The Value Of PRM In Enabling High Payback IOR

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Innovative uses of seabed seismic technology can help operators achieve considerably higher returns from new and mature fields. High potential returns with low risk and lower lifetime cost of ownership are increasingly attractive.

An increase in hydrocarbon recovery factors from a producing reservoir can make a significant economic contribution. In Norway, for example, it is estimated that "a 1% increase in the recovery rate for fields that are currently operating will increase oil production by approximately 570 million barrels of oil". Assuming an oil price of NOK 570 per barrel (A$95.00), "the gross sales income from such an oil volume is approximately NOK 325 billion"* (A$53.5 B).

It is acknowledged that many of the enabling technologies deployed on fields on the Norwegian Continental Shelf that have contributed to the high recovery rates have been developed through close cooperation between international seismic companies and regional operators. Indeed, the use of 4D seismic on the Gullfaks field alone has been estimated by Statoil to provide value creation equalling about NOK 6 billion (A$1 B), with the value creation from 4D seismic over the last 10 years estimated at more than NOK 22 billion* (A$3.7 B).

As a result, it is likely that the number of seabed multi-component time-lapse (4C/4D) seismic permanent reservoir monitoring (PRM) systems (See Figure 1) will increase in the years ahead as successive surveys on four existing field installations (See Table 1) fulfil their promise to deliver 4% to 6% additional recovery. Asset managers who have studied the results know that the benefits of 'on demand' 4D seismic over the life of the field far outweigh the cost. To help overcome the inertia that can block operators in other regions from accessing these benefits, innovative feasibility, seabed risk mapping and illumination studies are being conducted to ensure effective project delivery and mitigate the potential risk that a PRM system installation costing tens of millions will not prove profitable.

Year	km	Operator	Region	Field	Comments
1995	30	BP, Shell	N Sea	Foinaven	Experimental
2002	8	ConocoPhillips	N Sea	Ekofisk	Test line
2003	120	BP	N Sea	Valhall	Operational
2004	10	Shell	GoM	Mars	Test line destroyed in Hurricane Katrina in 2005
2006	40	BP	N Sea	Clair	Operational
2007	120	BP	Caspian	CARSP	Operational
2007	1	Multiple	N Sea	Tjeldbergodden	Test line
2008	4	ConocoPhillips	N Sea	Ekofisk	Test line
2008	1	Multiple	N Sea	Tjeldbergodden	Test line
2009	25	Statoil	N Sea	Snorre	Test line
2010	200	ConocoPhillips	N Sea	Ekofisk	Operational
2012	30	Petrobras	Brazil	Jubarte	Installation Q4 2012
2013	90	Shell	Brazil	BC-10	Planned
2013	260	Statoil	N Sea	Snorre Phase I	Planned
2014	165	Statoil	N Sea	Grane	Planned
2015	230	Statoil	N Sea	Snorre Phase II	Planned

Table 1. Chronology of PRM trials and implementations.

These risk mitigation studies have been developed because the upfront cost of a PRM installation is expensive compared to alternative approaches to seismic data acquisition. Although a US$50 MM to US$100 MM PRM system requires about the same level of investment as one deep-water well, PRM investments are often seen as major projects with too much technical and commercial risk. This perception is slowly changing given the industry's track record over the last 10 years and the slowly emerging published results from operators who made the leap of faith to install the early PRM systems.

The early adopters now understand that a PRM system is considerably less risky than a deep-water well and they have learned that a well-designed PRM system is capable of delivering a substantial reward. The PRM prize can reach an ROI of five to 25 times the cost of the investment because the superior images are delivered frequently enough so that they can impact all aspects of improved oil recovery (IOR) programmes. This is well understood by oil companies such as Statoil which has recently approved large PRM system implementations on the Snorre and Grane fields to support its strategy of achieving a production rate of more than 2.5 MM boe per day by 2020.

PRM systems impact IOR programmes so significantly because stationary arrays of sensors offer geoscientists a new "super high definition resolution" dimension to time-lapse seismic. Simply by ensuring that no sensor movement takes place between subsequent surveys, and that the data is full azimuth, data resolution and accuracy are greatly improved. This substantive improvement reduces processing time, and costs, while enabling informed reservoir management decision making that impacts five significant drivers of improved recovery:

- Better in-field exploration
- Improved well placement
- Optimised completions
- Fracture monitoring from active and passive micro-seismic
- Flood front monitoring.

Geoscientists and engineers who manage fields with PRM systems are experiencing these benefits because they are not limited to the compressional data of a towed survey. By leveraging 4C/4D data they can map minute pressure changes, monitor saturation and phase changes, and manage reservoir drainage. With these inputs, production can be optimised with better planning of in-fill drilling locations, improved sweep efficiency, and most importantly, accurate knowledge of what is going on between the wells (See Figure 2). Drillers are even taking advantage of permanent seismic array data to understand geomechanical rock properties and to monitor cuttings disposal beds to avoid overcharging them.

In common with experience in the telecommunications industry which has relied on optical fibres for over 30 years, the latest PRM systems use fibre-optic technology that has been qualified to deliver a 25+ year life in deep water. By way of an example, proven optical hydrophones and orthogonally-mounted accelerometers in Stingray seismic sensing arrays have a low noise floor and a 180 dB dynamic range. Cables on these systems are lightweight with simple and reliable connectivity that have been rigorously tested and qualified to military standards. With no subsea electrical power requirements, the seabed array is connected through a riser cable to a compact acquisition and recording unit situated on surface facilities, an FPSO or tied back to a remote host facility up to 500 km away.

Unlike towed streamer surveys, ocean bottom cable surveys or node surveys, permanent sensors installed on the seafloor minimise the impact on existing oilfield infrastructure and enable highly repeatable, cost-effective time-lapse seismic imaging in and around obstructed zones. PRM systems are much less costly over the life of the field and present a significantly lower health, safety and environmental risk (See Table 2).

As many mature offshore fields have low recovery factors, the question being asked is no longer "Why 4C/4D PRM?" – the question now is "Why not 4C/4D PRM?" ■

	Towed	OBC	Node	Permanent
Man-hours / 200 km² survey	36,000	235,000	72,000	10,000
Major risk	Towing	Cable lay	Node lay	Gun work
CO_2 emissions per survey	High	High	Medium	Low

Table 2. Qualitative HSE risk comparison of four types of 4D surveys adapted from Seismic Surveillance for Reservoir Delivery, Education Tour Series, EAGE 2012.

* Meld. St. 28 (2010–2011). An Industry for the Future – Norway's Petroleum Activities.Whitepaper Report to the Storting, published by the Norwegian Ministry of Petroleum and Energy, Norway, 2011.

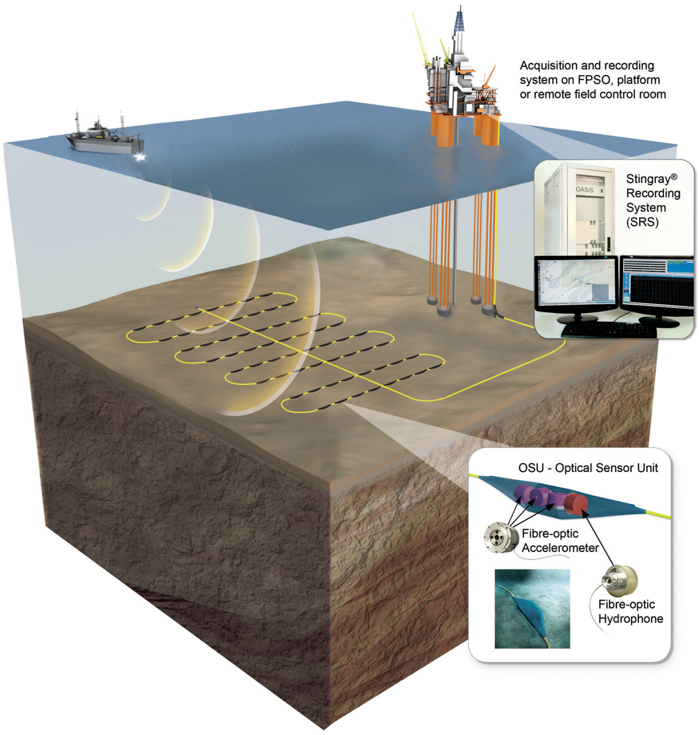

Fig. 1. A typical seabed array of bi-directional optical cables linked to a production facility allows operators to affordably monitor production and injection performance on demand and to improve recovery with lower drilling and EOR expense.

Image courtesy of TGS

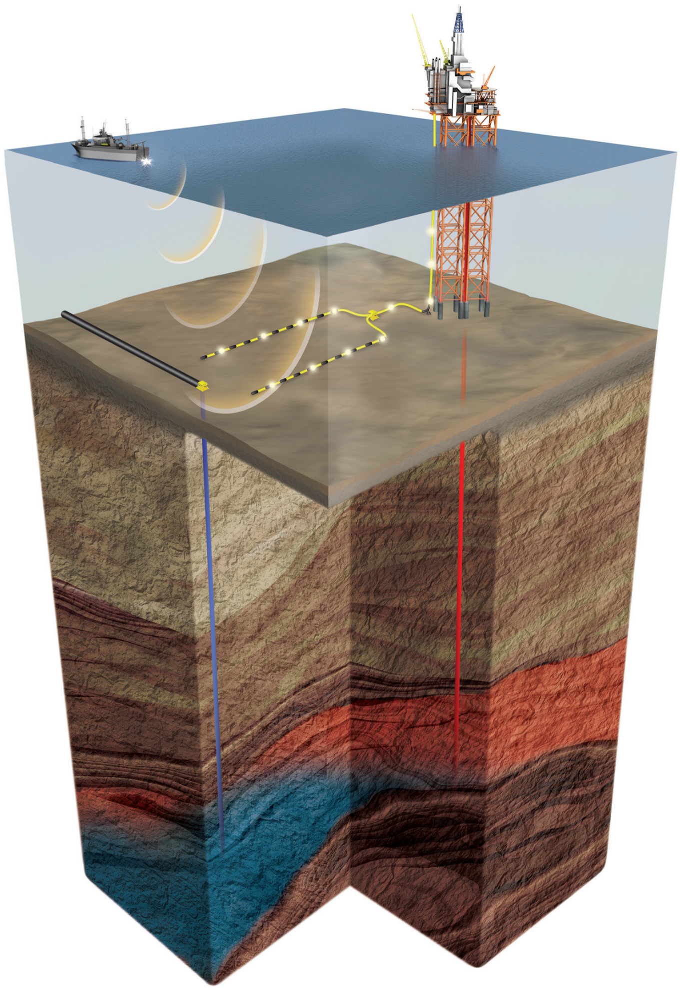

Fig. 2. An array deployed between producers and injectors gives dynamic detail needed to optimise sweep efficiency, identify bypassed oil and detect compartmentalisation by seeing what is going on between the wells.

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