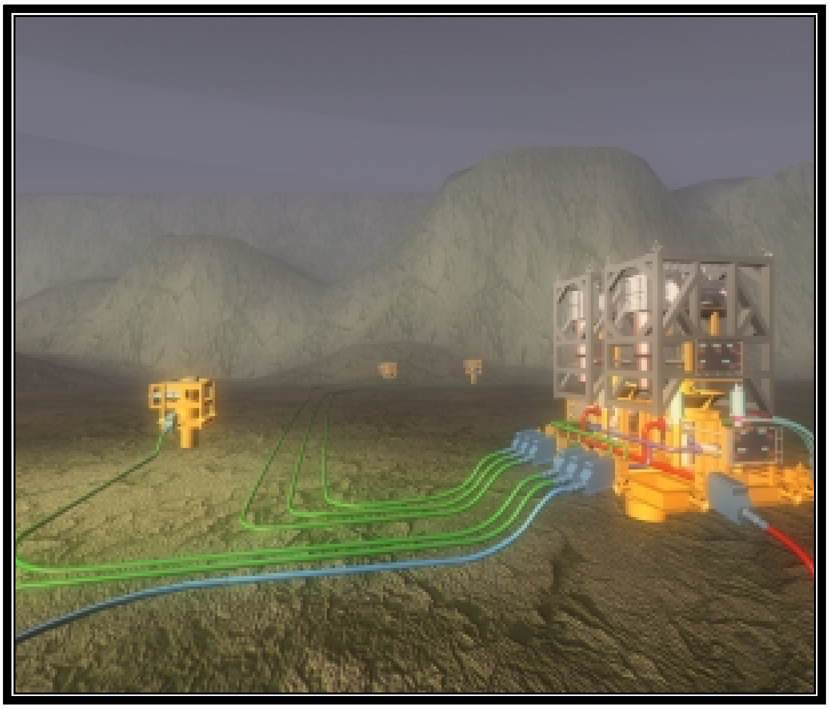
A Solution to the Challenges of Deepwater Tiebacks that Offers Significant Production Advantages



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Deepwater: needs and issues

An increasing number of rich hydrocarbon fields are being discovered in deepwater e.g. in the Gulf of Mexico, in the Campos Basin off Brazil, and off West Africa. However, deepwater tiebacks present what are euphemistically called "challenges"!

One of the main concerns is the apparent need to locate all the field development equipment that may be required throughout the entire field life, on the seabed at the outset. The philosophy being that this avoids costly intervention. However, it increases the initial CAPEX and leads to assembling a sizeable "factory" on the seabed. This necessitates large installation vessels and needs a lengthy commissioning "window", all of which adds to the installation costs and reduces the net present value (NPV) of the field. The real need is for a method by which only the equipment that is initially needed is deployed, and by which it can be readily changed out or added to without the need to halt production. This would enable a field to be developed on an incremental basis incurring low initial CAPEX whilst uncertainty in the field is high.

As each field is different from the next, seabed installations are, almost without exception, designed accordingly. This results in a lack of standardisation with the consequent need for a variety of installation equipment, interfaces and procedures.

Having installed the equipment, the next nightmare is a general lack of reliability. Equipment failure in deep water will inevitably result in high intervention costs and any early-life failures may entail repeated sorties to the offshore field, thus further reducing the NPV. Even worse, there is the need to shut-in the wells whilst equipment is being changed out. As we all know, there is no automatic guarantee that shut-in wells can be successfully started up again.

It has been assumed by some, that the issue of reliability can be overcome by the use of insert-retrievable equipment, on the basis that the most vulnerable components can be removed and replaced. However, this involves additional wet-mateable interfaces and isolation valves and consequently *diminishes* reliability! Furthermore, in replacing the failed item, it may prove that the symptom has been treated but not the underlying cause, so further trouble can be expected!

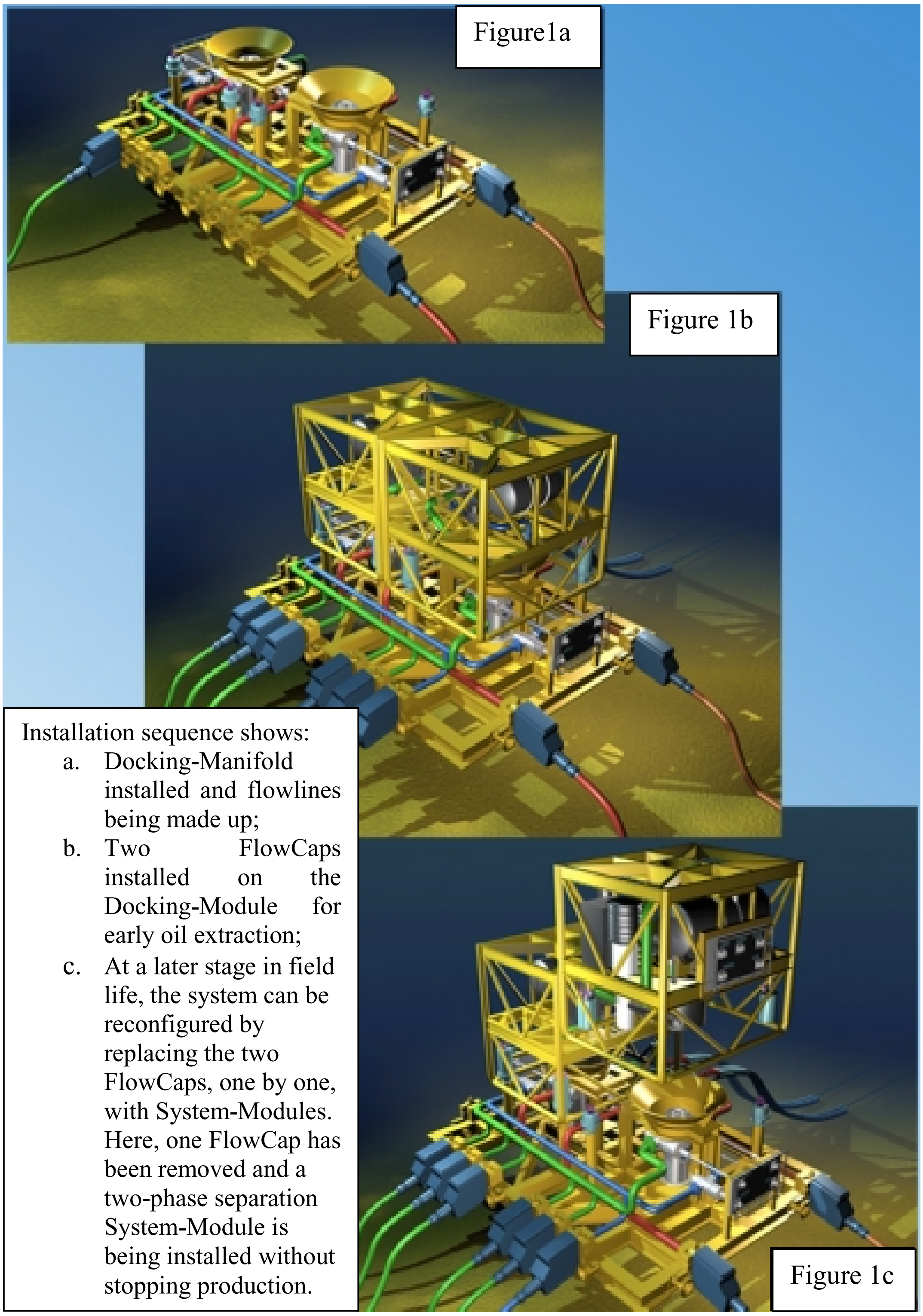
Furthermore, owing to the vagaries of field characteristics, some of the equipment initially installed may never be needed during field life; some of it may not successfully start up after a prolonged period of inaction on the seabed.

It is not difficult to visualise the problems faced by an engineer when he is looking at a VDU screen showing an ROV camera picture whilst he is trying to analyse a fault on the seabed 1,500 metres below his expensively chartered vessel. Field production may have stopped and he is under pressure to find a solution quickly.

The solution

The solution to all these problems is to adopt an incremental approach to field development. This enables a field to be developed in several stages, first oil being obtained shortly after the installation of the initial, basic equipment. NPV is at once maximised whilst initial CAPEX is minimised and the cost of additional equipment is amortised throughout the field-life timescale. This is achieved without employing new technology. It is made practicable by the use of a System-Modular installation in the vicinity of the wells. Alpha Thames successfully completed underwater trials of an electrically powered and controlled System-Module at the end of the ÆSOP project that was supported by the Commission of the European Communities and by a JIP; the trials of the System-Module were witnessed by representatives of the EC, Conoco, Statoil and Shell in September 1999.

A complete seabed installation is known as an AlphaPRIME™ CPU (Central Processing Unit). The CPU can be regarded as a hub that can distribute power to the wellheads and other field equipment, that can provide intelligent monitoring and control, and from which further field development can be readily achieved.



Installation sequence shows:

a. Docking-Manifold installed and flowlines being made up;
b. Two FlowCaps installed on the Docking-Module for early oil extraction;
c. At a later stage in field life, the system can be reconfigured by replacing the two FlowCaps, one by one, with System-Modules. Here, one FlowCap has been removed and a two-phase separation System-Module is being installed without stopping production.

Figure 1 – AlphaPRIME™ CPU: Installation Sequence

The CPU consists of a simple Docking-Manifold (see Figure 1a) that is installed, usually on a monopile, on the seabed. The Docking-Manifold contains only field-proven equipment and does not include controls or actuated valves. In a “green field” scenario, early installation of the Docking-Manifold can be made at the same time as the pipelines. The fluid connections for the System-Modules are provided by multiported wellhead-type connectors which, initially, can be fitted with simple FlowCaps (see Figure 1b) that enable the early flow and monitoring of first oil. Connections to the pipelines are made using any proprietary pipeline connection system.

The Docking-Manifold can accommodate two System-Modules (see Figure 1c) which, in turn, can accommodate a wide range of systems and equipment to suit any field scenario such as: manifolding; HIPPS (High Integrity Pressure Protection System); two-phase, three-phase or even four-phase (including sand handling) separation and boosting; and water re-injection. The separation systems can be gravity-based or dynamic. A typical AlphaPRIME™ CPU, with two System-Modules in operation, can process some 40,000 bbl/d. If, at any time during field life, additional processing capacity is required, another CPU can be installed, thus continuing to develop the field on an incremental basis.

The System-Modules can be reconfigured during field life, either in response to changing field characteristics (such as increasing water cut) or to include new technology when it becomes available (such as subsea gas compressors) without needing to interrupt production or shut-in the wells. In this way, equipment is provisioned and deployed only when it is needed, thereby reducing the initial CAPEX budget. At the end of field life, the System-Modules and the Docking-Manifold can be readily retrieved for refurbishment and re-use elsewhere, thus amortising their costs over a number of fields.

Each System-Module has a footprint of only 5 m by 4 m; it weighs between 25 and 50 tonnes, depending upon the equipment to be accommodated. Therefore, System-Modules can be changed out by relatively inexpensive lightweight vessels such as DSVs with suitable lifting/handling equipment. All operations are diverless; location and connection of the System-Modules in the Docking-Manifold, and any subsequent retrieval operations, only require the assistance of a work-class ROV.

There are only three wet-mateable interfaces per System-Module, namely for fluids, power and controls. This increases system reliability, particularly as these connections utilise existing field-proven technology; the multi-ported fluid connector is a modified “wellhead-type” connector and the high voltage/power connector can be either an Alpha Thames ELEx Connector or any other suitable proprietary connector, according to the Client’s choice. The controls/chemical injection connector would be a proven proprietary stab plate assembly. In this way, although different processing systems can be deployed, each System-Module has a common interface.

A significant feature is that the processing, boosting, monitoring and control, and power distribution systems are integrated into each System-Module at the design stage. Upon completion of assembly, this approach is further reinforced by thorough system integration testing in the factory. This ensures that all the equipment is compatible and any faults can be thoroughly investigated and rectified. It is important to bear in mind that the apparent cause of a fault may turn out to be a symptom as opposed to the root cause.

The System-Modules are electrically powered and controlled by well-proven, industry standard, programmable electronics. Each module is supplied by means of an integrated services umbilical (ISU) that delivers high-voltage power, electric control and injection chemicals. The absence of hydraulics, the utilisation of all-electric power and control, and the minimal number of wet-mateable interfaces combine to optimise reliability. As previously mentioned, this is especially important in deepwater applications.

Indeed, reliability/availability are the main concerns of any operator with regard to equipment that is either located downhole or on the seabed. Alpha Thames take a risk-based approach to reliability; detailed failure modes, effects and causes analysis (FMECA) is undertaken in order to identify all possible failure modes and to enable highly reliable solutions to be realised that, in the unlikely event of failure, only result in loss of performance rather than a complete loss of function.

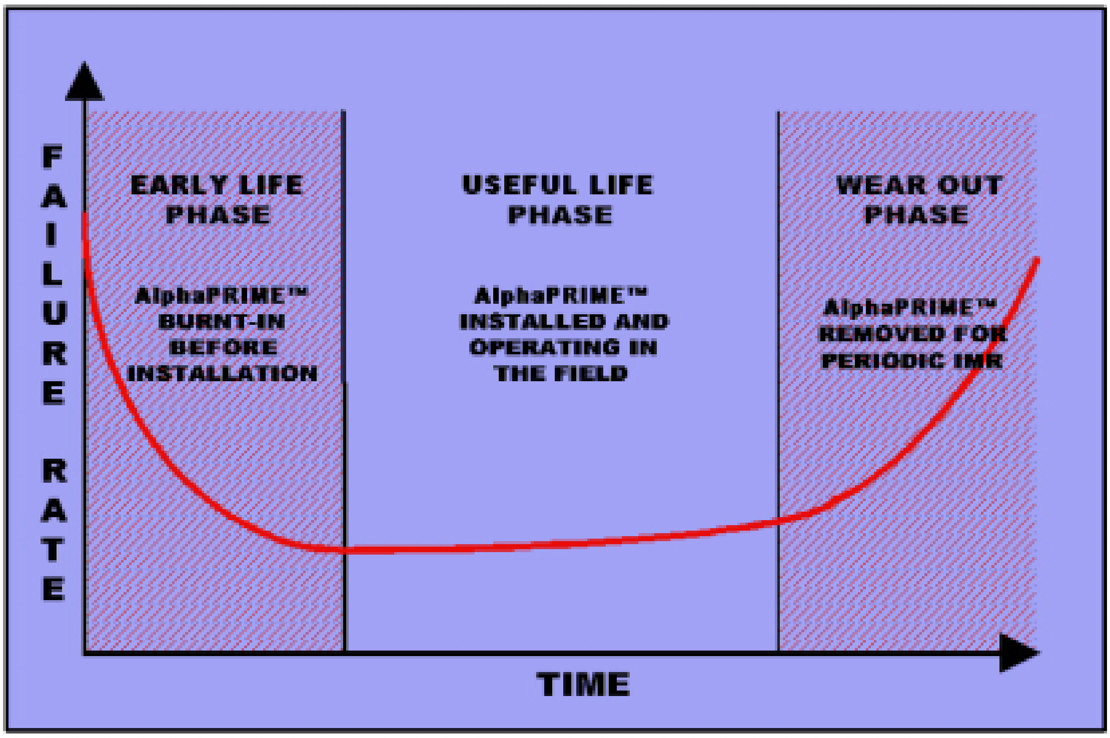


Figure 2: Reliability "Bathtub" Curve showing the optimum reliability of AlphaPRIME™ in the field

Furthermore, each System-Module is "burnt-in" before it is shipped to site so that early-life failures (as in the "bathtub" curve, Figure 2) can be identified and eliminated in the factory. This confers a significant benefit upon its on-field reliability and performance as is illustrated by the graph, which shows how the early (and most financially significant) part of the System-Module's working life is spent on test in the factory. Problems are identified and rectified in the workshop and the module is only installed on a Docking-Manifold when the entire system has been functioning faultlessly for a required period, i.e. when it has reached the beginning of its useful life phase; it will then be functioning at its optimum reliability. If required, stump testing can also be undertaken immediately before deployment. The systems are self-monitoring, ensuring that any downward trend in equipment performance is identified and that the necessary remedial action is taken before end-of-life equipment failures take place; the System-Module can be recovered before the wear-out phase begins. This ensures that optimal system reliability is maintained because the equipment is only in the field during its useful-life phase. Although this is the norm for topsides and shore-based industry in general, this philosophy has not, until now, been available to subsea systems.

Each System-Modular installation comprises at least two identical operating System-Modules, both of which operate continuously so that there are no problems associated with starting up “dormant” equipment. If one System-Module has to be removed for any reason, such as planned maintenance or reconfiguration, the remaining System-Module(s) continue(s) to function.

For an application utilizing two System-Modules, each one would normally be sized for 60% of peak throughput, i.e. the system could handle 120% of peak flow. As the maximum peak throughput would only be for a short period of the overall field life, this would allow a minimum of 60% of peak flow to be maintained during System-Module change-out, without shutting in any of the wells or ceasing production. Again, because the maximum peak throughput would only occur for a comparatively short period of time, each System-Module could have the capacity to process up to 100% of the total throughput during most of the field life. However, the capacities of the System-Modules can be varied at the design stage to suit the Clients’ requirements.

It may be seen from the foregoing that the System-Module that is delivered to the field is a fully tested, self-contained system that is capable of operating autonomously but in concert with identical System-Modules in the installation. As each module has only three wet-mateable interfaces, installation is readily accomplished within short weather “windows”. Commissioning consists only of pressure testing and basic functional testing. Significant cost savings are therefore achievable. The subsequent retrieval of a System-Module for maintenance or for re-configuration and, ultimately, its decommissioning are also readily accomplished.

The low stress solution to any problem that might occur, and that is available through system modularity, is to recover a System-Module and quickly replace it with a fully integration tested spare. Production is restored and the problem can then be taken back to the workshop for a thorough hands-on examination in a warm, dry environment where colleagues can be consulted to share their expertise in resolving the problem. The team can complete the task confident that the highest standards of engineering have been employed in the remedial work and they have the reassurance that comes from having seen the system thoroughly tested before it is returned to the seabed.

Personnel stress is not usually considered as a factor in subsea engineering. However, any engineer who values the sense of well being that comes from knowing he has done a professional job, free from the pressures of lost revenue and worsening weather will appreciate that system modularity has something to offer him as an individual.

Long tieback problems are also relevant

As if the problems considered so far are not enough, additional problems arise from having long tiebacks which may well be associated with deepwater development.

In a long tieback pipeline, as the pressure drops, the gas breaks out of solution in the produced fluid. The resultant “slugs” may well cause flow assurance problems for which multiphase pumping is often specified as a remedy. The problem can best be overcome by first-stage gas separation on the seabed in the vicinity of the wellheads. The separated oil and gas can then be transported to the host by separate pipelines; the liquid phase(s) being pumped to the host, whilst the separator pressure is sufficient to transport the gas.

Multiphase pumping needs complex, speed control systems that are often heavy, bulky and expensive. However, first stage separation on the seabed enables single speed pumps to be used; they can be selected to run at their most efficient and reliable speed. Fluid levels in the separator are continuously monitored and are adjusted as necessary by fast acting modulating valves that are fitted with electric actuators. These actuators have been developed and thoroughly tested by Alpha Thames.

Hydrate formation occurs in multiphase pipelines when the produced fluid cools in the pipeline over long distances. Separating the produced water from the gas on the seabed removes this propensity and also significantly reduces expenditure on hydrate inhibitor. The separated water may be used for water injection purposes. The need to transport significant volumes of unwanted liquid to the host may thus be avoided together with a reduction in topside treatment capacity requirements.

Power transmission and control problems are increased with distance, particularly if hydraulic control is used. System-Modular installations provide an all-electric processing system which has power and control lines incorporated in an integrated services umbilical which may also include chemical injection lines. The System-Modules can also be connected to each other to form a “ring main”. This has the advantage that any one System-Module can be isolated by means of switchgear in the adjacent System-Module(s) and/or that at the host facility. Therefore, it is possible to isolate and retrieve a System-Module, whilst maintaining power to the remaining modules, even if its switchgear is faulty. Each System-Module has a main transformer within a pressure-balanced housing. It also has a power and control pod that is a pressure vessel with two compartments, one for power equipment (secondary transformers and switchgear) and one for control equipment.

All the equipment within the power and control pod operates in a dry, notionally one-atmosphere environment; this enables well-proven, industry-standard, highly reliable, solid state, “real time” electronic control systems to be utilised. The programmable logic controller (PLC), which is located in the power and control pod, controls the process and responds to signals from the subsea sensors. By this means, the seabed system continuously monitors and controls itself. Where configured for separation, the fluid levels in the separator are monitored continuously and, when necessary, electric actuators adjust modulating valves on the output lines from the separator.

As most process values vary fairly slowly, the requirements for data transmission to and from the host facility are moderate. The control system sends data to a topside master control unit (MCS), only needing to alert topside staff of unusual events, whereupon manual control can be assumed. As the system is software-controlled, software changes can be made at the MCS, via the communication link, often without interrupting the production process. As the System-Modules function as autonomous systems, they can be programmed to continue to operate (for a pre-determined time) in the absence of control signals from topsides, after which they will automatically shutdown in a pre-determined manner.

Pressure and temperature sensors are located inside the power and control pod; sensors are also fitted to verify that there has been no water intrusion. There are also sensors that monitor voltages, currents, electrical insulation and contactor positions to ensure that information relating to the electrical and electronic system conditions are provided at the MCS.

A System-Modular installation can be regarded as the central processing unit (CPU) of a field development system; it can act as a control centre that provides feedback data, especially as it operates autonomously yet offers the operational flexibility of being reprogramable from the host facility. Moreover, the System-Modules can incorporate reservoir surveillance and testing. The System-Modules can distribute power to neighbouring seabed systems and, if required, they can be configured to include hydraulic power units (HPUs) in order to control conventional electro-hydraulic trees.

Further economic advantages

A well known additional benefit is that seabed separation and liquid boosting will enhance reservoir drawdown. It significantly increases the production rate in the early years of field life thus significantly enhancing NPV; it also increases overall yield thus prolonging viable field life whilst reducing overall expenditure. Using Brent field data as a basis, it has been calculated that up to 75% extra production can be achieved by employing seabed separation and boosting in deep water, compared with conventional topside methods. Independent authorities have calculated that savings of $2 to $4 per barrel can be achieved in Gulf of Mexico or UKCS scenarios.

Seabed separation reduces the need for injected chemicals; in field studies recently undertaken by Alpha Thames, this has proved to be a highly significant economic factor.

Conclusions

The technology described in this paper has existed for many years, it is only the System-Modular approach that is novel. The extensively patented System-Modular method of deploying, operating and retrieving seabed processing systems also relies only on existing technology. As has been explained, it offers a means of developing a field incrementally, consequently spreading CAPEX over the life of the field instead of principally at the beginning.

Flow assurance, reliability and maintainability have been addressed as have installation, reconfiguration, retrieval and decommissioning.

The challenges of deepwater tiebacks can therefore be overcome without further delay!

Figure 3 – Demonstrating the ease of installation of Alpha Thames' prototype System-Module during its in-water trials