Many questions follow a hydrocarbon discovery. How much oil or gas is there; how much is recoverable; how fast can it be recovered; how much capital expenditure is required and what will be the return on investment? Answering these questions invokes a dilemma: Reservoir development may not proceed without assessment, but gaining adequate data for assessment requires some degree of development. Historically, well tests usually lasted less than a week, while time to first oil was measured in years. Development infrastructure built to specifications drawn up using well-test data often took dozens of months to build, install and commission. Yet when fields came onstream, production facilities sometimes proved inappropriate because reservoir performance and effluent characteristics differed vastly from what had been predicted.

Increasingly, oil companies are seeking to minimize financial risk and accelerate return on investment. Lacking the confidence to go directly from a two-day well test to full-field development, operators use extended well tests to deliver comprehensive, dynamic data and reduce economic uncertainty. When unwilling to wait for installation of conventional infrastructure, they are using low-cost, reusable production systems to speed up cash flow and cost-effectively bring marginal fields onstream.

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Today, smaller reservoirs and tighter economic conditions put operators under increasing pressure. Oil companies want to reduce exposure to financial risk by acquiring superior data, and need assets to quickly start paying their way. These requirements have changed the conventional order of field developments. Extended well tests (EWT) and early production systems (EPS) may be used to maximize data acquisition while minimizing development costs and generating cash flow. They allow commercial production and evaluation using dynamic data to be carried out simultaneously.

A final development strategy may now be formulated using high-quality, dynamic production data from EWTs lasting up to 120 days. This reduces development risk and eliminates conservatism in facilities design (see “How Better Data Reduce Risk,” page 21). According to Jon Turnbull, Machar Team Leader, BP Exploration Operating Company Limited, “There can be a world of difference between developing a field on the back of a few days of well flow from a small number of wells, and observing production over a significant period of time.”
Then, even before any full-scale facilities are installed, an EPS may rapidly produce tens of millions of barrels of oil, cutting time to first oil to months or even weeks. In some cases, a marginal field may be developed for its entire life using low-cost facilities based on modular and reusable equipment.

At their simplest, EWTs use standard, generally available well-test equipment upgraded for more rigorous safety and increased effluent treatment requirements. Well-testing technology has seen significant advances over the past 10 years, including high-technology drillstem test (DST) strings, environmentally clean burners to flare gas, and highly accurate, stable gauges. Perhaps one of the strongest incentives for these improvements has been the need to test high-pressure, high-temperature zones.1 For these critical wells, only equipment of the highest integrity may be used, and techniques like risk assessment and quality management have become increasingly necessary.

If the well is not already completed, the first stage of an EWT must in effect complete the well. A packer is set to isolate the producing formation from wellbore fluid hydrostatic pressure. Downhole gauges measure pressure changes and a subsurface valve is used to shut in or flow the well. Rather than a production Christmas tree, EWTs frequently use DST well-control equipment.

On surface, produced fluids are separated, treated and sampled, and stabilized oil is exported. Typically flowing for 30 to 120 days at rates of up to 30,000 BOPD [4770 m³/d]—high compared to the 5000 to 10,000 BOPD [800 to 1600 m³/d] achieved in a typical DST—some 10% of the contacted reservoir volume may be produced. Sale of produced oil will often cover EWT operating costs.

Higher flow rates and longer production periods allow the reservoir pressure sink to be reached earlier and make boundaries more likely to be seen than with a short DST. To handle these higher rates, EWT process equipment must be more efficient than the production hardware used in standard tests to allow not only phase separation and measurement, but also the export of oil with commercial characteristics.

In many cases, testing and early production projects require equipment that has more stringent specifications than typical well-testing process and control hardware. At the heart of such projects is the need for a flexible, economical way of evaluating reservoir potential. Schlumberger Wireline & Testing employs standardized modules and components to deliver this flexibility, allowing rapid mobilization of EWT and EPS equipment as well as fast-track development of marginal fields.

Predesign and advance engineering accelerate delivery of equipment that traditionally has long lead times—sometimes more than a year. Additionally, to allow rapid response to emergencies or projects with short lead times, standard and reusable components are kept in stock. Standardization also reduces maintenance costs and improves reliability. After initial installation, capacity and process capability may be easily modified to fit changing reservoir requirements.

Although components may be standardized, the way they fit together cannot be standard. For each well or reservoir, process engineers look at fluid composition and production criteria, and feed this information into a simulator to optimize setup and meet specific gas, water, power generation, loading and export requirements. After decommissioning, separators, heaters and pumps can be reconfigured to service another reservoir.

To illustrate the scope of EWT, EPS and marginal field development techniques, this article looks at three case studies selected from more than 40 projects undertaken by Schlumberger Oilfield Services product lines since the 1970s. In each case, production systems technology has been deployed to deliver superior data, early oil, or both, thus reducing financial risk and delivering rapid cash flow to oil companies. Although these techniques are equally appropriate for onshore or offshore fields, the examples discussed here are all offshore projects, where higher risk promotes greater teamwork and cooperation overall.

Building blocks of Schlumberger Wireline & Testing standardized process plant. Twin, three-stage separator trains may be run in different configurations. Each train is capable of handling up to 35,000 BOPD (5565 m³/d), depending on effluent characteristics. Identical first and second stages are designed to handle flow surges of up to 20% above their capacity, while each of the two oversized third stages is able to process 80% of total plant capacity. For further flexibility when three-stage separation is not required, the standard plant may be reconfigured as three two-stage plants or two two-third plants.
Machar EWT/EPS, UK North Sea

In some cases, it is hard to distinguish where an EWT operation ends and an EPS begins. A good example is the Machar field operated by BP Exploration Operating Company Limited in the UK North Sea (above). 3

The Machar field is a carbonate reservoir overlying a salt diapir, where a salt dome has pushed up creating a steeply dipping, dual-porosity, fractured chalk formation with oil contained in the tight matrix, but produced from natural fractures (next page). Discovered in 1972, the field had uncertain commercial prospects until 1994, when a two-phase appraisal project was initiated.

Phase one was designed to test deliverability of the reservoir. It involved an EWT that used two existing wells to prove that sufficient economic reserves could be produced by natural drive. BP awarded an integrated services contract for the Machar test and production system to Coflexip Stena Offshore, Sedco Forex, Schlumberger Wireline & Testing and Schlumberger Integrated Project Management—the TAP (Turnkey Additional Production) alliance of companies. 4

How Better Data Reduce Risk

At its most basic level, a conventional production test allows “back-of-the-envelope” calculations that attribute total production to expansion of the oil in place:

\[
\text{production} = \text{compressibility} \times \text{oil-in-place} \times \text{pressure depletion.}
\]

This can be regarded only as an order-of-magnitude estimate. To fine-tune this result using the simple production-equals-expansion assumption, a value for the compressibility of the total system—acquired through extensive pressure-volume-temperature (PVT) experiments and core analysis—and accurate pressure depletion data are required. To be useful, a test must record a drop in reservoir pressure during production. The bigger the field, the greater the volume of production necessary to deliver a significant pressure drop and the longer the test.

However, this production-equals-expansion model is not appropriate if the reservoir has an active aquifer, expanding gas cap, or other complicated drive mechanisms. One way of taking these factors into consideration is to perform material balance calculations that integrate production history, pressure history and PVT properties from extended well tests and early production systems to give bulk estimates of oil in place.

These calculations will not take into account such issues as segmentation of the reservoir into distinct flow units, stratification of each flow unit into various layers, or the impact of water injection on recovery. To address these factors, a preliminary reservoir model must be constructed that approximates the production history of the field. This working simulation of the reservoir may be constructed at an early stage only with the availability of continuous bottomhole pressure data from wells that is supplied by an EWT or EPS.

After this, recoverable reserves may begin to be calculated and the full-scale development strategy—in terms of number and type of wells, and process facilities needed—can be formulated. In the past, a paucity of data led to over-conservative platform and facility designs capable of handling the most extreme, worse-case situations for a reservoir. By better understanding likely reservoir needs, facilities may be scaled down and development costs can be reduced.
How Machar reservoir drapes over the salt diapir. The Machar structure, most of the well locations and the target for the new well—designated 23/16a-20—are shown with respect to previously drilled Well 3/16a-10, sidetrack 10Z, and the subsurface (top right). Not shown are natural fractures that made the location of wells so difficult. The steep dips of the diapir with respect to the salt dome (middle) are also shown along with a plan view of the reservoir (bottom).
True to the objectives of integrated services, this contract included significant scope for sharing risk and reward between BP and the TAP companies (see “Machar Risk and Reward,” next page).

A modular facility offering two-stage gas-oil separation with pumping and metering to a quick-disconnect export line was designed, prefabricated and installed on the Sedco 707 semisubmersible rig. Oil was exported via a 1-mile [1.6-km] long flexible subsea pipeline to the dynamically positioned storage and shuttle tanker Stena Savonita, which, when full, transported oil to the terminal at Tetney, England.

Because of the size and flexibility of the 700-series semisubmersible, there was no problem locating new equipment on the deck. The only limiting factor during hookup was capacity of the living quarters. Electrical and instrumentation hookup was the most complicated part. In all, nearly 18 miles [30 km] of cable was needed to link the rig command-and-control system with the new equipment.

Such was the speed of the design and installation of facilities that first oil flowed 5.

The rig was moved onto location in March 1994. New production equipment was installed and commissioned while the rig was recompleting the two existing, but suspended wells—designated 23/26a-6Y and 23/26a-18Z—that would be used for phase one production. Installation took about two months, with 15% of project costs saved by not using a shipyard.


5.
Machar Risk and Reward

According to Jon Turnbull, Machar Team Leader, BP Exploration Operating Company Limited, BP has long wrestled with the difficulty of aligning the goals of contractors with its own. The central problem is that the operator’s costs are the contractors’ revenue. Any cost-saving initiatives reduce the contractors’ revenue, while the operator pays the penalties in cost overruns if things go awry.

One way of overcoming this is to develop a payment mechanism so that the contractor shares in the rewards of a successful project, and similarly shares in the penalty of failure. The rationale for developing such a mechanism is to change the behavior of those who are actively involved in a project or operation so that they are focused on a successful outcome.

The Machar EPS was an ideal candidate for this approach since it involved the cooperation of a number of major organizations in the Turnkey Additional Production (TAP) alliance—Coflexip Stena Offshore, Sedco Forex, Schlumberger Wireline & Testing and Schlumberger Integrated Project Management—in a single project with clear objectives and readily measurable deliverables.

For phase one—natural depletion—a risk and reward mechanism was constructed, based on overall efficiency; health, safety and environment (HSE) performance; and total production. The efficiency element assumed a production efficiency of 77% based on expected weather downtime and shuttle tanker discharge time, during which production ceased. There was a downside cap limiting contractor exposure in the event of significant lost time. The HSE element was included to reinforce mutual objectives and ensure that significant reward payments would not be made in the unlikely event of unacceptable HSE performance.

Finally, to align objectives to production volume, efficiency having been defined as time-rather than production-related, a payment was made to reflect contractor sharing in the possible range of financial outcomes for the project—sharing to a degree in the reservoir risk but not in the risk of a fluctuating oil price.

For phase two—water injection—the risk and reward structure was slightly modified to reflect changed objectives. The efficiency and production elements were combined into a single measure to reflect average daily production. However, to qualify for reward payment, TAP had to achieve a minimum water-injection ratio.

The results of both phase one and two exceeded BP’s expectations and significant reward payments were made to TAP. The mechanisms ensured that BP gains in cost savings were greater than the reward payments. A bigger question is whether the incentives changed the behavior of the people involved in the project—compared to how they would have acted under a conventional contract.

Jon Turnbull is convinced that the incentive contract did change the way people acted, but not on its own. “In order to be effective, the contract had to be reinforced by appropriate behavior, awareness and understanding,” said Turnbull. “In addition, it was vital that an element of the reward was paid to the individuals who made the project successful.”

To gain approval to operate the Sedco 707 as a production facility rather than a drilling rig, it was necessary to prepare a new design and operational Safety Case. As the first drilling contractor to submit a Safety Case in the UK after the Cullen Report on the North Sea Piper Alpha disaster, Sedco Forex was well positioned to do this. This particular Safety Case was drawn up by Sedco Forex in consultation with BP and the UK Health and Safety Executive.

A further hurdle facing North Sea operators is the need to gain UK Government Department of Trade & Industry (DTI) approval for development strategies. In this case, the DTI put a cap on the extent of phase one production by limiting the permissible change in gas-oil ratio, the volume of oil that could be produced and the amount of gas that could be flared. Well 23/26a-6Y had been completed close to the gas cap, so an increase in the gas-oil ratio was expected during phase one. In fact, there was no large increase, which helped prove a higher reserve base than was previously thought, and also confirmed that the reservoir had a robust flow regime. Because of the success of phase one, BP decided to go ahead with phase two—testing the sustainability of production and whether additional reserves could be gained by water injection.

The plan for phase two was developed while phase one was still under way, ensuring no interim demobilization. A month of engineering followed by four months of manufacturing and prefabrication preceded the upgrade. The process equipment was modified, converting it to a three-phase system from the two Machar wells at 30,000 BOPD in June 1994, within 19 weeks of project approval. During the subsequent 11 months of phase one, some 7.7 million bbl [1.2 million m³] of oil were produced, generating $130 million revenue for BP.

6. The Safety Case must show that management systems comply with the requirements of health and safety law; that there are arrangements for regular independent audits of the system; that hazards with potential to cause major accidents have been identified; and that risks of major accidents have been evaluated and all reasonable measures will be taken to reduce risks to personnel.

For a full explanation of Safety Cases:
that increased production capacity to 35,000 BOPD [5565 m³/d]. Produced-water and seawater treatment equipment was installed, including a deaeration tower to reduce oxygen content in the injected water to below 20 parts per billion. Normal lead time for delivery of water injection pumps can be up to a year. Therefore, the rig mud pumps were adapted for treated seawater injection at 40,000 B/D [6360 m³/d]. This was about half as expensive as using dedicated pumps.

All this extra equipment was installed during the three-month production shutdown between phases one and two. At the same time, one of the two existing producers—Well 23/26a-18Z—was converted to water injection and a new production well—designated 23/26a-20Y—was drilled to the base of the oil column. This well was then stimulated by Dowell using an acid-fracturing treatment that yielded a record-breaking 460-fold increase in productivity index (see “Machar’s New Well: Drilling and Stimulation,” next page).

A new DTI production license was granted. With water injection under way, water breakthrough in the reservoir was expected. However, when the test was concluded in June 1996, there had been no water breakthrough and the produced oil remained dry throughout. Ten months of early production yielded 6.8 million bbl [1.1 million m³] of oil, involved 9 million bbl [1.4 million m³] of injected water and demonstrated the viability of a waterflood in this field.

In summary, the tests showed that under natural depletion some 60 million bbl [9.5 million m³] of recoverable oil reserves remain. Adding a waterflood doubled producible reserves to 120 million bbl [19 million m³], narrowing the range of uncertainty surrounding development of the field.

The EPS proved more reliable than anticipated. An uptime of 77% was originally factored into the risk and reward formula, including shutdown time when the Stena Savonita was shuttling oil to shore. In practice, greater than 80% uptime was achieved. There were also no lost-time incidents or discharges into the sea, and production targets were exceeded.

The Machar field will now be developed as part of the 405 million bbl [64 million m³], seven-field Eastern Trough Area Project (ETAP) and will be tied into the Marnock field platform using subsea completions. Drilling of the four new wells that will drape the Machar salt diapir starts in 1997 with first oil expected from the full-field development in October 1998 (above). Underscoring the reusability of this design, Conoco UK is using the Sedco 707 for an EPS in the North Sea that is similar to the one in Machar field.

**Yme Field Production System, Norwegian North Sea**

A key element limiting the volume of oil that could be produced from Machar field was the amount of gas that could be flared. The Sedco 707 had originally been scheduled to stay on phase-two production until September 1996. However, having established viability of the field under waterdrive, BP was reluctant to continue operations with the EPS beyond June because further production would have meant additional flaring of associated gas.

In the Norwegian sector of the North Sea, development of the marginal Yme field (roughly pronounced *eeh-mah*) using a production system on a jackup rig addressed the issue of gas production. Some produced gas is used to generate electricity. This power is then used to compress the remaining produced gas for gas lift and reinjection back to an underlying formation.

The Yme field is located in 312 ft [95 m] of water some 90 miles [145 km] offshore about midway between Stavanger and the Ekofisk field. The field is operated by Statoil on behalf of itself and partners Saga and Deminex. This production project is in three phases. The first phase, Gamma West, is the main structure. The second phase, Beta East,
Machar’s New Well: Drilling and Stimulation

The Machar discovery was proven using eight appraisal wells with five sidetracks, but drilling has always been difficult in the field. The fractured chalk reservoir is steeply sloping on the flanks of a salt dome and the angle of the beds makes drilling difficult. Field development problems are further exacerbated by the presence of the salt dome that distorts seismic data. In fact, there were two sets of overlapping 3D seismic data for Machar field, each yielding different subsurface models. GeoQuest interpreters used log data, vertical seismic profiles and core information to develop sedimentological models that were used to constrain the 3D seismic data and improve the subsurface structural model.

The two wells in production during phase one were Well 23/26a-6Y, completed close to the gas cap, and Well 23/26a-18Z at the base of the reservoir. The objectives of a new well—designated 23/26a-20—were to have a high-angle production well and to acquire a minimal set of logging data to aid in identification of productive fractures. Two nearby wellbores that had been abandoned during appraisal—Well 23/26a-10 and its sidetrack, 23/26a-10Z—provided geologic control over the top reservoir target location (below left). During drilling of Well 23/26a-20, real-time resistivity and gamma ray logging-while-drilling data were used to help locate the well on the seismic image.

If borehole angle is wrong when drilling down a steep flank, wells can miss their targets by a long way. In this case, an unmapped fault skewed the interpretation and Well 23/26a-20 had to be sidetracked twice before hitting the target, even though control-wells 23/26a-10 and 10Z were only 130 ft [40 m] away. The first attempt hit a ridge into which reservoir fluids had percolated 2000 ft [600 m] higher than expected. The second attempt penetrated 492 ft [150 m] too low and encountered too much water. The second sidetrack well was completed in the target fractured reservoir. In the end, total well depth was 9216 ft [2809 m] with a maximum 62.8° deviation. The diapir had thinned more than expected, so the well penetrated only about 492 ft of reservoir, instead of the planned 2165 ft [660 m]. However, a stimulation job that followed more than made up for this shortfall.

After underbalanced perforating using expendable 21⁄4-in. Enerjet strip guns at two shots per foot, a well test was performed. The new well was then acid fracture stimulated using eight-stages of cross-linked gel pad followed by MSR (Mud and Silt Remover) treatment fluid—a mixture of hydrochloric acid with mud- and silt-suspending chemicals. Perforation ball sealers were used after each stage to divert treatment fluids into the tightest part of the reservoir (below right).

The job was carried out by the Dowell stimulation vessel BIGORANGE XVIII pumping through the subsea completion. Prior planning ensured that all elastomeric seals were compatible with the acid, so there was no need to kill the well. Following the 5740-bbl [912-m3] fracture treatment, a second well test showed a 460-fold increase in productivity index—a new world record.

![Well 23/26a-20Y and its predecessors. The first drilling attempt—Well 23/26a-20 (black)—hit a ridge where reservoir fluids had percolated 600 m higher than expected. The second attempt—Well 23/26a-20Z (blue)—penetrated 150 m too low, encountering too much water. The third try—Well 23/26a-20Y (green)—was completed in the fractured reservoir target.](image)

![Machar hookup and record-setting stimulation. The 5740-bbl acid fracture treatment of Well 23/26a-20 was performed by the Dowell BIGORANGE XVIII stimulation vessel in a single operation with very low treating pressures. The step-like bottomhole pressure development (top right) shows where diverter balls sealed perforations, pushing gelled acid fracture fluid to other, tighter parts of the formation. Because subsea equipment was designed to be compatible with the acid, there was no need to kill the well, which helped achieve the 460-fold increase in productivity and avoid subsequent formation damage.](image)
is a nearby, smaller structure. Other prospects have been identified for an as yet unspecified third phase. Gamma West was the location of the field discovery—Well 9/2-1—which was then suspended. An eight-well template has now been installed on Gamma West. Following a dry hole, Well 9/2-3 was drilled and suspended at Beta East and a three-well template was installed (below).

Maersk Giant, one of the world’s largest jackup rigs, is operated by Maersk Drilling. In January 1995, Maersk subcontracted Schlumberger Wireline & Testing to design, install and operate the Yme field EPS. The project scope was to equip the rig in accordance with Det Norske Veritas Production “N” Class and to satisfy Norwegian Petroleum Directorate regulations. Detailed engineering specifications were not issued with the contract. By November of the same

**Yme Field Layout**

Maersk Giant jackup

Subsea well and structure

Beta East

Gamma West

Maersk Giant jackup

Shuttle tanker

Storage tanker 945,000 bbl
[150,000 m³]

Flexible 8-in. flowline

Anchor lines

**Yme field development. The process plant is located on the Maersk Giant jackup rig positioned over the Gamma West reservoir. The Beta East reservoir is exploited using subsea wells tied back to the production facility by 7.5-mile [12-km] long flexible flowlines. Gas lift and chemical injection lines have been laid from the rig to the subsea template, although at present, both wells are flowing naturally. Produced oil is sent via a 1.5-mile [2.5-km] flowline to a 945,000-bbl [150,000-m³] permanent storage tanker with a submerged turret loading system. Shuttle tankers periodically connect to the permanent storage tanker to transport oil to shore.**
The Yme 1400-ton [1.5-million kg] process plant before and after installation. The 50,000-B/D [8000-m³/d] capacity plant was placed on one of the Maersk Giant pipedecks. However, the rig is still able to continue drilling during production. A fire wall separating the living quarters and cantilever deck from the process area was constructed.
Winter 1996

First oil was produced from Yme field to the tanker by February 1996. There are two main three-phase, two-stage separator trains, capable of a maximum fluid capacity of 50,000 B/D [8000 m³/d]. The system handles a maximum gas input of 28 MMscf/D [800,000 m³/d] with three compressors—two main and one low-pressure/high-pressure booster—preparing gas for power generation, gas lift and reinjection. No gas is expected to be flared during normal operations (above). There is one 37,750-B/D [6000-m³/d] high-speed pump for water injection.

Handling Yme produced gas. There are two main gas compressors each with a capacity of 14.1 MMscf/D at 2500 psi [400,000 sm³/d at 17.2 MPa]. After compression to 4700 psi [32.4 MPa] using the combined low-pressure and high-pressure booster compressor, up to 400,000 m³/d may be reinjected, with another 10.6 MMscf/D [300,000 sm³/d] for gas lift and 3.5 MMscf/D [100,000 sm³/d] as fuel for power generation.

Two 6-MW gas turbines supply electrical power to the gas compressors, water injection pump, electrical submersible pumps (ESPs) and process utilities, while offering up to 1 MW of power to the rig. By using gas to generate the required 12 MW of electricity, up to 88 tons [90,000 kg] of diesel are saved every day.

With the process equipment installed, the rig was moved onto location in November 1995. Final installation and offshore commissioning work followed and the original discovery well was recompleted and brought onstream at the end of February 1996. Since then, two additional producing wells have been drilled on Gamma West and one of them has been brought onto production. Both wells use ESPs to aid production. In addition, a dual, gas and water injection well has been drilled. Water is currently being injected at some 37,750 B/D.

Ultimately, there will be up to seven producing wells and one dual-completion gas/water injector on the Maersk Giant template. On Beta East, the original exploration well and another new well—drilled and completed by semisubmersible rig Deep Sea Bergen—have been brought onstream using subsea completions and dual flowlines to the Maersk Giant.

The original plan anticipated at least three years of production, although current predictions estimate that the wells will be on line for at least six years. Norwegian mythology relates that after being killed by his sons, the body of the god Yme became the earth, the sky and the rest of our world. In choosing this name, Statoil clearly sees the Yme field development as a precursor of future EPS projects and marginal field developments offshore Norway.
E-BT Marginal Field Development, Offshore South Africa

The progression from Machar field EPS to the production system on Yme—gas flaring to gas utilization—is clear. The next step is for production system providers to also take responsibility for the subsea part of developments as well as crude-oil storage and export. In this third example, an alliance led by Schlumberger product lines has responsibility for delivering oil from the mudline to the refinery.

The E-BT project will be South Africa’s first oil development and first floating production system. SOEKOR E and P (Pty) Ltd. is the field operator along with partner Energy Africa Bredasdorp (Pty) Ltd. An alliance led by Schlumberger Oilfield Service product lines—Schlumberger Wireline & Testing and Sedco Forex—plus Fred Olsen Tankers, has entered into an agreement with SOEKOR and Energy Africa to upgrade and operate the semisubmersible Sedco 1 (renamed Orca) as a floating production facility for the E-BT field. Phase one of the project is to deliver first oil in early 1997. The second phase is to operate the field for an estimated period of four years (above left).

This is a turnkey offshore development. The scope of work includes procuring and upgrading the semisubmersible rig, providing subsea trees and carrying out well installation work, providing and installing the catenary anchor leg mooring (CALM) buoy facilities, commissioning all the equipment, providing the export tanker and transport to the refinery, and managing and operating the project for the entire production period. Schlumberger Oilfield Services will provide project planning and management; Sedco Forex will provide rig upgrade and rig management services; Schlumberger Wireline & Testing will be responsible for the process plant and production operations. Fred Olsen Tankers will provide the CALM buoy for exporting oil, a customized tanker for storage and transport to the refinery, and tanker management.

The project alliance is working with the field and reservoir management team of operator SOEKOR. The alliance will be turnkey equipment supplier, except for completion tubulars and components, which will be supplied by SOEKOR. The rig and associated process and buoy equipment belong to SOEKOR and Energy Africa.

During 1996, Orca was upgraded at a shipyard in Simons Town, South Africa. Following an audit and fatigue analysis, a program of life enhancement and structural strengthening was carried out. Rig accommodations have been modernized, the mooring system was upgraded to withstand marine conditions offshore South Africa, and the drilling equipment was enhanced to provide full workover capability. Oil storage capacity has also been installed inside the rig’s three columns—nine tanks and a total capacity of 30,000 bbl.
Intelligent Production Systems

Intelligent production systems (IPS) are based on the premise that liquid yield of a hydrocarbon separation process can be improved if process-operating parameters are fine-tuned as wellstream composition and reservoir conditions vary, or ambient conditions change. These improvements may typically be in increments of a few percent—100 BOPD per 10,000 BOPD.

For example, the wellstream may originate from several zones, each saturated with different types of crude oil. There may also be an areal variation of crude gravity and sharp fluctuations in seasonal temperature that affect surface operations. The net effect is that the separation process will be inefficient unless operating parameters are adjusted to meet changing demands.

A typical system for production optimization consists of a dedicated PC-workstation installed either at the operator’s offices or the production facility. In either case, a communication link via modem is required to transmit data between the facility and the office.

The PC will host the IPS process simulator and the proprietary interface, which permits retrieval of essential process parameters from a data base at the production facility—including upstream and downstream choke pressures, separator pressures and temperatures, and gas and oil flow rates. These data are then filtered, validated and directed to a simulator that computes the current optimal conditions of separation.

Besides pinpointing optimal separation conditions, the simulator also raises flags if measured and computed values disagree significantly. This is an effective way of diagnosing process irregularities and abnormalities. In short, the IPS simulator is a tool to aid in the proper management of process facilities.

An added dimension is upstream and downstream optimization, which is particularly relevant when injection programs and artificial lift systems are implemented, or when choke manifolds operate under subcritical conditions.1 In the latter case, variation of separator pressures can have an impact on reservoir deliverability and well producibility. Hence, it is imperative that the process simulator be linked to a working upstream model to optimize the production system.

**More Data and Early Oil**

When designing a production system, whether as an EPS or to last for the life of the reservoir, it is important to use well-test data to optimize processing hardware. Then, data gathered during the productive life of the reservoir may be used to fine-tune EPS operating parameters and maximize production. For example, as produced fluids or flowing conditions change, the hydrocarbon separation process can be altered slightly to improve liquid yield. This may be achieved using intelligent production systems, a powerful production management tool that optimizes reservoir depletion by linking permanent monitoring and reservoir modeling to an online topside simulation. Operating conditions can now be fine-tuned to yield maximum liquid hydrocarbons (see “Intelligent Production Systems,” above).

There is no doubt that operators are increasingly inclined to consider imaginative ways of extracting data and early oil from their assets. The Schlumberger Wireline & Testing production systems group has been active since 1974—a track-record that may be traced back to the days of Flopetrol Schlumberger—and has notched up cumulative production of an estimated 350 million bbl [55 million m³] of oil. The ten plants currently in operation deliver an average of 190,000 BOPD [30,200 m³/d]. However, new projects now under way will dramatically increase this tally.

Early production systems are akin to full-scale development projects. They require the same planning, regulatory approval and safety analyses. At the same time, these solutions rely on a wide range of human and institutional interfaces. Many of these interfaces are already well-known to the well-testing community. Other interfaces, for example those concerning offshore storage facilities and shuttle tankers, may be relatively new. However, it is clear that the service industry tradition of rapidly deploying equipment and services using multifunctional teams is helping operators profit despite ever-tightening margins. —CF