Engineering Aspects in the Design and Implementation of Onshore Smart Oil Fields

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Summary

The smart-field concept is deployed through disseminating elements of tools and infrastructure integrated to bring a level of smartness that can improve the performance of an oilfield asset in a sustainable way. The design and implementation of these tools and the infrastructure's underpinning smartness can differ on the basis of oilfield conditions. Greenfields, for example, can be engineered upfront to leverage all tools and deliver smart-field value from the beginning of the asset's life. On the other hand, smart-field tools and infrastructure for brownfields would be designed selectively and be implemented on the basis of several engineering and economic considerations.

The main functionalities of an onshore smart field are remote operation, real-time information, and collaboration realized by the following tools and infrastructure:

- Subsurface permanent downhole gauges (PDHGs)
- Subsurface flow controls
- Wellhead instrumentation
- Telecommunications infrastructure
- Supervisory control and data acquisition (SCADA) and control system
- Field-to-headquarters (HQ) connectivity
- Collaboration work environment (CWE)

This paper outlines the engineering aspects to be considered in the selection, design, and implementation of tools and infrastructure for onshore smart fields.

Introduction

When the smart-field concept was introduced approximately a decade ago, people began talking about how it would integrate people with process and technology, and how this would benefit oil operating companies meeting operational challenges and confronting problems related to production sustainability, operating cost, reserves recovery, and health, safety, and environment (HSE). However, there was little information available on how oil operating companies would implement the concept.

It took some time for operating companies to understand that smart-field benefits are realized through the new operation practice a smart field introduces to oil-production operations, allowing remote real-time-performance monitoring and improved decision making. **Fig. 1** shows the distinctive features of a smart-field new operation practice.

Remote Operation and Real-Time Information

Historically, remote operation and real-time information in oil fields have focused on gas/oil-separation plants, but have had limited application on upstream wells. A key feature of the smart field is to introduce remote surveillance and operation to production and injection wells and provide access to real-time data.

Because the wells of onshore oil fields are usually spread over remote areas (often with hostile environments), a remote operation and surveillance facility has strong business drivers. On one hand, it meets HSE challenges that impose constraints on production operations:

- Minimizes the need to travel at night or in bad weather
- Minimizes exposure to hazards
- Helps to avoid flaring

On the other hand, it provides operational and performance enhancement:

- Operate widely spread facilities with smaller staff
- Visit a facility prepared for a problem that is known to exist
- Shut in remote facilities to avoid adverse consequence

Collaboration

Operation of oil fields and management of oil reservoirs have a tendency to be treated as separate activities run by different teams. Smart-field practice aims to integrate oil production and reservoir management and provide an environment that allows staff to operate in a collaborative, multidisciplined manner. Bridging the physical gap between the field and the HQ will create a new operation practice that ensures proactive initiatives and right-time informed decisions to help sustain production and improve recovery. To enable these features in onshore oil fields, the following interdependent essential tools and infrastructure at both field facilities and remote HQ should be in place:

- Subsurface PDHGs
- Subsurface flow controls
- Wellhead instrumentation
- Communication infrastructure
- SCADA and control system
- Fields-to-HQ connectivity
- CWE

The Abu Dhabi Company for Onshore Oil Operations (ADCO) began introducing the smart-field concept and building smart-field-enabling tools and infrastructure as early as 2002, when the engineering activities of North East Bab (NEB) field development started as the first smart field in the United Arab Emirates. Since then, ADCO has continued building smart-field-enabling infrastructure, under projects developing new fields or upgrading existing fields. **Fig. 2** shows essential tools and enablers of a smart field in a typical ADCO oil field, with one central degassing station (CDS) and several remote degassing stations (RDSs).

While building smart-field enablers can be cost effective when included as part of a greenfield-development scope, it is a challenge in brownfields, where economic and engineering limitations exist. In the following subsections, we go through the engineering

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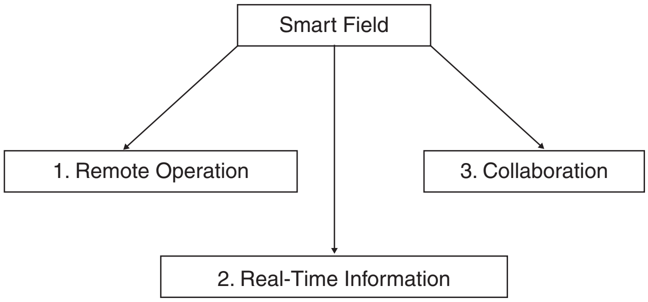

Fig. 1—Distinctive features of the smart-field operation practice.

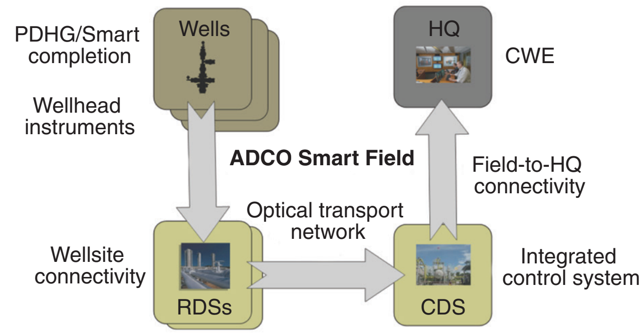

Fig. 2—Onshore-smart-field tools and infrastructure.

aspects in the selection, design, and implementation of smart-field tools and infrastructure for onshore oil fields.

Subsurface PDHGs. Subsurface measurement is required to monitor the reservoir pressure, temperature, or flow to enhance reservoir understanding and validate the reservoir model, and to monitor injection contribution to formation to optimize production/injection and improve recovery factor. Obtaining subsurface data by direct well intervention is quite a challenge to onshore oil operating companies that have a large number of, and different types of, wells scattered over a wide area. Besides the cost, the risk of losing tools in the wellbore and the potential HSE risks limit the frequency of direct well intervention, and, hence, limit the capability to properly manage the oil reservoirs.

The real-time data from PDHGs allow for a much faster response to reservoir behavior and constant adjustment of injection and production for each reservoir zone. Many engineering aspects should be taken into account when selecting and installing PDHGs:

- Parameters to be measured (pressure, temperature, flow)
- Type (optical vs. electronic)
- Reliability track record
- Operating temperature
- Interface with wellhead and completion components (wellhead modification, pass-through packer)
- Complexity of installation and need for cable splicing/connectors
- Need for corrosion-resistance-alloy material
- Surface installation and connections
- Power requirement
- Communication of data
- Interpretation of data

Considering these aspects, downhole gauges can be installed in newly drilled wells in new fields and in both newly drilled and worked-over wells in mature fields. Besides PDHGs in several oil producers and gas-injection wells, ADCO has recently installed the longest recorded distributed temperature sensor (DTS) in a horizontal well at one of its oil fields.

Subsurface Flow Controls. The benefit of subsurface flow controls depends on understanding the reservoir behavior, so the combination of using subsurface-flow-control devices with the acquisition of subsurface data is essential and is usually referred to as smart completion. A smart-completion system may consist of subsurface isolation and inflow controls, permanent downhole pressure and distributed temperature sensing, surface control and monitoring system, data-acquisition and -management software, and other related accessories.

Subsurface-flow-control devices improve the recovery of hydrocarbons because they allow production from multiple reservoirs with fewer wells and isolation of watered-out zones or high-gas/oil-ratio zones. Additionally, because the subsurface-flow-control devices are controlled from the surface, the number of well interventions over the field life is reduced, saving costs and eliminating hazards exposure.

Subsurface-flow-control options include passive inflow-control devices (ICDs) and active interval control valves (ICVs). Although ICDs were developed originally to counteract the horizontal-well water- or gas-cusp problems and ICVs were developed to control commingled production from multiple reservoirs, the variety of their applications has proliferated and their application areas now overlap. It is a complex process to select the optimal subsurface-flow-control device between ICVs or ICDs for a particular well completion. Several engineering aspects should be considered when selecting and installing subsurface-flow-control devices:

- Type (ICV vs. ICD)
- Advantages in production operations
- Reliability records
- Reservoir uncertainty
- Formation characteristics
- Level of flexibility

The development of subsurface flow controls provides an unprecedented opportunity to close the loop on information, achieve control of production, and attain optimization of recovery (Al-Mubarak et al. 2009). ADCO has installed smart completions with several ICVs in a vertical well producing from multiple reservoirs.

Wellhead Instrumentation. Wellhead instruments are the main components in remote monitoring and control. Basic well-monitoring parameters may include

- Oil-production pressure and temperature
- Annulus pressure
- Lift-gas flow, pressure, and temperature
- Injection-fluid flow and pressure
- Electrical-submersible-pump (ESP) motor current
- Hydrogen sulfide release
- Well-test flows
- Status of production and injection safety valves

Basic well controls may include

- Open/close of production and injection chokes
- Shutdown of production and injection wells

The selection and installation of wellhead instrumentation in new fields are simple, but when installing wellhead instrumentation in mature fields, several engineering aspects should be carefully considered:

- Process connections
- Power supply
- Data communication
- SCADA and control-system interface
- Interruption to production operations
- Operating temperature and need for shelters
- Type of transmitters (wired vs. wireless)

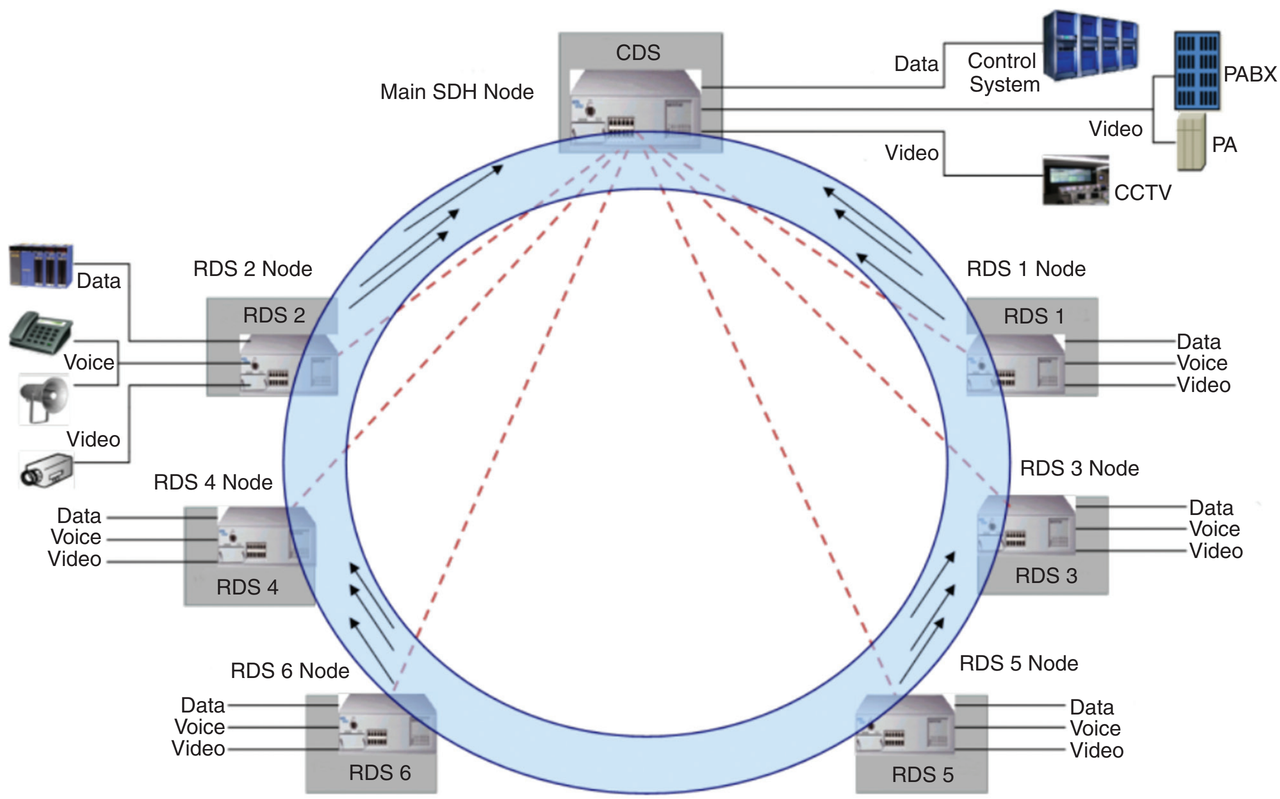

Fig. 3—Onshore-smart-field SDH transport network in ring topology.

Cost effectiveness is important in mature fields where most wells lack wellhead instrumentation. Wellhead instrumentation is installed by default under all new field-development projects, and, recently, ADCO has started a program to install wellhead instrumentation in phases for all existing wells in brownfields.

Communication Infrastructure. Communication infrastructure is the main smart-field enabler that provides the bandwidth required for remote operation and collaboration activities in the field. The cost of building communication infrastructure is a challenge to the upstream oil industry. In addition, it can be difficult to build communication networks in onshore oil fields because of the physical location and terrain. Equipment and licenses can add significant expense, especially if the wrong solution is selected. Communication infrastructure in the field includes the field transport network and wellsite connectivity

Field Transport Network. The bandwidth requirement of a smart field has led operating companies to develop and build private transport networks over their oil and gas fields to serve for the transmission of data, voice, and video. Optical networks and backbones are deployed primarily in onshore oil and gas fields to connect remote stations to the central station and satellite fields to the main field logically. These networks are cost effective in new fields in which it is feasible to lay fiber-optic cables along oil-transfer lines during construction or to make use of optical ground wires (OPGWs) on new electrical overhead transmission lines (OHTLs). In mature fields, however, it can be quite expensive to install an optical transport network across the field.

Wireless broadband networks are more cost effective in brownfields, but with limitation in bandwidth capacity and distance compared with optical networks and with restriction in frequency licensing.

The proven transmission technology for private optical transport networks in onshore oil fields is the synchronous digital hierarchy (SDH), covered by International Telecommunication Union standards G.707, G.783, G.784, and G.803, typically in ring topology to provide resilience against equipment failure and optical medium break at any location (Al-Majid 2001). The optical transport network is used for all telecommunication systems, including private automatic branch (PABX), public address (PA), and closed circuit television (CCTV).

ADCO has completed the installation of field optical transport networks in all operating fields. **Fig. 3** depicts a typical SDH field transport network connecting a CDS and several RDSs.

Wellsite Connectivity. The connectivity of wellsites is essential for remote well surveillance and rig communication.Wellsites in an onshore oil field are typically scattered over a very wide area and can be many miles away from the nearest gathering station. Linking the wellsite to the field transport network at a gathering station is referred to as the first mile connectivity. First mile connectivity of wellsites can be made over wireless connection or fiber-optic-cable connection. Wireless connection is the most feasible option for natural flowing oil wells at both new fields and brownfields, especially when oil flowlines are installed above ground, because the cost of laying and connecting fiber-optic cables to remote oil wells can be prohibitive. When selecting the appropriate technology for a wireless connection, the amount of bandwidth needed for rig communication should be taken into account. The emerging Worldwide Interoperability for Microwave Access (WiMax), covered by the Institute of Electrical and Electronics Engineers standard IEEE 802.16, can provide those needs. On the other hand, fiber-optic-cable connection could be a feasible option for gas-injection wells and gas lifted oil wells in which fiber-optic cables can be laid along the same trench of underground gas lines. The same applies to ESP-lifted oil wells in which OPGWs are used for connection.

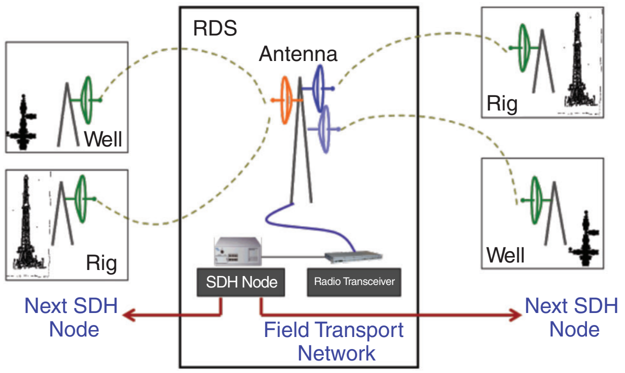

Fig. 4—Basic setup of wellsite wireless connectivity.

With wellsite connectivity through wireless or fiber-optic-cable connection to the nearest node of the field transport network, the required telecommunications infrastructure should then be in place to enable the smart-field concept. **Fig. 4** shows the basic setup for wellsites with wireless connectivity.

In addition to economic factors, when selecting telecommunications solutions for onshore oil fields, the following engineering aspects should be carefully considered:

- Current and future need of bandwidth
- Distance and coverage
- Conforming to standards
- Expandability and portability
- Power supply
- Operating temperature and need for shelters
- License regulations

Assessment of different technologies is essential in identifying the most-feasible solutions to meet the requirements. An effective combination of field-proven wired and wireless technologies is a key factor for meeting smart-field communication requirements.

Wellsite connectivity is provided by default under all new-field-development projects, and, recently, ADCO has started a program to install wellsite connectivity in phases for all existing wells in brownfields.

SCADA and Control System. Historically, SCADA is used in oil and gas fields to collect event-driven data from remote wells and gathering stations with serial connection over narrowband radio. It is not meant to monitor or control remote facilities in real time. SCADA is traditionally a disparate system with human/machine interface separate from the main separation station distributed control system (DCS), with serial interface to the DCS in case certain events would need operator intervention. The development of object linking and embedding (OLE) for process control (OPC) introduced a better solution to interface SCADA to the DCS, but it typically remained a separate event-driven system.

As onshore oil operating companies build private field optical transport networks enabling high-speed, reliable, and low-latency communications, SCADA systems are able to provide real-time control. SCADA, with the standard transport control protocol/internet protocol suite of protocols, can be deployed easily over SDH because SDH can provide physical and logical link layers for SCADA (Stein and Geva 2006).

The new generations of DCS designs are built with an Ethernet-based network that can be extended using routers and switches. Hence, it becomes possible to extend the DCS network either directly or over SDH to remote field stations. As the DCS local area network (LAN) is extended to remote stations, it also becomes possible to merge SCADA functions into DCS and connect SCADA servers as direct nodes of the DCS LAN.

SCADA in onshore oil and gas fields can no longer be provided by separate systems but as part of an integrated control and safety system comprising DCS, safety systems, and SCADA. The advantages of this approach are that it enables a single platform for operations, it provides a lower lifetime cost of support, and it eases future upgrade and expandability work. While this approach is easy to implement in new fields, it is not possible in mature fields where no optical field transport network exists. An option in mature fields that have no telecommunications infrastructure in place is to use public wireless services for the remote acquisition of data from remote wells.

An integrated control system is installed by default in new fields, and ADCO has a program to integrate SCADA and DCS in all brownfields.

Field-to-HQ Connectivity. Field-to-HQ connectivity is important for smart-field collaboration and integrated operations. The telecommunications solution for field-to-HQ connectivity should consider the high bandwidth requirements for streaming video and massive data transport needed for rig communication and should connect all fields.

The options for field-to-HQ connectivity for onshore oil operating companies are limited. Building infrastructure from several fields hundreds of kilometers away from HQ in a main city is not feasible. Possible options, depending on availability, are to obtain high-speed connectivity services (e.g., multiprotocol label switching from public telecommunications companies) or to lease OPGW dark fibers over existing OHTLs from public power-transmission companies to establish the transmission network. The last option is available to ADCO and has been selected for field-to-HQ connectivity.

CWE. CWEs are physical locations for integrated operations, where staff in the field and at HQ acquire real-time information and can communicate and work in teams of multidiscipline engineers, meeting virtually at any time (Foss 2012). The CWE design would support the following work processes:

- Daily integrated surveillance and interaction
- Production optimization
- Well and reservoir management
- Integrated planning

To achieve its objective, the CWE usually has the following components:

- Integrated asset operation model
- Production dashboard software
- Collaboration software
- 3D projection equipment at both HQ and field
- Space-distributed liquid-crystal displays
- Audio/visual system, including several video conferencing points

When designing a CWE, the following should be considered:

- The CWE should adhere to the company's information-technology (IT) -division standards for projectors and video conferencing so that future support and upgrades can be covered through companywide support contracts.
- The design of the floor layout, furniture, audio/video equipment, IT network, and dashboards should be selected carefully for the required functionality.
- The design should anticipate changes over a 3- to 5-year horizon. It should be sized to accommodate additional manpower, and the technology should fit in with future company migration programs.
- All key stakeholders are involved in defining the work processes, especially if parts of the work processes are to be automated.

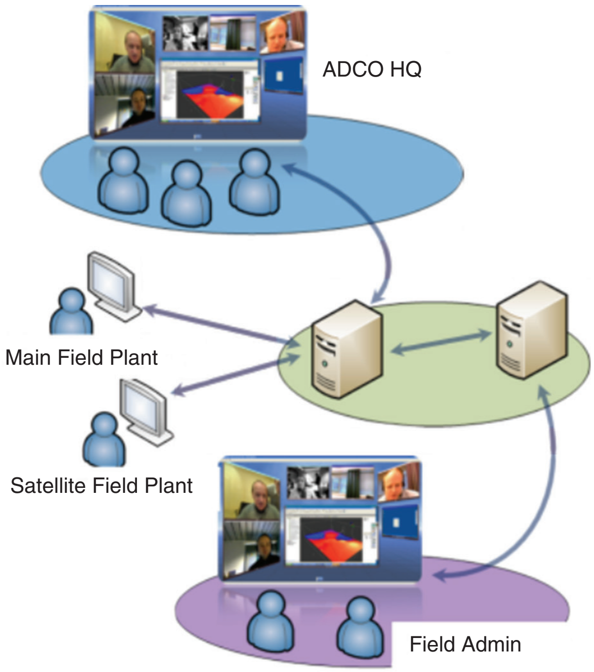

Fig. 5—CWE integrated operation.

- To create an environment that is inspiring to work in, it may be necessary to include an interior-design specialist in the design team.

Fig. 5 depicts a CWE integrated operation setup. ADCO has already built a CWE for the NEB field and has a program to build a CWE for all fields once the necessary infrastructure is in place.

Challenge

It is still a challenge to introduce the smart-field concept to production and injection facilities of onshore oil fields, especially in existing fields where the essential enabling tools and infrastructure are not in place and need considerable investment to build. However, as the time of "easy" oil is coming to an end and oil operating companies face challenges to increase recovery from mature reservoirs and develop marginally uncertain reservoirs, the business case for a smart field becomes more appealing and the challenge is fading (Al-Yateem et al. 2011).

Conclusion

As fields mature, they become more complex, with the introduction of enhanced oil recovery and improved oil recovery to aged facilities, which leads to a massive increase in measurements, data handling, and analysis to ensure the value of the field is realized and that HSE standards are maintained. Smart fields provide the radical change in operating practices that allows this to be achieved. The real concern is to recognize this requirement early enough to ensure that smart-field tools and infrastructure are in place at the same time that additional operational complexities hit the oil operating companies.

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