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Fiber Optics Sensing Systems for Subsea Applications—Sensing Capabilities, Applications, and the Challenges Being Faced in Order to Provide Reliable Transmission of Data for Online Reservoir Management

B.K. Drakeley, SPE, Weatherford International, and Svein Omdal, SPE, StatoilHydro

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Abstract

The industry has seen the gradual implementation of step-change optical sensing technology as one way to address the issue of reliable permanent downhole gauges. This paper will include case histories that indicate an ever-broadening acceptance of this technology with application scenarios ranging from simple single-gauge installations to multi-zone intelligent wells with integrated sensing and remotely activated in-well zonal flow control - true Smart or Intelligent Wells, with now over 600 installations worldwide.

Present measurement capabilities include Pressure and Temperature, Distributed Temperature Sensing (DTS), Single- and Multiphase Flowmeters, Seismic Accelerometers and hydrophones, and the paper will also detail additional downhole and subsea optical sensing systems currently under development.

As subsea continues to play a vital role in our industry, it has been recognized that there are a number of challenges to be addressed before optical sensing systems will be widely adopted subsea.

These challenges are being addressed in part by a new thirty member company industry group, SEAFOM (Subsea Fiber-Optic Monitoring) – this group's activities will be described.

In addition, a number of operating and service companies have on-going related initiatives. For example, StatoilHydro has an Integrated Operations (IO) initiative aimed at significantly increasing overall recovery rates of subsea production assets. As part of that initiative, StatoilHydro and Weatherford signed a three year Technical Development Cooperation Agreement in June 2006. This project will make real-time reservoir monitoring and downhole data available everywhere on a StatoilHydro network infrastructure.

This paper includes the rationale for selecting fiber optics as the baseline technology and also describes the technical solution for an open, high speed communication infrastructure. The project is also developing interfaces towards existing subsea systems with only electrical, low bandwidth communication systems. Solutions are being developed for both Green and retrofit Brown field applications.

Introduction

Well production and injection program optimization systems in the offshore (as well as land) environment are becoming increasingly well established in our industry. Core elements of these systems are in-well monitoring systems that deliver high-performance measurements throughout the lifetime of the well.

Since the first in-well fiber optics pressure/temperature (P/T) gauge was installed in a land well in Europe in 1993, the industry has been attracted to fiber optics in-well sensing technology by a key list of capabilities and characteristics that include:

- Unique sensing capabilities e.g Distributed Temperature Sensing (DTS)
- Reliability over existing electrical monitoring systems

  - Passive
  - No electronics downhole
  - No moving parts
- Ideally suited for harsh environments
  - High temperature capability
  - Vibration and shock tolerant
- High data transmission capability
  - Multiple sensors on common fiber infrastructure
  - Technological advances driven by telecoms industry
- Multiple sensor types on single fiber
  - Reduced number of penetrations in tubing hangers and downhole packers

As a result, hundreds of in-well fiber optics sensing systems have been installed since the first one back in 1993. In-well fiber optics sensing capabilities commercially available today include:

- Point P/T–over 170 gauges installed
- DTS – several hundred installed
- Single-phase and multiphase flowmeters – over 30 meters installed with single-, two- and three-phase measurement capability
- Seismic accelerometers – over 40 seismic stations deployed.

It is not the purpose of this paper to describe in detail the capabilities of each of these types of sensing system or the science behind them. That has been dealt with in a number of prior publications.[1] The paper will however focus first on case histories of applications of these sensors.

In-well Fiber Optics Based Permanent Monitoring Systems – Installation Case Histories

Pressure/Temperature (P/T)

The first production well to use a Bragg grating-based optical pressure gauge was installed in deepwater in the Gulf of Mexico in April 2000 and the gauge continues to operate reliably today. This was a platform-based installation with a single pressure gauge above the production packer and is used for reservoir pressure monitoring.

From this very simple type of installation there has been gradual movement to more complex multi-zone pressure and temperature monitoring. For example, in November 2003 a three-zone monitoring system was installed in Nigeria to provide reservoir monitoring to support remotely operated flow control systems on a zonal basis. This true Intelligent Well system gathers reservoir information and permits the operator to make zonal level flow regime adjustments.

Distributed Temperature Sensing (DTS)

Fig. 1 shows the addition of DTS (monitoring across all three zones) to zonal P/T measurement (single gauge above the production packer and three gauges monitoring each producing zone) and a remotely operated zonal flow control system in a well installed in a land well in South America in January, 2006. The objectives achieved were to monitor production pressure in the three zones available to adjust the flow regime and with the DTS system characterizing the production contribution from each of the three zones.

Combined P/T and DTS monitoring systems have also been installed in conjunction with Intelligent Well Sand Screens, with DTS deployed outside of the well screen. One such installation was deployed in West Africa in April 2006.

Fig. 2 shows a DTS system – in this case a horizontal dual injector - deployed in open hole in a Middle East well in August 2003. This system provided DTS data during warmback and a high injection zone was also identified. The system is also used for periodic injectivity monitoring.

In-well Flowmeters

An optical flowmeter was installed offshore in Trinidad in March 2002. The flowmeter provides real-time quality measurements of downhole pressure, temperature and oil and gas flow rates on a continuous basis. Though configured as a three-phase meter, the well has yet to experience any water production to date, with the result that capability has yet to be tested in this application. Analysis of data from the flowmeter determined that the free Gas Volume Fraction (GVF) downhole increased from 0 to 60% in the first month of production, indicating gas coning. Total mass flow rate measured by the flowmeter was consistent with well test results to within ±5% for nearly all data points. The gas rate is well within ±10%.

A four-zone intelligent Water Alternating Gas (WAG) injector was installed in a platform well in the Norwegian sector of the North Sea in May 2004 (**Fig. 3**). The completion includes three optical single-phase flowmeters with integrated P/T gauges and one on/off and three variable downhole valves for controlling injection rates into each of the four zones. Water injection up to 7,500 m^3/d started in June 2004 and software modification for the flowmeters was required at an early stage due to the vibration induced in the downhole valves by the high injection rates. These software modifications were all completed remotely from the supplier's U.S. location. In November 2005 the injection program was converted from water to gas, up to 2.1 10^6 Sm^3/d Similar vibration issues arose and software modifications were successfully accomplished as before.

The flowmeters have revealed interzonal cross-flow during shut-ins as well as identifying thief zones. The combination of downhole valves and flowmeters allowed full control and monitoring of zonal injection rates and has proved a valuable tool in managing reservoir pressures and optimizing production for the client. One or two injection well slots are believed to have been saved, allowing for additional producers. A typical injector costs more than USD10 million.

In another application, three flowmeters were also successfully installed in late 2006 in a multi-lateral production well in the Middle East along with three remotely operated variable flow control devices.

In-well Seismic Accelerometers

Fig. 4 illustrates the first offshore permanent in-well fiber optics seismic installation in an injection well in the Norwegian sector of the North Sea in March 2006. This was a multi-station (5), multi-component (3C), tubing conveyed fiber optics seismic array with P/T gauge fully operational. The in-well optical seismic sensors are being interfaced to an existing permanent Ocean Bottom Cable (OBC) seismic system and in-well seismic imaging and monitoring data have been successfully acquired during scheduled 4D seismic surveys.

In October 2006, an onshore installation took place in Kazakhstan where 24 seismic sensors (the highest number installed to date) in an 8 station, 3 component array are being used for microseismic monitoring of a sour gas injection program.

Optical Permanent Monitoring Systems in Development

There are a number of additional types of fiber-optic sensing systems either in development or at the point of first field installation. Amongst them are:

- In-well
  - Array Temperature Sensing (ATS) – increased accuracy and resolution over DTS systems
  - Distributed Pressure Sensing (DPS)
  - Sand production monitoring and quantification
  - Flowmeters for extreme horizontal well applications
  - Distributed strain measurement (e.g. for risers)
- Subsea
  - OBC 4D/4C
  - Flow assurance

Early Experiences with Subsea Well Installations

The first subsea well fiber optics permanent monitoring system was installed in 1996 in the Guillemot field in the North Sea. This system consisted of a subsea optical instrument incorporated in a subsea instrumentation pod and an optical wet-mate for a vertical subsea tree.

Three subsea monitoring wells at Shell's Heron field and one subsea well at Shell's Egret field followed in 1998 to 1999. The sensor was monitored from surface through an optical cable that was integrated in the umbilical and through a vertical wet-mate connector to the pressure gauge located in the well. This configuration reduced the complexity of the subsea monitoring system by replacing the subsea instrumentation canister with an instrument that was readily available at the surface.

These installations were successful in demonstrating both the optical system hardware, including optical cable, instrumentation and connectors, and the processes required to install optical systems in North Sea environments. However, the sensor technology in use at that time incorporated extremely complex mechanical packaging. This resulted in performance deterioration and the sensor technology has since been superseded by Bragg Grating technology (other measurement techniques are used by some suppliers).

Interestingly, since those first examples, subsea installations have been notable by their absence.

Challenges Facing Subsea Well Installations

The vast majority of all in-well fiber-optic sensing system installations have been in offshore dry tree and land wells. To take advantage of the opportunity presented by the growth and significance of the subsea well market, a number of challenges and barriers need to be addressed

These challenges are readily transparent, for example a lack of qualified marinized instrumentation for deployment subsea in situations where there is no fiber in the umbilical or where the tie-back distance exceeds the reach of the instrumentation if placed topside. Some marinized instrumentation qualified for P/T and ATS sensing systems is scheduled for deployment subsea in 2008; there are also development projects planned for marinized instrumentation that will address the needs of other sensing system types – however there is simply no widespread commercial availability.

The canister to be placed in the subsea pod for use in the 2008 planned subsea installation complies with Intelligent Well Interface Standardization (IWIS)[2] option 2. For other applications it can be configured as an ROV retrievable canister according to IWIS option 3.

Another obvious 'gap' area is that of subsea Xmas Tree/Tubing Hanger (XT/TH) optical wet mate connector systems. Some qualified wet connector systems are available today, but have temperature/application/capability limitations. Once again, active development/qualification programs are in process – but there is simply no widespread commercial availability of XT/TH optical wet connector systems.

In February 2006, an SPE ATW with the title "In-well Optical Sensing–Subsea Well Applications–Are We Ready?" was held in Galveston, Texas. This was attended by over 130 delegates from Brazil, Canada, France, Germany, Indonesia, Japan, Norway, the United Kingdom and the U.S.A., demonstrating the world-wide interest level. During this ATW issues were identified[3] that prevented increased usage (amongst other areas) and these proved to be more than merely technology gaps. Although brainstorming sessions led to some good ideas on how to close some of the gaps and overcome some of the barriers it was clearly apparent that it would take a sustained effort to "solve" the overall problem and widespread interest in forming a new industry group to lead that effort was expressed.

New Industry Group

As a result a "launch" meeting was held in June 2006 and a new international industry group, SEAFOM,[4] was formed to promote the growth of in-well and subsea fiber optics monitoring installations in subsea applications. The scope of the group also extends to relevant technical issues for dry tree applications and downhole optical challenges common to on-shore as well as offshore wells. Today there are 35 member companies. Membership is open to those operators and service/research companies developing, interfacing with and deploying in-well and subsea fiber optics monitoring systems and those components and communications systems required for subsea well applications.

The group is developing "industry" processes and procedures and taking other steps that it believes will facilitate the desired growth.

StatoilHydro IO Project

In addition to SEAFOM, there are a number of operating and service companies (StatoilHydro among them) pursuing related ongoing initiatives to address the gaps and barriers.

In June, 2006, StatoilHydro and Weatherford signed a three year Technical Development Cooperation Agreement relating to the development of:

- Integrated Fibre Optics Subsea Systems (IFOSS) – an integrated subsea fiber optics communication system
- Downhole Sensors (DHS) – fiber optics based

The scope of the project is illustrated in **Fig. 5**.

This project is part of the much larger StatoilHydro Integrated Operations initiative aimed at increasing overall recovery rates of subsea and Tail End production assets.

This paper focuses on the Integrated Fiber Optics Subsea System (IFOSS) part of the project, for which Weatherford forged agreements with FMC Technologies and Nexans Norway.[5]

Why Fiber Optics Were Selected

Downhole and subsea instrumentation systems have traditionally utilized the infrastructure provided for by subsea controls for transmission of data via copper cables. Initially, the use of optical fibers in subsea communication systems was driven by distance and data speed requirements and the need to eliminate the interference from high power transmission (e.g. pumps). As fiber communication speed is drastically increased in comparison with traditional copper cable communication, industry standard communication protocols are used.

The Project Activities

The IFOSS activities in the project challenge and complement the traditional and state of the art subsea communication topologies and technologies and address:

a. Analog transmission of data measured by fiber optics sensors
b. Solutions for seabed conversion of optical measurements
c. Capacity and flexibility of traditional subsea communication systems
d. Retrofit high speed communication in systems with only electrical cables in place
e. Technology, features and standards from the telecom industry.

The aim is to develop a seamless infrastructure for communication and control from reservoir to topsides to land base.

State of the Art Subsea Communications

With the introduction of optical fibers there are two "common" alternative architectures which are shown in **Figs. 6 and 7**.

Redundant routers are shown in Fig. 6, where optical communication is converted to electrical signals. In subsea routers an IP network is used to communicate with the subsea control modules and (in parallel) with other subsea equipment, marinized interrogators of fiber optics sensors, for example. The routers have spare Ethernet connections and future fiber connection points are also provided. Power conditioning and downstream electrical distribution switching and fault isolation is performed. The system may feature low speed back-up for the fiber optics communication by traditional electrical communication via the power line to a subsea router. Additionally, the back-up communication via the power line may be extended all the way to each subsea control module.

In Fig. 7, one-to-one connection of fibers is used, with a redundant set of fibers provided for each subsea control module. This system features a network for communication between the subsea control modules and may include back-up for the fiber optics communication by traditional electrical communication via the power line.

The criteria for selection of one of these alternative fiber based configurations are:

- Cost: fiber connectors are in the region of five to ten times more expensive than traditional electrical subsea connectors
- Perceived reliability: in particular, the desire to minimize the number of disconnects of fiber connectors
- Data speed limitations of electrical local distribution
- The need to distribute the fibers all the way down into the well.

Wide use of industry standards to facilitate "plug and play" functionality is being applied (e.g. Ethernet and CanBus). OPC functionality and IWIS for downhole equipment is supported. The merits of WITSML/PRODML for data transfer are being investigated as well as FDT/DTM and other standards and structures for remote housekeeping and maintenance. As a result, the system will be able to handle changing interfaces in all different modes of operation from drilling and completion, via production to intervention, as well as mid-life upgrades.

The majority of subsea fields in operation today have no fiber optics infrastructure and so within this project it is necessaryto develop technology to facilitate high speed electrical communication via copper cables – thus accommodating the needs of Brown fields.

Technology from the telecom industry is being examined in detail and, where appropriate, will be marinized. In addition, the DC power system built into some of the telecommunication systems has a power capacity compatible with many (but not all) subsea and downhole controls and monitoring requirements.

Today, fiber optics is the dominant transmission medium for telecommunication because of the high bandwidth, noise immunity and long-distance capabilities. One example of a fiber optics cable between the island of Svalbard and the town of Harstad installed in 2003 has 8 fibre pairs, each capable of transmitting 32 channels of 10 Gbps giving a full system capacity of 2.56 Tbps, corresponding to 45 million modem lines at 56 kbps.

Existing communication infrastructure should, wherever possible, be used when connecting the offshore location to a network accessible for the remote users. It is expected that new infrastructure will be based to an increasing extent on standard telecommunication protocols and optically amplified fiber optics cable systems.

The inherent bandwidth of optical communication is huge and WDM is now widely used in the telecommunications industry. A typical wavelength channel in a WDM system is 10 Gbps (40 Gbps available), which should be sufficient for most purposes, depending somewhat on the bandwidth requirements for the sensor network. However, additional wavelength channels of 10 Gbps (or 40 Gbps) can be added if required.

Fiber optics telecommunication cables are installed subsea between all continents, as well as along continent coastlines. Experience has shown that the reliability of such systems is very high and the fiber optics subsea telecommunication technology is mature and standardized. This technology enables communication over several thousand km and for span lengths of several hundred kilometers, and is the only practical high bandwith communication technology available.

Conclusion

Over the past two years, the demand driven by operators for more well flow and reservoir data has resulted in completions using more types of in-well optical sensing systems in both land and dry tree applications worldwide, as illustrated in the case histories presented in this paper. With the inclusion of remotely activitated in-well zonal flow control we now see true intelligent well installations being readily deployed.

With more types of sensing capabilities on the way, the type and amount of data available continues to grow, improving decision-making in production optimization. However, this also brings its own challenges in terms of data delivery.

If this optical sensing influence is to grow in subsea well applications, a number of technology gaps and barriers must be overcome. It is extremely encouraging to witness the overall industry approach to seeking solutions, both as industry groups and in consoritia.

Reliability and measurement stability will continue to be the overriding requirements for a monitoring system that will last for the life of the well.

StatoilHydro has initiated several ambitious technology projects addressing the key business challenges of cost efficient production and increased recovery factor for subsea installations and fixed platforms. The IO project is defined as one of their focused R&D projects and is part of the corporate initiative for Integrated Operations. Through this well-established, three-year R&D project StatoilHydro, together with Weatherford and their partners FMC and Nexans Norway, will develop a modularized fiber optics “plug and play” system where future functionality can be added into the system.

The Integrated Fiber Optics Subsea System vision (**Fig. 8**) is getting closer to reality.

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Figures

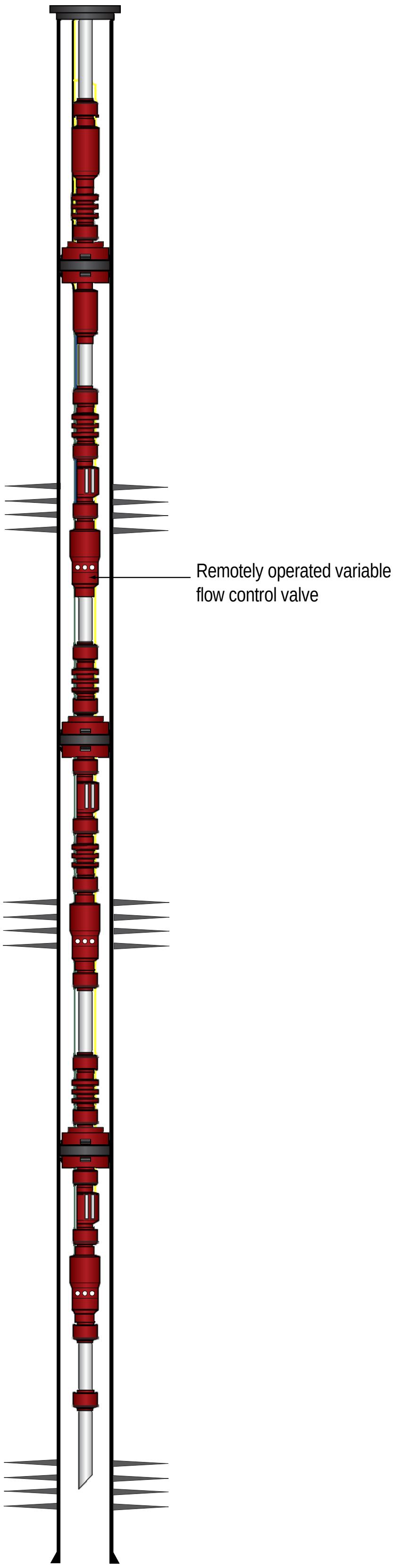

Fig. 1. Intelligent well with multi-zone P/T, DTS and remotely operated variable flow control.

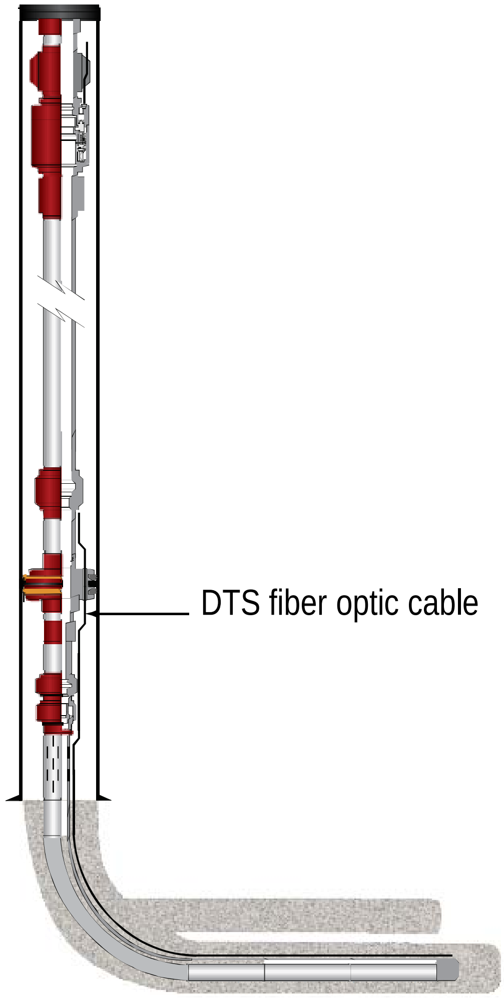

Fig. 2. DTS in open hole.

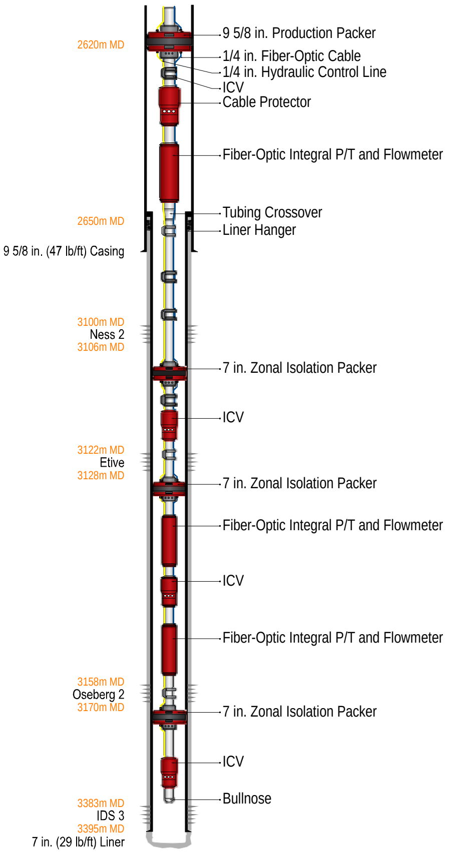

Fig. 3. Four-zone WAG injector and three in-well optical flowmeters.

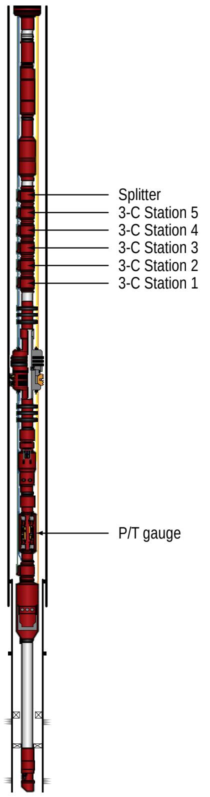

Fig. 4. First offshore 4D permanent in-well fiber-optic seismic installation.

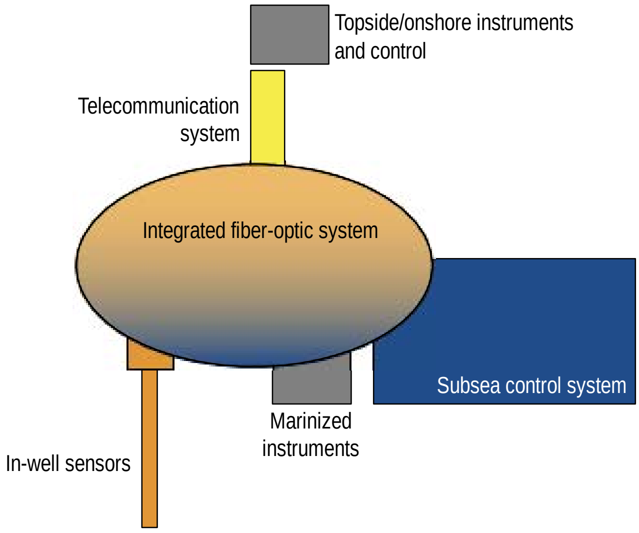

Fig. 5. Integrated fiber optics subsea monitoring and communication system.

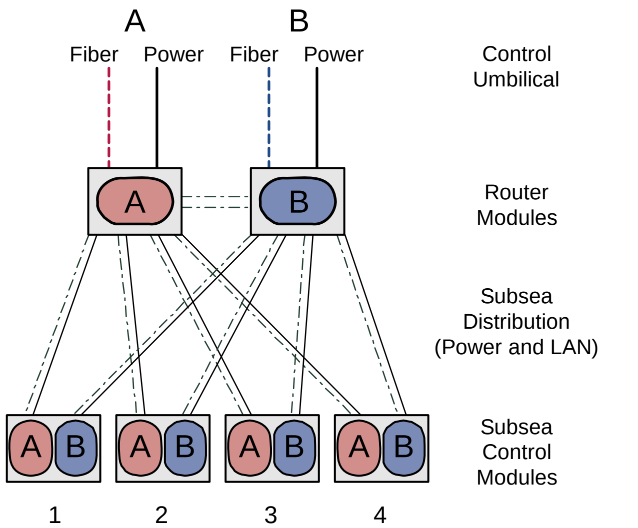

Fig. 6. Subsea distribution with fiber optics transmission from controls facility to subsea routers and local electrical distribution.

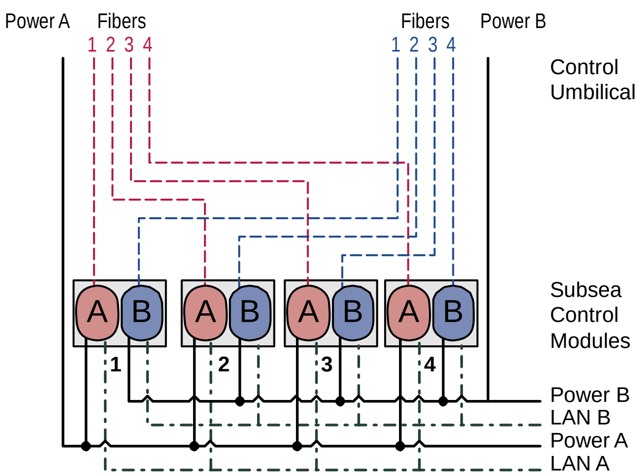

Fig. 7. Subsea distribution with fiber optics transmission to each subsea control module and well featuring (electrical)

LAN between wells.

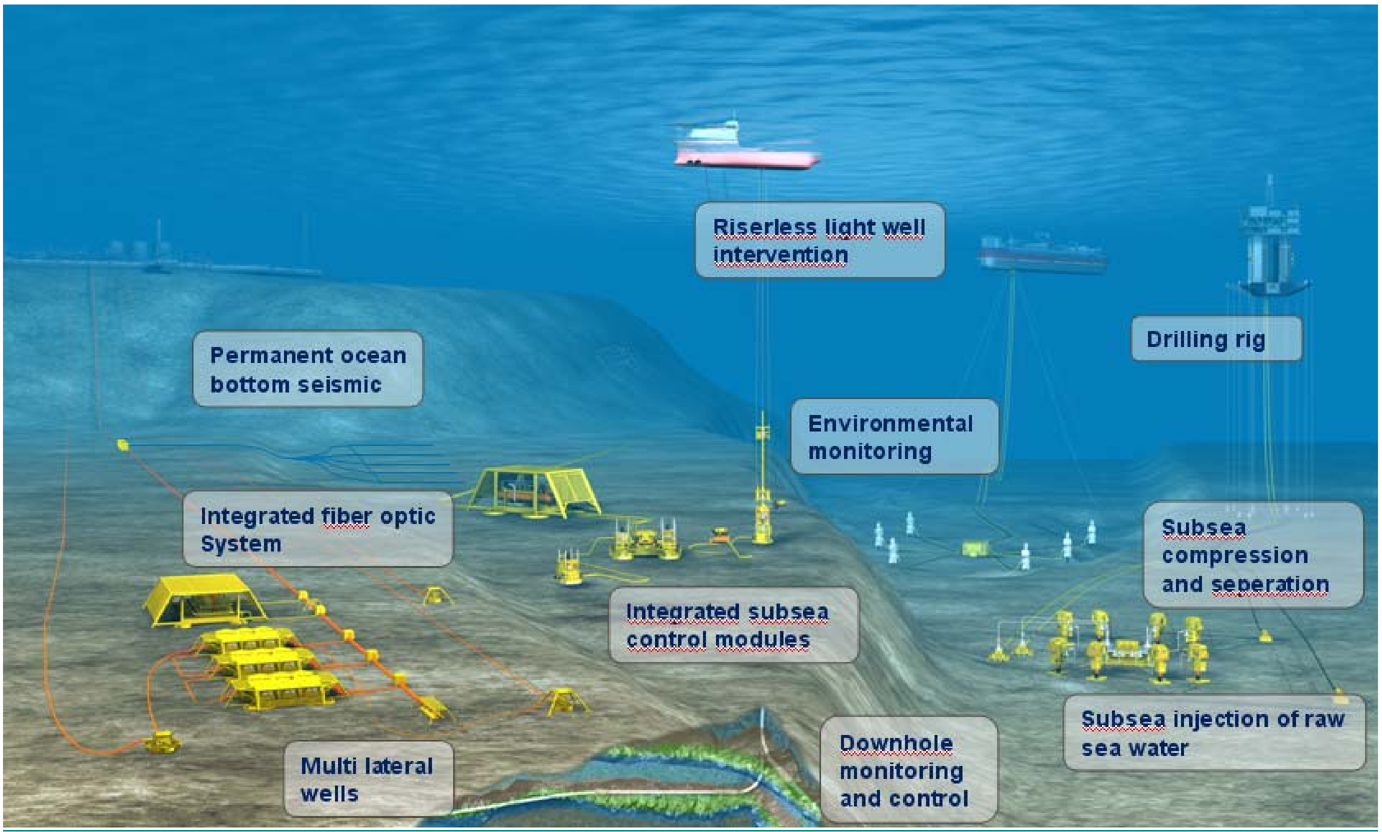

Fig. 8. Integrated Fiber Optics Subsea System vision.

References

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