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The development of Integrated Operation Centers

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Abstract

To face today's challenges that especially applies mature field developments like higher rig costs, limited bed space and more performance-based tendering, the oil industry has to evolve.

Integrated Operations is not a new concept, but has gone through an extensive development since the first ones in the 80's, and is even still developing. A lot of different efforts have been made, and are still being made.

The BEACON concept that was first explored together in conjunction with BP and Norsk Hydro has in this thesis been analyzed and discussed. This model has exceeded all expectations, and has surely been implemented into Baker Hughes' core strategy. A standardized model has been adopted, and exported to other areas of the world.

The list of benefits is long, far exceeding the challenges. There is no doubt Integrated Operations is something for the future. It will continue evolving, include more disciplines, and bring the service companies and operators even closer.

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1 Introduction

In the oil industry, rapid technology development is something that has been in its nature since its birth. From the first bits and the first electrical resistivity log (by Schlumberger) to today's hybrid rollercone/PDC bits (Kymera by Hughes Christensen) and ultra-deep reading resistivity (DeepTrak by Baker Hughes). Technology advancements has always been the key to get an edge and ahead of competitors.

Also in the personnel/organizational side of the business, there has been some advancement. IO, or integrated operations, is the term used for the new technologies with the aim of first and foremost, reduce POB and thereby reduce the overall HS&E risk for offshore operations. One can say there have been primarily 2 generations of IO development, whereas we are currently in the second generation. The first started in the 1980's including Mobil's Drilling Data Center and Amoco's Critical Drilling Facility ran in GoM. The second generation has been building from the lessons learnt from these, with Baker Hughes and Statoil taking point on the NCS.

The purpose of this thesis is to explore the journey IO centers has gone through and where the future lies for this concept. Focusing on Norway and Baker Hughes' BEACON concept, the thesis will try to uncover benefits, challenges and possibilities both for the service companies and the oil companies (with focus on drilling).

2 Integrated operations

Integrated operations (IO) can be defined as work processes utilizing and making real-time information available for personnel independent of location to optimize and increase operational efficiency. IO result in significant changes to current work processes and operation forms and lead to closer integration onshore-offshore, contractor-operator and between different disciplines. Decision "loops" are expected to be shortened and based on enhanced use of real-time information. IO are expected to support major changes to manning requirements offshore and creation of new positions in the oil and gas industry. The global oilfield workforce has halved since the 1980's yet the industry has managed to increase world oil output, in part due to increased efficiencies compensating for the reduction in human capital. Production from mature oil fields, such as the North Sea, is predicted to decline, and the ability to reduce both development and operating costs is essential to ensure the future of these mature fields. IO will thereby play an important role in enabling the oil industry to adapt to these challenges to ensure viability in these maturing provinces.[1]

2.1 First Generation

In the 1980s, high oil prices and increased drilling activity combined with technologic advances including digital drilling data availability, led to operation centers for drilling being seen as a viable business case for three operators in the GoM. There were three different companies initiating three different centers; Superior's Real Time Drilling Data Center (DDC), Tenneco's Central Site Data Center (CSDC), and Amoco's Drilling Command and Control System (DCC). Only the former still exists, as ExxonMobil Drilling Information Management Center (DIMC).[4]

2.1.1 Superior's Real Time Drilling Data Center (DDC) [1981 – present]

The DDC was in turn an innovative initiative as part of Superior Oil's strategy to take advantage of economic incentives offered in the 1978 Natural Gas Policy Act. This involved drilling deep, high-pressure gas wells in Texas and Louisiana, during a time in which the US rig count was establishing record numbers above 4,000, experienced crews were scarce, and drilling these wells would be a significant technical challenge. This resulted in a joint agreement with Dresser Magobar, with Superior owning and operating the central facility and renting the rig-based data units from Magobar.

The Center started operations on October 1st, 1980. Traditional lines of command were honored, and the Center was merely a tool to assist the rig site personnel with back-up surveillance and assist office personnel responsible for certain decisions. The Center survived through the 1980's, despite going through a merger (Mobil acquired Superior in late 1984), lower oil prices, and lower rig counts. In fact, data centers were added both in Lafayette, The Woodlands, and at former Mobil offices in New Orleans and Houston. These were established to allow drilling teams to have access to resources such as multiple data displays, plotters, and direct rig communications. However, the role of the DDC remained firmly focused on 24/7 support of multi-well drilling operations by providing involved parties with a common set of reliable data and tools for decision making.

By 1989, US Rig count had dropped below 1,000, and the extension data centers in both Houston and New Orleans had been closed. Despite this, the Dallas facility had adapted its telecommunications resources to support what is described as a "synergistic relationship between personal computers and a central computer and communications facility." The use of graphics terminal emulation software provided user with all the functionality previously supported by the terminals but with the added benefit of integration with other applications, such as data transfer to spreadsheets or drilling engineering applications.

In a 1994 report[4], the Center was deemed highly successful. They too had less emphasis on the Center's function as a surveillance tool, but more on the Center's role in providing telecommunications support and gathering and managing data on behalf of the drilling organization. It was reported that information recorded during well control operations had been used by Mobil to develop more accurate estimates of loads imposed on casing and the probability of their occurrence[4]. When participating in a Drilling Engineering Association joint industry project to develop a Wellsite Advisor Well Control Program, the Center provided the most complete, highest quality data sets for actual examples of kicks (Booth, 1994).

In late 1999, Mobil was acquired by Exxon, and the Drilling Data Center (renamed the Drilling Information Management Center) went through another period of transition. As with the Mobil Superior merger, the reorganization led to ExxonMobil adopting the model of a centralized drilling organization. The Vice President of the new organization was an alumnus of the original Superior Lafayette organization, which helped promote the role of the center in the new organization.[3]

2.1.2 Tenneco's Central Site Data Center (CSDC) [1983 – 1990]

Tenneco's CSDC commenced operations in September 1983 in Lafayette, not far from the Superior Oil facility. In the early 1980's, Tenneco had a high level of activity in the GoM during times when costs were high and rig efficiency low. There were several similarities in the companies' respective strategies; like Superior, they saw an opportunity to improve efficiency and reduce costs by establishing a central facility to receive data from computerized mud-logging units. Their vision (very similar to Superior's), was to offer a 24/7 back-up surveillance and data acquisition and management for operations efficiency tracking and technical analysis. By the time Tenneco's center started operations, however, US rig count had dropped to approximately 50 % of the 1981 peak which resulted in the Center being cost constrained and focused on reducing drilling costs from the outset.

The system began with a modest 5 Mb of hard disk storage, which by 1986[5] had been increased to dual 132 Mb drives. Data transmission was via existing microwave links at 2400 baud, which had to accommodate transmission of real time data and support of any remote devices on the rig to interact with the central facility. Unlike the Superior center which was staffed by company personnel, the Tenneco center was manned by contract Baroid mud-logging personnel. This arrangement led to challenges in terms of responsibility and accountability. There was some reluctance on the part of the rig personnel to accept the system, this was in turn addressed by establishing a proper communications protocol. Analysis of the more available data led to the realizations that the amount of time actually spent on bottom drilling was "typically only 20 % of the total time of the well", and thus a better informed approach to improving overall efficiency and reducing cost.

After Chevron's acquisition of Tenneco in 1988, like Superior's different mergers, subjected the Drilling Center to fresh evaluation. The VP of Drilling at Chevron was supportive of the concept and a study was undertaken to determine what it would take to adapt the center to the needs of the larger company. This led to the decision of building a new, significantly upgraded facility in Houston at Chevron's Drilling Technology Center (DTC). The design was quite different from the original Tenneco system, and had future enhancement in mind in terms of increased functionality and support of global operations. The system was run on UNIX workstations with a software which offered a richer more graphical user interface.

UNIX equipment was also installed at the rig site, with a local database to provide continuity of service in the event of loss of communication. This was different from the Lafayette design and a different strategy than Superior's; who invested in robust telecommunications and kept all processing at the central facility. The Lafayette CSDC continued operations until the Houston facility went live in early 1991. The timing was very unfortunate, the US rig count had declined further to well below 25 % of what it had been in the early 80's. The long term plan was to extend the use of the center to Chevron's international operations, however, this required first consolidating the traditional GoM internal client base. With GoM rig count down and costs up, daily rates for the service were significantly increased and proved unpopular during times of cost reduction. The new facility ceased operation in 1992, and the Lafayette outdated facility was also shut down.[3]

2.1.3 Amoco's Drilling Command and Control Center (DCC) [1984 – 1989]

Amoco's DDC, which started operations in September of 1984 was quite different from both the Superior and Tenneco center in terms of both vision and functionality. The name is revealing of a more ambitious scope and a futuristic vision which was the brainchild of Keith Millheim. The DCC was a subsystem of a Critical Well Facility (CWF) located in Tulsa[6]. The latter comprised advanced computing systems, satellite communications infrastructure, and a team of technical experts with a combination of operational and research credentials. Among the advance tools available to the was an Engineering Simulator for Drilling[7] developed in conjunction with Logicon, a defense contractor whose simulation experience included the F-16 Advanced Flight Simulator. The system was designed with "critical" wells in mind, those with attributes such as "high risk, frontier location, remote, deep water, great depth, expensive, technically difficult, adverse environment, environmentally sensitive". The system was conceived as a "new approach to drilling wells".

The telecommunications, computing systems and software represented "state of the art". Dedicated satellite communications supported voice, data and video links to drilling operations. The system transmitted one channel of full motion video and one of freeze frame video at any given time. Cameras were also located behind one-way mirrors at the console in Tulsa and at a video console on the rig. The operator could select any combination of one full motion and one freeze frame view including face-to-face teleconference sessions with the person behind the one-way mirror on the rig. The user interface to the custom developed software relied on touch screens to navigate to and select options from four screens of menus. There were "no keyboards". The software also made "extensive use of color graphics" to show, e.g. cement displacement progress by the way of an animated wellbore schematic. Other screens showed similar graphical depiction of key drilling or pumping equipment and relevant parameters.

The ESD was capable of "real time and faster than real time simulations of drilling a well" using "more than 70 linked mathematical models to describe the bit, solids control devices, hoisting system solid transport etc.". The simulator was connected to the database and could be initialized to current conditions "in a matter of minutes" thus permitting rapid analysis of problems encountered or simulation ahead of the bit to evaluate various scenarios.

Information captured automatically by the way of the real time system was supplemented by a suite of activity specific reports covering mud, solids equipment, bit selection and performance, surveys, costs tracking etc. Foreman states “Experience thus far has shown this prototype system to be a clear indication of what the future holds for drilling operations”.

Use of the CWF was an integral part of an ambitious strategy to drill five wells in the Navarin Basin, Alaska as described in a subsequent publication[8]. The strategy was to drill four to six wells in a single season during a weather window which typically extends from June to December. The approach was highly systematic, treating all the major activities and components as interdependent parts of a complex system. This included two arctic class semisubmersible drilling rigs, a warship and tanker, an onshore aviation base, dedicated helicopters and some 300 personnel in the field at any given time. The CWF team used the Engineering Drilling Simulator to plan the wells, e.g. to evaluate the viability of a potassium lime mud system, and to assess and reconfigure the solids control system to better handle this drilling fluid. Since the Critical Drilling Facility relied on a high level of communication between the field and Tulsa, both rigs were fitted with gyro-stabilized satellite antennae to support the voice, data and video communications described above. Cameras were placed on the rig-floor, moon pool area, helideck, main deck and shale shakers. Images could also be transmitted from a subsea camera, a camera on a ROV and a camera placed on a microscope to view samples. The CDF operated on a 24/7 schedule with engineers and technologists “constantly running simulations on the EDS, either planning for the next well, analyzing past drilling performance or planning for some operation on the two rigs. The CDF methodology called for development of a pre-spud “Optimum Drilling Plan” which would be “thoroughly reviewed by Company management”. In an interesting divergence from traditional protocol, a Drilling Supervisor at the Tulsa CDF was responsible for making sure the plan was implemented at the rig.

The results are described as “spectacular. The CDF systems methodology responded quickly and effectively to all critical situations and resolved the problems.” The most important part of the CDF approach, reduction of the learning curve, was amply achieved with a claimed improvement rate three times the industry average.

The CDF was also used to support operations in Egypt, however Navarin Sea drilling campaign was the closest it achieved to realizing Millheim's vision. Although focused on global, remote high cost operations, the fact that during 1986 US rig count plummeted did not bode well for the level of continued investment which was required. In 1989 CDF operations were halted, the center decommissioned and staff redeployed.[3]

2.2 Second Generation

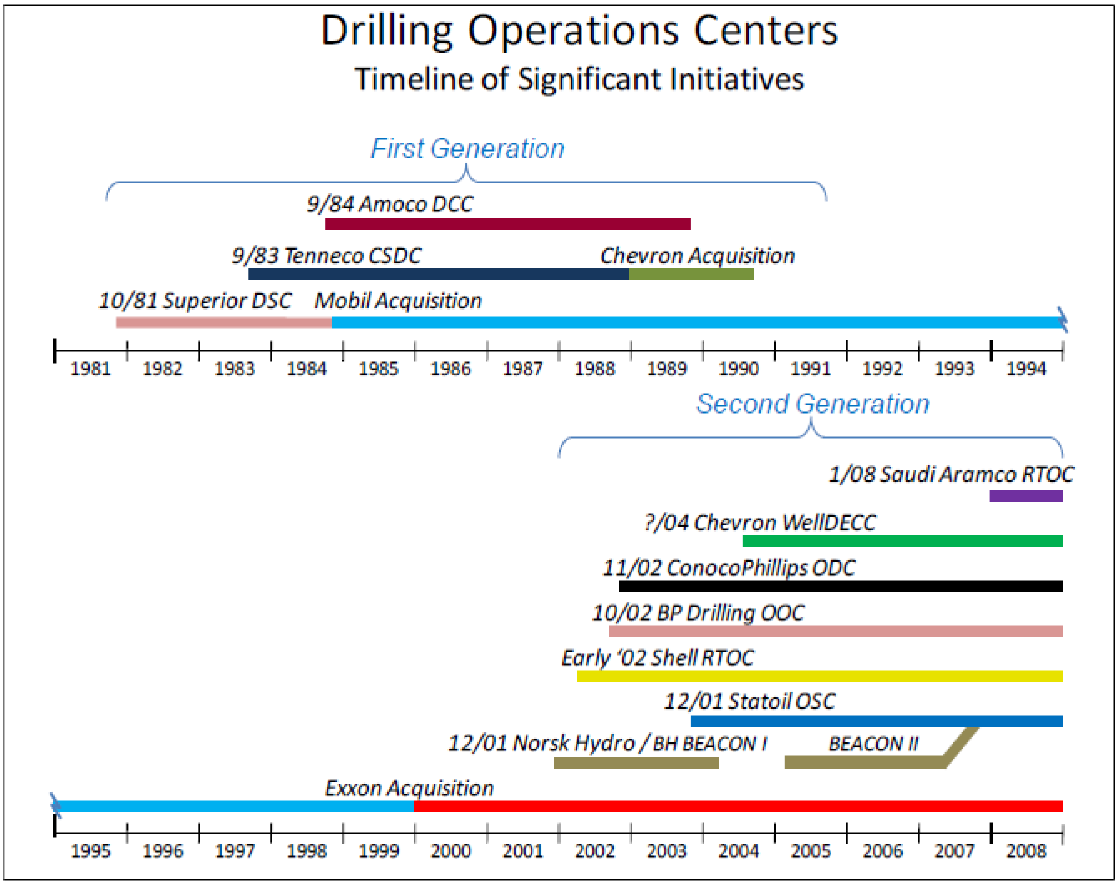

Figure 1: Timeline overview of operation centers[9]

Moving on to the second generation, one can immediately observe this generation's advantage compared to the last generation – considering the huge evolution of information technology up to the millennium. In the late 90's, interest in drilling operations centers was renewed in the North Sea. Approaching peak production at the end of the decade, both the government's and the operators' strategies started to shift toward long-term sustainability, efficiency and cost management. In 1998/1999 a 1,143 kilometer long fiber-optic cable with 24 fiber stands was installed from Kårstø on the west coast of Norway as the backbone for a shared communications infrastructure. The access to reliable low-latency broadband made effective video conferencing possible, and revolutionized the communication between onshore and offshore providing the office personnel onshore with practically the same level of access to real-time data as to that at the offshore installations. Together with the development of LWD tools and RSS tools, real-time interpretation and geosteering made complex reservoirs like Troll, Valhall and Heidrun viable.[9,10]

In this chapter, companies on the NCS with unique concepts will be explored.

2.2.1 Statoil Onshore Support Center (OSC) [2003 – present]

Statoil's Onshore Support Center which began operations in December 2003, was established as a response to the company's need for higher precision in drilling complex 3D wells, which in term placed higher demands on both planning and steering processes. An internal DART project (Drilling Automation in Real Time) begun in 1999, focused on improvements in well positioning, data transfer and data quality control. The latter was a prerequisite for timely interpretation of well progress within a shared earth model. This allowed the asset team onshore to actively support decisions rather than following up as in traditional work flows. DART Link, an Internet based transfer protocol for depth-based drilling parameters, directional surveys and LWD information, established a standard format for data acquisition from multiple vendors and led to the development of the WITSML industry standard.

The support center, located in Statoil's mid-Norway office, was a multipurpose facility with an operations area and collaboration and visualization rooms. Its initial role was to support regional drilling and completions activities, but it was also considered a pilot for integrated operations in Statoil.

In 2005, Statoil created a corporate initiative for integrated operations with a goal of becoming a global leader. This involved extending processes which had been developed on the NCS to meet the need of global operations. A "follow-the-sun" concept was tested as a way of providing continuous coverage of global operations based upon standard daytime schedules at three locations; Houston (GMT -6), Norway (GMT +1) and China (GMT +8). The latter site was simulated in the Houston facility. The initiative tested the viability of supporting key elements of standard global processes for well construction without the need for evening and night shifts at a single location. The approach is described as Man, Technology and Organization (MTO) based, with process as a fourth important element. The underlying architecture provides access to 2D and 3D applications by means of a thin client architecture and terminal servers with secure access to data in centralized sources. The new approach was pilot tested in support of drilling operations in a 12 ¼" hole section on the Asgard Field, where the collaborative work processes were well established. Daily tasks performed by land-based personnel, such as QC of real-time data and directional drilling and surveying services were handed off at the end of office hours at each of the three locations. The pilot was deemed successful and led to a recommendation to proceed with a phased approach to implementation of Global Network Operations. Challenges identified were “mainly related to clear vision and strategy, leadership, culture, people and practical issues”.

The merger of Statoil and Norske Hydro in October 2007 resulted in a convergence of similar strategies, and a shared commitment to integrated operations. A Subsurface Support Center (SSC), staffed with experienced operations personnel and technical specialists, is described as “.. a hub for communications of knowledge between professional networks and the operational assets”. The SSC staff has access to the same real-time data used by local operations groups around the world who are responsible for 40-50 drilling and well work operations underway at any time. The SSC staff has a proactive role both in the planning and execution phases. This broad involvement gives them an opportunity to promote consistency with corporate guidelines and in application of best practices. Indeed the SSC’s broad view of operations allows it to evaluate experiences and share knowledge. The SSC is staffed on an 8/5 basis with a multidisciplinary duty team available to provide 24/7 support when needed.[9]

2.2.2 ConocoPhillips' Onshore Drilling Center (ODC) [2002 – present]

The Onshore Drilling Center plays a vital role in the planning and drilling of Ekofisk development wells. Goals for implementing this center included reduction in POB, fewer iterations in well-trajectory planning, reducing drilling cost, and improved integration between drilling and geology workgroups. It started operations in November 2002, and its primary tasks are well planning (visualization center) and drilling monitoring, particularly geosteering. During the geosteering phase, the center has 24/7 coverage by Ekofisk geologists, making sure that horizontal wells are optimally placed in the reservoir. It is located at ConocoPhillips' office at Tananger, adjacent to the drilling operations and planning team. Round-the-clock manning of the center is achieved by means of 8-hour shifts during the week and 12-hour shifts at weekends. Five offshore positions were eliminated and replaced by onshore roles and/or reassignments of tasks.

Real time displays and video monitoring/conference capability enables the ODC crew to keep a good overview of the operation and maintain proper communication with the offshore crew. Improvements in modeling of such things as Torque and Drag have been a focus area, with a goal of improving drilling optimization decisions. Training and competence building has also been focused on, with the new ODC design and technology improvements being better for this purpose. The visualization center is equipped with high end Barco projectors with PIP capability for multiple source utilization, which is an excellent platform for multidisciplinary well planning processes. The system is also frequently used in stereo mode for 3-D viewing of well trajectories and geophysical/geological data.

Transmission of real-time LWD data was initially based upon the wellsite information transfer standard (WITS). With just under 1 year of operation, the center was deemed to have been successful in reducing the number of well-planning iterations, improving the placement of complex horizontal wells, and providing remote support of cementing operations. Remote control of a rotary-steerable system from the ODC was tested successfully, raising the interesting prospect of further remote-control and automation initiatives.

Recent publications described different aspects of the ODC. The first focuses on eDrilling, a process involving real-time drilling simulation, 3D visualization, and control[11]. The simulation is achieved by means of multiple integrated models: "flow/hydraulics including temperature, torque/drag, vibration, rate of penetration, wellbore stability, and pore pressure". The real-time maintenance of these models at the ODC was used to support proactive forward-looking involvement in offshore drilling operations. Developing and maintaining robust and responsive real-time models, particularly in an environment with a large degree of uncertainty, is challenging. The models are described as having "the appropriate degree of complexity". Data flow between them is achieve by means of a data-distribution server, which supports the various frequencies and formats required. The overall architecture of the ODC is described as based on an "open system" with WITSML used to exchange data with service companies and partners.

The second paper focuses more on the people and process aspects of integrated operations. By this time, the concept of integrated operations, promoted by the Norwegian Oil Industry Association (OLF), had become well established and is used as a backdrop for describing the extent of change aspired to. They have defined the first generation of integrated operations as integration of offshore and onshore processes within a time frame from 2005 to 2010. The second generation of change would lead to "new operational concepts" enabled by broader integration across companies and greater automation in a time frame from 2010 to 2015. The former would require data and taxonomy standards within key domains, the latter would require standards that span multiple disciplines, a shared industry ontology. The paper discusses how the development and testing of concepts such as information overload, decision theory, decision models and Bayesian networks, stating that after systematic testing, these new decision-support processes are being gradually introduced at the ODC.[12]

ConocoPhillips' focus on real-time simulation using multiple interdependent technical models is reminiscent of Amoco's strategy for their Critical Well Facility, developing suitable models and keeping them current so that reliable results are readily available. While all drilling operations centers use models to some extent, a recent trend has been to take advantage of a broader range of direct measurements of down hole conditions, such as drill string dynamics, rock mechanical properties, pressure while drilling and borehole imaging. In the past, down hole conditions (e.g. ECD and WOB) were modeled on the basis of surface measurements. Today these parameters can be measured directly, however, modeling remains a prerequisite for prediction and automation.[9,10]

2.2.3 BP's Onshore Operations Center (OOC) [2002 – present]

BP are in Norway running two big field centers; the Valhall hub which has been in production since 1982, and the Ula hub which has been producing since 1986. They have both gone through a number of upgrades, since they were built, whereas Hod has been remotely producing since 1990 from Valhall and Tambar from Ula since 2001.

Figure 2: Location map showing fiber optic link[13]

With the fiber optic cable installed previously mentioned in this chapter, BP did a bit of experimentations to find out what opportunities existed to exploit the new telecommunications link and what degree of reliability could be achieved. Two separate project groups were established, one from the Operations team known as "Operations Center 2000" and a second from the Drilling department called "Team 2000".

The Operations Center 2000 project was a project with the aim of investigating how far it was possible to take the concept for remote monitoring, maintenance and even operation from onshore. One of the outcomes of the work done in this project was the establishment of a pilot onshore operations support center, or "Virtual Business Support Center" as it was then called. The center housed remote operator stations for all operated fields at the time. However, it was not permanently manned, and was only used on an ad-hoc basis. The center provided a useful facility to asses new technology, for example the first version of the Valhall facilities optimizer and the model based slug controller for the Hod to Valhall pipeline were both tested and commissioned entirely from the onshore center, without anyone having to go offshore. New concepts, such as prototype for wearable PC based video conference tools, which later became known as Visiwear, were tested from the center. The first steps were also taken towards remote performance management by interfacing to offshore machinery monitoring and vibration data in the center. A good example of an early success was that an onshore production engineer, working remotely in collaboration with the offshore staff, managed to identify and implement a change that delivered a 5 % increase in production in on one of the fields.

The project Team 2000 was conducted in collaboration with then named Baker Hughes INTEQ, testing different way of working, i.e. new work processes where IT and telecommunication technology could be used to transfer large amount of data between offshore and onshore, thus changing the work distribution between onshore and offshore. The idea represented BP's vision of "The decisions are made by the right person, based on the right knowledge, independent of time and place".

The objectives of the Team 2000 pilot were to test out the concept of remote support on two Valhall wells. In cooperation with Baker Hughes INTEQ it was agreed that services with regard to Directional Drilling, Measurements While Drilling, Surface Logging Systems and Drilling Fluids would be performed at the same level of quality as with a traditional offshore based service, but where the offshore crew was reduced from 10 to 6. The driver for both companies in a long term perspective was to increase the service and quality level through the Team 2000 concept.

The strategic objectives of the pilot were:

- Maintain good HS&E results
- Increase NPV through improved well positioning, made possible by fast data access and analysis
- Reduce client costs through improved quality of delivered services
- Reduce Baker Hughes INTEQ costs

The technical set-up for the Team 2000 project was much more sophisticated then of the Operations Support Center described in the last section. The offshore drilling location was linked to BP's offices, which was then again linked to the pilot onshore operations support center established at Baker Hughes' offices via the Secure Oil Information Link[14]. The results and conclusions from the pilot was that it was a success and proved that remote support was possible and that the transformation in working practices led directly to reduced operating costs, improved oil recovery and improved HS&E performance. The Team 2000 was taken forward by Baker Hughes and is today known as the BEACON concept, which will be discussed in the next chapter. The work done in this pilot was then used then the BP Drilling Onshore Operations Center was developed.

The aim of establishing the Drilling OOC was to create a single, shared and interactive workplace and thereby achieve greater integration between offshore and the onshore drilling effort. The OOC was of course connected to the new Valhall Injection Platform Rig via the fiber optic cable previously mentioned to enable real-time communication. The OOC was designed to be an integral part of an enhanced team effort focused on efficient well construction. The OOC has provided 24/7 support for the Valhall Injection Platform drilling operations since. The importance of making informed, multidiscipline decisions continuously during the drilling of wells was a significant driver for why BP chose to do this.

Three critical success factors were identified in BP's strategy, change the work process, adapt the physical environment and change the culture. A pilot phase of the initiative was completed in Q1 2001 and at that time, operations were suspended due to a combination of "Human factors … compounded by reliability and maintenance problems". Services reverted to the prior, rig-based processes while systems were redesigned to address the deficiencies. "Many of the difficulties encountered were attributed to poor communications and alignment between the parties involved". After changes were made, the new processes were implemented a second time and became commercial by the end of 2001.

Ensuring that all drilling data normally available offshore was also available in the OOC, enabled positions or functions primarily concerned with data monitoring, processing and reporting could be located in the OOC. However, running equipment and physical interaction would of course still require positions to remain located on the rig, e.g. mud logging.

As the first of its kind, it set the direction for the drilling industry. The benefits identified:

- Identified cost saving $3.1 million after 3 months operation
- World's first remote operated cement job
- Moved approximately 10 positions from offshore to onshore
- Enabled 2 drilling operations on Valhall with limited bed space
- More and better involvement in planning and execution of wells

The success of the OOC was that BP created a communications arena where multidiscipline resources can communicate based on a common and current situational awareness. For example, reservoir geologists work in the OOC while conducting geosteering in horizontal sections. They share interactive visual models in real time to communicate both the reservoir team's needs and help to resolve unexpected results. The OOC has assured that the wider team's competence is involved in deciding on complex operational challenges; a prerequisite of delivering wells in one of the most challenging locations in the world: the Valhall Crest. The OOC concept has stimulated behavioral changes and broken down the borders between on- and offshore as well as between the different disciplines.

The Valhall OOC also has other operation and production facilities which has been considered as successes, e.g. the Integrated Operations Environment for production improvements on the Ula field, pilot testing of tools and etc. These will not be discussed as the focus will be kept on drilling.[9,13]

3 Baker Hughes' Baker Expert Advisory Center/Operations Network (BEACON) [2001 – present]

In the late 1990's, Baker Hughes realized that a great deal of effort had been expended, developing new and improved technologies that led to significant improvements in well delivery times. However, NPT remained high, and further improvements in operational efficiency were still necessary. Not much effort had been devoted to develop the organization, identifying better and smarter work processes. IT and telecommunication technology seemed to offer a great potential to improve work efficiency and to use the most important and scarce resource, human capital in the form of expertise in new and better ways.

It was again this fiber optic cable infrastructure on the NCS which triggered Baker Hughes' decision to explore the world of remote operations. As described in the last chapter, the Team 2000 project initiated in 1997 together with BP and Norsk Hydro marked Baker Hughes' entry to their remote operations concept. The main goal was to use information communications technology to relocate people/work/positions from offshore to an Operations Service Center onshore, aiming to reduce POB, enhance operational support through development of collaborative work processes and optimized utilization of specific expert resources. This concept was later renamed BEACON becoming deeply rooted in the company's vision and goals, and still is today. It was believed that the transformation of working processes would lead directly to reduced operating costs, improved oil recovery and improved HS&E performance, both for the service company and the operator (as described in the last chapter for BP). After reviewing the success and failures from the first pilot phase for BEACON, Baker Hughes re-launched BEACON in phase two, which is generally how the center is today.

3.1 First phase BEACON

3.1.1 Pilot phase

Planning started in 1997, with pilot projects initiated with Norsk Hydro on the Troll field in May 2000, and with BP one month later on the Valhall WP platform. A temporary Operation Service Center with the capacity to support five simultaneous rig operations was established in Stavanger, Norway. A total of six wells were drilled using the pilot, two on the Valhall field for BP and four on the Troll field for Norsk Hydro.

Learning from the first generation centers, they found it important to address each of the people, process and technology issues and their interaction towards a successful implementation. Recognizing that not only technology changes had to be implemented, but also long-term cultural changes which could be even more challenging. To minimize implantation risks, it was decided to introduce the changes step by step, with each supported by a clear strategy and action plan. Three main steps were defined; changing the work processes, adapting the physical working environment and making the cultural change.

Changing the work processes was seen as the most important and also the most difficult step. The work processes were altered simultaneously with the transfer of personnel onshore to emphasize that a change had taken place. With the new high speed, high bandwidth fiber optic connection, they seized the opportunity to move the mud logging operator and MWD/LWD operator onshore.

The traditional mud-logging systems were designed assuming that the operators could intervene when required, for example to repair or calibrate the sensors. But by doing this move, changes had to be made to the work processes, including cross competencies and training, to match the new working practices. Initially, crews operating both onshore and offshore ensured safe and full service coverage. Gradually the offshore specialists were moved onshore until close to 100 % of the tasks identified for remote operations were carried out onshore from the BEACON center. Directional drillers were cross-trained to provide a limited MWD service in addition to the traditional directional drilling tasks and responsibility for the downhole tools. The cross-trained fluids engineer assumed responsibilities for checking and maintaining sensors.

Several improvements were identified at the end of the pilot phase. In particular, mud logging services proved difficult to transfer onshore and these services reverted to conventional offshore operations whilst the deficiencies were investigated and rectified. Only drilling and MWD/LWD services continued to be operated remotely from the onshore service center.[15,16]

3.1.2 Re-launch

Equipment was re-engineered, human processes were reevaluated, and ownership of the implementation of the concept was shifted to the rig supervisors. Onshore services were reintroduced during the summer of 2001. The surface systems were redesigned so that remaining Baker Hughes rig site personnel could perform the necessary hardware maintenance. The surface systems were made more robust and newly developed software for remote control of rig site gas equipment was deployed. Sensor and gas equipment maintenance was traditionally a data operator duty and resolving these issues were key to moving the position onshore. Processing computers were moved onshore, while sensor and gas equipment remained in the mud logging unit on the rig.

Certain systems associated with the remote control were brought onshore. This also reduced the need for assistance to run the system from offshore. However, by doing this, a network break would prevent the data operator from performing his work tasks. A gas reading display, not dependent on the logging data system, was placed in the doghouse. Consequently, if a network break should occur, the gas system would still display the return mud gas content enabling operations to continue. In addition, the network break would prevent the data operator from recording data. With these changes it was concluded that the uptime for the modified surface logging system would be higher than a conventional rig site based system.

In January 2002, an award granted by the Norwegian Research Council's the Demo2000 program, to develop a rig and operator independent ultra-reliable mud logging service capable of remote operation. These systems were later implemented to complement the transfer changes, they include;

- A reduced maintenance gas trap, the CVT (today known as Xtract), which was an innovative method for agitating gas out of the return mud
- A new surface signal collection system, termed the Remote Process Interface (RPI), which reduced the number of components and allowed onshore operators to check the status and configure the signal collection remotely
- A fully remote controllable gas pneumatics system, responsible for repeated delivery of a constant volume of uncontaminated gas to the sensor

Figure 3: Remote controllable systems developed in the Demo2000 program[16]

- A remotely monitored hydrogen generator used to feed hydrogen to the flame ionization detection system (FID), which demands gas samples that are free of moisture and dirt to meet the stringent requirements on gas readings, set by both the authorities and customers

Further analysis also showed that by changing locations, the normal interpersonal communications had been disrupted. In addition to raising awareness of the changes, videoconferencing equipment was installed linking the onshore center with the main display PC's offshore (company man, geologist and logging system unit) to enable some level of face-to-face communication to continue. Telephones would still be the main communication channel as during the pilot phase.

After review, many of the difficulties encountered during the pilot trials were attributed to poor communication and alignment between the various parties involved. When managing projects of this nature, close communication and involvement between the operator and service company at both management and operational levels is essential. People, process and technology issues should be given equal weight. With the above changes, the mud logging service was transferred onshore for the second time in November 2001. BEACON operations were commercialized at year-end. Two wells had now been successfully drilled supported by the onshore center. The performance improvement was reflected in the service quality reports completed by the operator's rig site supervisors.[15,16]

Also in the SPE paper 78336[15], it was considered a success, with these findings;

- Real-time support from specialized onshore networks available, including geologists and petro-physicists, software support, drilling optimization and the workshop. When problems arose, the expertise would be more easily accessible and the response time will be shorter compared with similar situations encountered during conventional operations.
- The critical mass of experienced and qualified people in the operations center would reduce the dependence on individuals.
- The implementation of new equipment and software would be easier due to the enhanced possibilities for training.
- Closer follow up from customer teams, product lines and logistics.
- Faster access to databases for analysis, quality assurance and correlation with offset wells.
- Enhanced support in the planning of future wells whilst minimizing the impact on ongoing operations.
- Creation of a learning environment where the focus is on experience transfer and knowledge management across traditional service boundaries.
- Higher level focus on the remaining offshore personnel and their development, to ensure a true integration of all services.
- Administrative tasks such as reporting and routine engineering analysis, previously handled by offshore personnel could be transferred onshore, permitting the offshore personnel to focus on the ongoing operations.

3.2 Second phase BEACON

IO was specified as the standard service delivery model by Norsk Hydro when the drilling services contract expired in 2003 and a new tender was held. One of the tender conditions was that costs associated with supplying service from an onshore support center were to be covered by the service provider. As the winning bidder, Baker Hughes initially used the BEACON services under the new contract and delivered the services in line with the model developed during the pilot and initial commercial phases discussed in the last chapter. However, with revised terms it became evident that this business model was unsustainable. Baker Hughes and Norsk Hydro decided to halt IO in spring 2004 to revise the service delivery concept and business model to better meet the expectations of both organizations.

The revised BEACON model was pilot tested on the Troll field during autumn 2004 and commercial service commenced in January 2005, and has been in service since. The main elements of the concept include development of new positions as well as revising old ones, implementation of a new business model, definition of onshore shift based working conditions in co-operation with unions and greater focus on work process improvements with key client end-users. Besides addressing project economics, the revised concept was designed to reduce POB compared to standard operations, strengthening focus on rig-based operational performance and further expand work process integration between client G&G groups and the supplier FE support organization that will lead to improved real-time decisions being taken on quality assured FE data.[1]

3.2.1 Development of positions

It is often assumed that specific tasks completed by specific personnel will be unaffected by the transition of those personnel from offshore to onshore. The most common assumption is that the only additional requirement is a robust communications system between the onshore and offshore locations. Too often, little thought is put into the changing behavioral aspects and relational processes which were accepted in a traditional operation but cannot to be duplicated in the new setup.

The traditional offshore mud logging/MWD/directional drilling positions are (in short);

Mud logger/sample catcher – They are the second hand of the wellsite geologist, responsible of collecting and handling the mud cuttings as per the customer's orders, examining the samples and analyzing all lithological data for producing a log and calibrating and maintaining primarily the gas equipment, but also the other mud logging sensors (but this is the data engineer's overall responsibility).

Data engineer – They are the eyes and ears of the driller, responsible for handling surface systems setup and parameter input, real-time data acquisitioning, system control, maintenance of mud logging sensors and volume control (pits/well/gas).

M/LWD engineer – They have the responsibility for the downhole tools, programming when on surface and communications when downhole, and final deliverables.

LS/RPS – They have first and foremost the responsibility for the radioactive sources which are run in some of the downhole tools, and has seniority over the M/LWD engineer, therefore also covers some of his tasks or oversees them.

DD – They are responsible for the directional drilling, and serve as the go-to-guy for the geologists when it comes to geosteering.

Several remote operations models for SLS, M/LWD and directional drilling had been tried out throughout phase 1 and 2. From models where day shifts were done offshore and night shift done in the remote operations center, to a remote SLS model where both day and night shifts for data operators were located in the remote operations center. Due to the model diversity, their supervision, maintenance and evolution becomes cost and time-intensive. A standardized global set up for remote operations was therefore initiated, based on the extensive experiences gained over the past 10 years. Efficiency, quality and value have been proven for several operators and rigs/platforms/wells.

The changes implied;

Mud logger/sample catcher → **Logging Geologist (LG) *offshore***

In order to remove tasks from the data operator, who now has extra responsibilities as an ARTE, the mud logger is trained on-the-job to operate the gas system and perform calibration and basic maintenance on all SLS sensors as well as reset and initialization of computers.

Data/M/LWD engineer → **Advantage Real-Time Engineer (ARTE) *offshore***

A new position called was created to replace both the data and the M/LWD engineers at the rig site. Offshore data engineers has to be cross-trained (usually a standard four-week training program) in performing basic M/LWD functions with respect to programming and decoding, as well as monitoring of SLS drilling data and M/LWD survey and log data. Most of the reporting functions and QA/QC of data and logs were moved to the remote operations center (BEACON).

The ARTE is responsible for handling surface systems setup and parameter input, real-time data acquisition regardless of product line (telemetered downhole data, surface sensor data and third party data), downhole tool configuration, testing, maintenance, and sensor calibration. The integrated surface acquisition system enables the ARTE to control all of the above real-time functions from one workstation. By removing offline and post-run duties from the ARTE job description, the offshore engineers is able to focus on well-site execution.

The ARTE position is required through all phases of the well, supplying traditional mud-logging services during non-drilling phases when MWDs would typically be demobilized. The new ARTE position provided significant improvements to the work processes and operational continuity, since these crews are usually dedicated to one rig. This results in improved HS&E through rig familiarity, improved teamwork with the rig crew and in-depth project understanding.

Data/M/LWD engineer → **BEACON GeoScience Engineer (BGSE) *onshore***

The BGSE position was created to take the offline tasks that the data/M/LWD engineers used to have. They are responsible for processing real-time and memory data from downhole tools, QA/QC of FE and mud-logging deliverables, generation of all daily, post-run, section and EOW logs and reports, as well as liaising with client operations geologists.

The position is onshore-based and crews eight-hour shifts (twelve-hours in the weekend), residing in local community. BGSEs develop an in-depth operational knowledge through field and project dedication, daily interaction with clients' geologists, and guided competency development as part of the local, internal petro physical group. Operational data undergoes quality assurance and quality control in real time, to support improved and faster decision making within the client well group. Non time-critical log production (e.g. memory files, database sets) is transferred offline for further process by the remote operations center.

By moving log production onshore and retaining data acquisition at the rig site, the dependency of ultra-high bandwidth communications is largely reduced. This enables replicating the model in locations where communications availability is below North Sea high standards.

IO has enabled changes in workflows, roles and responsibilities to better utilize resources and improve the quality of information delivered to decision makers. The concept is based on moving tasks, rather than positions, away from the rig site. The roles of ARTE, DDx, LS and LG are still on the rig site, whilst roles in geosciences, drilling optimization and technical support are positioned in the IO center. Onshore positions are permanently connected to a global pool of experts available 24/7 to advise as required, and to ensure high-quality service delivery. This new organization structure onshore/offshore enables more efficient experience transfer and reduces delays associated with troubleshooting. Close interaction between the technical support, geosciences, and drilling application engineering teams, is all part of the daily work process to rapidly solve issues and provide answers while drilling.

Directional Drilling Supervisor (DD) → Cross-trained Directional Driller (DDx) *offshore*

In order to turn a DD into a DDx, he/she must undergo a standard training program on M/LWD tool handling and BHA makeup. Once trained, the DDx supports the ARTE engineer with M/LWD tool handling. In some cases the DDx can also be certified as a Radiation Protection Supervisor (RPS) which reduces the need to have a LS/RPS offshore.[1,17]

3.2.2 Setups

Baker Hughes Norway is currently running three different kinds of personnel deployment, two of which has been developed through the BEACON concept.

The first is of course the standard offshore setup, with;

- Offshore: 2 x DD, 2 x data engineers, 2 x M/LWD engineers, 2 x LG (on demand), 1 x RPS/LS (on demand) = total 6 – 9 persons
- Onshore at the BEACON center: 24/7 tech support engineers, 24/7 drilling optimization services (on demand), 24/7 reservoir navigation services (on demand after office hours) = 24/7 continuous eight-hour rotational shift plan

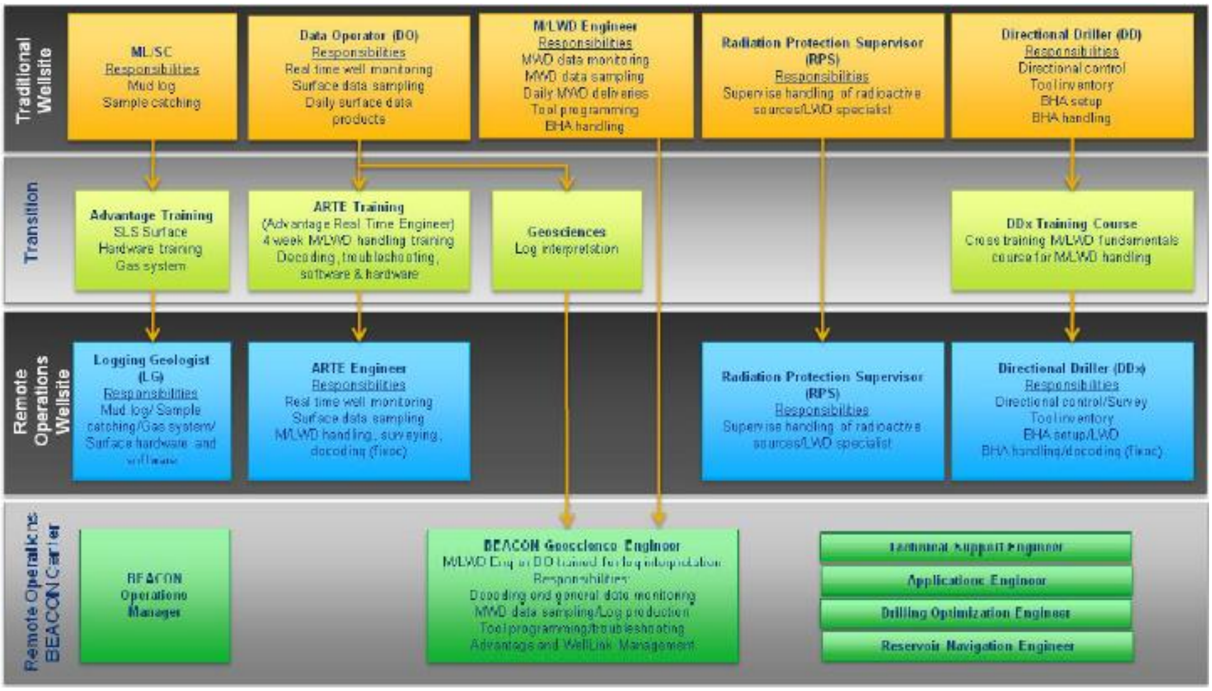

Figure 4: The Development Process for Remote M/LWD Services[17]

The second is with remote M/LWD services;

- Offshore: 2 x DDx, 2 x ARTE, 2 x LG (on demand), 1 RPS/LS (on demand) = total 4 – 7 persons
- Onshore at the BEACON center: 24/7 BGSE crew, 24/7 tech support engineers, 24/7 drilling optimization services (on demand), 24/7 reservoir navigation service (on demand after office hours) = 24/7 continuous eight-hour rotational shift plan

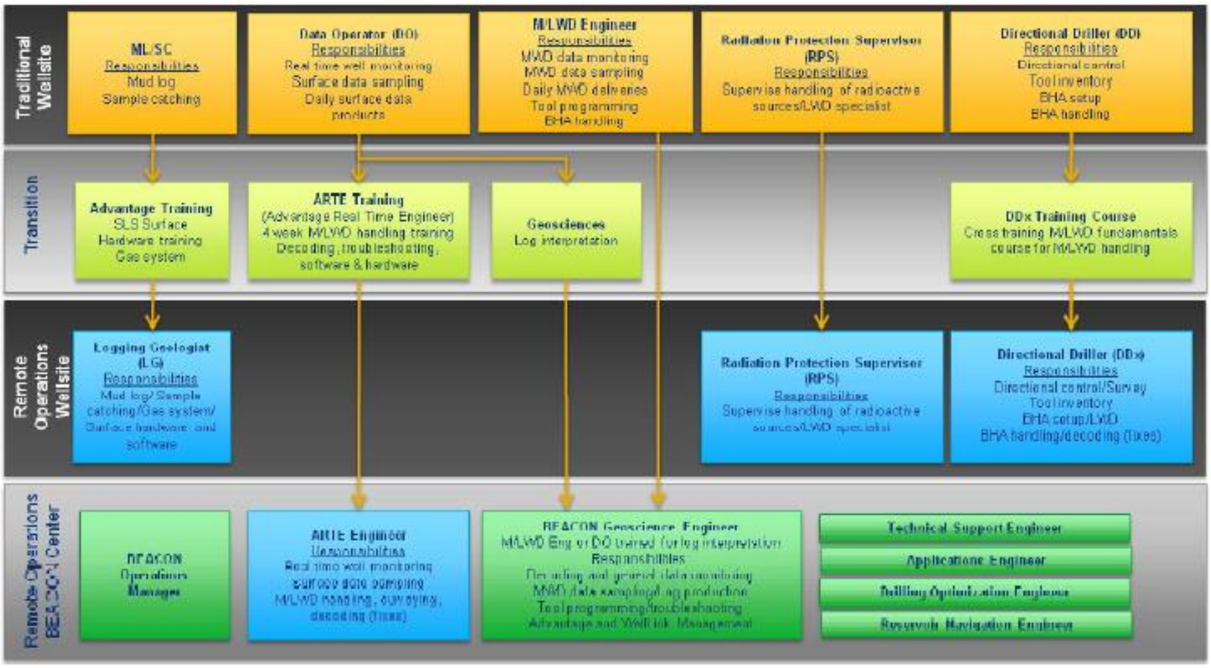

Figure 5: The Development Process for Remote SLS and Remote M/LWD Services[17]

The third is with both remote M/LWD services and SLS;

- Offshore: 2 x DDx, 2 x LG (on demand), 1 x RPS/LS (on demand) = total 2 – 5 persons (mud engineer handles the gas equipment and mud logging sensors when no LG is mobilized)
- Onshore at the BEACON center: 24/7 ARTE, 24/7 BGSE crew, 24/7 tech support engineers, 24/7 drilling optimization services (on demand), 24/7 reservoir navigation service (on demand after office hours) = 24/7 continuous eight-hour rotational shift plan

Remote mud-logging services requires direct phone lines and/or UHF connections to the drill floor, CCTV mounted in critical areas, and full access to offshore data servers for mud logging with remote control capability. This level is currently implemented for BP on Valhall WIP and Maersk Reacher, while most of the Statoil rigs/platforms are using the second solution. Most of the other operators still uses the traditional setup.[17]

3.2.3 Other BEACON services

Drilling Optimization

Drilling optimization is all about optimizing the drilling parameters like BHA, bit, but also live operational parameters as WOB, RPM, torque and so on. By adjusting and fine tuning such factors, the goal is to reduce risk with early detection and resolution of drilling problems, reduce NPT, improve drilling system reliability, and reduce operational risk and drillpipe fatigue/damage, such as twistoffs.

Drilling optimization and risk mitigation is seen as a key area to support an efficient and successful drilling solution for ever more complex wells, especially in mature field developments. Baker Hughes and Norsk Hydro developed back in the day a Drilling/Bit Optimization Coordinator (DBC) responsible for the drilling and bit optimization services focused on enhanced BHA selection and drilling procedures, performance evaluation and performance communication. In close cooperation with the 24/7 BEACON drilling optimization service, improvements in the ROP and meters drilled for every BHA, overall number of meters drilled per day, improvement in bit life, less bit trips and overall performance improvement and reduction of NPT.

Technical Support

To support and facilitate the rapid technology development related to M/LWD services and to promote high reliability records, the technical support in the BEACON center can assist ARTE / DDx in case of downhole/surface issues related to tool-programming, troubleshooting etc. Other tasks include; QC post-run data and aid support for rerun decisions, rig up support, problem reporting into a knowledge base for knowledge transferring. In Q1 2013, it was also decided to implement a (currently 12 hour daily) SLS technical support, which can assist everything related to surface systems and software.

In addition to the local technical support, Baker Hughes has a Global technical support function, consisting of a centralized community of general senior support advisers and subject matter experts responsible for providing answers and solutions to product line-specific questions. In case of high-priority issues, a 24/7 help desk is available. Currently there are two hubs available, on in Houston, and the other in Aberdeen, and both offers global support.

Reservoir Navigation Services

Reservoir navigation, more commonly known as geosteering, is the service of using real-time data to first and foremost land the well in the target horizon, ensuring optimal entry, then maintaining the well bore in the zone of maximum interest, and to predict and avoid the reservoir exit. With uncertainty in geology, seismic and depths, RNS aims to reduce these uncertainties by minimizing the number of sidetracks and the costs associated with NPT. By geosteering optimal, production and ultimate recovery can be increased and enhance the completion strategy and thus reducing costs.

The RNS service involves pre-well planning, real-time reservoir navigation, and post-well evaluations. Traditionally, a RNS supervisor would gather the information needed, prepare the geological and resistivity models to generate the basis to do the job, followed by a final meeting and delivery of the pre-drilling plan. The RNS supervisor would then go to the rigsite and work with the wellsite geologist who most likely would not have been involved in the pre-phase of the process, leading to misunderstandings, disputes and need for clarification. Today, every job has a dedicated Reservoir Navigation Supervisor working normal office hours, either at the well-site, in the client office or from an IO center. The assigned supervisor normally does all the planning and post-evaluation, but he/she is also running the job real-time during normal office hours. It is first after office hours, and during the weekends and holidays that the BEACON RNS crew takes over. The supervisors briefs the BEACON engineers on-duty and prepares the models and software for the BGSEs, and what they basically do is the real-time geosteering advising the client for the optimal well path, and also daily reporting to the personnel involved.

This service is a good example of the development of real-time utilization of IO centers. Instead of having dedicated personnel assigned to offshore work requiring crew changes and different personnel throughout a single job, relying on one project-dedicated RNS supervisor and five rotational BEACON RNS specialists covering 24/7 limits the total crew involved to six people per project. It also ensures close involvement from the rest of the remote operations group. During a short time-frame, the personnel are exposed to field-specific challenges, in addition to learning about the work processes from other fields and operations. Having multiple RNS operations ongoing continuously enables rapid learning and development of subject matter experts in a much shorter time-frame. This enhances the process and increases the service value and the level of advice expertise.

Other services linked to BEACON

To enable the BEACON operations working with the ARTE model, there are a number of subject matter experts working normal office hours supporting the operations.

These include:

- Drilling Applications Engineers
- Downhole/Surface Technical Support Team
- Reliability Engineers
- Drilling Advisory Specialists
- Survey Management Team
- Geoscience Team

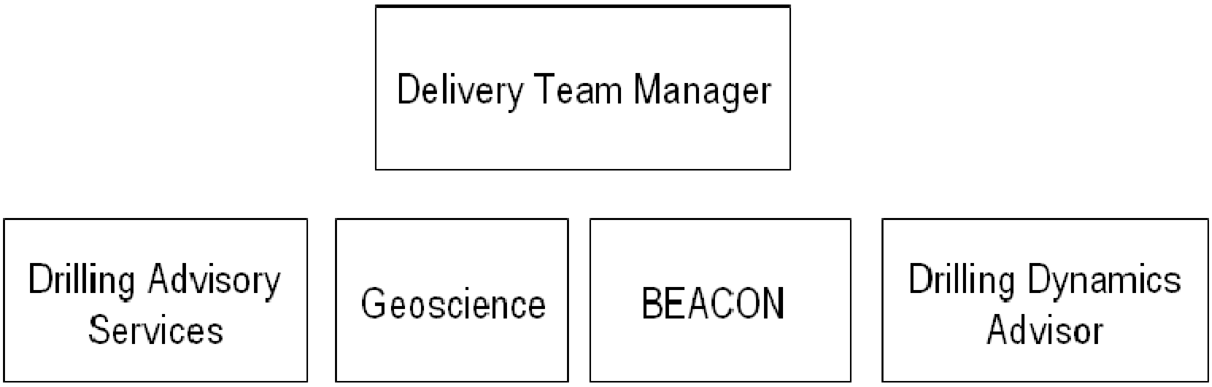

Figure 6: An organizational chart representing cross-divisional expertise in the planning, execution and evaluation phases of the well. The ogranization described is a continuous organization and not an ad hoc development group.[18]

This figure represents the actual real-time working structure where the different individuals are working toward achieving one common goal. The Drilling Advisory Services is a group of highly knowledgeable engineers with background in drilling and formation evaluation, acting as the lead engineers for any drilling optimization project. The Geoscience group focuses on data acquisition and analysis to ensure a flawless delivery of the well. BEACON takes care of the 24/7 operation both for the data acquisition and drilling optimization. The final discipline making up the group is the Drilling Dynamics Advisor. This dedicated focus is necessary for interpretation and expert guidance based on the science of the environment, including the generation of downhole vibrations and the complex nature of the energy released in the drilling process.

3.2.4 Implementation

During the first year of phase 2, there was an obvious need to develop streamlined and continuous work process standards, and all work descriptions were updated. Detailed checklists were implemented to ensure quality levels and service level agreements were defined to set clear expectations determine workload and enable required planning.

The human component was a focus of the implementation. Successful implementation of such a radical change in operational practices requires much more than a mere definition of roles and responsibilities, standard operational procedures (SOP) and infrastructure setup. For this purpose, a full time project manager was assigned during the roll-out period, with focus on internal communications, competency development, training and managing technical adjustments required to ensure a proper fit among the new cross-trained personnel, onshore personnel and technology. The project manager was later replaced with a BEACON Operations Manager, responsible for handling daily operational tasks in close cooperation with customer and internal departments.

The definition of two new job categories required a negotiation with unions to define working conditions for both positions. For the ARTE position, it was relatively straightforward, whilst negotiating working conditions for the onshore BGSE positions was more demanding as a number of key changes had to be addressed. As the engineers had to be living locally in the area, this represented a major life change for many offshore based engineers, and implementing a shift based working schedule to support 24/7 operations had not previously been addressed with the unions. The success of this negotiations was a key element in developing BEACON phase 2, and in the end, a 5 week shift rotation with 8 hour shifts as base and 12 hour shifts during the weekends and holidays was agreed.

The training and competency development to fit the new job positions was also a particular challenge as no training program existed for the new positions and had to be created locally. Again the ARTE position was a bit easier as this position is, to a large degree, a cross-trained M/LWD and mud logging position. Training for mud logging personnel consisted of all MWD tool training, whilst M/LWD personnel had to acquire experience in operational monitoring. The BGSE position had an increased focus on G&G, which required adjustment to training material to achieve both short and long term goals in relation to service level and quality of service. Even today, there is no specific training for the BGSE position, it consists more or less of the same courses as the ARTE attends, and the rest of the competence has to come from on-the-job training.

Since the commercial launch, BEACON phase 2 has been rolled out to more than 30 different rigs/platforms. The tasks being conducted from BEACON have gradually been expanded to include other advanced remote-enabled services; including drilling optimization, technical support and reservoir navigation services (RNS).

The goal was to standardize the remote operations concept to enable this type of service level from an IO center anywhere as required. The model is global and training programs are standard. This has secured continuous delivery of a high-quality service level, with reduced footprint at rig site. This model not only improves operational efficiency, but also aids in filling the generational gap and expertise scarcity currently faced by the oil industry.

4 Discussion

4.1 Technology

The most important enabler for IO centers is the quality of the telecommunications. With the fiber optic link on the NCS, together with micro wave connections which is usually provided to semi-submersible rigs from fixed platforms (normal on for example the Troll field), the BEACON concept works next to perfect. The challenge is when these kinds of high speed connectivity aren't available, then satellite connection may be the only option. That is the case with two of the semi-subs on the Troll field (because of being out of range from the platforms micro wave is not available), latency is around 5-600 ms, but the connection is good and constant. As long as the replication is up and working, all BEACON tasks can in theory be done in the IO center, except for some minor tasks. Challenges with the phone connection (especially with challenging weather) has though been experienced with pre-section meetings having to be re-scheduled.

But implementations in other parts of the world has also been done. As an example, a remote operations center in Aberdeen is today the main remote support hub for operations in Africa on a daily basis. The model's successfully implementation in the North Sea led Statoil and Baker Hughes to replicate it in Brazil for three rigs. All real-time data, file transferring, and remote access to offshore servers and communications systems are satellite-based for the Peregrino project, since there is no fiber-optic infrastructure in place. This will be the case in most areas of the world, but this proved that a dedicated 256 Kbit/s should with normal circumstances be sufficient. Lessons learned during the different phases of the Europe BEACON implementations allowed seamless Brazil implementation and a decrease in total personnel requirement for the project. Experienced BEACON geoscience and ARTE engineers from Norway were temporarily relocated to Brazil for the first well to fast-track the learning process both on- and offshore. In parallel, personnel from Brazil were sent to Norway for training and familiarization with Statoil's reporting systems. First rig for Statoil on the Peregrino field was operational in the fall of 2010, and the second and third rig started operations in February and March, 2011. During the last year, the BEACON concept was also implemented in Basra, Iraq.[1,17]

4.1.1 WITSML (Wellsite Information Transfer Standard Markup Language)

With integrated operations, arose a need for the same kind of industry standard for data acquisition. Standards such as HTTP, TCP/IP and POP have really revolutionized the telecommunications, and recently, new web standards as SOAP and XML have extended the capability to allow software to talk to each other regardless of the location of the computing device or the type of platform the application is running on. Two main components are needed to allow these new workflows. The first is the definition of a standard data transfer format for moving data between applications, commonly known as XML schemas, and the second is the introduction of new applications that can utilize these XML schemas for input and output of data, enabling seamless communication between different applications. Allowing decision-makers in all kinds of industry to work within and across company and organizational boundaries, the same type of infrastructure is now seen used by oil and gas companies for securely automating data transfer in a vendor-neutral environment.

Currently, service companies have offered proprietary data transmission of their own data into their own company-operated data hubs. Today's drilling operations often integrate multiple service providers, thus requiring multiple measurements and data streams simultaneously. The oil company has to consolidate this data by incorporating multiple custom links that connect to multiple offsite vendor data hubs or servers. When an oil company decides to change vendors on the well site, this temporary infrastructure and link has to be modified to handle these changes. Although it is a good step toward automated workflows, it requires significant IT support, customization, and constant maintenance.

Utilizing standard technical computing/software solution is becoming more prevalent as operators realize that there are cost efficiencies to be gained by moving away from in-house data formats and protocols to solutions that have a wider industry user base. This also enables the operators to eliminate supplier specific formats/protocols from their work processes, promoting vendor independence and further helping reducing costs.

With the introduction of WITSML, these processes are eased up and requires far less maintenance to achieve this seamless real-time transfer of information. WITSML is a data transfer standard built upon SOAP and XML standards with schemas defined for data and information associated with the drilling and well processes. Mainly used for efficient transfer of real-time information, WITSML also enables standards for moving report data, BHA information, cementing information, daily “morning” reports, and related information. Actually every type of data or structured information in any format that is generated on the rig can be transferred using the WITSML data transfer standard.[1,19]

4.1.2 Wired Pipe

In an attempt to take real-time communication to the downhole tools to the next level, the wired drill pipe technology was introduced by Novatek Engineering and Grant Prideco (IntelliServ) in 2003. Commercially launched in 2006, the network utilizes a high-strength coaxial cable and low-loss inductive coils to provide bi-directional drill string telemetry at speeds up to 57,000 bits per second. This allows large volumes of data to be obtained from the downhole tools, and thereby enhancing the decision making process greatly.

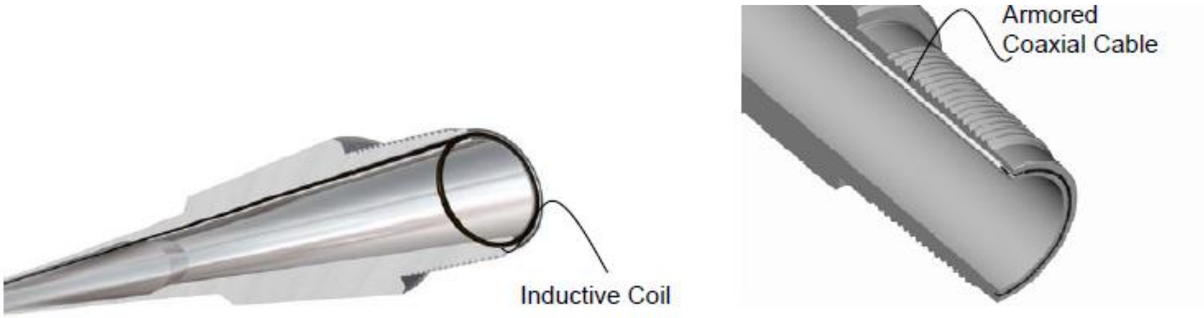

Figure 7: Section view of double-shouldered pin tool joint, armored coaxial cable and inductive coil used in drill string telemetry network[20]

Through the insertion of a physical and electrical interface to the telemetry drill string, existing MWD/LWD/RSS tools can be made fully compatible with the network, enabling higher bandwidth communication than any other form of downhole communication systems between all connected tools and a surface acquisition system. During 2006, Norsk Hydro used the semi-sub rig West Venture drilling in the Troll field offshore of Norway, as the first location to run their first wired pipe run.

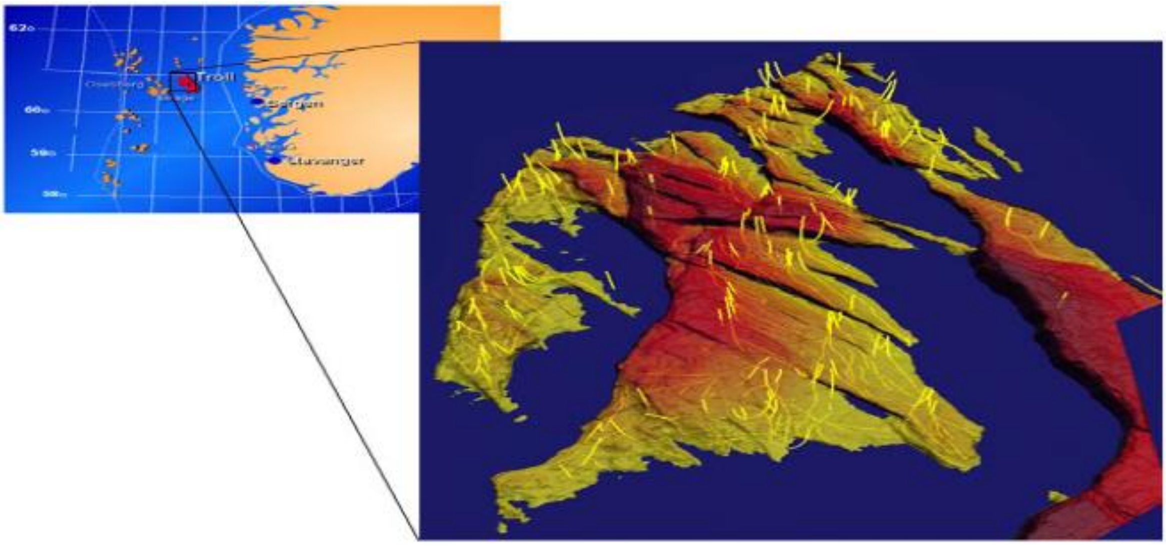

Figure 8: Overview of the Troll West Field, located approximately 80 km west of Bergen, Norway[20]

The Troll field is located NW of Bergen in the North Sea, covering an area of about 770 km^3, and consists of three main structures with a thin but exploitable oil column (10 to 26 m) below a thick gas column. It is one of the largest oil fields on the NCS, and has been producing since 1995. The Troll field's reservoir section is a complex environment consisting of shallow marine spit bar deposits, and is segregated into clean sands (C-sands) comprising well-sorted shore-face deposits with permeability ranging from 1 to 20 darcy, and micaceous sands (M-sands) with permeability below 1 darcy, which comprise lower shore-face deposits. The multi-lateral horizontal oil producing wellbores are geosteered within the C-sand, close to the oil-water contact to minimize the risk of pressure depletion from gas breakthrough and to produce successfully from the thin oil column.

Calcitic nodules and calcite cemented stringers up to several meters thick, derived from shell material within the sands, occur throughout the reservoir and creates challenges for the drilling operation. Many of the stringers have stratigraphic significance, but predicting their distribution is difficult as they are only locally developed. Zones of calcite cementation are randomly scattered throughout the reservoir. These calcite stringers can cause the drilling assembly to be forced aside to the easier drillable sands, and potentially result in high local doglegs, which again can create significant stresses to the BHA. Selection of the optimal combination of application specific drill bit, drilling system, and appropriate procedures and practices is all well and good in terms of meeting these stringer challenges, but with data transfer limitations of mudpulse telemetry bandwidth limit the amount of data available in real-time, this can be a bottle neck to fully take advantage of the optimized BHA.

In this case well, Hydro employed a string consisting of a mud motor enhanced RSS, a high data density drilling dynamics measurements tool, a high resolution formation evaluation measurement tool (multiple depth of investigation resistivity, azimuthal gamma ray, borehole density imaging, and neutron porosity) and a formation pressure testing tool. With the previously described conditions with the significant volumes of calcite stringers, the well demanded a high degree of proactive intervention both at the wellsite and from the operations support center personnel to avoid wellpath deviations and high local dogleg occurrences.

Remote operations from BEACON has been a traditional service for the wells on the Troll field, with the WITSML standard as the primary enabler. Drilling optimization service is the service provided from BEACON that benefits the most with the amount of data available. The earlier drilling dysfunctions and their associated root causes can be identified, the better decisions can be made to mitigate unwanted situations and the easier it is to continue drilling rather than tripping for failed equipment or a prematurely worn bit.

The versatile multi-sensor data acquisition and diagnostic tool used on Troll, records critical downhole drilling parameters that give a detailed insight into downhole conditions. The tool samples downhole raw data at a frequency of 1 kHz, which it processes, analyzes, and records to memory on a sliding five-second loop. However, since traditional MWD mud pulse telemetry has limited transmission bandwidth and there are also demands for other type of data, it is not possible to transmit all the recorded five-second data real-time to surface. Thus, typical data train communications include averaged static data (bending moment, DWOB, DTOB, etc.) and averaged or peak diagnostics data (stick/slip, whirl, lateral vibration, axial vibration, etc.) that indicate the occurrences and severity of drilling dysfunctions. These data are then presented on a real-time display alongside FE data, surface-acquired data, and other downhole data, such as near-bit inclination and steering data, to create as accurate and complete picture of the downhole situation as possible. The transmission interval of the different downhole data will vary depending on their importance, but typical intervals are 20, 30 or 60 seconds. An excerpt of the time-based drilling optimization real-time log is presented in the figure below. Here the transmission of the data was greatly affected by downhole vibration.

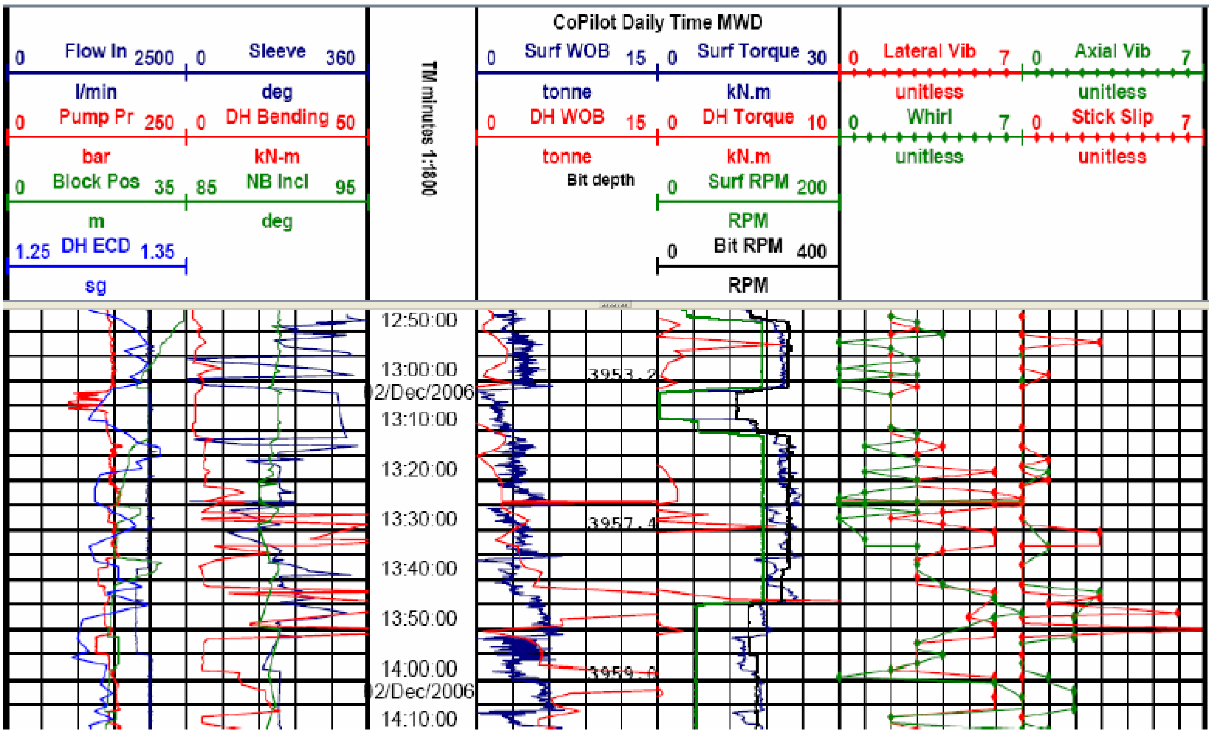

Figure 9: Log excerpt of a time-based drilling optimization real-time log with reduced data due to downhole vibration[20]

In most cases, the real-time log available from traditional mud pulse telemetry gives the drilling optimization engineer a good understanding of the events downhole. However, at times the display can be difficult to interpret even for a trained eye, for instance when noise from pumps/vibration affects the mud pulses and subsequently blurs the telemetry. This can lead to lack of or false data, which again in terms can lead to a trip for failure if harmful drilling dysfunctions develops without being detected.

Wired pipe enables real-time transfer of uncompressed downhole data to the surface, undisturbed by pump noise or vibrations, and with minimal time delay. Essentially comparable to memory data, which can be seen in the figure below.

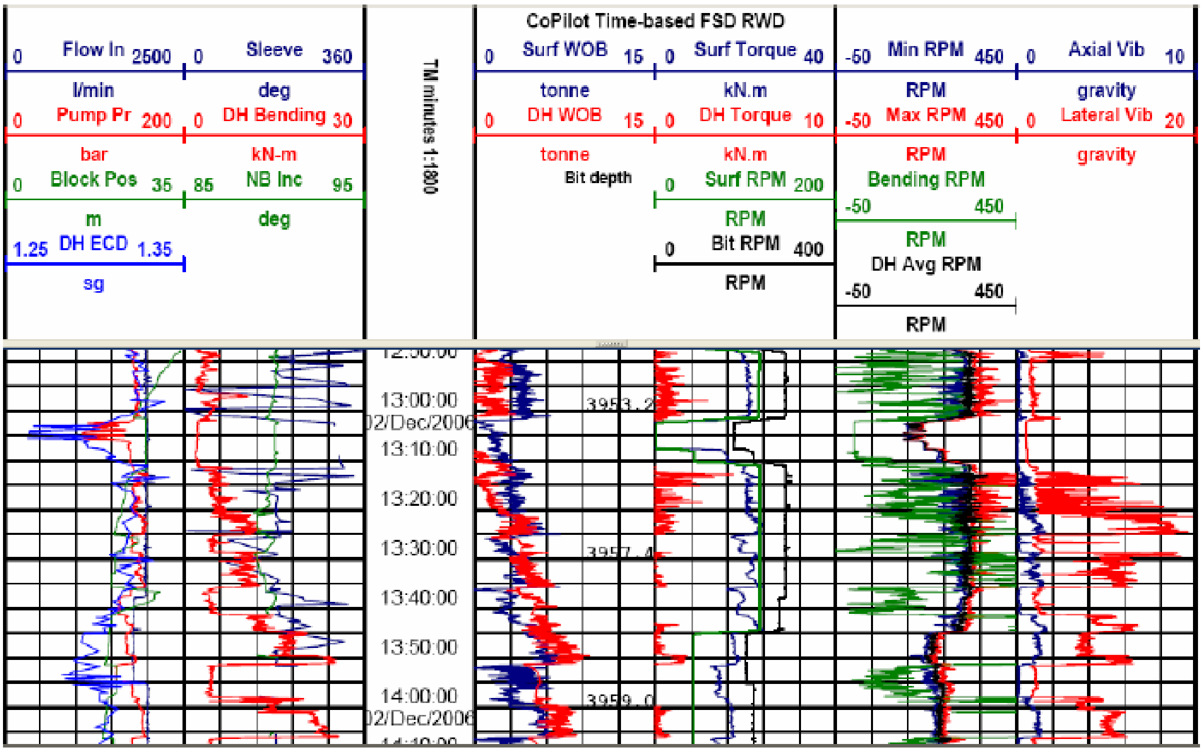

Figure 10: Log excerpt of memory log that is available real-time through wired drillpipe telemetry[20]

For the drilling optimization engineer, the main advantage of wired drillpipe telemetry, as can be seen when comparing the two logs, is the delivery of a real-time log that displays a more steady, distinct, detailed and accurate picture of the downhole drilling environment. This increases the understanding of the real conditions downhole and enables early detection of drilling dysfunctions, thus helping the identification of the associated root cause, and facilitating swift appropriate action to resolve these problems. Furthermore, the presence of detailed real-time information enables the detection of even the smallest trend changes, which can be of vital importance especially when evaluating drastic mitigating action that typically requires time to be effective.[20]

When it comes to Formation Evaluation, one significant advantage enabled by wired pipe data rates, is the huge improvement in Azimuthal Gamma Ray and Azimuthal Density images. Gamma Ray data in each of two opposed detectors are collected in eight sectors per 360 degree rotation. Data for density images are collected in sixteen sectors. Not to mention StarTrak HR electrical imaging which collects in 120 sectors. While Reservoir Navigation

Services have previously used dips calculated from GR, density and electrical images, real-time automated dip computation processing from wired pipe data is not yet commercialized. Real-time gamma ray and density images are generally very suitable for correlating geologic features, structural dip calculations, better understanding the borehole environment, helping to identify intervals of interest for possible pressure testing, and for reservoir navigation applications.

4.1.3 WellLink

Monitoring of drilling parameters and conditions typically occurs at the rigsite, but it is becoming increasingly common to collect and transmit this data to real-time operating centers and individual subject-matter experts. This practice enables the rigsite to bring in expertise that may not be available on the rig, and to better anticipate and respond to anomalies and emergencies. This trend has been made possible through the deployment of data infrastructure supported by WITSML.

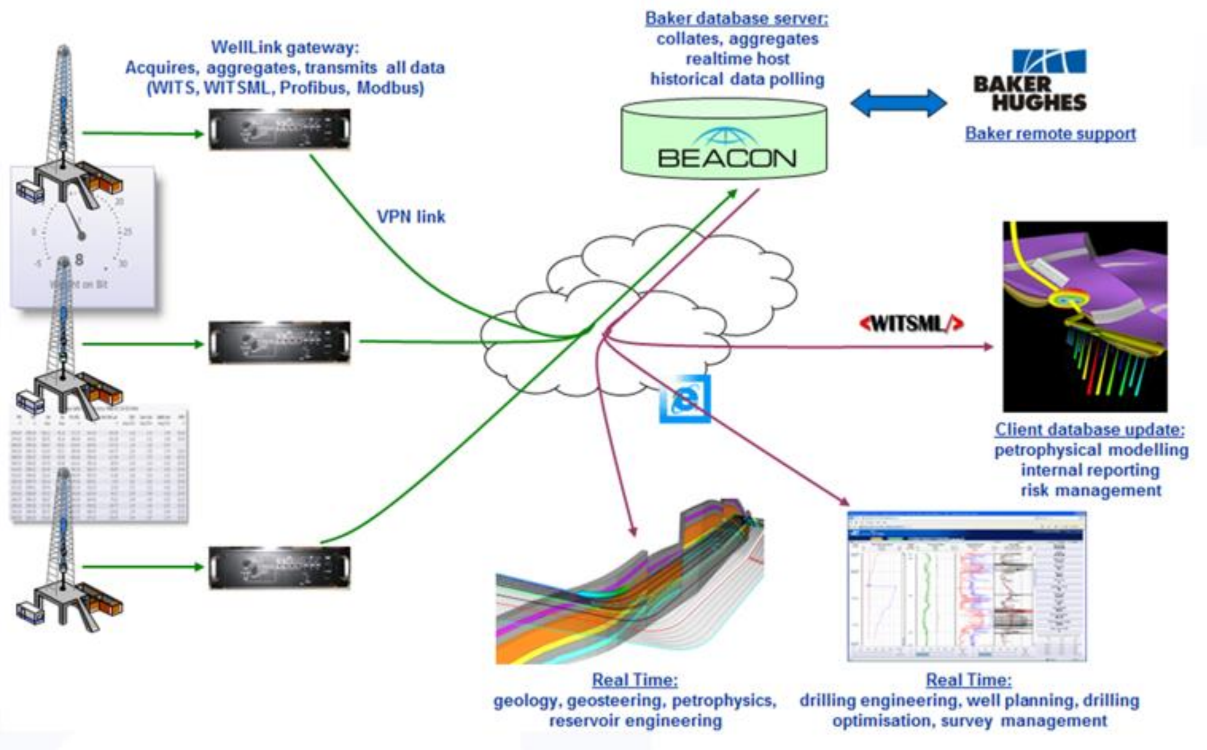

Figure 11: WellLink data flow[21]

Baker Hughes has together with the Kongsberg Group developed an exceptional software to follow rig operations from remote locations. WellLink RT service optimizes the web-based delivery of advanced visualization and analysis capabilities for real-time data. This web-based interface can be accessed from wherever you are in the world, and Is easy to use and configure, graphically integrating any type of WITSML data from sources such as MWD/LWD, mud logging, wireline, casing, cementing, completion, weather, position, anchor, drilling instrumentation and drilling equipment.

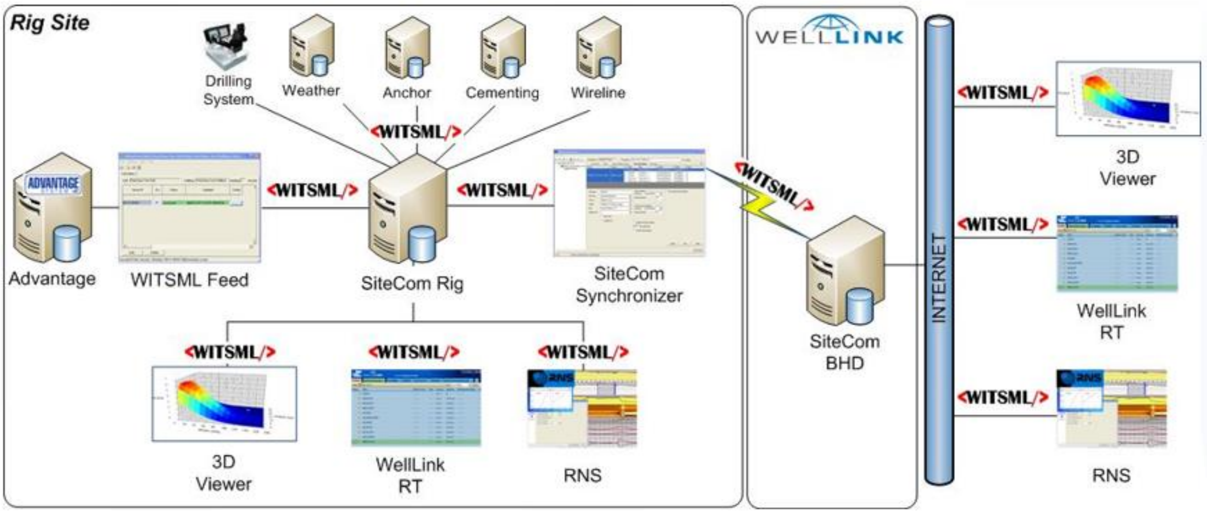

Figure 12: WITSML as an enabler[21]

This globally-integrated environment features geographically redundant systems enabling collaboration with clients, support of remote operations and real-time decision making by professionals regardless of their disciplinary or geographic location. The GUI is fully customizable and one can select and view whatever data in whichever way you want. The servers includes an optimized database for real-time data and wired-pipe data volumes, reducing bandwidth requirements to the server and the client through compression.[21]

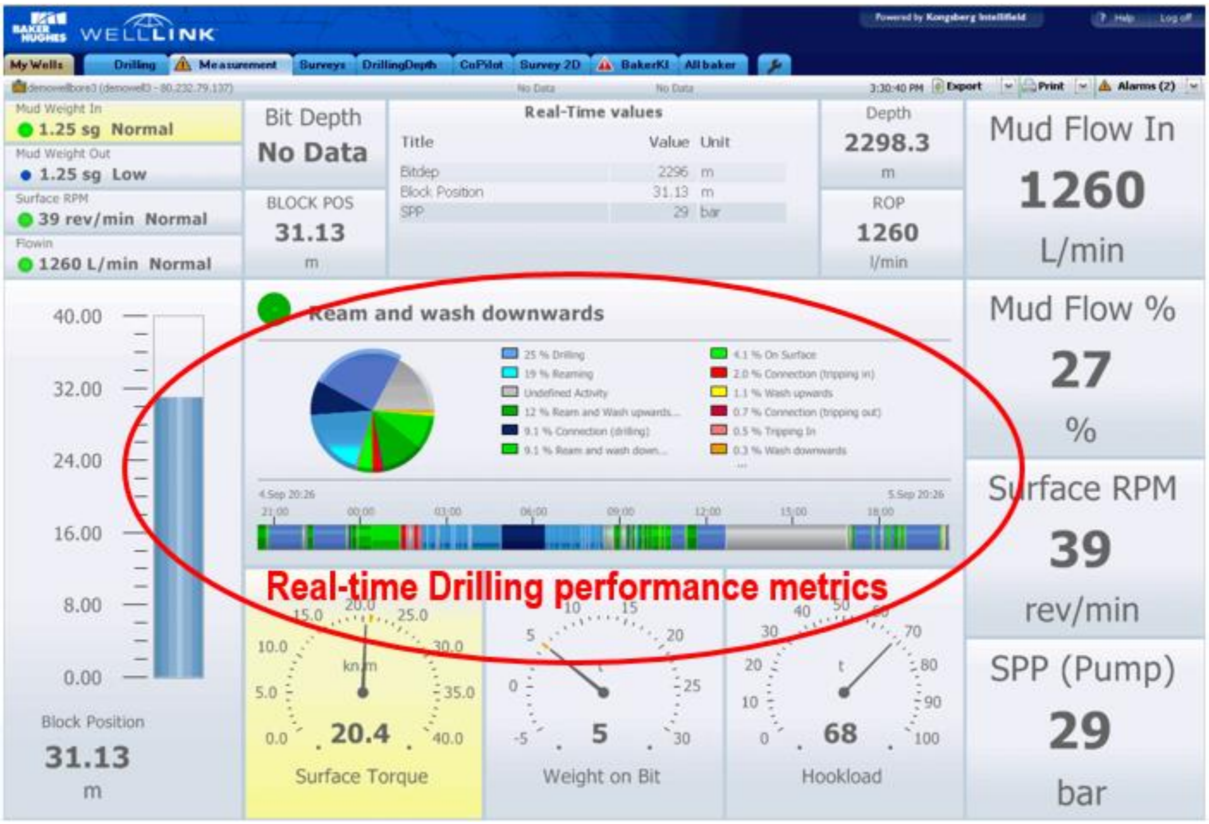

Figure 13: Example of a WellLink RT display[21]

WellLink is designed to deliver data through the WITSML standards, which enables vendor-neutral solutions, it actually converts nearly any source data (WITS, LAS, NMEA, OPC, ODBC) at the well site to the WITSML standard.

4.1.4 WellLink Radar

Seeking to reduce NPT associated with wellbore integrity and downhole failures, oil and gas service companies have implemented real-time operations and remote surveillance centers with knowledge management systems collection best practices, knowledge cubes along the wellbore and lessons learn. On the other hand though, drilling activities are inherently data intensive, and as the amount of available data increases, it is difficult for engineers to interpret the situation in a short period of time.

A possible solution is a software system that provides real-time decision support together with engineers with the necessary training and experience. The WellLink Radar Remote Drilling Advisory service offers 24/7 real-time surveillance, interpretation, and expert advice within a collaborative environment for enabling enhanced decision making to optimize drilling, reduce NPT, improve safety to personnel, and minimize the probability of a loss-of-well control incident. This service requires minimal IT infrastructure requirements as all IT is handled via Baker Hughes' BEACON centers, and no additional staffing is required as the service is run remotely by experienced engineers.

Drilling Problems	Problem Sub-Type	Symptoms	Root Causes
Pipe Sticking	**Differential Pressure**	Increase in torque and drag Inability to move the pipe Circulation of drill fluid is not interrupted	High differential pressures Thick mud cake continuous high fluid loss to formation) Low-lubricity mud cake Excessive embedded pipe length (time delay in operations)
	Mechanical Sticking	Increase in torque and drag Inability to move the pipe Circulation of drill fluid is interrupted or prevented (pressure increase)	High accumulation of cutting in the annulus Borehole instability - caving, sloughing, plastic squeezing
Lost Circulation	**Exceeding formation fracture gradient**	Flow out less than flow in No flow out when pumping Pressure spikes (surface and/or PWD)	Improper mud weight Excessive annular friction pressure -> high ECD Improper hole cleaning -> high ECD Mud weight / ECD exceeds Fracture pressure
Pipe Failure	**Wash out** **Twist off** **Parting** **Burst or collapse** **Fatigue**	Loss of standpipe pressure Sudden loss of standpipe pressure Loss of string weight / hookload Loss of communication with MWD/LWD	Bending load reversals over time Excessive torque Induced tensil stess exceeds material tensile strength Continuous cyclic loads Corrosion due to high Oxygen, CO2, Chlorides, H2S Bending load reversals over time
Borehole Instability	**Hole closure or narrowing** **Hole enlargement or washouts** **Fracturing** **Collapse**	Increase in torque and drag Sloughing shale Cavings at shakers	Rock mechanical properties Salt "flowing" Mechanical insitu stresses Disturbance of insitu equilibrium from drilling process Mud density not sufficient to return equilibrium to normal Erosion due to drilling fluid Chemical interaction of fluids and formation Capillary presssure imbalance between pore fluid and drilling fluid
Hole Cleaning		Pipe sticking Premature bit wear Slow drilling Formation damage - fracturing Excessive torque and drag Trouble during logging and cementing	Inadequate annular velocity Hole inclination angle Drill string rotation ROP Drilling fluid properties Characteristics of the cuttings

Figure 14: Usual drilling dysfunctions WellLink Radar can address

WellLink Radar utilizes the DrillEdge case-based reasoning platform from Verdande Technology which provides automated case-based reasoning capability that facilitates experience reuse and allows remote service engineers to focus their attention where it is required and applies best practices consistently. The technology actively filters and brings relevant experience to the engineers' attention by identifying symptoms as they occur from patterns in real-time drilling data. These trends that develop over time are used to diagnose and predict potential problems before they occur enabling engineers to reuse lessons learned from previous operations more efficiently and apply expertise consistently to proactively make recommendations for corrective action and avoid potential problems. Relevant information is literally highlighted to your attention, and helps prevent critical well events. Usual drilling problems that can be addressed by WellLink Radar; pipe sticking, lost circulation, pipe failure, borehole instability and hole cleaning.

The DrillEdge software identifies a historical case with previous cases with similar parameters as the current drilling situation. Based on a similarity score of the current situation compared to historical situations where problems have occurred, the software automatically flag patterns and trends. No two problems are ever the same, so the difficulty lies in recognizing which differences are important and which are spurious to the problem. In drilling, this identification can be difficult, as the sensor data must be interpreted with an understanding of the geology, fluid systems, drillstring, and tools as well as how actions by the driller affect the process and measurements.

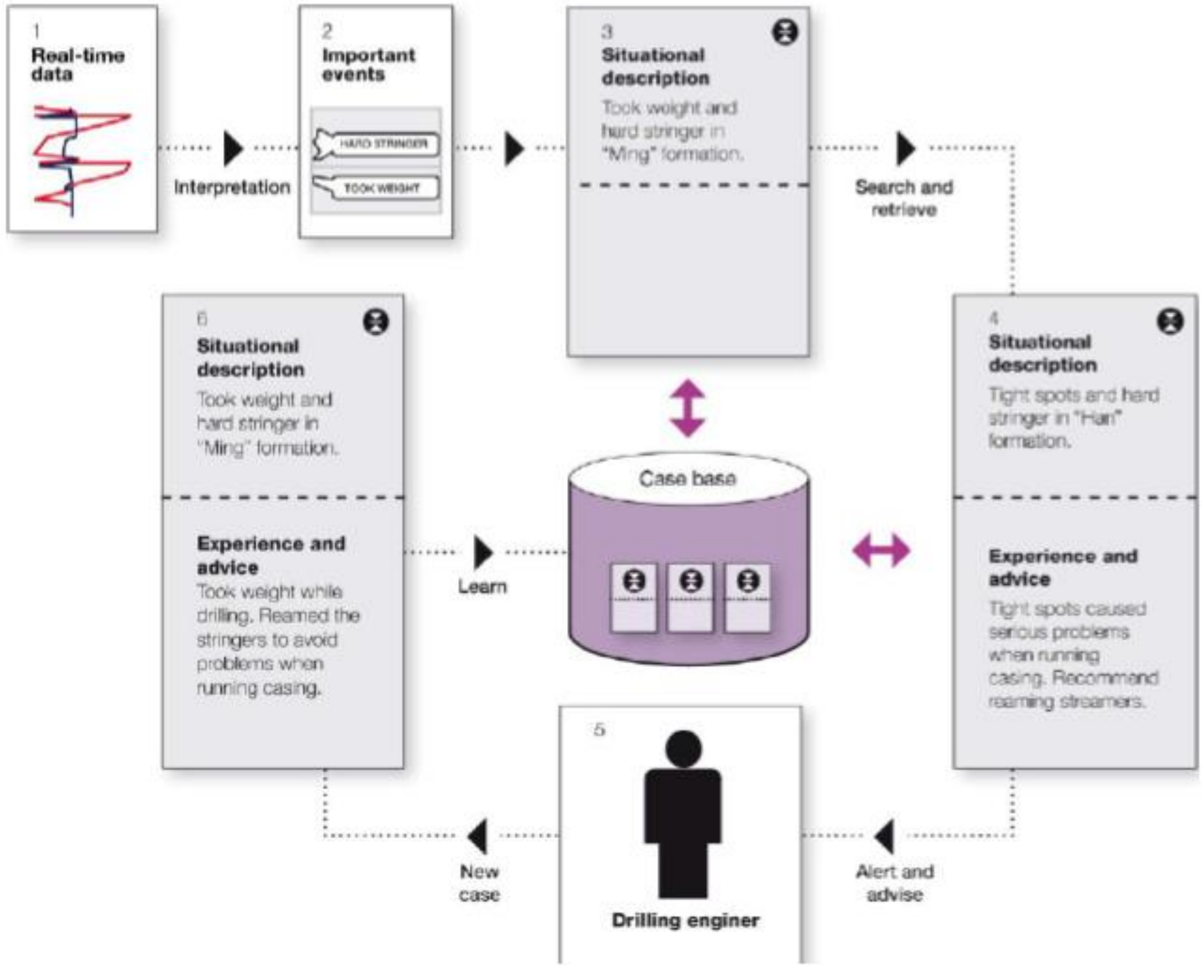

Figure 15: Case-based decision support model[22]

DrillEdge reduces information overload by highlighting the most relevant data and knowledge for the engineers to see and interpret. Together with the DrillEdge software, the WellLink Radar service engineers provide 24/7 real-time remote surveillance, advising and recommending the best course of actions through defined protocols. Also they deliver daily logs, reports and does EOW reporting for experience transfer. The overall goal is to reduce NPT due to specific drilling problems and thereby increase the customers' project value.[21]

4.2 Personnel related/HS&E

Bed space limitations are becoming ever more critical in the North Sea as operators upgrade mature installations and man the rig with maintenance personnel simultaneously as concurrent drilling operations are required to maintain existing production. BP's Valhall WIP platform, installed in 2003, was designed for minimal manning, and not only reduced CAPEX during platform construction by reducing the lodging capacity requirement, but delivers a reported 20 % OPEX saving through reduced well-site headcount.[13]

Early in the implementation of BEACON phase 2, studies showed that by using the BEACON concept for five rigs, 40,000 fewer offshore hours being worked by Baker Hughes employees and has reduced helicopter shuttle traffic by 600 crew movements – per year.[1]

Bottom line is that the reduced head count indisputably reduces HS&E exposures.

4.2.1 Decision making

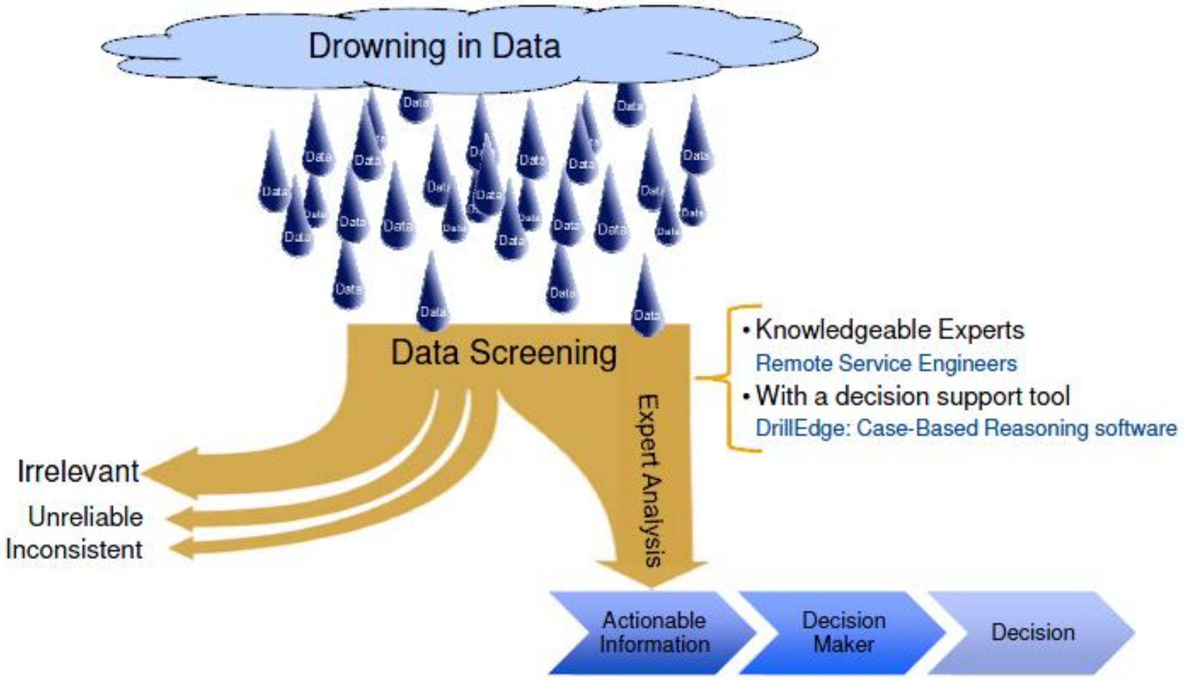

Figure 16: WellLink RADAR is a decision support service[21]

With the faster and richer information flow, more agile and better decisions will be taken. 24/7 real-time monitoring will allow earlier detection of warning signs, and more pro-active decision environment. Connectivity to global subject-matter experts, leading to much better decisions. With the 24/7 support from an IO center, such as the RNS, there is no doubt the decision making has been improved. Another example is the Drilling Optimization team collaborating with DD, and last but not least the Technical Support acting like the gurus.

As seen in the previous chapters, just the fact that the different disciplines now share the same set of data, is a huge improvement for the decision making processes. Being on the same page lets collaboration across departments blossom, enabling decisions considering all perspectives and information to be taken.

4.2.2 Development and training

Uptake of new drilling, completion and production technologies will be required to maintain economic viability in mature fields. The successful deployment of these technologies will provide a challenge in an environment with a high circulation of skilled workers, an ageing workforce, inexperienced off-/onshore personnel and reduced bed space. Those companies that can develop innovative service delivery methods that address these challenges will gain a competitive advantage. The IO centers provide a safe environment where experienced engineers can coach new engineers while exposing them to a broader spectrum of cases, significantly reducing learning curve time, but also providing 24/7 available support to the new engineers offshore.

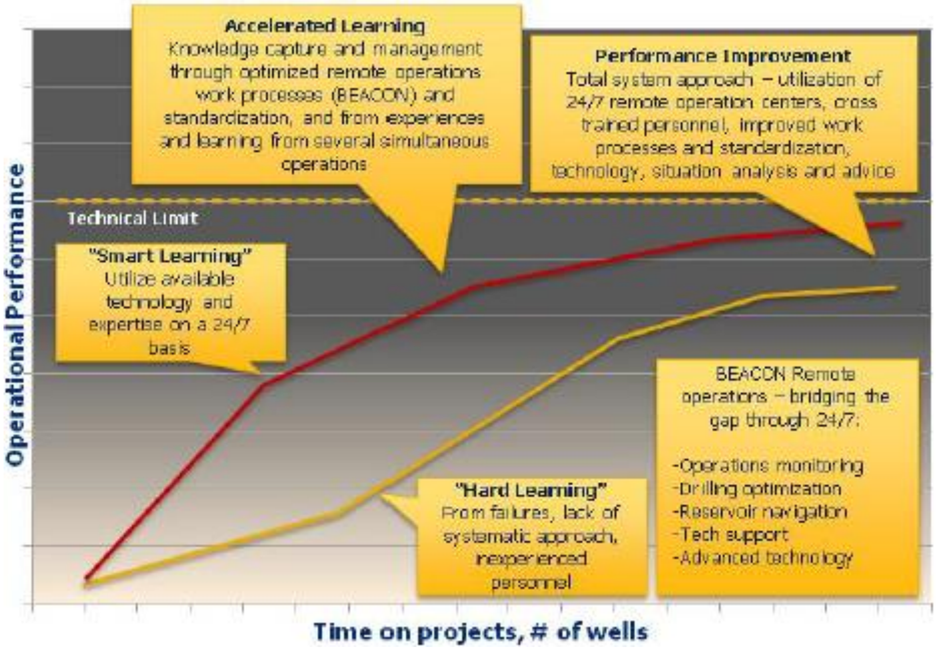

Figure 17: BEACON learning curve compared to traditional learning curve[17]

Crews from IO centers can supervise multiple rigs, with virtually no limit as long as the resources and setup allows it. Therefore, when comparing offshore crews working normal offshore rotations to IO center crews, the latter will be much more exposed to different kinds of situations.[1,17]

4.2.3 Reliability

A key variable for performance optimization lies in improved reliability. With the BEACON concept, with Norway as an example, have proved to improve reliability and decrease NPT. A key to achieving this was reliable, consistent and trustworthy workflows, and a solid organizational setup.

A significant effort has been made in Baker Hughes to try to adapt to the integrated operations model – the movement of operations from offshore to onshore, including a complete redefinition of work processes and responsibilities. Different models and approaches have been sought to facilitate a better collaboration environment for primarily the drilling and geoscience department, but also different departments or disciplines involved.

To create a strong multi-skilled and cross-divisional team, the organizational structure had to be changed to obtain the best possible delivery of the well. The creation of a multidisciplinary team, enabled focus on both the data acquisition as well as the real-time usage of the data, giving a more widespread understanding of the well objectives and common foundation for all the involved parties. Reliability as one of the key parameters is then increasingly understood, along with the different aspects of drilling practices, the understanding of the rock itself, and the overall drilling environment.

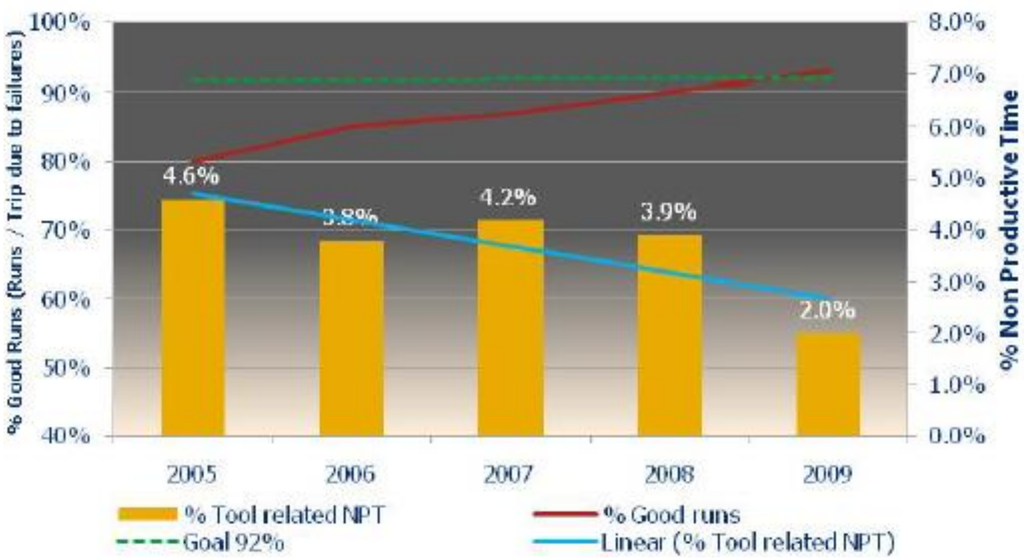

Figure 18: Baker Hughes reliability development 2005-2009[17]

4.2.4 Collaboration

One of the key factors impacting the performance of IO teams is the relationship between the onshore and offshore crews. Too often it is assumed that the crews will simply continue on a “business as usual” basis. This ignores the behavioral divide between the well-site and IO center.

Speaking to Sigmund Pettersen, an ARTE who worked offshore for 2 years and now situated in BEACON Technical Support, he’s confident that Baker Hughes BEACON model is a success, although there are some challenges as the geographical distance inhibits perfect communication between the off- and onshore crew.

In Baker Hughes, fixed arenas are setup to communicate the participants the operation ahead. It starts with the IPWP (Integrated Pre-well Planning) process which is a formal peer review involving resource allocations, drilling application engineers, reliability engineers and downhole/surface technical support engineers. The project scope for the upcoming well is discussed, and the project manager assumes the role of the IPWP process owner, responsible for ensuring that the IPWP process provides the work scope, a list of key considerations in the planning, coordination and execution of integrated services and a tool for assessing potential technical risks.

Also pre-section meetings are always held, where the personnel offshore, DDx/ARTE/RPS meets (phone conference) with the BEACON crew, formation evaluation, drilling optimization and technical support, and of course the project leader. Topics that will discussed are; HS&E, operational overview, equipment/software/deliverables and other relevant to the operation ahead.

In the end, an after action review is done, aiming to capture lessons learned for application to improve future performance.

Otherwise, the Geoscience department has a morning everyday where operations (BEACON) and office-based subject matter experts discusses log responses, data quality and processing of data, both real-time deliverables and final ones. Deviation and irregularities are also discussed making sure the different log responses is due to rock variations and petrophysical variations and not because of equipment issues.

The drilling optimization and technical support also have their own morning meeting with representatives from reliability engineering, drilling applications and downhole/surface technical support discussing tool performance, progress and issues related to drilling parameters.

All these processes together ensures a good response to the communication challenges expected in the integrated operations model. In addition, day-to-day communication between the offshore crew and BEACON is also vital.

4.3 Costs

The economic impact of implementing IO on an industry wide basis is significant; implantation on the NCS can increase oil recovery by 3-4 %, accelerate production by 5-10 % and lower operational costs by 20-30 %; NPV of IO on the NCS is estimated to be NOK 150 billion. According to a report published by OLF in 2007.[1]

Whilst BEACON successfully transferred MWD and mud logging work processes into the onshore center it did not place these positions within an onshore working environment framework. In conjunction with the local union chapter, an exemption to regulatory proscribed onshore working regulations was implemented. Working conditions for the onshore positions were regulated according to the OSA and crews retained their offshore schedules (2 weeks rotations at 12 hours per shift). In line with the offshore union agreement, crews also retained their residential location, resulting in considerable logistical effort and cost being expended to transport and house hands whilst they were on-duty in Stavanger.

The business model implemented for the first generation BEACON center included coverage of these costs by clients in the form of a BEACON service-fee, additional to traditional compensation formats of equipment rate per meter and headcount per day. Focus on reducing these rates, coupled with performance penalties, will accelerate over time (especially as production declines) and can potentially drive supplier profitability so low that it no longer becomes attractive for service providers to operate in certain locations and diminish investment in new technology.

The solution that has been developed and in use today, is a service based compensation format for personnel where the client pays for a service (suite of tools with agreed deliverables) and allows the service provider to find the most effective method to supply that service to defined quality assurance criteria. This new kind of contractual agreements is a step change for client organizations who typically desire to see any optimization of service delivery reflected in a lower job-ticket and also is a step change for suppliers who are incentivized to develop innovative solutions to ensure their financial health.

This new model fits with the service delivery optimization efforts such as multi-skilling and replacing traditional rig-based experts with support from BEACON (e.g. drilling optimization/RNS). By developing an in-depth understanding of the client's well objectives and long term challenges, additional opportunities to develop new services and further streamline service delivery can be defined.

E.g. with the reservoir navigation services provided, requires Baker Hughes to implement a petrophysical competency development plan for BEACON GeoScience Engineers, further developing the close working relationship with the Statoil well groups. This would further develop a resource pool and work processes that will support optimization efforts within client organizations by allowing some tasks to be transferred to service providers with confidence.

4.3.1 BEACON versus traditional setup

It is obvious with the reduced footprint needed at the rig site, there are cost reductions that can be directly linked to the BEACON model.

An analysis regarding the up manning the last year with Baker Hughes successfully winning a tender held by Statoil regarding approximately 26 rigs has been conducted.[23]

Simplifying this calculation a bit, the following assumptions have been made:

- ARTEs, M/LWDs, DEs all belong in the C matrix in the salary matrix table, as freshmen
- Using the OSA salary matrix table from January 1st, 2013[24]
- ARTE/M/LWD/DE yearly salary would be 580,000 NOKs, considered half of the shift would be night shifts with regards to bonuses
- BGSE salaries from internal salary calculation sheets, also as freshmen
- BGSE yearly salary would be 620,000 NOKs
- ARTEs, M/LWDs, DEs have the 2/4 schedule (2 weeks on, 4 weeks off)
- Each rig would have 2 x ARTE or 2 x DE / 2 x M/LWD on duty continuously
- Not considering DDx and LG as the manning would be the same for both setups

In the traditional setup, each rig would need 2 x DE and 2 x M/LWD, with the 2/4 schedule, it would mean 6 of each for the total crew per rig; 6 x DE and 6 x M/LWD.

Rigs:	**26**		**Total:**
Salary figures in NOKs	*DE*	*M/LWD*	-
Crew:	156	156	312
Salary base:	580,000	580,000	-
Total salary cost:	90,480,000	90,480,000	180,960,000

For the BEACON setup, each rig would only need 2 x ARTE, with the 2/4 schedule, it amounts to 6 for each rig. In BEACON, only 2 new BGSE were employed for each of the 5 shifts.

Rigs:	**26**		**Total:**
Salary figures in NOKs	*ARTE*	*BGSE*	-
Crew:	156	10	166
Salary base:	580,000	620,000	-
Total salary cost:	90,480,000	6,200,000	96,680,000

This analysis shows that just considering salary, huge savings are made using the BEACON concept. Of course, the calculations are simplified, M/LWDs does not need to stay on the rig as much as ARTEs/DEs, even so ARTEs/DEs can also be demobilized in periods. But nevertheless, considering costs related to training, transportation, accommodation and just straight up costs in the process of employing new employees are greatly reduced. Not to mention the reduction of head count saves both the service company and the operator a lot of money.

5 Conclusion

The process described in this thesis has revealed the values and challenges associated with integrated operations over time. Integrated operations is definitely here to stay, and a short list of benefits can be summarized:

- Meeting ever so demanding performance-based contracts
- Standardization
- HS&E
- Rig/field familiarity
- Talent/expertise development
- Centralizing core expert knowledge that are available 24/7 (Tech Support)
- Maximizing human capital
- Minimizing NPT
- Minimizing costs

Challenges:

- Communication between off- and onshore
- Dependent on good telecommunications connectivity

As the lists suggests, the benefits greatly exceeds the challenges, even though the dependence on good connectivity is very crucial. No doubt there is a lot gains possible with integrated operations, but if the costs of implementing an acceptable telecommunications infrastructure exceeds these gains, it might not be feasible after all.

Although the described examples involved building IO centers close to the point of service, the model has proven to allow the complete removal of distance as variable for defining support location, as long as cultural, and time-zone particularities are contemplated and remote-support personnel have the required knowledge of local applications and lithology.

During the fall/winter of 2012/13, after Baker Hughes was awarded an extensive Drilling & Evaluation contract from Statoil, Baker Hughes had to man up heavily with mostly inexperienced fresh-from-University with little to no experience. As discussed throughout this thesis, heavy savings is possible with the BEACON concept, and one can only speculate how big of a role this played in winning the tender. Nevertheless, Statoil gave Baker Hughes huge credit for the implementation, as they had foreseen more challenges than what was actually seen. It is the personal opinion of the author that a big part of this success can be credited to the BEACON integrated operations concept, especially with the Tech Support function, not only with specific support as regards to QC of the new ARTE's tasks, but also with just the idea of a 24/7 available support.

As we move into the future, the current integrated operations models will continue to evolve towards further integration of several classic services like directional drilling, MWD/LWD, mud logging, drilling fluids, wireline logging, cementing and pumping as well as production monitoring and optimization. Standardization will be a major goal, not only in terms of vendor neutral solutions, but also across all of the above mentioned disciplines, and more. Simultaneously, a gradual shift from integrated operations into automation will continue to drive change of paradigms. The next move will be into predictive analytics and advisory systems, proposing alternative actions in response to measured variables, which will continue to evolve towards the ultimate goal of full automation as seen possible with WellLink Radar. For this to take place, and for human judgment and assumptions to be partially or totally replaced, further advance in integration of surface and downhole data, lessons learned, standard operational procedures need to be developed. Closer collaboration is across departments will be more evident, but also collaboration across company borders will most likely unfold. This path, if embraced, will continue to lower lift costs, diminish HS&E risk exposure and increase ultimate recovery.

Nomenclature

ARTE	=	Advantage Real-Time Engineer
BEACON	=	Baker Expert Advisory Centre/Operations Network
BGSE	=	BEACON GeoScience Engineer
CCTV	=	closed-circuit television
DBC	=	drilling/bit optimization coordinator
DD	=	directional driller
DDx	=	cross-trained directional driller
DE	=	data engineer
FE	=	formation evaluation
G&G	=	geology and geophysics
GoM	=	Gulf of Mexico
HS&E	=	health, safety & environment
IO	=	integrated operations
LG	=	logging geologist
LS/RPS	=	logging specialist/radiation protection supervisor
LWD	=	logging while drilling
MWD	=	measurements while drilling
NCS	=	Norwegian Continental Shelf
NOV	=	National Oilwell Varco
NPT	=	non-productive time
NPV	=	net present value
OLF	=	Oljeindustriens Landsforening
OSA	=	offshore service agreement
PDC	=	polycrystalline diamond compact
POB	=	personnel on board
RPM	=	revolutions per minute
RSS	=	rotary steerable system
SOAP	=	simple object access protocol
UHF	=	ultra-high frequency
VP	=	vice-president
WOB	=	weight on bit
XML	=	extensible markup language

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