Abstract
The increase in data provided by advanced surveillance systems, such as the new Subsea Monitoring and Control (SMC) platform (Amin et al 2004), allows innovative ways to monitor subsea systems and production operations extending from the sand-face to the host facilities. This enables productivity optimisation through closed loop actions based on factual real-time information.

The combination of real-time data acquired from subsea monitoring systems with modelled and historical data, expert analysis and real-time productivity optimisation tools, provides the operator with detailed analysis of production and hardware performance. It allows interventions and production operations to be planned more efficiently, thereby reducing downtime, production loss and operating expenses.

In the last few years, the industry has dramatically increased the number of intelligent seabed and downhole monitoring devices in the subsea industry with the introduction and acceptance of multiphase flow metering, fibre optic temperature and flow sensors, intelligent well flow control devices and similar systems. Exploration and production (E&P) companies have launched a number of initiatives to develop smart-field technologies, infrastructures, data visualisation and analysis applications.

This paper will review the application of SMC as an enabler for the subsea surveillance solution and focus on the benefits of an open, transparent and high-speed subsea area network. The paper will demonstrate how the resulting improvements in subsystem interface engineering, system reliability and production optimisation could relate to economic gains in both capital expenditure (CAPEX) and operational expenditure (OPEX) phases of future subsea field developments.
Introduction

For the purpose of this paper, a subsea surveillance system is defined as follows:

- An infrastructure extending from the reservoir to the end users desk—that may be at the offshore host facility, client engineers’ office or any third-party data management system
- An infrastructure that is optimised by design to improve subsea production
- An infrastructure that increases the volume, reliability and accuracy of reservoir, environment and equipment data
- An infrastructure that provides a flexible, expandable and a highly adaptable remote monitoring subsea network
- An infrastructure that creates a platform to accept advanced production optimisation software tools that provide event identification, predictive alarming and expert analysis

In 2002, Cambridge Energy Research Associates (CERA) began a study into the digital oilfield of the future (DOFF) involving interviews with over 150 industry experts, as well as studies on the technologies available and the operator needs and business drivers (Severns 2004). To realise this vision, the study detailed a number of important capabilities that were key in the implementation of the DOFF including full monitoring of the asset from reservoir to process, the ability to view this data remotely, improved tools for data analysis and visualisation, and more advance and reliable monitoring and control systems.

The DOFF study identified four main drivers for increasing value which could be gained from its implementation:

- Enhanced recovery
- Lower operating costs
- Increased daily production
- Reduction in capital costs

The study estimated the net present value (NPV) for both green field and brown field reference deepwater oil cases and determined a 14 percent and 11 percent increase in NPV, respectively, could be achieved with the implementation of DOFF. Obviously there is a cost, however, this is relatively minor compared to the perceived savings and benefits.

The NPV increases stated above represent the full cost savings expected from the DOFF analysis including real-time drilling, intelligent completions, three-dimensional visualisation, remote sensing and monitoring and control. The DOFF study found the specific cost benefits gained by the implementation of advanced monitoring and control, predictive maintenance and networked systems to be in the region of 1–2 percent, which equates to a significant saving in the high levels of CAPEX associated with deepwater
fields. The actual cost of the hardware and software required to realise these savings is small compared to the operating costs associated with equipment maintenance, recovery, repair and installation, and with deferred production as well as the intangible value of the operator’s reputation.

For subsea fields, improved subsea design and advanced surveillance can lead to two distinct cost savings:

- **Increase in production** through the use of intelligent wells, reservoir and subsea modelling
- **Reduced intervention costs and deferred production** by reducing equipment failure

These two areas are represented within the two field process loops with reservoir optimisation identified as a slow-loop process and optimisation of monitoring and control equipment based on key performance indicators (KPI) in the fast-loop process.

### Table 1: CERA Economic Analysis of NPV for DOFF in Green Field and Brown Field Developments

<table>
<thead>
<tr>
<th>Case</th>
<th>Green Field</th>
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<th></th>
<th>Brown Field</th>
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<tbody>
<tr>
<td></td>
<td>Base NPV</td>
<td>NPV Change</td>
<td>Percent</td>
<td>Base NPV</td>
<td>NPV Change</td>
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<td>100</td>
<td>7</td>
<td>803</td>
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</tr>
</tbody>
</table>

*Source: Cambridge Energy Research Associates (Severns 2004)*

Figure 1: Field Process Loops (Fast/Slow)
Most wells require intervention during their lifespans. Interventions—whether installing or servicing control valves, changing gas lift valves, production logging, pulling failed tubing, removing scale or paraffins, perforating new sections, or squeezing cement into perforations to shut off water flow—extend the productive lives of wells and provide additional well and reservoir data. Subsea interventions, however, are not performed routinely because their associated costs and risks are considered prohibitive. Because of the lack of routine intervention, a subsea well’s overall production performance is estimated at only 75 percent that of comparable land and platform wells (Amin et al 2004).

With the increase in deepwater operations and the low number of suitable vessels, the cost for a deepwater subsea intervention has risen significantly with current vessel costs in the region of $200k USD to $400k per day. Cusak (2005) presented a report estimating intervention costs for maintenance or replacement of subsea equipment at over $50m and deferred production of over 3 million barrels in the Foinaven and Schiehallion fields in the West of Shetland. Postponement of well workovers and subsea operations/maintenance due to the lack of availability of intervention vessels, poor weather conditions, hostile offshore conditions during winter, and other factors can lead to significant deferred production and increase in field operating costs.

The ability to allow the planning of intervention campaigns in advance on a field basis rather than a reactive campaign on single wells—or even to simply reduce the number of interventions—is essential. Due to the high costs involved, maintenance programmes are generally infrequent (every six or 12 months) and onsite maintenance is often reactive after a failure has occurred, rather than preventive.

There already exist a number of applications and developments aimed at reservoir surveillance, production improvement through control of intelligent wells, water/gas breakthrough detection, and other procedures, as detailed by de Jonge (et al 2003). This paper, however, will focus on the second method of cost reduction, which is an equipment focused solution using real-time subsea data.

High bandwidth subsea-to-surface communication systems, like Schlumberger’s SMC system, result in a significant increase in the amount of production data available to the operator on the platform or floating production storage and off-loading (FPSO) and onshore. Reliable real-time well performance data enables analysis, decision-making and control.

This increase in available production and diagnostic data has allowed new production optimisation and event detection tools to be developed and, as presented by Holland (et al 2004), more information is provided by continuous measurements than by sporadic measurements. However, this increase has also lead to a number of problems including how to validate and transfer large quantities of data and the integration of the data into existing software infrastructures and applications.
The application and analysis of the acquired data may also be limited as the required expert knowledge may not be available to analyse the data or to make recommendations for preventative actions. The detailed knowledge of the subsea and surface equipment often lies with the equipment suppliers rather than the operator’s reservoir and production groups, and the ability to provide the appropriate people both onshore and offshore with the knowledge to analyse the problem is essential.

The primary goals are to reduce intervention and production deferral through the following four steps:

• Improve subsea equipment selection and design
• Improve subsea surveillance
• Provide the engineer with the right information at the right time
• Allow the engineer to plan operations in advance

However, to implement the ‘digital oilfield’ for subsea development there are a number of hurdles to overcome.

This paper will identify the current limitations of subsea surveillance, and will propose systems and tools to overcome these limitations and to perform advanced surveillance and subsea infrastructure design with the goal of enabling the DOFF vision in deepwater.

**Current Subsea Limitations**

The industry recognises the inherent limitations of today’s subsea production control systems, or PCS (Theobald 2005). This is particularly true as it restricts the availability of high frequency data, production and equipment diagnostic data, for analysis on the hosting facility or onshore. These limitations include:

• Low data rates for subsea sensors—due to the legacy modem technology used by current PCS the data bandwidth from surface to subsea over an umbilical can be in the region of 2400 baud, which, shared between a number of production subsea control modules (SCM), results in a very low update rate of data at the surface. For example, to acquire real-time data from a typical subsea multiphase meter, a dedicated baudrate of 9600 is required. Recent subsea projects have specified a 15-second update rate for production and downhole data, and even lower frequency update rate for advanced sensors such as multiphase meters, reducing the value of these measurements to the operator.

• Lack of diagnostic data (fast loop data)—due to the low data rates provided by the PCS, diagnostic data from intelligent sensors (e.g. downhole gauge, multiphase meters, etc.) is often ignored to reduce the bandwidth loading to surface. This results in the absence of real-time and historical diagnostic data that is required for predictive alarming and fault-finding tools.
• Lack of transparency: today, data acquired from seabed and downhole sensors is collected by the subsea control system processor over a local master/slave communications link, and then passed to the surface along with the tree production pressure and temperature data and valve control line pressure data. A number of production systems provide a pseudo-transparent interface for standard protocols such as Modbus where messages between third-party acquisition systems—surface and subsea sensors—are passed through the PCS. These types of systems are not truly transparent as the third-party communications are still routed through the PCS processors on surface and on the tree. This means that communication messages for sensors are queued along with requests for tree production data and valve control, and are often given lower priority. This limitation is being addressed, albeit slowly, by the use of fibre optic modems from a number of production control suppliers, although the quoted update rates are still low especially for long step-out distances.

• Lack of plug and play: the integration of new sensors in networked surface and on-shore control systems is easily done with today’s technology. This is not the case with subsea PCS systems, where sensors’ data and subsea-to-surface communications are routed through processor in the PCS SCM. This means that any subsea sensor must interface with the SCM processor rather than with its associated acquisition system on the surface, leading to increased interface engineering and testing costs and reliability reduction. The subsea industry Intelligent Well Interface Standardisation (IWIS) and Subsea Instrumentation Interface Standardisation (SIIS) initiatives (Baird 2001) are addressing the subsea electronics and communication interface issues for downhole and seabed sensors respectively through the ISO13628-part 6 standard.

• In-time data: the low data rates and lack of communications management often result in the required sensor data being queued and/or delayed. Timestamp information is often not included with data from subsea sensors and is added at the production SCM or at the surface as it is acquired. This can result in problems when matching the data to other sensor data, e.g. well production data with permanent seismic.

• Limited expandability: current PCS are designed for purpose which is primarily tree valve control with little room for expansion. The addition of a new sensor during the production phase is difficult requiring the mechanical (subsea connector, mounting, etc.) and electrical (power and communications) interfaces to be in place prior to deployment of the PCS or through retrieval of the tree and/or control system to surface to make the required modifications. Additionally, the space available inside the PCS subsea electronics module is limited reducing the number of subsea electronics interface boards and sensor equipment that can be used with some of today’s PCS module, only providing three or four interfaces to external sensors. This will become more and more of an issue as new sensor technology is developed, such as subsea fibre optic sensors which require the optical components (laser, etc.) to be subsea.

• Infrastructure design: downhole and seabed control and monitoring equipment needs have to be defined early in project development. Advanced monitoring and
control equipment has to be squeezed into the design often after the PCS has been tendered, which can result in reduced or unavailable functionality.

Figure 2 shows a production SCM with a range of typical monitoring and control equipment.

**Figure 2: PCS SCM with Typical Sensor Configuration**

Fast subsea data update rates are needed to avoid loss of information when data is scanned at low rates e.g. pressure profiles for tree valve operations, downhole equipment power supply voltage spikes, etc. Similarly, the initial pressure and temperature data recorded during a well shut-in contain important reservoir information and may require a high data rate for pressure/flowrate analysis. A number of PCS provide a ‘fast-scan’ option, which allows certain data points from a single SCM to be passed to surface at a higher rate. This, however, is usually to the detriment of other data points and other SCMs.

Current PCS are designed primarily for tree and downhole safety valve control and to monitor the pressure and temperature at the wellhead. This requirement has not changed significantly in the last 10–15 years. The majority of the modifications to PCS over the last decade were for new monitoring systems (downhole gauge interface cards, sand detectors, flow meters). A great deal of both software and hardware development work has to be carried out to interface new sensors into the existing PCS system design. Prior to the IWIS interface being proposed, suppliers of downhole gauges had to provide a different electronics card for each PCS supplier. In some cases these modifications have resulted in reduced reliability in both the PCS and the third-party equipment.
**Alternative Solution—Open Subsea Network**

The solution to the problem is to separate the production and surveillance functionality on the seabed. This should allow the PCS to perform all production control functions such as tree and downhole valve control and production safety related monitoring and control, e.g. emergency well shutdowns. All monitoring equipment, except production safety related equipment, would be routed through a separate surveillance system. It consists of a stand-alone subsea data hub (SDH) mounted on the tree or manifold and provides a high-bandwidth open-architecture communications link to surface, allowing additional sensors to be added subsea, as shown in Figure 3.

![Figure 3: Separate Subsea Control and Surveillance Systems](image)

Two major advantages of separate surveillance and control systems are that the operation of the surveillance system does not necessarily affect the existing infrastructure, and that it can be retrieved without interrupting production. Further advantages of this split in functionality include:

- Surveillance system network reduces bandwidth loading on PCS
- Sensors can be added during development stage without impacting tree/controls delivery
- Tree can be pre-prepared with surveillance module receptacle and generic wet-mate connectors for sensors with the sensor types undefined
- Surveillance system can be small and retrievable with a workclass ROV using standard tooling
- Future-proof subsea infrastructure by providing spare ‘plug and play’ connections subsea
- Reduce risk by having standard trees and control systems which vary little from project to project
The Schlumberger SMC surveillance system (Amin et al 2004) provides a local network on the seabed that is also IWIS compliant; so instrumentation, data hubs and control modules can interact seamlessly. This module mounts on the Xmas tree, manifold or any other suitable infrastructure and interfaces with a traditional PCS. The key benefits of the functionality listed below include: improved system integration with reduced interface engineering, improved system reliability and availability, and provision of the necessary infrastructure to enable production optimisation. Functionality provided by SMC includes:

- **Plug and play**: Open architecture reduces interface development and testing costs, and allows new sensors to be added as they become available (e.g. in-well seismic, subsea cameras, distributed temperature sensor (DTS), deposition sensors, etc.).

- **Open network**: An open communications network brings the subsea into line with surface and land process systems that have already benefited from a networked approach. Additionally, the open network allows the third party to use surface technology subsea (no customisation or one-off solutions).

- **True transparency**: The open network allows surface acquisition systems to communicate directly with the sensor on the seabed or downhole. This means that communication handshaking between the two devices is direct rather than through the PCS processor on the surface and subsea, as in most systems today.

- **High bandwidth**: Advanced surveillance systems such as the SMC system can provide communication links with bandwidths up to 100 MB/s. This high-speed link not only allows real-time data, including diagnostic data, to be acquired from existing subsea sensors, but also enables the use of new sensors and data rate intensive equipment (such as subsea video, in-well seismic, etc.). The high bandwidth also reduces communication timing issues.

- **Network management**: The open network and use of standard protocols such as TCP/IP allows the surface-to-subsea communications link to be managed. This includes standard network functions used on land networks such as bandwidth allocation, message prioritisation, network ‘storm’ protection and diagnostics through simple network management protocol (SNMP).

- **Data security**: The open network allows management tools, such as virtual local area networks (VLAN), to restrict the delivery of messages on the network, thus allowing a third-party sensor and acquisition system to exist on a separate ‘virtual’ network from other devices on the network where they see only messages from each other.

- **Increased space**: The majority of new subsea sensors require electronics interfaces on the seabed which require real-estate within a subsea electronics module. As space is limited in existing PCS SCMs, a separate surveillance module can accommodate the larger numbers and increased dimensions of third-party electronics that will be required by the DOFF, as well as provide power and a communications path to surface.
• Expandability: The open network and increased room for electronics subsea provided by surveillance systems (such as the SMC system) allow electronic and mechanical interfaces to be pre-installed in preparation for future sensor installations. This facilitates the procurement of the subsea monitoring and control equipment without the need for upfront information about the final sensor requirements and interfaces. The ability to route serial communications over the network allows sensors to be interfaced easily after installation of the surveillance system with the provision of mechanical interfaces and subsea wet-mate connectors.

• Flexibility: The open architecture modular design of the SMC system makes it suitable for use with any monitoring and control equipment on the seabed or downhole—such as subsea pumping units and subsea separation units—without impacting the PCS. Additionally, the use of a network represents a more practical alternative to the traditional master/slave system, promoting the development and use of intelligent sensors.

• Subsea data processing: The surveillance module can hold additional capabilities to process high frequency raw data locally, which cannot be transmitted to surface due to the volume of data, e.g. digital signal processing (DSP) for subsea vibration analysis.

• Shorter delivery times: This is possible due to reduced interfacing through transparency and use of standards.

A recent demonstration was funded by a major operator where a third-party downhole equipment supplier connected a proprietary surface acquisition system and subsea sensor into the SMC equipment and was able to immediately demonstrate the functionality of the standard third-party equipment over the SMC TCP/IP network without additional interfacing or software and electronics modifications. This reduced the time taken to interface a third-party sensor from subsea to surface from weeks to hours, hence minimising interface engineering efforts and costs.

The CERA group identified that the trends in the technology towards an industrial Ethernet-based system providing alarming, device-to-device distributed communications, robustness and lower cost sensors will lead to appreciably better systems. The use of these networked solutions would provide higher reliability, built-in redundancy and improved monitoring of facilities.

The subsea TCP/IP network provided by the SMC system brings this functionality subsea and links the subsea sensors to the platform or FPSO network, which in turn can be linked to an onshore network. This connectivity not only allows remote configuration of subsea equipment from onshore, but more importantly, links the onshore engineer to his/her field.

This connectivity allows the development of a data flow from sensor to an onshore operations centre (OOC) or onshore support centre (OSC), identifying and reducing interfaces and complexity while providing an open and expandable system architecture.
for future sensors and analysis software. CERA identified the benefits of the DOFF and the onshore centres as providing:

- Reduction and discontinuation of manual data gathering and input tasks
- Emphasis on visit-by-exception to resolve equipment and production issues
- Flexible staffing based more closely on consulting models where each knowledge worker is assigned to two or more project or asset teams
- Centralised offsite monitoring

Figure 4 shows the process steps from sensor through subsea surveillance system to onshore engineer, as well as the equipment and interfaces provided by an advanced surveillance system. Due to the varied types of third-party seabed and downhole sensors used within the subsea environment during production, providing compatible tools and using industry standard interfaces is essential in the acquisition and analysis of subsea data.

Figure 4: Subsea Sensor to Operator Workflow

Subsea Infrastructure Design

Decisions regarding the selection of subsea control and monitoring equipment and the infrastructure required to support it must be made early on in the project design phase to allow procurement of long-lead delivery items such as the umbilical and subsea production system. Often decisions must be made on the infrastructure before the engineer knows what monitoring equipment is required for seabed and reservoir surveillance. Unfortunately, it can often be a case of using what was successful on a previous project.

A significant amount of upfront project CAPEX is spent on engineering for equipment selection, interfacing and design, and the process is generally iterative requiring multiple revisions and case studies identifying risks and limitations before a final solution is adopted. Restrictions on sensor placement, electrical power and communication data rates imposed by the PCS can often drive the selection of the sensors.

Often limitations placed on the control and monitoring equipment by the subsea infrastructure or control system are not realised until later in the bid process. At such time when details on the interfacing and operation of third-party monitoring and control equipment are finalised, it would either be impossible or prohibitively expensive to change design. This would result in reduced monitoring capabilities, increased costs, slower data update rates and restrictions on future expansion.
A tool is required which will allow the operator to develop multiple case studies for a field in order to select the right infrastructure and monitoring and control equipment early in the design phase to maximise surveillance and reduce interfacing, system engineering and costs, and increase reliability/uptime.

The operator should be able to balance surveillance requirements (e.g. downhole gauge data update rate at surface, flow assurance monitoring, additional diagnostics for advance monitoring, etc.) against power and communications infrastructure, as well as automate a costly and labour intensive task often performed by third-party engineering companies.

The tool could provide:

• Subsea communications, electro-hydraulic power and equipment design/drawing tool
• Subsea equipment objects—gauges, pumps, valves
• Risk identification and development of risk matrix
• Interface identification with associated responsibility
• Import facility from external design and analysis applications—production system analysis software (PIPESIM)
• Hydraulic power analysis—umbilical, infield jumpers, wellhead, tree, tubing hanger feedthroughs
• Comparison of different power/communications options (fibre optic, power-line modem)
• Data update rates and limitations
• Umbilical and infield distribution power and communication requirements and recommendations—core sizes, number of cores, power losses in umbilical
• Subsea connector configuration and interfacing
• Redundancy analysis
• Report and tender scope generation
• Maintenance schedules proposals
• Reliability availability maintainability (RAM) analysis of subsea infrastructure
• Failure mode identification for hazard and operability (HAZOP) and failure modes and effects criticality analysis (FMECA)

The scope of the tool may be extended to include equipment catalogues providing costs and schedule estimates for each design case.

The tool would also allow the engineer to develop a data management strategy and workflow identifying requirements for network infrastructure, databases, and so forth, based on the subsea monitoring and control equipment specified for each case and the bandwidth provided by the subsea surveillance system.
**Wellsite Data Gathering and Delivery**

This increase in real-time data at the wellsite call for an offshore-to-onshore data management system to handle the transfer of the production data to the operator and/or service company onshore database.

The hosting of the data onshore allows visualisation and analytical tools to be employed, thereby reducing the volume of data and providing the operator with information and event notification that is relevant to the engineer. This includes the calculation of KPIs from measured data and associated models, predictive alarming and the utilisation of decision-making tools such as chemical injection optimisation, system performance monitoring and the detection of events and trend violations by raising red-flag failures with an associated severity level.

As both operators and service-company engineers have a vested interest in the production and diagnostic data acquired from subsea sensors through remote monitoring, there is a need to deliver the data to multiple targets or databases onshore, i.e. an operator operations centre and service company support centre. The operator will be more interested in the production data provided (pressure, temperature, flowrate) for production analysis and optimisation, whereas the service-company engineer can apply his/her knowledge of the equipment and wells to the diagnostic data to determine possible faults, operating issues or predict failures in the equipment.

Additionally, the data required onshore must be collected from multiple sources at the wellsite—including production control systems, platform control systems, third-party acquisition systems, and other sources—often using a variety of communication protocols.

Data gatherers such as Schlumberger’s WellSite Interface (WSI) system allow data to be collected from multiple wellsite acquisition systems over both serial and Ethernet communication links and from direct I/O (e.g. 4-20mA signals from local sensors with an integrated acquisition system). The data is then packaged into Wellsite Information Transfer Mark-up Language (WITSML) files and pushed either to a local or remote operator database and, if required, an onshore externally hosted database. A web-based user interface allows the onshore engineer to browse the acquisition systems connected to the WSI remotely and select the data points he wishes to pass onshore.

Currently, the industry standard WITSML data format is primarily for drilling data, however, there is an ongoing initiative guided by the Petrochemical Open Standards Consortium (POSC) group to develop similar data schemas for production data. Figure 5 shows a possible configuration of the WSI or offshore data gather.

The ability to send the data securely is essential especially when sensitive production data is involved. The use of the Hypertext Transfer Protocol over Secure Socket Layer (HTTPS) protocol for encryption when passing the WITSML data files onshore provides a good level of data security.
Service company hosted systems are becoming increasingly more common, such as production real-time infrastructure, or PRTI (Theuveny 2004). The latter is a central data management infrastructure developed by Schlumberger to host real-time production data and application workflows, and make them available worldwide on the internal company intranet and to operators via the internet with total security. PRTI provides operators with the ability to subscribe, according to their needs, to various levels of services in the monitoring, surveillance and optimisation of their oil and gas production. A number of PRTI workflows have been developed to provide the operator with data analysis functions including visualisation tools, calculation of KPIs, performance indicators, alarming and other functions. Today, these workflows include:

- espWatcher™ provides a remote surveillance facility for ESPs, allowing an engineer to view field or well data for each ESP using a standard web browser. The workflow provides alarming and event detection as well as pump performance indicators and reports (Theuveny 2004).

- ProductionWatcher™ allows an operator to view well production data remotely using a standard web browser. The workflow provides additional information on productivity (completion performance), gradient (flow assurance indicator for solids deposition), drawdown (flowing pressure management) and alarming. It also provides trend and event detection.

- PhaseWatcher™ provides monitoring, data validation and surveillance of multiphase flowmeters. Supplies the operator with oil, gas and water flow rates, line pressure and line temperature, as well as information on meter operation and accuracy, scale detection and fluid properties monitoring through automated reporting.

**Figure 5: Subsea Sensor to Operator Workflow**
Applications must also be made to operate locally at the wellsite or within the operator’s onshore centre, and provide validated event detection and notification in areas such as monitoring of subsea equipment conditions and flow assurance attributes in pipelines and risers. These tools can be integrated into the operator’s onshore centre system to allow an engineer to launch the third-party tool directly from the operations centre interface when an event is detected.

As these tools do not require additional hardware in place and can utilise data from existing PCS and surface systems, they can be used on existing brown field developments using the available low-frequency data as well as integrated into new green fields.

The transfer of large quantities of data onshore and the storage and management of this data can be costly and require significant infrastructure. While there may be a need to provide high-frequency production data onshore for reservoir and production engineers, equipment and system diagnostic data is not required at these high rates and is often of little use to the onshore production engineers. Alternatively, analysis tools at the wellsite are designed to use the high-frequency diagnostic data from the local acquisition systems and sensors to provide event detection for slugging, vibration analysis and other preventive measures. This would eliminate the need to send the raw data onshore which reduces the loading on data communication systems as well as data storage and handling costs.

**Condition Monitoring Tool**

With the availability of data management tools to allow the transfer of real-time subsea data to onshore support or operations centres, the operators often find themselves provided with large quantities of raw data but little information of what the data indicates or context to allow operational decisions to be made. Tools must be designed to reduce the quantity of data presented while increasing the information provided to the operators.
Current ‘surveillance tools’ gather and display data but often still require the operator to examine the data to determine events occurring in production or equipment. Additionally, the tools that are available today are generally production focused rather than equipment focused in an effort to increase production through surveillance mainly in fields with intelligent wells.

Production and diagnostic data from each sensor is collected on the surface and the supervisory control and data acquisition systems and data historians generate data alarms in the form of high/low limit alarms generated either locally at the platform or at an onshore operations room, but often these limits are not updated throughout the life of the field. Additionally, these alarms are specific to a certain parameter or component (e.g. downhole gauge pressure) but the problem may be related to another component on the production flowpath. In many cases, equipment failure or production loss may be identified early by monitoring data acquired from a number of subsea monitoring devices simultaneously.

Examples of this are:

- Increase in sand rate detected by manifold sand detector
- Intake pressure increase detected at seabed multiphase pump
- Downhole distributed temperature increase at ESP

In today’s systems, three separate alarms may be generated but not well understood by an operator with limited subsea experience; their criticality may not be identified and merely treated as individual equipment faults/failures.

What this information is actually pointing to in this example is that the downhole ESP is running outside its operating range and pulling sand into the well which may damage the pumping equipment. The solution is to reduce the subsea ESP pump variable speed drive at the surface to reduce the pump rate extending the life of the equipment.

Notification is electronically sent to the individual(s) responsible and most familiar with the equipment, and the engineer is provided with the right context (e.g. well depth, fluid properties, etc.) which is required to make an informed decision on the problem and the remediation required. This also reduces the need for knowledge sharing by providing the appropriate information to the right people at the right time.

Rather than provide a complete control loop process (i.e. monitor, analyse and control), the goal of the tool is to monitor, analyse, recommend and provide alerts to the engineer who needs it, whether through a visualisation tool, historian interface or email, with all the necessary data to make the appropriate and informed decision. The email or report can contain contextual data as well as schematics—process and instrumentation diagrams (P&ID)—to provide the engineer with all the data required to analyse the event. The tool can also be linked to an operator’s messaging, support or maintenance
ticketing application in order to provide the engineer with the timely information to manage the event.

Automated control is an excellent solution for some control issues offshore, such as choke operation to control slugging, but often there are associated systems and factors which must be taken into account prior to a control action being performed. For instance an intelligent automated system could increase methanol injection to the well based on a hydrate alarm in the pipeline, however the knock-on effect of this is that additional volumes of methanol are required on the platform which must be costed, bought, transported, stored and eventually extracted. Or the solution may be that the chemical injection valve on a particular tree is blocked and the methanol is being directed to other wells. An advanced tool would alert the operator to the event and provide information on remediation and the cause and effect of the remediation strategy.

To demonstrate this analysis method, the Schlumberger Subsea group developed a software decision tool that would provide real-time condition monitoring of ESP using real-time data. This would reduce the quantity of data to process and provide the operator with immediate recommendations to improve production while reducing possible equipment failure.

The decision tool uses a Bayesian case based reasoning method to determine field events using a weighted model applied to production data. Real-time data is fed to the tool from acquisition systems and data historians using industry standard interfaces. The operator would be alerted of an existing or predicted problem either through the production data management system or by email. The tool could also be used for data validation and calibration.

The proposed analysis method allows for uncertainties and unknowns in the data, provides a ‘confidence’ level (0–100 percent) for each event detected and is built on expert knowledge of the domain rather than a trained network. The tool could be scaled to account for multiple well fields, downhole gauges, ESPs, downhole and seabed valves, sand/corrosion monitors and others.

Case based reasoning (CBR) consists in diagnosing a problem by remembering a previous similar situation (library of cases), and reusing information and knowledge of that situation. The Bayesian engine utilises the library of cases and predefined probability distribution functions to derive the chances of success of each possible diagnosis given the specific situation described by the user.

The cases are developed by equipment and industry experts using knowledge of the tool design and field experience and are validated against historical data from known operating equipment and failures. The ESP knowledge base is developed from over 600 cases. These knowledge bases can also be used by support engineers offline and as part of engineer training programmes.
Figure 7 shows a screenshot from the ESP condition monitoring tool. The operator can select a time period from the available data set and the tool will populate the input parameters to the case based analysis set. The cases are shown expanded on the right with an indicator showing the ‘fit’ of the case to the data set and the confidence of the decision. If more than one case fits the data, the engineer can use other information and experience to select the appropriate case. This new decision can then be fed back into the case set to be used in future analysis.

There are a number of tools available that inform the operator of a production or system event by the comparison of modelled data against continuously measured data where, if a deviation is detected, the operator is alerted of the problem either within the field or with the actual model. The Schlumberger Flow Assurance Design and Sentinel (FADS) real-time alarming and diagnostic interpretation tool is one application of this type providing flow assurance alarming locally at the wellsite.
Flow Assurance Surveillance Tool

Flowlines and risers in deepwater projects are subject to a range of physical and chemical conditions that decrease or even stop flow. Typical examples are the formation of hydrate plugs or the deposition of solids such as waxes or asphaltenes. The decrease of production rate and the high cost of flow remediation mean that these conditions must be monitored and avoided.

Integrated flow assurance solutions combining fluid property data with hydraulic and thermal analysis eliminate the over-treatment that occurs when chemical applications are designed for worst-case scenarios. The frequency and intensity of remediation techniques using thermal, chemical or mechanical methods—such as pigging—can be reduced; and catastrophic problems leading to interruption of production for extended periods, such as plugging or gelling, can be avoided. Data is acquired from multiple data sources and sensors in real-time at the wellhead, subsea manifold and surface facility. These include wellhead pressure, temperature and flowrate, boarding pressure and temperature at the host facility, to detect or predict the formation of wax and hydrate deposits and allow the continuous updating of models. To provide improved flow assurance alarming and the quality of the flow assurance monitoring, a Sensa fibre-optic monitoring system can be deployed to acquire distributed temperature measurements along a seabed pipeline or riser.

The FADS application provides real-time alarming for hydrates in subsea pipelines and risers using temperature data acquired from distributed temperature sensing (DTS) fibre-optic lines in the pipeline or riser to warn the operator if the production is entering a hydrate region.

To reduce the volume of data that has to be delivered onshore, the FADS application not only performs all data acquisition, modelling and alarm generation locally at the wellsite, but also provides the onshore operator with a means of viewing the real-time and historical data remotely. The FADS system is composed of two software applications:

- **Designer** is a configuration and visualisation tool which resides onshore.
- **Sentinel** is a data acquisition and analysis tool which resides offshore.

**Figure 8: FADS Application Overview**
The FADS Designer application provides an operator interface allowing project configuration and viewing of real-time and historical data and alarms. The FADS Designer resides onshore within a client or Schlumberger office and uses a combination of thermodynamic, heat transfer and hydraulic models to generate appropriate system performance envelopes that are utilised by the Sentinel application.

The FADS Sentinel application resides at the wellsite offshore and is responsible for the acquisition of discrete point and distributed temperature data using industry standard protocols. If required, the SMC system surface and subsea systems can be used for the acquisition of real-time data from subsea or locally from the platform or production control system.

The Sentinel is responsible for the comparison of the real-time data against the modelled data to determine the likelihood of the hydrate formation or other flow assurance concerns in the pipeline and/or riser (Ratulowski et al 2004). The Sentinel generates real-time alarms that are sent to the platform/FPSO control system via OLE for Process Control (OPC) and to an onshore flow assurance expert via email.

The flow assurance alarm allows the operator to alter the production rates and chemical remediation plans to reduce the risk of hydrates or solids deposition. This results in reduced chemical usage, improved use of pipeline heating and reduction in pipeline/riser intervention (e.g. pigging).

As with the condition monitoring tools detailed earlier, the aim of the flow assurance tool is to provide the operators with all the information they require at the right time. The operators at the wellsite should require no knowledge of the sensor data values or
flow assurance models and software. They will only be required to understand the significance of the alarm. They will know how to view this diagnostic plot in their control environment and share it with production and operation engineers or managers. Flow assurance experts are required only for configuration and tuning of the tool and are able to perform diagnosis of the data using the Designer remotely when a flow assurance event is detected.

Current areas of development for the next versions of FADS include:

- The addition of solids precipitation models to enable monitoring of wax and asphaltene
- The development of a thermal transient model allowing alarming of hydrates/solids during shut-in
- Real-time optimisation of chemical injection programmes and in-line heating

These improvements will provide the operator with advanced warning of the onset of hydrates or solid precipitation in the riser and/or pipeline. The Sentinel will provide the offshore production operator with a continuous countdown timer indicating the estimated time until formation/deposition during shut-in or start-up conditions or ‘no-touch’ time.

**Interfaces and Standards**

The use of industry standard protocols in the acquisition, management and application of data from seabed and downhole sensors is essential in the development of cross product and supplier sensors, acquisition systems, software applications and infrastructure. The tools developed for advanced surveillance must be compatible with existing and planned data management systems used in both offshore and onshore support and operations centres.

Within the subsea domain, the IWIS group have specified a standard mechanical, electrical and software interface for intelligent well equipment, such as pressure/temperature gauges and flow control valves, based on TCP/IP serial communications. This effort has recently been expanded to seabed sensors by the development of the SIIS group.

The formats used for the handoff of production data from the acquisition system on the platform or FPSO to the offshore or onshore historian vary depending on operator and system in place. The IWIS standard specifies OPC as the standard for surface data handoff, however, a number of legacy systems today use protocols such as serial Modbus, Profibus, and direct IO, which increase the interface engineering required. As detailed in the section above, tools like the WSI can be used to gather data from these varied systems and provide the acquired data to the operator in a standard format.

The Wellsite Information Transfer Specification (WITS) format was developed in the 1980s by a group of operators and service companies as a standard data format for the transfer of drilling data from wellsite to onshore.
However, the format had a number of limitations and, in 2000, a new format was proposed called WITSML for the transfer of drilling data which allowed streaming data and provided context.

The WITSML format is XML based and extensible with a number of oilfield data objects (well, rig, fluids) that can be used for data exchange between different service company’s software systems, which means that operators can easily transfer the drilling data received onshore into their corporate database and use standard visualisation and analysis tools regardless of the service company at the wellsite.

In 2002 the custody of the WITSML specifications was transferred to the POSC group, which is involved in the initial development of the specifications of a mark-up language for production data called Production XML (ProdML). It is anticipated that this will become the standard for data exchange for production data from the wellsite.

Early involvement in the development and eventual adoption of these standards is essential for the integrated sensor-to-engineer process and the uptake of the DOFF within the industry. Figure 10 shows the industry standards in use today against the sensor-to-engineer workflow.

**Figure 10: Subsea Sensor to Operator Workflow Showing Interfaces**

![Subsea Sensor to Operator Workflow Showing Interfaces](image)

**Future**

The extension of the existing data analysis tools to perform accurate failure prediction is seen as the next step. True fault prediction tools require access to large quantities of historical production data and the use of data mining tools to determine patterns in the data and the integration of contextual data. For example, the ability to predict failures in downhole ESPs requires knowledge of the well, fluid properties, ESP mechanical configuration, number of interventions and other factors.

There have been a number of studies on equipment failure prediction, but these tend to be academic based on the analysis of historical data and extrapolating using distribution forms. The drawback with these studies is that failure rates are identified as dynamic and
a number of unknowns or covariates exist. To accurately predict the remaining equipment lifetime, a method of analysis must be used which allows for unknowns and multiple variant, and uses current equipment operational and configuration data. Survival analysis is concerned with the modelling of time to event data, such as the lifetime of an engine component.

Software tools could be developed using analytical approaches to provide a dynamic estimation of remaining equipment life with an associated confidence level. Additionally, an analysis of the critical components affecting equipment failures allowing future installations and components in similar conditions to be selected correctly to extend the life of the equipment.

These tools would allow the operator to schedule intervention, maintenance and part ordering prior to an equipment failure, thus reducing the production downtime and prolonging the life of the equipment. However, the availability of long-term historical equipment and production data with contextual information is essential for the development of accurate failure prediction tools.

The expansion of the WITSML data format to production data will be a key factor in the development of cross-product and company surveillance tools. Additionally, the current WITSML schemas are well focused as the format was historically developed for drilling. This must be expanded to include subsea infrastructure, such as pipelines and manifolds, to allow data packaging and management for a full subsea field development to be implemented.

**Conclusions**

The development of advanced surveillance tools will be essential to the improvement of production uptime and reduced interventions for subsea developments, thus reducing the lifetime operating expenses for the field. Surveillance improves subsea equipment availability and operating procedures leading to increased uptime.

Advanced selection and design tools used at the conceptual and front-end engineering phases of field development can further reduce interfacing and identify risks and reliability issues early in the design stage. Integration of these solutions allows the operator to develop a cost-effective, data-rich, subsea infrastructure with built-in advanced monitoring to help realise the primary objective of increasing productivity and system reliability.

The introduction of dedicated flexible monitoring and control systems is paving the way to increased overall productivity with improved reservoir and assets management. Additional gains are realised from fewer interventions and reduced operating costs over the life of the field, and from minimising upfront design costs when considered at the conceptual and front-end engineering and design (FEED) stage.
The increased data rates from advanced subsea control and monitoring systems provide high-frequency data for modelling and production optimisation tools. Additionally, the open network surveillance systems—such as the SMC platform—reduce interfacing and testing. Open industry standard protocols for data delivery allow data from multiple sources to be used in subsea equipment surveillance. Local wellsite analysis tools can use this high-frequency diagnostic data to generate equipment alarms and reduce the need to transfer all the data onshore.

In summary, the application of the appropriate technology towards a subsea surveillance solution brings true value to an operator. The implementation of an SMC based system will realise significant cost savings by providing:

- Development cost reduction through improved system integration and reduced interface engineering.
- Operational cost reduction through improved reliability and system availability
- The necessary infrastructure to utilise advanced production optimisation tools

As these technologies become proven through field trials and permanent installations, it is now the responsibility of the subsea community to assess the cost/benefits and be more aggressive towards the adoption of subsea reservoir/production surveillance systems in tandem with the more traditional tree-centric control systems. Solutions must be considered at the FEED stage and tender structures have to be adapted to allow surveillance options to be independently considered.

References


