Production/Facilities

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Subsea processing is one of the most interesting technologies being introduced to the oil and gas industry. Treating the production flow at the seabed opens up opportunities to more-remote oil and gas reservoirs around the world. This operation is especially important because the industry is running out of reservoirs that are easy to produce, meaning that the focus is placed on how to produce oil and gas from longer-offset offshore fields in deeper reservoirs with difficult bathymetry.

A growing number of subsea multiphase pumps have been in operation around the world for several years to address less-than-ideal natural-reservoir-drive conditions. This growth has been followed by successful installation of subsea separation in the North Sea to address less-than-ideal flow characteristics and production of sand and unwanted byproducts. These technologies are being combined at a systems level to optimize reservoir recovery and management. Recent startups of combined subsea-separation, -boosting, and -injection systems offshore Africa, Brazil, and the deepwater Gulf of Mexico are adding to subsea processing's maturity and widespread acceptance.

Subsea processing continues to take steps into the future with project sanctions that use gas/liquid separation and oil/water separation. The next generation of processing systems will focus on more-compact solutions that will be well suited for deepwater applications. In addition, considerable effort is being made in the area of raw-water injection, low-/no-oil-fraction discharge, and subsea gas compression, all promising great potential for greater hydrocarbon extraction, saving the costs for additional surface infrastructure. **JPT**

Production/Facilities additional reading available at the SPE eLibrary: www.spe.org

IPTC 12377 *• "Plant Integrity and Reliability are the Keys To Improving Profitability" by S.D. Kapusta, Shell, et al.*

SPE 115074 *• "Corrosion and Hydrate Control in Wet-Sour-Gas Transmission Systems" by J.J. Moloney, SPE, Baker Hughes, et al.*

Offshore-Connectivity Solutions for the Oil and Gas Industry

The oil and gas industry is forced to go into deeper water further offshore to find new oil or gas. At the same time, the industry is placing more emphasis on integrated operations driven from onshore control centers. Highly reliable communications solutions are required to fullfil these objectives. Large bandwidth and low latency links between offshore facilities and the shore are essential for communications to all company personnel and contractors engaged in the offshore development areas. The full-length paper describes overall solutions to address these needs and reviews available technologies.

Introduction

Exploration and production of offshore fields is evolving and makes use of various modes of communication. Many oil companies are establishing operations centers where technical expertise is located. Telecommunications from the field to these centers is becoming critical, and solutions exist to make communication both efficient and dependable, with a choice of different technologies listed in Table 1 in the full-length paper.

Dry/Dry Solutions

The dry/dry solutions adapt the traditional shore-to-shore telecommunication application so that it can be used with different types of offshore assets such as a fixed platform or floating assets such as a tension-leg platform, a spar, or a floating production, storage, and offloading vessel (FPSO). One would prefer ring or loop architectures connecting each asset with its own spur by use of a branching unit (BU). The system is designed to allow the platforms to be independent and limits the number of risers per asset to one, compared to a simple daisy chain. For the last-mile connection, a dynamic riser is required to access floating assets, while a simple J-tube may be sufficient with shallower fixed structures. Another complexity may come from the use of fiber-optics (FOs) rotating joints because the latest generation of FPSOs tends to adopt a turret architecture, allowing the vessel to rotate freely. In most cases, studies are required to validate and qualify the riser design according to the requirements of the structure and the local weather conditions. A second approach is to equip an umbilical with fiber and allow the last-mile connection to take place subsea with a combination of wet-mate connectors and subsea manifold. In this case, a special cable termination is provided allowing remotely-operated-vehicle (ROV) handling of the wet-mate connector by use of a length of flexible hose. Both approaches are valid and will solve the last-mile issue adequately.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 117254, "Offshore Connectivity and Ultra-Long Tiebacks Solutions for Oil & Gas," by ***A. Lecroart, R. Michel,*** *and* ***J.P. Odier,*** *Alcatel-Lucent Submarine Networks, originally prepared for the 2008 SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Australia, 20–22 October. The paper has not been peer reviewed.*

Dry/Wet Solutions

From a communication standpoint, the deepwater environment can be characterized best by extended reach, more than 100 km between any two points and sometimes more than 500 km away from shore. The environment may be severe. Consequently, there is a trend to implement more subsea processing, resulting in more control located subsea around the wellheads.

The solutions proposed are all based on the use of a single-conductor standard communication submarine cable. When used in conjunction with a direct-current (DC)/DC converter subsea and a sea return mechanism, a sizeable amount of power can be distributed locally on the remote subsea field. A power level of 10 kV is used to minimize the current in the cable to reduce the transport losses to a minimum. Delay-free broadband communications also are provided locally by means of the optical fibers of the submarine cable.

In this new subsea-cable network, offering Ethernet and DC-power distribution, the aggregated data necessary to the control systems are typically communicated back to shore at approximately 100 Mbit/s. The DC/FO cable solution is independent of any umbilical solution, and a 1+1 configuration is recommended. This solution provides open data-communication interfaces for easier integration with subsea-control-system equipment.

Solution Overview

This single-conductor submarine-cable technology is offered to connect subsea control systems, either by tiebacks to a platform or with a stepout from land direct to a field. The initial hydraulic control systems have evolved, first into electrohydraulic systems and now into alternating current (AC) all-electric systems with fiber communications such as in the Snovit 145-km stepout in Norway. However, at these distances, AC transmission becomes inefficient because the capacitance of the cables induces losses in the power transport.

Standard submarine-cable systems with repeaters have proved DC powering for much longer systems, up to

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12 000 km, and can offer communications for long distances. As the capability of subsea telecommunication cables is studied for this application, a number of their networking features are attractive:

- BUs can distribute power and communications from a single cable to several interfaces within a field. This introduces the possibility of conserving risers by using a single cable to control a number of fields.
- Duplicate cables can provide hot standby capability, ensuring high availability (approximately 99.99%) while each still supports multiple nodes.
- Connectivity could be provided for additional subsea nodes on a permanent or temporary basis with extra fibers and underwater terminations.

Interfaces. The key to rapid progress and successful simple-system integration is to develop open interface standards—where possible, based on existing land standards and practices.

For communications, it is proposed to adopt the widely used Ethernet standards. The most suitable initial choice appears to be 100 Mbit/s. This offers high capacity that will provide substantial margin for future needs and good availability of high-reliability components for practical modem and router implementation. This communications interface will be offered both subsea and topside. Other options are available if more bandwidth is required.

Similarly, for subsea power, the provision of a 400-V DC supply allows a good balance between efficient power distribution and selection from the wide availability of components to be used within the control system. Furthermore, provision of power levels up to 10 kW will enable operation of a range of valve-control systems.

Additionally, a subsea mechanical “interface” is required. Wet-mate connectors may be used for communications and power; the termination assembly will be a “lighter” version of existing umbilical termination assemblies.

Cable. The cable is the standard cable used for repeatered solution. The industry benchmark is a 17-mm diameter for the deepwater cable. This cable is built around a stainless-steel tube, a wire vault, a copper tube swaged onto it, and a polyethylene wall. This lightweight cable can be protected additionally with different types of armored packages, and it comes in lightweight, lightweight-protected, single-armor, and double-armor forms. The fibers are submarine-specific and are procured with a 1.8% screen test to guarantee excellent cable mechanical and optical characteristics. The cable electrical insulation is qualified to sustain a 12-kV operational voltage for 25 years and is compatible with the use of electroding fault-detection methods.

Repeaters. The repeater provides amplification of two way optical digital transmission signals in the erbium amplification window of approximately 1550 nm. It also is designed for a 25-year lifetime. The repeater is modular in construction and can be equipped for use with cables having from one to eight fiber pairs. The repeater performances such as output-power level, amplifier gain, number of wavelength division multiplexing channels, and optical bandwidth are project dependent. The repeater uses invisible laser radiation.

Repeaters are powered in series from the terminal station at a constant current of either polarity and are provided with surge protection to prevent the internal circuits from being damaged by the large transients that can occur along a cable. Standard current values normally are approximately 1 A, but the repeater has been qualified to work with both lower and higher current values (as great as 8 A).

The internal atmosphere is controlled, the housing is sealed, and the thermal behavior of the repeater is managed through its design.

There is a supervisory system embedded in the repeaters. The purpose of the supervisory system is to permit performance monitoring of the repeater. Transmission faults on a single fiber are readily located by use of the supervisory system. There is signalling to the repeater (in or out of traffic) and signalling from the repeater. Supervisory responses are sent to both ends of the system on all wavelengths.

BUs. The BUs provide for capacity-add and -drop capability, allowing creation of derivations (spurs) from the main backbone line (trunk). Capacity drop can be partial where only a few wavelengths can be dropped for each branch, or it can be total, and in this case, a whole fiber pair gets diverted to the branch. Different optical filtering methods are available in the case of the partial drop (also called optical add/drop multiplexer), allowing the amount of capacity that is required for each branch to be adjusted.

The BUs benefit from an optically commanded power-switching capability. The BU electrical state, therefore, is stable between any of the four configurations possible, and only the optical command can modify its electrical state. The standard configuration for this dry/wet application would be to have all three BU legs (A, B, and C) connected together. The other three states, used for operation and maintenance purposes, consist of having one leg (A, B, or C) locally grounded at the BU while the other two are connected together. In particular, any trunk section between two BUs can be isolated. The most attractive characteristics of the optically power-switched BU lays are their practicality (it is remotely controlled) and its safety.

Installation and Maintenance

It is important to evaluate the hazards that submarine cables can face to ensure that the proper choices are implemented for cable protection. External aggression can be considered in terms of two categories: human factors and natural factors. Human factors are mainly commercial fishing, vessel anchors, and other seabed activities. Commercial fishing is responsible for more than 75% of cable aggression faults, and most trawler-related faults occur in water depths of less than 500 m. Natural factors are seabed current, marine life, hostile seabed terrain, earthquakes, underwater landslides, and abrasion. These natural factors account for less than 10% of cable faults. Cable burial is the natural remedy for bottom fishing and is an all-round, field-proven, and effective means of protecting the cable against bottom trawling. In a stable seabed, cable burial to no less than 0.75 m is deemed sufficient against fishing aggression.

There are dynamically positioned cable-laying vessels equipped with deep-sea plows capable of installing the cable 3 m below the seafloor in soft soils. ROVs also are used for trenching or to perform other remedial work when the conditions are such that plowing is not efficient. **JPT**

Cryogenic Technology for Processing High-CO_2 and -H_2S Gas Reserves

Global natural-gas reserves increasingly are reported with significant CO_2 and/or H_2S content. Concentrations of 20 to 40% are not uncommon. Commercialization of such resources poses significant economic and technical challenges. Approximately one-sixth of ExxonMobil's hydrocarbon resources are categorized as sour gas. With these volumes, ExxonMobil has the industry's largest sour-gas resource base and has more than 50 years experience in managing sour gas.

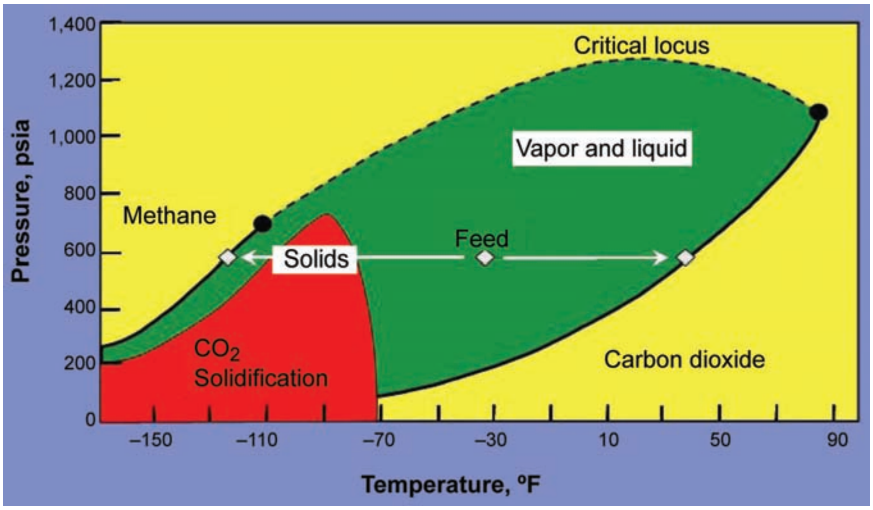

Fig. 1—Thermodynamic basis for separation of CO_2 from methane.

Introduction

Monetization of lesser amounts of saleable methane/hydrocarbons while at the same time producing, removing, and disposing of major quantities of acid-gas contaminants calls for technologies that can reduce capital and operating costs. The proper disposal of these contaminants adds to the challenge. Release of CO_2 to the environment is not desirable, its geosequestration is a much better alternative, and it would be better yet if it can be turned into a product stream to be sold or used for enhanced-oil-recovery (EOR) purposes. Similarly, alternatives for the disposal of H_2S are needed because the conventional conversion to elemental sulfur led to the saturation of many markets. While there has been a recent resurgence in the demand for sulfur, uncertainties about widespread demand sustainability encourages the development of alternative H_2S-disposal options.

The cryogenic technology, developed at ExxonMobil Upstream Research Company, is being advanced to the commercially ready stage in response to these needs. The first choice for many separations in the gas industry are those that take advantage of the simplicity provided by differing relative volatilities and phase behavior and are implemented by flash drums, separators, and distillation and fractionation towers. In the presence of methane, and to yield sales-quality gas, such separations imply very low, cryogenic temperatures of –120°F and lower, depending upon the operating pressure. CO_2 solidifies at these low temperatures. The experimental measurement and analysis of CO_2-solidification conditions in the presence of methane were pioneered in 1954. Shortly thereafter, a new process was proposed for freezing CO_2 from natural gas by flashing a cooled gas stream into solidification conditions and using a cyclonic device to separate the resulting slurry into solid CO_2 and liquid methane.

While the concept of CO_2 separation by solidification was first suggested more than 50 years ago, most separation processes have preferred avoiding solidification conditions and the handling of very-cold solids or slurries. For this reason, conventional technologies for CO_2 removal from natural gas are based on principles that do not involve cryogenic temperatures. Most are solvent-based, capturing CO_2 with a chemical, physical, or hybrid solvent and reversing the process to discharge the captured CO_2. Conventional technologies were developed at a time when relatively small amounts of contaminants had to be removed. Fields with higher levels of acid gases were bypassed in preference to economically more attractive fields. While conventional technologies are well-suited for

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This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper IPTC 12708, "Controlled Freeze Zone™ Technology for Enabling Processing of High CO_2 and H_2S Gas Reserves," by ***J.A. Valencia, P.S. Northrop,*** *and* ***C.J. Mart,*** *ExxonMobil, originally prepared for the 2008 International Petroleum Technology Conference, Kuala Lumpur, 3–5 December. The paper has not been peer reviewed.*

low levels of contamination and can be extended to medium levels, their applicability becomes limited both economically and technically with high concentrations of CO_2 and H_2S in the natural-gas stream.

Single-step CO_2 and H_2S removal is a cryogenic process for the separation of CO_2 and H_2S from natural gas involving the controlled freezing and remelting of CO_2. In a novel approach, rather than avoiding the solidification of CO_2 like most cryogenic treating processes, the trademarked cryogenic process allows it to freeze under specifically controlled conditions, and in a specially designed chamber.

Process

The issues with cryogenic temperatures and solidification of CO_2 can be understood better by referring to **Fig. 1,** which is a schematic representation of the pressure/temperature diagram for the methane/CO_2 system. This diagram shows the vapor/liquid saturation lines for pure methane and for pure CO_2 up to their critical points (668 psia and −117°F and 1,071 psia and 88°F, respectively) and the locus of the critical points of their mixtures. In addition, it shows the conditions under which solid CO_2 will be present, which involve temperatures lower than −70°F. In a constant-pressure distillation process, a feed stream, containing a mixture of the two components, would be fed somewhere near the middle of the distillation column. Heat would be added at the bottom of the column to drive off the lighter, more volatile component, methane. The amount of heat added would be dictated by the amount of methane that is acceptable to be lost in the CO_2 bottom-liquid product stream. The lighter methane emerges at the top of the column, at very cold temperatures, where some of the overhead is condensed and refluxed to drive down residual CO_2 and to achieve the desired vapor product purity, either pipeline quality (2 to 4% CO_2) or feed quality for liquefaction into liquefied natural gas (LNG), typically 50 ppm CO_2. Avoiding solidification by selecting a pressure above the highest solidification point presents a different limitation, that of the locus of critical points of the mixture. Further separation and purification is no longer possible as the vapor and liquid phases become indistinguishable from each other at critical conditions, while their residual CO_2 content is still far in excess of any saleable quality. Operating at pressures lower than the critical pressure of methane to achieve desired levels of methane purity implies addressing CO_2-solidification issues. This is illustrated in Fig. 1 by the horizontal line that progresses from a given "feed" composition toward pure methane and that contacts, crosses, and re-emerges from the solid-phase dome of the phase envelope.

A cryogenic tower essentially is divided into three zones: the specially designed cryogenic section that addresses the solidification dome and two conventional stripping and rectifying sections that address the vapor/liquid areas to the right and to the left of the solidification dome. In the lower portion of the tower, below the cryogenic section, methane is stripped or recovered from the bottoms-liquid stream, which contains CO_2 and other acid-gas contaminants, by conventional distillation. Above the cryogenic chamber, the CO_2 content is reduced, if necessary, to meet pipeline or LNG feed quality, again by conventional distillation in a rectifying section.

Liquid from the upper conventional-distillation section, that is about to enter solidification conditions, is sprayed into the cryogenic chamber, which is open and unobstructed. As the liquid droplets fall, they encounter warmer temperatures. Methane and any lighter components such as nitrogen, if present, vaporize. The residual concentration of CO_2 in the droplets increases, leading to solidification. The solids that form fall onto a liquid layer at the bottom of this chamber that is maintained above solidification temperatures. A liquid, above solidification conditions, emerges from the bottom of the cryogenic chamber and is directed to the stripper section to recover valuable methane. Similarly, vapors from the bottom conventional-distillation (stripper) section rise through the cryogenic chamber and encounter colder temperatures. CO_2 condenses or frosts onto the falling spray droplets or solid crystals, further contributing to the solidification process. The solids formed in the cryogenic section are pure CO_2, thus providing greater separation factors and high efficiency for this section. Their removal from the vapor stream results in a product exiting the top of the cryogenic chamber that is significantly depleted of CO_2.

Fig. 2—Cryogenic-process pilot plant.

The cryogenic process operates at constant pressure, the selection of which can be optimized primarily on the basis of field-gas pressure, sales-gas pressure requirements, tower size, and refrigeration requirements. Operating temperatures will be dictated by the actual feed compositions and prescribed product specifications. Operations at 500 psia would involve overhead temperatures of approximately −125°F, bottoms temperatures of approximately 30°F, and cryogenic-section temperatures in the −70 to −110°F range. A cryogenic tower normally would include all three sections, but depending on the sales-gas specifications and feed-gas composition, the rectifying section may not be necessary.

Fundamentally, the cryogenic technology provides the ability to process natural gas more economically without imposing limitations on the level of CO_2 or H_2S contamination it can have. It separates the CO_2, and any other acid-gas components present, into a liquid stream that can be pumped easily for geosequestration or for use in EOR operations, while yielding a high-quality methane product.

Pilot Plant

The cryogenic technology was invented in 1983 and was patented in 1985. A 0.6-MMscf/D pilot plant was built

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near Houston, in 1985. It was operated in 1986 and 1987. The cryogenic pilot plant, shown in **Fig. 2,** was the first application in the industry to demonstrate successfully the freezing and remelting of CO_2 as part of a natural-gas separation process. The pilot plant processed feed gases with CO_2 contents ranging from 15 to 65%, at pressures of 550 to 600 psia. While it was designed to achieve pipeline-quality overheads, its overhead gas stream not only met pipeline quality but approached LNG-feed quality by reducing its CO_2 content to a few hundred ppm. Methane losses in the bottom stream were targeted for 1%, but performance as low as 0.5% was achieved. The pilot-plant operations were very successful at demonstrating the concept of controlled freezing and remelting of CO_2 and provided valuable operating and design information.

The mid-1980s oil-price collapse further impaired the overall economics of producing highly sour natural-gas resources, and additional pilot-plant activities were suspended. However, commercialization studies and the pursuit of refinements continued.

Commercial Demonstration

To enable an effective and efficient scaleup of this technology to facilities capable of processing up to 1 Bscf/D, a commercial demonstration plant (CDP) currently is being built in Wyoming. The design of the CDP began in 2007. The project is currently in the engineering, procurement, and construction phase and will be operational in late 2009. The Wyoming location was chosen to host the CDP because it will allow cryogenic-technology testing not only with CO_2 but also with H_2S. In addition, it has one of the largest acid-gas-injection facilities in the world; thus, it also will allow the cryogenic unit to demonstrate the ability to pump its bottoms stream for geosequestration.

The operational objectives of the CDP include the demonstration of processing of higher volumes of gas under a variety of operating conditions and with a wide range of CO_2 and H_2S content representative of the worldwide areas where there is need for and potential applicability of the technology. These data will allow the establishing of scaleup parameters and the development of process-, equipment-, and mechanical-design information that will enable the design and operation of up to 1-Bscf/D-range cryogenic facilities. The feed gas to the pilot-plant unit did not contain H_2S. In a commercial application, the stringent product specifications (less than 4 ppm of H_2S) will drive the design of the rectification sections (reflux rate and number of stages) for sales-quality gas, while the 50-ppm-CO_2 specification for LNG-feed quality is likely to continue driving the rectification design for LNG-feed applications.

Conclusion

The cryogenic technology involves a simpler single-step process for the separation of acid gases from methane. It imposes no limitation on the amount of CO_2 or H_2S present in the feed gas, providing economical processing of very-sour gases. The acid-gas components are discharged as a high-pressure liquid stream, providing economical reinjection of this stream, for geosequestration or for EOR purposes. Integration of this technology with acid-gas injection provides an alternative to sulfur plants for H_2S disposal. **JPT**

Efficient Conceptual Design of an Offshore Gas-Gathering Network

Offshore gas-gathering networks require large capital investments in wells, subsea equipment, pipelines, and compression systems. A thermal/hydraulic integrated-production model (IPM) was used to evaluate many design options for such systems. IPM calculations were performed to establish the phasing of drilling, field development, and compression necessary to sustain required gas-delivery rates.

Introduction

Conceptual design in the upstream industry can confirm if a project concept is economically feasible and then directs later design stages toward an optimal design. Many options must be analyzed to find workable solutions and highlight the potential of new technologies. With new developments in harsher environments and with fluid properties becoming more difficult, the possible use of a traditional tieback solution decreases and the need for new technologies increases. Consequently, a multidisciplinary approach to concept design is beneficial because disciplines such as drilling, flow-assurance, process, and corrosion engineering may influence feasibility as much as traditional subsurface factors. The difficulty is keeping the disciplines aligned with each other. This is particularly difficult during conceptual design when the rate of change is usually at its greatest.

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 116593, "Efficient Conceptual Design of an Offshore Gas-Gathering Network," by ***M.J. Watson,*** *SPE,* ***N.J. Hawkes, P.F. Pickering,*** *SPE, Feesa, and* ***L.D. Brown,*** *ConocoPhillips, prepared for the 2008 SPE Asia Pacific Oil & Gas Conference and Exhibition, Perth, Australia, 20–22 October. The paper has not been peer reviewed.*

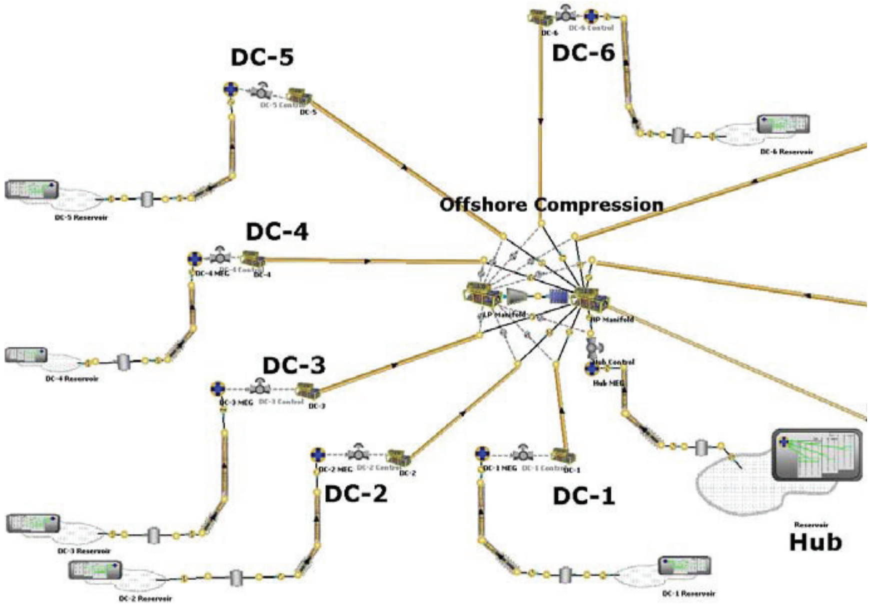

Fig. 1—Screen shot of the offshore gas-gathering-network model.

The system of interest is a large gas-gathering network with multiple drill centers. Although common, these fields are in a region with extreme ambient-temperature conditions where the annual window for drilling is comparatively short. A key objective was to investigate the development plan for offshore facilities within which the drilling schedule could be "stretched out" while maintaining the required gas-production rates.

The model for this study is shown in **Fig. 1.** It consists of eight small gas reservoirs (DC-1 through DC-8), individually tied back to an offshore processing and compression facility on a larger reservoir (the Hub), which is approximately 150 km from an onshore processing facility. Production commences with wells at the Hub. When production from the Hub field declines below the capacity of the processing facility, satellite fields are brought on successively. When compression is required, the wells are switched from a high-pressure (HP) to a low-pressure (LP) manifold in a manner to meet production targets and minimize compression horsepower.

Modeling Method

The system was analyzed with an IPM technique, a single simulator capable of predicting the behavior of the entire production-system network, from the reservoir to the onshore processing facilities. The simulator is a thermal/hydraulic IPM, rigorously conserving mass, momentum, and energy across the network; therefore, temperature is predicted accurately in addition to the prevailing pressures and flow rates. This method, combined with compositional tracking, enables accurate prediction of thermophysical properties, by use of an interface to the pressure/volume/temperature package and with the simultaneous calculation of flow-assurance issues, such as hydrate

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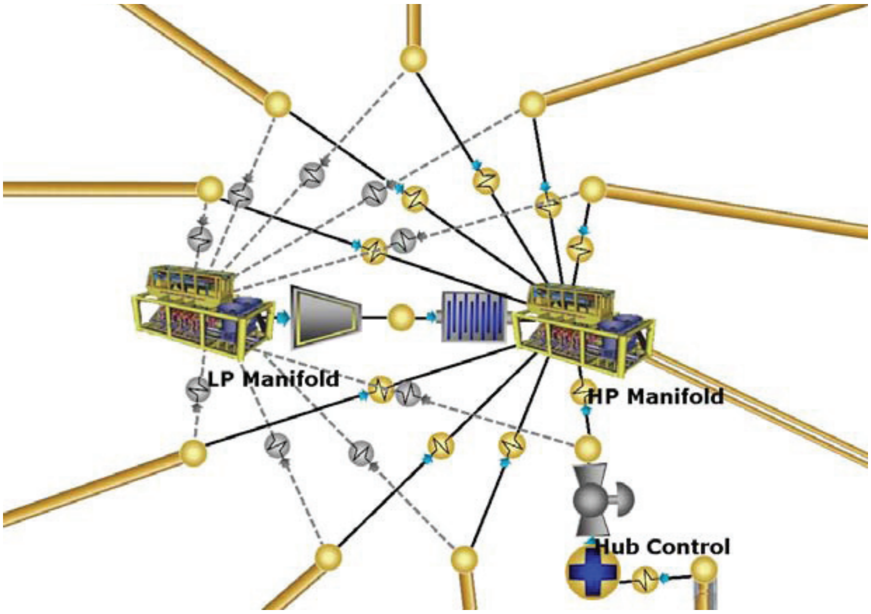

Fig. 2—Simple offshore-compression-system model.

formation. Therefore, the production profile is predicted by balancing the pressures and flows in the network, subject to the hydraulic potentials of its components plus any user-imposed rules, such as setting the maximum flow rate through a choke or carrying out a set operating procedure if a particular event occurs.

To perform simulations, the simulator uses an equation-oriented numerical technique. The IPM simulator has two reservoir descriptions: a material-balance method based on a 1D tank model and a lookup table containing reservoir-depletion characteristics defined by the subsurface discipline. In this study, the reservoirs were modeled with the lookup-table approach with simple pressure-vs.-cumulative-produced-gas decline curves. At each timestep, the composition of the produced gas was saturated with water at constant reservoir temperature, but with declining reservoir pressure.

As the reservoir pressure declined, the mole fraction of water in the gas phase increased, which in turn increased the aqueous-phase-flow rates in the flowlines over time. Similarly, the hydrocarbon composition of the fluid also changed over time, and the completions were assumed to be in a gas zone; hence, once a reservoir entered the retrograde region and condensate began to drop out, the condensate remained in the reservoir, yielding a leaner produced-gas composition over time.

The IPM simulator allows up to ten phases to coexist in the network simulation, including three hydrate phases, wax, and ice. Hence, the precipitation of solids can be predicted and, provided the user has entered appropriate events, flow-assurance procedures can be carried out during a simulation. Hydrates and ice were the main flow-assurance concerns in this system; therefore, continuous glycol injection at the wellheads was implemented to prevent solids from forming and causing blockages.

A mechanistic multiphase model was selected to simulate the hydraulic behavior of the gas wells. Over the life of the wells, the flow regime is between annular and churn (froth). To manage wellhead pressure best, which is critical for gas-well delivery, the flowlines were permanently in stratified flow.

It is preferable to operate the system at a rate above the critical rate to prevent liquid accumulation and limit the size of onshore slug catchers. Hence, it is desirable to predict the liquid-holdup curve as a function of flow rate and the position at which liquid holdup begins to increase markedly with reducing flow rates.

In this assessment, the critical flow rate is between 450 and 600 MMscf/D. If the twin export flowlines are operated at rates below this critical rate for several weeks, the liquid volumes generated could cause significant operational difficulties. These difficulties could arise when the flow rate is increased and the large liquid volumes are swept out and arrive as a large liquid surge at the onshore processing facility.

In addition to uncertainties with the modeling methods (e.g., magnitude of interfacial friction between the gas and the liquid), other uncertainties affect the predictions and, therefore, hydraulic-related risks. One such uncertainty is the effect of flowline topography, which is often poorly defined at the time of concept selection. For this study, only coarse elevation profiles were available. The actual geometry will be considerably more complicated and will follow a smooth curved path through the known elevation points. A series of geometries was generated for different undulation assumptions. Sinusoidal waves of various amplitudes and wavelengths were superimposed on the straight-pipe geometry. Even these small-amplitude sinusoidal undulations are sufficient to change the location of the minimum turndown flow rate by approximately 200 MMscf/D.

During concept development, it is important to identify limit-state requirements for the system that are based on the range of definition available. In this case, the production system should not operate either pipeline at less than 700 MMscf/D. Without defining the sensitivity range, 500 MMscf/D might have been used as an acceptable operating limit. The range of operating limits can have significant design and availability risks for the offshore-production and onshore-process-concept selection.

Fig. 2 shows the offshore compression system. The process system includes a single compressor with its cooler, and two manifolds (LP and HP) together with a network of manifold pipe work. The routing of gas from the various fields to either the LP or HP manifolds is controlled with user-defined logic. The primary objective was to establish the magnitude and timing of the offshore compression systems by optimizing the producing center and production availability.

Well/Production Availability. Access to the site for drilling wells had seasonal limitations. Phased production and drilling were important criteria for concept selection. The logical scheme developed for the model was as follows:

1. Gas was produced from the Hub reservoir at 900 MMscf/D as soon as six wells were predrilled.

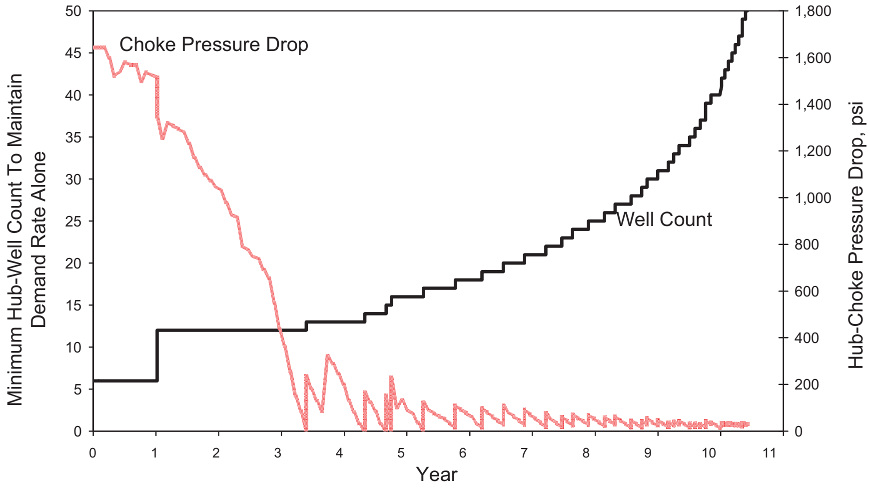

Fig. 3—Diminishing returns from incremental wells on Hub facility, without compression.

2. An additional six wells would be available at the offshore Hub facility 1 year after startup. The onshore process facility would be ramped up to its full 1,800 MMscf/D capacity.

3. In these early years, gas from the Hub flowed directly into the export pipelines (i.e., no offshore compression is required). Glycol was injected at the Hub to avoid hydrate and/or ice conditions in the export flowline.

4. The maximum well count at the Hub is determined before offshore compression and/or additional tiebacks become more economic.

5. Just before the system drops off plateau production, the Hub wells are directed to the LP manifold and compression is used to maintain 1,800 MMscf/D production.

6. The timings of the drilling sequence for the subsea centers and compression requirements were key evaluation criteria for the IPM. Initially, production from all new satellite fields was directed to the HP manifold.

7. When the system's production rate declined below the onshore process requirements, the DC-1 wells were directed first to the LP manifold, where the pressure again was balanced to optimize compressor power.

8. If the compressor power requirement was exceeded and the system was about to drop off plateau, the next satellite field, DC-2, started production to the HP manifold.

9. Then Steps 5 through 8 are repeated to bring on DC-3 through DC-8 and switch them from the HP to the LP manifold, accordingly. The tradeoffs between offshore-compression power and timing, HP/LP manifold-pressure definition, well availability, and subsea-center availability were core concept-definition requirements.

Results

Once 12 wells had been drilled on the Hub, further wells could be drilled to delay the need for offshore compression. The first stage was to investigate the diminishing returns caused by adding a new well on the Hub every time production was about to drop from the target rate when producing to the HP manifold, up to a maximum of 50 wells. **Fig. 3** shows the minimum Hub-well count required to maintain the demand rate (900 MMscf/D in the first year and 1,800 MMscf/D thereafter). For reference, the pressure drop across the Hub-well chokes and into the HP manifold is shown. The value of increasing well count at the central Hub declined because of the ever-declining reservoir pressure. For example, in Year 4, fewer than one new well is needed each year; between Years 6.5 and 8; more than three new wells are needed each year; and between Years 8 and 10, eight new wells are needed each year.

An offshore-compression-power sensitivity study was carried out ranging from 0 to 60 MW, in 15-MW increments. The greater the offshore-compression capacity, the longer the delay between new satellite fields starting up. The first 15 MW delayed the offshore-compression need by 1.5 years. An additional 15 MW added another 6 months to the delay. An additional 15 MW (i.e., 45 MW total capacity) added only 4 months to the delay. However, the first 15-MW addition reduced the need for three subsea drill centers (DC-6, DC-7, and DC-8) to meet the production profile. These three subsea centers represent 12 subsea wells. A 30-MW total capacity delayed the requirement for DC-5, which represents four subsea wells. Adding compression capacity beyond 30 MW to meet the production-life requirements did not eliminate the need for additional subsea wells. Therefore, the asset value increased for 30 MW of offshore compression, but additional value was limited for compression greater than 30 MW.

Determining the optimal offshore-gas-compression capacity required economic analysis of the system to compare the relative costs of various drilling rates, the offshore-compression capacity, and the relative values of the gases from each satellite at the various condensate/gas ratios generated during production. There was a diminishing return upon increasing the compression power beyond 30 MW. The deliverabilities of the tubing and tieback flowlines are nonlinear with the offshore LP-manifold pressure. As the pressure was reduced, the gas velocity increased, and the frictional pressure drop increased nonlinearly with gas velocity.

Conclusions

IPMs enable investigation of hundreds of development strategies and the effects of key design variables (such as drilling schedule, tubing/pipeline sizes, production capacity, and artificial lift) on the revenue stream. Even with significant uncertainties in the base data, such studies can improve later design definitions and highlight the technical-definition range that must be used to increase value.

However, technical issues associated with new developments are often complex, because of the nature of the fluids, field location, or novel technologies required to make these developments economic. Recent numerical methods (such as the equation-oriented approach) enable use of IPMs with the same level of rigor as traditional flow-assurance or process-system investigations. Issues of concern to other disciplines can be accounted for during the production-profile generation, reducing the number of design iterations and reducing the number of unnecessary design assumptions. **JPT**