adjustable valves or by isolating the zones and producing them sequentially. In addition to using flow control valves, a new system that equalizes reservoir inflow along the whole length of the reservoir, ResFlow, is now available.

Balancing production within a well can also help to delay water or gas breakthrough. Choking back or shutting off production from the problematic zone using intelligent-completion technology enables the other zones to continue draining the reservoir, which improves the extraction ratio, without well intervention. Optimizing production in the reservoir can improve sweep efficiency and reserves recovery, and extend field life.

It is important to design the completion systematically and from the perspective of the reservoir.
Equalizing inflow

Early water and gas breakthrough can occur through high-mobility zones, particularly in carbonates, where there can be huge permeability contrasts over short distances. ResFlow is a new system that optimizes production in openhole completions by equalizing reservoir inflow along the wellbore. This self-regulating system is simple, robust, and reliable. A series of sections is installed with isolation packers. Each section has a LineSlot screen, which is wrapped around a base pipe. Reservoir fluid enters the screen and flows between the screen jacket and the base pipe (Fig. 3). The fluid then enters the production string through ceramic nozzles.

Nodal analysis is used to select the optimal combination of nozzle sizes. Fluid at higher flow rates is subjected to greater flow restriction, which stimulates production from zones with lower flow rates (Fig. 4). The system is self-regulating, has no moving parts, and requires no downhole telemetry or permanent well instrumentation. There is no risk of the nozzles plugging because they have diameters more than 10 times the screen’s slot size.

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Oil and water in Middle Eastern carbonates

Water control in Well A

Water control in carbonates is an important objective for many operators. Maximum-reservoir-contact wells are being drilled by Saudi Aramco to maximize production rates and increase oil recovery ratios (they can provide a threefold increase compared with vertical wells) with considerable cost reductions per unit of production. Intelligent-completion technology is being used to achieve balanced production from these multilateral wells to control drawdown and to reduce water cut. The system ensures sustainable oil production in a challenging carbonate reservoir with faults and fractures and also offers the added value of the possibility of testing each lateral separately.

Other oil companies, such as India’s ONGC, are also pursuing a policy of drilling maximum-reservoir-contact wells with intelligent completions, but in sandstones, with the additional objective of providing sand control.

Well A is a maximum-reservoir-contact well completed in a giant Middle Eastern field. It drains a heterogeneous carbonate reservoir and has two multilateral junctions on the mother bore. With a standard completion, and because of the reservoir heterogeneities in the area, the water cut rose to 23% within a year, thus reducing the oil production rate and increasing the water treatment and disposal costs.

In April 2005, an intelligent completion was installed to control production from each of the lateral legs (Fig. 5) in Well A. This was the first Schlumberger intelligent completion in this particular field.

Successful intelligent completions are not just about technology: they also require a systematic approach to planning that includes information from reservoir models. Multidisciplinary teams working across traditional business areas in both the oil company and Schlumberger developed the project from initial concept to production.

Reservoir modeling was a critical part of the completion design. The pressures from each lateral were simulated for different water cuts using PIPESIM* production system analysis software to provide data for the design process.

The intelligent completion installed uses three QUANTUM MultiPort packers and three TRFC-HN AP valves to control production from the lateral legs and the mother bore. During equipment and flow testing, each of the valves was actuated through more than 10 cycles (110 positional changes), which was equivalent to several years of operation, to demonstrate the technology’s reliability.

A WellWatcher* real-time reservoir and production monitoring system provides pressure and temperature data, which is sent to the oil company’s main offices via the InterACT* real-time monitoring and data delivery system. This information, along with multiphase flow rates measured using PhaseTester* portable multiphase periodic well testing equipment, is used to adjust the downhole control valves and maximize the oil production and minimize the water cut.

Following installation of the intelligent completion, oil production was maintained at 950 m$^3$/d; the well continues to produce with zero water cut. Early diagnosis of problems prevented the other laterals being choked back, and actuating the valves from the surface eliminated the need for intervention in the well, which avoided lost production.

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Falah field Well FD-11

Dubai Petroleum Company (DPC) has also used a similar intelligent-completion design for water control in carbonates. The company drilled a well at Falah field to produce from two zones via upper and lower lateral legs. However, it is notoriously difficult to predict when and where water breakthrough will occur in carbonate reservoirs, and the upper leg of the well began to produce water within a year. The lower leg was still producing oil at 160 m³/d, but DPC had to abandon the entire well because the upper leg could not be isolated.

When DPC decided to drill a new well in the field, intelligent-completion technology was included in the design. This would enable the asset team to monitor and control production from the lateral legs.

Well FD-11 was the first intelligent completion to be installed for DPC, which is a joint venture between the Dubai government and ConocoPhillips, and the first installation in the world for ConocoPhillips. The completion was installed in April 2005 after almost a year of detailed design work, manufacturing, and testing.

The intelligent-completion technology is connected to a QL permanent packer. Production from the lower zone is brought from this packer through tubing to the 9 5⁄8-in casing, and production from the upper zone flows through the annulus (Fig. 6). The valves that control production from both laterals are positioned relatively high in the well, in the low-deviation section, where they could be retrieved using slickline. However, the intelligent-completion technology is reliable, and retrieval has not been required.

The tubing and valves can isolate or choke back either of the two lateral legs, and a dual gauge sensor provides the pressure and temperature information that DPC needs to make informed production-optimization decisions. The monitoring gauge is positioned in the tubing wall and can therefore measure the pressure and the temperature inside the tubing and in the annulus to provide information on the lower and the upper lateral legs respectively.

Well FD-11 has the world’s first installation of a hybrid electric–fiber-optic control line. The dual gauge’s electrical cable has a built-in fiber-optic line to provide laser-temperature profiling from the QUANTUM MultiPort packer to the surface. Production in Well FD-11 is supported with gas lift, and the temperature profiles enable DPC to monitor the gas lift, valves and optimize the gas lift system. Built-in monitoring eliminates the need to run wireline production-logging tools and provides continuous, rather than sporadic, information.

Within the first year of operation, the flow control valves had undergone more than 160 individual positional changes in Well FD-11. Now that the technology is thoroughly field proven, new fit-for-purpose completions are being designed that will increase the net present value for this kind of intelligent completion for water control. For example, the valves used in this first completion have more positions than necessary for this particular application, and simpler, more cost-effective valves are being developed.

In the future, when excessive water production has caused one or both legs to be shut-in, it is possible that the oil and the water in the shut-in leg will separate and that the oil will build up sufficiently for the flow control valve to be reopened and additional production to be gained.

Intelligent injection

Injecting fluids can maintain reservoir pressure and improve reservoir sweep efficiency and recovery factors. However, the injection flow profile is rarely uniform, particularly in carbonates where large permeability contrasts between the matrix and fractures can lead to extremely uneven injection fronts (Fig. 7).

High-permeability streaks or fracture systems can capture most of the injected fluid, which results in poor reservoir sweep efficiency. However, intelligent completions can be used to equalize the injection rate along the wellbore. For example, ResInject is a self-regulating system designed to even out injection rates despite the presence of heterogeneous permeability (Fig. 8).
Fluid enters the unit’s housing through ceramic nozzles in the base pipe. It then flows into an energy-absorbing chamber between the base pipe and the LineSlot screens, and then into the reservoir. The nozzles and energy-absorbing chamber prevent formation erosion. The desired pressure drop, which is independent of fluid viscosity, is calculated using nodal analysis software and dictates the combination of nozzle sizes used. The system is simple, robust, and reliable, and does not require downhole telemetry or permanent well instrumentation.

If a high-permeability theft zone exists, the ResInject nozzles self-regulate to prevent a significant increase in the injection rate to this zone. Low-permeability zones receive more water than they would using a standard screen completion. Consequently, the system reduces field-development and well-intervention costs by • enabling multiple injection zones to be managed • making injection profiles more uniform, with reduced injection in high-permeability zones • delaying water breakthrough • increasing oil recovery.

The ResInject system had its first installation in April 2006 for Statoil.

Intelligent artificial lift in Indonesia
CNOOC wanted to increase the total production from the north-east Intan field by drilling infill wells (Fig. 9). Nine targets were identified, but the existing platform had only three remaining well slots. An additional platform to provide more well slots would have cost USD 3.5 million. A two-leg multilateral with an intelligent completion using artificial lift was proposed as a way to access the two sandstone targets from a single well slot. The well had to cost less than and deliver a higher production rate than two typical Intan field horizontal wells for it to be commercially viable. To make the intelligent-completion option more attractive, a lease-based business model was developed, so that the intelligent-completion assembly was an operating rather than a capital expense.

The proposed well had a Technical Advancement of Multilaterals (TAML) level-6 classification (see Middle East & Asia Reservoir Review, 2, pages 28–33, for a full explanation of TAML levels). This is the highest level of complexity and gives pressure and mechanical integrity at the multilateral junction and selective access to each leg. Integrity was required as the two producing zones have significantly different reservoir pressures.

The net present value and the rate of return were calculated and showed that a TAML level-6 intelligent completion was economically viable. A simpler multilateral, such as a level-3 or 4 completion, would have had similar costs when rig time was taken into consideration, but would not have delivered the required functionality.

The first three sections of Well NEIA-24ML were drilled, and the bottom 37 m of the third 12 7/8-in section was underreamed to 17 1/2-in to facilitate the expansion of a RapidSeal® completion system. The multilateral junction, which was at 84 m measured depth and an inclination of 24°, was expanded and cemented in place, and the retainer was drilled out. A drilling deflector was then installed, and the first 6 5/8-in lateral leg was drilled. The second leg was drilled, and the laterals were completed with stand-alone premium sand screens because there was the risk of sand production.

The intelligent-completion design included a dual-gauge sensor to measure the pressure and the temperature of the tubing and annular flow, and thereby record data from both lateral legs (Fig. 10). TRFC-HN AP and TRFC-HN LP flow control valves were included to enable the production engineer to choke back the flow from each lateral. Both valves were cycled 44 times during installation to demonstrate their reliability.
An ESP with a variable-speed drive and capable of pumping at 300 to 1,900 m³/d was included, together with a Phoenix artificial lift monitoring system to provide pressure and temperature data for the ESP intake, discharge, and motor. The ESP was necessary because of the low reservoir pressure. PhaseTester multiphase well testing equipment was installed to provide measurements at the surface.

This completion, for the world’s first level-6 multilateral well with intelligent completion and artificial lift, had to be deployed in one run, so a detailed procedure was defined and followed. The five subassemblies were constructed and pressure tested onshore and on the rig. Then the entire assembly was function and pressure tested on the rig.

The sands in the reservoir pinch out laterally, but they are sufficiently widespread to produce a strong water drive in the field. Early water influx has been identified from the monitoring data, and CNOOC has been able to delay water production by controlling production from the two laterals. Careful monitoring and analysis of the continuously acquired data are also helping to generate a better understanding of the field.

Downhole monitoring is aiding the reservoir engineers in calculating real-time productivity indices for each lateral leg and performing pressure buildup tests without well intervention. This information is used to optimize the production from each leg, maximize the drawdown, optimize the efficiency of the ESP, and update the reservoir model.

The project has shown that, if drilling is problem-free, the cost of a level-6 multilateral with intelligent completion and ESP artificial lift is less than the cost of two horizontal wells. After one year, the cumulative production from Well NEIA-24ML was approximately twice that of horizontal wells NEIA-26 and NEIA-28 (Fig. 11).

The intelligent-completion approach also reduces the need for mechanical intervention and its associated costs and risks. However, the level-6 design allows reentry, and CNOOC has reentered each leg twice for stimulation and has also doubled the ESP capacity to 3,500 m³/d.

**Intelligent gas lift**

Gas lift is used to increase oil production rates or to enable nonflowing wells to flow by reducing the hydraulic head of the fluid column in the well. Gas lift systems can also mitigate the effects of high water cut and help to maintain tubing head pressure in subsea wells. Conventional gas lift systems pump gas down the annulus from the surface and require a considerable investment in pipelines, compressors, and other equipment.

The terms auto, natural, and in situ gaslift all refer to systems that use gas from a gas-bearing formation or a gas cap to produce a well. The lift gas is produced downhole and bled into the production tubing at a controlled rate through a downhole flow control valve (Fig. 12). This is an application for intelligent completions that has the immediate attraction of eliminating the expensive infrastructure required by traditional systems. An estimated 60 auto gas lift systems have been installed, mostly in the Scandinavian sector of the North Sea.

Auto gas lift is not yet widely used, but it is becoming an established technology. In the right environment, it can generate additional value by

- eliminating the capital costs of gas-compression facilities or gas transport pipelines
- reducing the offshore-platform load requirements by removing the need for gas compression facilities
- eliminating the need for the annular safety valves that can be necessary in conventional gas lift environments
- enabling nonassociated gas to be produced without recompleting the well
- providing operators with a system to control gas and water coning
- eliminating interventions for resizing or replacing conventional gas lift equipment. This is particularly beneficial for subsea wells.

**Figure 11:** Cumulative production over 90 days for Well NEIA-24ML compared with the production of two standard horizontal wells in the same field.

**Figure 12:** Gas from a gas-bearing formation or a gas cap is produced into the annulus and bled into the tubing through a downhole flow control valve.

**The flow control valve technology developed for auto gas lift has also found applications in subsea and deepwater wells using conventional gas lift.**
Gas lift stability in Australia

Woodside is the first company to use intelligent completions for gas lift stability. The company is producing Enfield field, Western Australia, from a cluster of five subsea wells to a floating, production, storage, and offloading (FPSO) vessel. Oil is currently being produced without assistance, but artificial lift will be required as the pressure drops and the wells begin to produce water. The wells have been designed to accommodate this.

Woodside wanted to avoid the costs and risks associated with interventions in subsea wells, so gas was selected rather than ESPs for lifting. The concern was that ESPs might require replacement during the field’s life. Very few subsea wells use ESPs for this reason.

A wide range of gas lift rates, from 1 to 10 Mcf/d, will be required over the lives of the wells. Gas lift rates are determined by upstream gas pressure, the size of the downhole orifice through which the gas passes into the produced fluid, and the downstream pressure (that of the produced fluid, which will vary as gas is added). Traditionally, the diameter of the downhole orifice is fixed, and a choke on the subsea template controls the pressure to vary the gas lift rate. The orifice diameter needs to be large enough to accommodate the maximum gas lift rate, so for much of the productive life of the well it is oversized, which means that stability problems can develop at low gas flow rates through the oversized valve. The subsea production wells in Enfield field also have long flowlines that cross an undulating seabed, which would exacerbate any pressure instability.

Pressures and flow rates vary in all multiphase wells. In gas lifted wells, these fluctuations can develop into large oscillations that exceed the safe operating window for production facility separators. If the safe level were to be exceeded, the well (or all the wells in some cases) would have to be shut in, and it would take time and effort to get the well back on line.

Suboptimal gas lift equipment is routinely changed in platform-based wells; the initial small-diameter downhole orifices may be replaced with larger orifices as the reservoir pressure declines or as the water cut increases.

Woodside was interested in using an intelligent completion that would give it control over the orifice size, avoid pressure instability problems, and eliminate rig-based well intervention.

The WRFC-H slickline-retrievable flow control system is a hydraulically operated valve housed in a Camco® side-pocket mandrel. The system offers an alternative to a fixed orifice that enables the downhole gas lift orifice size to be varied from the surface. Crucially, the system is designed to operate for the life of a well, about 20 years, without intervention.

Production profiles for Enfield field were modeled to evaluate fixed orifice and WRFC-H systems. The model used reservoir simulations and other information to determine the optimum gas lift rates, and the orifice-valve and choke sizes that would be required throughout the lives of the wells. Taking system stability into account, the engineering team determined the best fixed-orifice diameter for each well and also the best WRFC-H slot size to cover the required range of gas lift rates and pressure ratios.

For fixed orifices, the range of gas lift rates is bounded by a lower limit relating to system stability and an upper limit arising from the orifice size. The multiple operating positions of the WRFC-H offer a much wider range of gas lift rates while maintaining system stability, which results in better oil production rates. Comparison of these two cases yields a figure for the incremental oil that can be used in economic calculations.

The net present value of using WRFC-H valves was calculated for the production profiles in two scenarios: a productivity index taken from the reservoir model, and a 25% lower productivity index in case the wells had lower productivity than predicted.

The results indicated significant economic benefits for the intelligent completion using the WRFC-H system. In both scenarios, the oil production profiles were accelerated. The model also showed increased gas lift system stability using the intelligent completion.

The simulations demonstrated the value of using an intelligent completion, and so the five production wells were completed with the WRFC-H flow control valves in 2005. With the intelligent-completions design, Woodside will be able to accelerate production and avoid pressure stability problems. The company can also optimize production without well intervention and has the flexibility to deal with changing reservoir conditions.

Smart fields are the future

Wellsite integration of real-time subsurface and surface information and control of downhole equipment from remote sites are realities for many wells. The challenges now are to decide what data to acquire, when to make downhole changes, and how to apply this technology on a field-wide basis. Eventually, responses to changing reservoir conditions may become automatic and require only minimal human intervention.

Figure 13: Enfield field has a cluster of five subsea production wells, connected to an FPSO vessel. Changing the downhole gas lift orifices would require rig-based well intervention, and the long, undulating subsea flowlines could exacerbate any gas lift instability problems. For these and other reasons, Woodside has become the first company to use intelligent completions for gas lift stability.