Innovative Solutions Enable Production Start of China's First Marginal Subsea-Tieback Oil Field

Mao Jiayou, CNOOC Ltd.

Summary
Liuhua4-1 (LH4-1) oil field is located 215 km southeast of Hong Kong in the South China Sea. The field was first discovered in 1987, but because of economic and technical challenges, it was not until 2012 that the development of this field became a reality. The 300-m-water-depth oil field was successfully tied back to an existing oil field [Liuhua11-1 (LH11-1)] through subsea pipeline, power cable, and multiplex control umbilical. The project executions included disconnection, life extension, and reconnection to the existing oilfield floating-production system (FPS). It was also China's first tieback subsea development project. To develop this marginal oil field, a number of technical challenges were overcome through a series of new technologies, and their successful development and implementation.

Introduction
The LH4-1 oil field is located in the Pearl River mouth basin at central rising Block 29/04. It is 11 km northwest of the LH11-1 FPS (Zuan et al. 2013). The confirmed geophysical reserves are approximately 3.0×107 m^3, and the water depth ranges from 260 to 310 m. The field facility is designed for 20 years of service life, with 15 years of field economical life.

The oil field uses a set of subsea production systems through subsea tieback to the existing LH11-1 oil field. The subsea-production systems comprise eight subsea horizontal wells, each completed with a downhole dual-electrical-submersible-pump (ESP) artificial-lift system. One of the wells is a multilateral well with a smart completion. Seabed equipment includes eight subsea horizontal trees rated for 5,000 psi and a central production manifold. Individual wells are commingled to the production manifold through 6-in. vertical jumpers. The outlet of the production manifold is connected to the subsea pipeline through an 18-in. vertical jumper. The fluid is then pumped through an 11.7-km 18×22-in. pipe-in-pipe subsea-pipeline system with inline pipeline-end terminations (PLETs) on either end. A bridging manifold is installed on the subsea side of LH11-1. The function of the bridging manifold is to receive fluid from the LH4-1 pipeline and existing LH11-1 subsea-production system. The mixed fluid is then transported through two LH11-1 existing subsea flexible flowlines to the floating production, storage, and offloading (FPSO) system Nanhai Shengli for processing and storage. The overall LH4-1 and LH11-1 oilfield layout is illustrated in **Fig. 1**.

The LH4-1 subsea control uses an electrohydraulic multiplex control system. The topside control system is located on the LH11-1 FPS Nanhai Tiaozhan. The primary topside equipment includes the master control station, the electrical-power unit, the hydraulic-power unit, the topside-umbilical-termination assembly, and the chemical-injection skid. Hydraulic control fluid, electrical-control power and signal, and chemicals are transmitted to subsea equipment through a multiplex umbilical that is 14 km in length. The subsea end of the umbilical is connected to a subsea-distribution unit. Electric and hydraulic flyleads distribute control signals and fluid to individual wells, respectively. The hydraulic side of the umbilical is composed of seven flexible hoses that are each ½ in. in size. The electrical side of the umbilical has three electrical quads. Each quad has four copper cores, which make up two loops, and each loop controls four wells, so that one quad is enough to control all eight wells. Power-line-communications technology was selected as the electrical-control methodology.

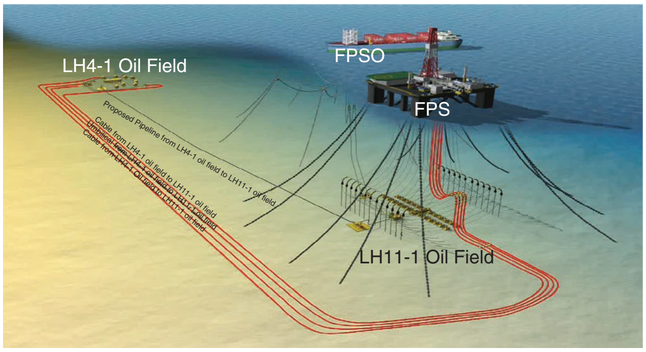

Fig. 1—LH11-1 and LH4-1 oil field layout.

The downhole ESPs are also driven from the FPS. The electrical power travels through the variable frequency-drive (VFD) on top of the FPS, through three of the 14-km subsea power cables, and then down to the subsea-power-distribution unit. Each power cable is composed of nine cores. Every third core controls one well, so each cable is capable of powering three wells.

The project had two major focus areas. One was to disconnect, dry-dock, upgrade, and reconnect the existing LH11-1 FPS, which had been in service in this field for more than 16 years. The second focus area was the new LH4-1 subsea-production-system tie-in to the existing LH11-1 subsea system.

Project Challenges
The nature of the development brought a number of uncertainties and challenges (listed in the following subsections) to the execution of the project. If any one of these challenges had not been dealt with properly, the entire project might have been a failure.

Challenges Related to the Disconnection, Dry-Docking, and Reconnection of the FPS.
1. Disconnection of FPS umbilicals and ESP power cables: There were 30 cables hanging over the FPS moonpool. In order for

This paper (SPE 170242) was revised for publication from paper OTC 25122, first presented at the Offshore Technology Conference, Houston, 5–8 May 2014. Original manuscript received for review 3 January 2014. Revised manuscript received for review 26 February 2014. Paper peer approved 5 March 2014.

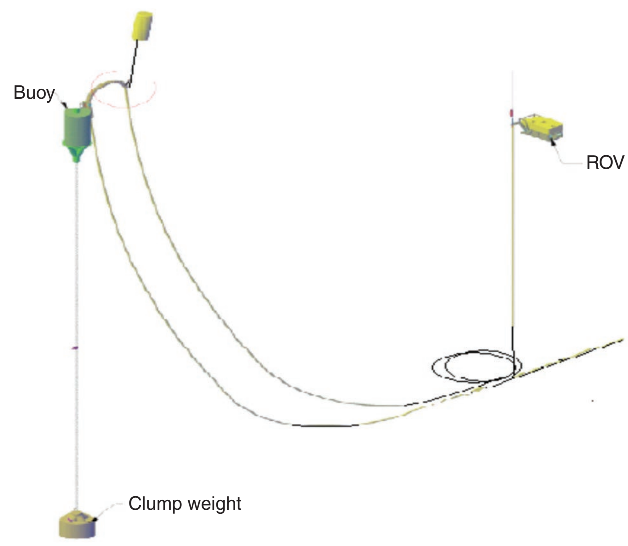

Fig. 2—Abandonment of a single cable.

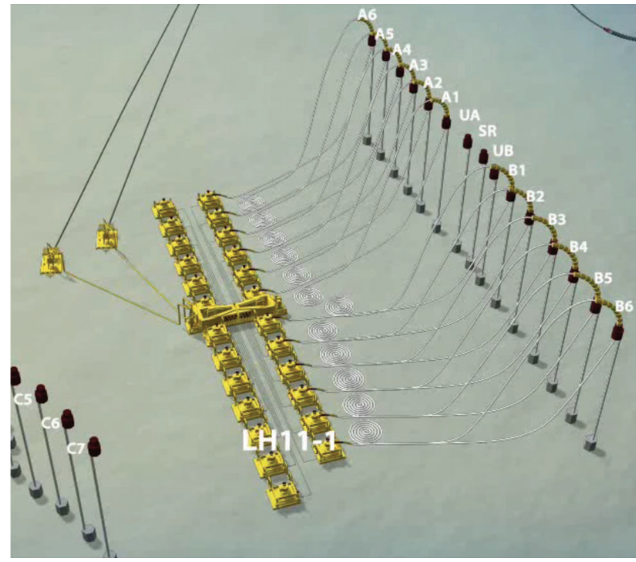

Fig. 3—Final effect with all cables abandoned.

the FPS to dry-dock, the first step was to disconnect these cables; however, this posed a major challenge in regard to time. To save production, a new methodology was developed to temporarily wet store these cables on the seabed instead of disconnecting and recovering the cables one by one to the surface. This new methodology would save a significant amount of time; hence, production, cable sealing, overbending, and laydown sequence were all key issues.

2. Protective disconnection of FPS mooring legs in the winter monsoonal season: The mooring legs were to be disconnected, stored on the seabed during the fourth quarter of 2011, and then reconnected after 5 months. There is little reference anywhere to project experience of FPS disconnection and reconnection; therefore, maintaining the FPS station under harsh weather conditions and effective operation of subsea remotely operated vehicles (ROVs) were major challenges of this operation.

Challenges Related to the New LH4-1 Subsea Tieback.

1. Disconnection and removal of two existing LH11-1 18-in. (diameter), 30-m long jumpers: These two jumpers were installed in 1995, and have been on the seabed for 16 years. Their hydraulic unlock system was no longer operational, and the mechanical-override force proved much greater than theoretical calculation. If the removal of the jumpers failed or if the subsea mating hubs were damaged, then both oil fields would have no means to come back into production.
2. Connecting the new LH4-1 jumpers to the existing LH11-1 hubs: The lack of information for the existing system, the congested subsea space, and the difficulty in passing the back-seal test all presented significant risks to field production.
3. Production-manifold installation encountered unexpected seabed-leveling problems: Drill cuttings and cement buildup in the vicinity of the wellheads seriously affected installation of the manifold to the center of the eight wells.
4. Subsea PLETs on pipeline installation and "stinger-" (S-) lay: The design, manufacture, and installation of PLETs by S-lay were first-time experiences in China. The challenges encountered during the design of the PLETS included the way in which the PLETS would pass through the tensioners, how they would pass by the stingers, and how to avoid problems of overstress on the pipe-to-PLET junction point during pipe laying.
5. Lack of experience by the project team in managing subsea-development projects: Because this was the first subsea-tieback-development project managed by a localized team in China, most team members came from different units within the company, with little or no experience on subsea projects. The majority came from the operations side.

New Technological Solutions

The implementation and development of new technologies and methodologies were central to the success of this project. Some of those implemented were existing technologies that were introduced in China for the first time during this project, and some were new technologies developed by the project team. All were applied to achieve economic effectiveness in the field and to mitigate risks and uncertainties.

New Technologies Related to Disconnection of the FPS. ***Disconnection and Wet Storage of FPS ESP Cables and Umbilicals.*** The LH11-1 FPS had 25 ESP cables, four control umbilicals, and one 2-in. service riser connected from the FPS moonpool to the seabed production system, which was located at a water depth of 320 m. These components had a steep-wave configuration from the FPS hang off down to the middle-water-buoy attachment and from the middle water buoy down to the subsea trees and manifold. Conventionally, the cables need to be recovered to the surface through a set of tools, including a topside reeler system, a treecap retrieval tool, guide wires, and a service-riser retrieval tool. A team of well-workover personnel also needs to be mobilized onboard. The primary concern with this conventional practice is that it takes approximately 48 hours to disconnect one cable, as shown in **Fig. 2.** Thirty cables would take 60 days of continuous work, which would lead to longer production downtime and higher cost. The second concern was that some of the cables had not once been retrieved in the past 16 years, and therefore, subsea disconnection might encounter unexpected difficulties, which would further extend the actual time frame.

The project team designed a more-efficient method of disconnection for the topside only, and temporarily abandoned the cables by coil down onto the seabed (**Fig. 3**). Because the cable pigtail had a set length and could not be cut shorter, a reusable cable-end seal against seawater ingress became necessary. An effective sealing device was developed and tested before being put into use. This device incorperated effective gland packing and was filled with silicon gel. A water-pressure-compensation diaphragm was also included. To avoid overbending movement to the middle-water-buoy cable-attachment bend restrictors, an uplifting buoy was designed and installed to the attachment before cable disconnection. A seabed coiling effect was achieved through rig movement and the assistance of an ROV. During the early stage of development, a storage basket

Fig. 4—FPS disconnection in harsh weather.

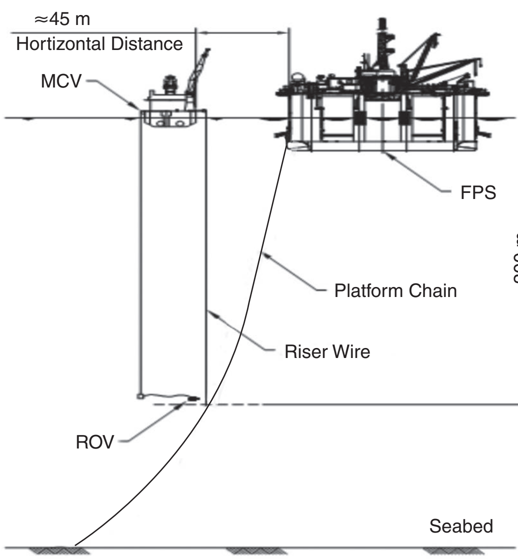

Fig. 5—Mooring-leg disconnection. (MCV=multipurpose construction vessel.)

was also considered, but was finally decided against for purposes of saving time.

Protective Disconnection of the FPS Mooring System. The FPS mooring system was an 11-point permanent-spread mooring (Zhong et al. 2013). Each mooring leg exited from the FPS chain windlass with a 4¾-in. platform chain. Below the platform chain was the in-water riser wire (503 m in length), followed by a 5½-in. ground chain, which was laid on the seabed. The disconnection process was to cut the last link of the platform chain, lay the riser-wire section onto the seabed, and then recover the platform chain with the windlass. Because of the unpredictable weather conditions in the later part of October in the South China Sea (with a typhoon still a possibility and with winter monsoonal bad weather becoming stronger), the mooring system was to be disconnected in the shortest possible time frame to lessen the amount of time the FPS would be exposed to weather risks, especially with fewer than four legs left in place. The developmental procedure also needed to consider the protection of subsea-production facilities and the FPS underwater structure (*API RP 2SK* 2008).

Because no reference experiences were available, the project team had to study disconnection procedures themselves. Several methodologies were reviewed, with one being to disconnect and abandon the entire mooring leg, including the platform chain, to the seabed. This would require later recovery and renewal of the platform chain with significant cost impact. Disconnection between the platform chain and the riser wire was selected as the better option, because it avoided recovery of the platform chain from the seabed, instead requiring replacement of the same. The platform chain would be changed out in the shipyard during dry-docking. A further optimization to the actual disconnection methodology was performed. The initial method involved installation of a sheave block at the cutting point with winch wires connected so that, after the chainlink was cut open, both the platform chain and the riser wire could be lowered down in a controlled manner. However, this method required much ROV preparation work, which is very sensitive to weather conditions. The workable time of an ROV is normally less than 50% at that time of year, which would have extended the disconnection time significantly. After careful study, it was decided that the sheave system would not be installed, but that during and after cutting, the riser wire only would be connected to the work-vessel winch wire. The platform chain would be allowed to freefall and swing back toward the FPS, finally left to hang below the FPS by the chain stopper; after this, the platform side would recover all the chains. Before performing this operation, the risks of the platform chain swinging back and hitting the FPS pontoon were assessed fully and a test was conducted. It was concluded that the water resistance would slow down the falling effect and avoid the overswinging effect. Contact energy was limited.

Another concern was the undercurrent (also called the soliton), which is typical in the South China Sea. It is formed as a result of the seawater temperature difference between the surface and the subsurface, coastline, and strait effects. The solitons are strong, steady ripples that can reach speeds of 2 knots. To better control the risk associated with the solitons, a soliton-monitoring device that could provide a 1-hour warning was set up 2 miles east of the platform. The monitoring device was anchored in the water column with a series of current sensors. The data were transmitted by means of satellite and accessed through the internet on a computer.

Fig. 4 shows the actual situation during disconnection. As can be seen from the image, the weather was harsh during the operation, and the soliton effect was severe during disconnection of the last four legs. Operations were halted several times to avoid significant vessel-collision risks during the chain cutting. To reduce the residual catenary tension of the mooring leg, there were instances when the working vessel came within 20 m of the FPS while the vessel winch wire and the subsea ROV were connected to the platform chain. **Fig. 5** shows details of the disconnection of a typical mooring leg.

New Technologies Related to the New Field Tieback. ***Removal of Existing Jumpers.*** One of the key steps in tying LH4-1 back to LH11-1 was to remove two existing 18-in. jumpers (red dotted line in **Fig. 6**) from LH11-1 and to install four new jumpers (solid red line in Fig. 6) that would connect the LH4-1 bridging manifold to the existing subsea hubs.

The existing jumper connectors were Torus hydraulic vertical connectors, which could be unlocked by means of a built-in hydraulic system or which could be unlocked mechanically by overpull to the override mechanism. Because the hydraulic unlock system had been in service for more then 16 years, the system malfunctioned, and the combination of marine growth, scale buildup, and deformation of the 30-m jumpers made the unlocking operation very difficult. Different methodologies were attempted, including a hydraulic jacking tool, comprising crane lift and jacking-tool operation, which was specially designed for the operation. This tool provided a stable hydraulic uplift force, which was more stable compared with the vessel crane-hook lift. Decoupling of the two jumper connectors by means of subsea cutting physically eliminated the long-jumper deformation effect.

For structures in deep water, there is not much that can be done in the event that something goes wrong. Because the connectors did not disengage at the designed force, we had to assess the strength limit of each connector component to decide the maximum forces that could be applied. The final disconnection was achieved with a maximum uplift force three times that of the calculated disconnecting force as determined by the connector manufacturer. The connectors were removed, and the subsea side hubs were cleaned and inspected. Later, new jumpers were installed to the existing hubs. Some of the connector seals failed at first; however, after careful cleaning of the hub and installation of new seal rings, all connectors passed the pressure test.

Inline PLET Design and Installation. The LH4-1 subsea flowline is an 18×22-in. pipe-in-pipe system. Both ends of the pipeline are equipped with PLETs that were to be installed with the pipeline S-lay. Critical questions surrounding the installation were the dimensional limitation of the pipeline tensioners and the stress and fatigue problems encountered when the PLETs rest on the stinger. The design of such a PLET was a first for the China design team. In order for the PLET to pass through the vessel tensioners, it was designed in two pieces—the base and the PLET. The PLET was designed with foldable wings that would remain folded when on the vessel and then would unfold in the middle water (**Fig. 7**). To solve the height limit, the PLET hubs were welded at the vessel back deck after the PLET passed through the tensioners. The welding duration was strictly controlled to avoid a problem with pipe fatigue. An antirotation method was used to make sure the PLET was in the upright position when landing on the PLET base (**Fig. 8**). A long-baseline system was used for accurate positioning of the PLET base and the PLET itself.

Long-Distance Power-Supply System for Downhole Dual ESPs. According to previous experience, the average running life of an ESP is approximately 3.5 years, which means that every 3.5 years, one well may need workover to change out the ESP. It can be very expensive for a satellite oil field to mobilize a drilling rig for a pump change out. Dual-ESP technology allows for one pump to be on duty while another pump is on standby. Therefore, if the original duty pump fails, the standby pump can be switched on remotely from the platform central control room. According to simulations and previous field experience, the mean time between failures for a dual-ESP system in one well is 5 years. This can enhance production uptime.

The tubing hanger in the dual-ESP system is a special design, with double power penetrations built in. The tubing hanger used for this project marked the first time such technology had been applied in Asia. Additionally, the subsea high-powered changeover switch that formed part of the subsea-tree cap was a hydraulically actuated high-voltage switch over. This was the first industrial application of such technology in China.

Long-Distance VFD Power Transmission. For this project, the subsea power cables were 14 000 m, the downhole ESP cable was approximately 1000 m, and the total power-transmission length was more than 15 000 m, which to our knowledge, was the longest VFD in the world.

In normal short-distance transmissions, such as LH11-1, the VFDs are voltage type. However, for long-distance transmissions, the high order of resonance becomes overlapped and amplified to such a degree that it will seriously affect the quality of the power source to the downhole pumps, which can cause the pump runs to become unstable. LH4-1 uses the current type of VFD, which can solve this problem. The power component used is called a symmetrical gate commutated thyristor, which is the best in the market. Because the VFD is a high-frequency drive, there is no need for step transformers, which saves valuable space on the existing platform.

The Application of a Simplified Landing String. In normal operations for well completion of subsea wells, a fully functioning subsea-test tree (SSTT) is standard tooling. The SSTT is a single source worldwide, requiring operators to rent this tool system during completions. This is a very expensive and complicated operation, with an estimated cost of USD 2 million to complete eight wells. Because of China's customs policy, the temporary importation and exportation process would be complicated and time consuming, taking on average more than 3 months to import and export the SSTT, with a significant cost burden.

On the basis of past well-completion experience for a known low-pressure field, it was worth the time to try an alternative and simplified method of well completion. Therefore, a simplified landing string was designed and manufactured by a subsea-tree manufacturer. It was a simple operation, and the development cost was approximately two-thirds the cost of the SSTT rental. Additionally, because this landing string belongs to the project, it will benefit future workovers.

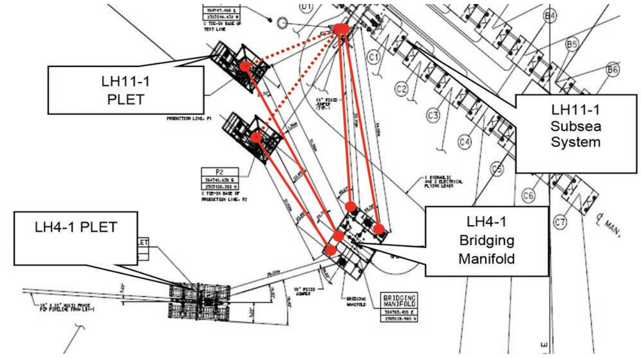

Fig. 6—Jumper removal and installation.

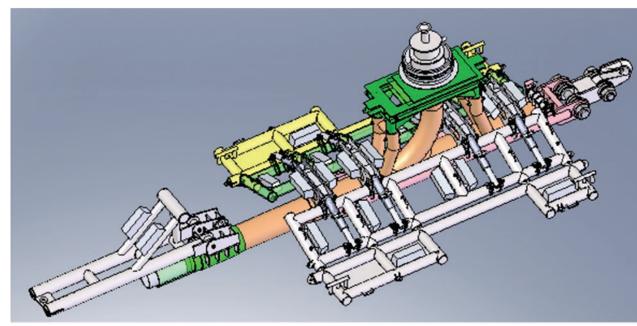

Fig. 7—3D model of foldable PLET.

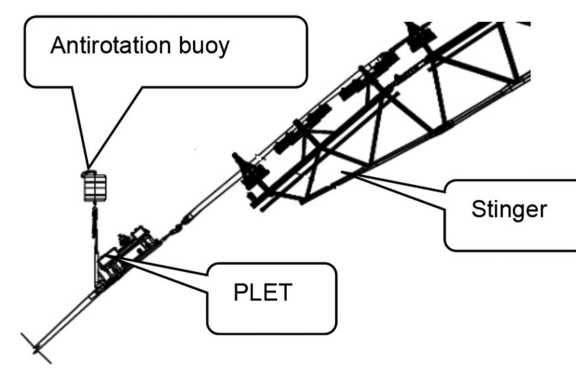

Fig. 8—PLET over stinger.

Fig. 9—Subsea pigging setup.

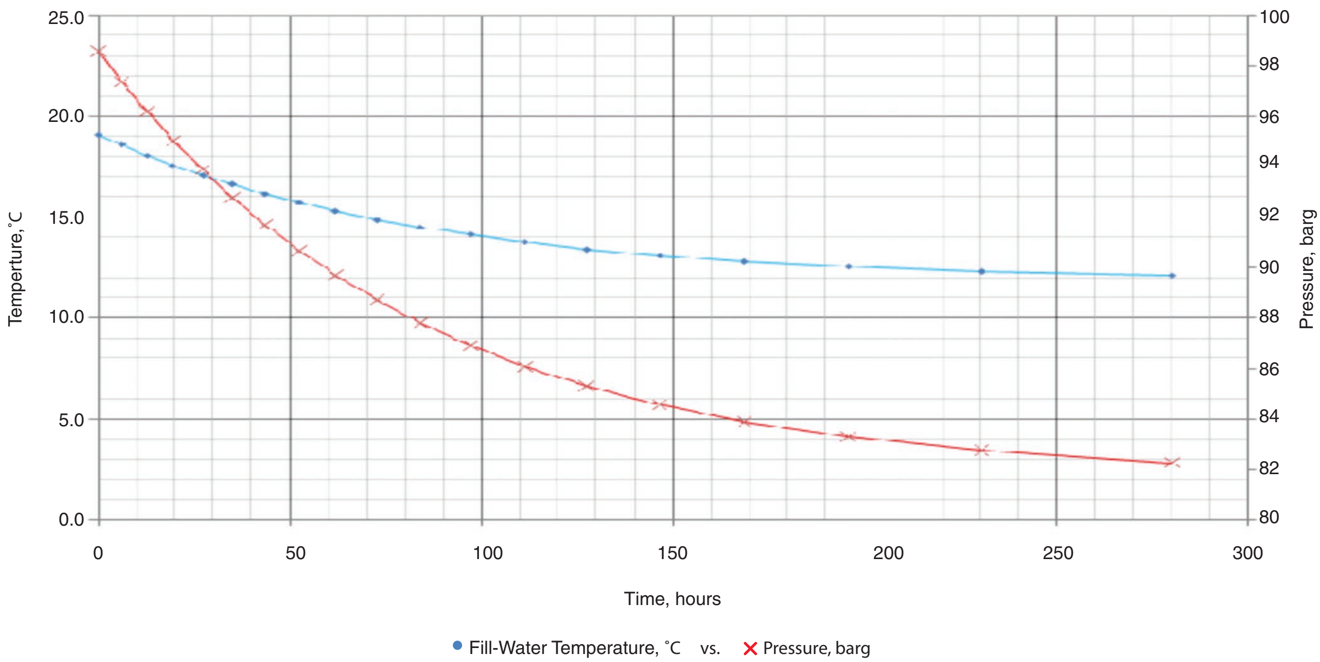

Fig. 10—Temperature/pressure curve.

Subsea-Flowline Pigging and Hydrotesting. Both ends of the LH4-1 subsea flowline are located on the seabed. The pigging and hydrotesting process for this type of flowline is quite different from that for a normal jacket fixed platform, which can be performed from the topside. This type of pipeline had to be pigged and hydrotested by means of a subsea pig launcher and a subsea pig receiver and by subsea hydrotest connectors. **Fig. 9** shows the subsea pigging setup used for this project. Again, this was the first application of such a system in China. All operations were performed by means of ROVs. For pigging operations, traceable pigs were used and a subsea-pig-arrival indicator was also used successfully.

For hydrotesting, the pipeline was a pipe-in-pipe insulated system, while the testing water was pumped in from the sea surface. The temperature difference between the surface and subsea was 12°C. According to the calculations, the temperature-equalization time inside the pipeline would be approximately 14 days. During the entire equalization period, the hydrotest pressure would also change with water temperature. The required acceptance criterion was a pressure drop less than 0.5% over 24 hours. It was highly uneconomical to have the pipeline-installation vessel wait 2 weeks for temperature equalization while hooked up for the hydrotest. Hence, an alternative acceptance criterion was to be set up and agreed upon by the contractor, the owner, and a third party. This alternative was to take into account the temperature effect by calculating the pressure/temperature curve and then comparing the pressure curve from the actual test with the calculated curve (**Fig. 10**). If both were in line for the first 24 hours, then the criterion was considered to have been met. This was agreed upon and exercised successfully, saving 13 days of vessel time, which equated to a cost savings of USD 5 million. The project-completion time was also reduced by 13 days.

Conclusions

The LH4-1 subsea development was the first subsea project managed by a localized project team. Because of the tieback-to-brownfield nature, the project team faced some major challenges, including the installation of pipeline terminations, hydrotesting of the pipe-in-pipe system, and VFD control over a long distance. Innovative solutions were required to allow for a cost-effective and safe removal and life extension of the FPS. Through such innovative solutions, these challenges were overcome successfully, and the field achieved first oil on 16 July 2012, 15 days ahead of the project target.

Recommendations

1. Subsea tieback into an existing oil field could encounter significant risks and uncertainties. These are to be fully analyzed and documented, with contingency measures in place before actual operation.
2. Workable weather-window selection should be integrated into the overall project schedule. For the South China Sea, performance of mooring-system operations is preferrable from May to June because, from July to October, typhoons pose a significant risk to the operation itself and to the schedule. From November to April, the winter monsoon season allows for a workable time frame of less than 50%.
3. Effective and timely communication with the third-party certification agency during design analysis and procedure optimization will help reduce costs and save time for the project.

Acknowledgments

The authors would like to thank all parties involved in the Liuhua field development for their permission to publish this paper. The authors also thank all the team members for their hard work and cooperation to make the project become a successful reality.

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Mao Jiayou serves as a project manager for upstream capital-expenditure projects with CNOOC China Ltd., Shenzhen. He is a certified project-management professional and holds an MS degree in mechanical engineering from Harbin Institute of Technology, China.