

## Chapter 2

# Platform Integration and Stationing

**Abstract** There are many kinds of platforms designed to be suitable for the specific working environment. For each platform design, there is a best corresponding platform integration method to make the operation safe and cost effective. Discussions in this chapter present various kinds of platforms and the corresponding integration method options. Through discussions with examples, the history of platform concept development and the corresponding platform installation technology are presented with information in certain depth. For fixed platform and floaters, the most used platform integration method is still by heavy lifting for both modularized topsides and integrated topsides. However, the design and fabrication of massive and heavy integrated topsides make the floatover method a better choice. The conclusion can be drawn from the installation activities of real projects carried out at different time along the offshore industry history.

In offshore industry, activities in offshore oil field need equipment be on site temporarily or permanently including platforms of both drilling and production. In this book, the word of “station” is used as a verb to mean putting the platforms to a position in the ocean ready for operations. To keep the platform at a selected spot with the constraint of moving horizontally is thus called stationkeeping. There are various ways to achieve stationkeeping of a platform. In water not so deep, fixed platform, compliant towers and jack-ups are directly standing on the sea floor through structures as jackets and legs by which the motion of topsides is under control. GBS including Condeeps sit on the sea floor and keep themselves at the spots by their heavy weight. For floaters like FPSOs, drilling semisubmersibles and drilling ships, DP (Dynamic Positioning) systems can also apply. TLPs station by high-tension tendons, while most of the FPSOs, semisubmersible production platforms and spars station by mooring systems. As we already touched the topic of platform design and construction, and clearly that for non-FPSO platforms, the topsides and the substructures are generally fabricated separately and then be integrated together. For some cases, platform integration happens before it is stationed in the field, but for others, the substructure is first stationed in the selected

spots and then the topsides is integrated with the substructure on site as already briefly talked in the earlier chapter.

The focus of this chapter is neither on the DP systems nor on the FPSOs. The discussion will be on various kinds of operations for platform integration and the methodology corresponding to the platform integration operations. Discussions in certain level of depth in this chapter present various kinds of platform integration methods. Some discussions go with examples and the rest of them are only at the introduction level. Hope that the materials presented show the spectrum of platform integration methods including the well-known heavy lifting and floatover methods. Floatover method is the core of this book and all discussions with technical details will be concentrated in the following chapters.

## 2.1 Self Installable Platform

The meaning of “self-installing” in this section is that the topsides and the substructure of the platform are physically already combined into one before the platform is stationed to the selected location at the field. The substructure generally consists of movable legs attached to the topsides. When the platform arrives at the pre-selected location in the field, the supporting legs will lower down to the sea floor. The legs will then anchor the platform in the location and support the topsides. Through further adjustment the topsides, the air gap reaches the design value and the platform is ready to serve. The whole installation process may need assistance of installation vessels such as OCV (Offshore Construction Vessel), AHT (Anchor Handling Tug), although the “self-installation” is applied.

The self-installable platform concepts are generally suitable to the shallow water and platform with smaller topsides, some platforms developed with these concepts have already been built and in service. However, efforts have extended to the application of self-installation concept in deepwater; one well-known trying was the Technip’s TPG 3300 and later evolved into EDP (Extended Draft Platform), which will be introduced briefly in this section. One of the intentions of developing these concepts is to create the advantage of relocating the platform during the service life. The design makes the relocation of the platform less complicated and cost effective.

A few concepts of self-installed platforms are introduced in this section: jack-ups, SPT (Suction Pile Technology)’s SIP (Self-Installing-Platform) II platform F3-FA and Technip’s EDP concept.

### 2.1.1 Jack-Ups

The Jack-up platform sometimes called “self-elevating” platform is no stranger to the Oil & Gas industry and started to serve the offshore industry since 1950s [1]. A Jack-up platform, also called Jack-up rig or Jack-up barge, works mainly in the

shallow water, some can go to the depth of 150 m and at most 190 m. The Jack-up concept distinguishes itself from other platform concepts by the characteristics of mobility and self-elevating capacity. So far, only a few Jack-up platforms in service are production platforms such as BP's Shah Deniz TPG500 platform in Caspian Sea [2, 3] (Fig. 2.1).

However, more of the jack-ups serve as drilling rigs and offshore supporting vessels including the ones carrying out offshore wind turbine installation in recent years. As an offshore drilling platform, jack-up platform can be moved to the drill site and quickly stands on the seabed by the legs lowered using onboard equipment and thus ready for the new well drilling (Fig. 2.2).

The first Jack-up platform was a drilling rig with three legs design by LeTourneau. The contract was signed on November 11, 1954. The platform was basically a large, shallow-draft barge, equipped with three electromechanically-operated lattice type legs. The construction of the platform was completed in December of 1955 and started the first drilling in March 1956 (Fig. 2.3).

The speed of reposition for new well drilling of Scorpion quite impressed the industry at that time, comparing only a few hours to days for other type of platforms. Jack-up platforms especially jack-up drilling platforms have been the most popular among various kinds of floating offshore structures in existence (Fig. 2.4). In the worldwide offshore rig fleet, there are more jack-up drilling platforms than MODU (Mobile Offshore Drilling Unit) such as semisubmersible drilling rigs and drilling ships. The total number of jack-up drilling rigs in the world was about 540 at the end of 2013.

There are many different designs of jack-up platform. However, the three (3) most important components are necessary, which are the water-tight floating hull providing required buoyancy for transportation, the supporting legs and the jacking systems lowering/lifting the legs when needed. Jack-up drilling platforms in earlier years had square or rectangular hulls with more than three legs, the earlier designed jack-up rig Mr. Louie in the North Sea even had sixteen legs. Most of the modern jack-up hull are triangular and with three lattice legs [4, 5].



**Fig. 2.1** BP Shah Deniz TPG500 production platform which is a Jack-up with 3 legs (courtesy of BP and Keppel Group respectively)



**Fig. 2.2** On the *left* is the three leg Jack-up drilling rig JU2000E of COOEC and on the *right* is the Jack-up offshore supporting vessel *Innovation* with four legs (courtesy of Shanghai Waigaoqiao Shipbuilding and Wikimedia commons respectively)

**Fig. 2.3** The first jack-up scorpion is designed and fabricated by R. G. LeTourneau, Inc. The hull size is  $186 \times 150 \times 24$  ft and the steel legs (spuds) are 140 ft long. The platform weighed 4000-ton (courtesy of Rowan)



**Fig. 2.4** On the *left*, it showed two different designs of jack-up drilling rigs waiting in Fourchon channel—one with *triangular* hull and lattice legs and the other with four columnar legs and a *rectangular* hull; The *right* photo is the British jack-up drilling rig with ten legs (Sea Gem) (courtesy of Houston Chronical and Duke Wood Oil Museum respectively)

The jack-up platforms including drilling rigs and production platforms can be moved with legs being jacked up in the air and the hull floating on the water surface by wet tow. However, most of the relocations were by dry tow using semisubmersible HLVs. The jack-up platform are floated on and sits on the deck of the submerged HLV and then being lifted up and transported to the new service stationing location (see Fig. 2.5). When choosing the vessel for dry tow, transportation stability need to be strictly checked along the selected route and the operation weather window. Not only the total weight is important, the COG of the jack-up platform is also critical since the legs are quite long and naturally the COG of them are high.

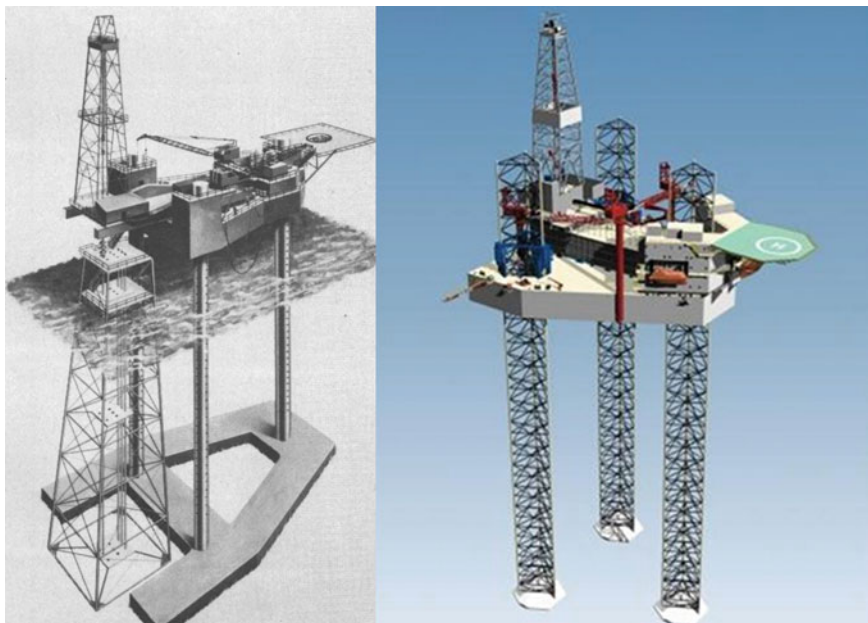
At the offshore site, as the hull still in the water providing buoyancy, the legs lowered down towards the seabed to set up the supporting foundation. The foundation is formed not merely by the legs themselves, but also including either the supporting mat attached to all the legs or one spud can be connected to a corresponding leg at its bottom (see Fig. 2.6). By these specially designed structures, a jack-up platform can stabilize itself with only a few feet of sea floor penetration thus make the relocation process much faster.

By using the mat or the spud can, the soil bearing area increases. On the left of Fig. 2.6, it shows a jack-up rig is on a rectangular flat “A” shaped structure with buoyancy chambers, which are flooded when submerge. The mat helps in weight distribution and reduces the bearing pressure on the seafloor. Mat structure are often used with columnar legs with the total weight of the platform not so high. It is not suitable for uneven seafloors or in areas where there are pipelines, boulders or debris on the seafloor [6, 7].

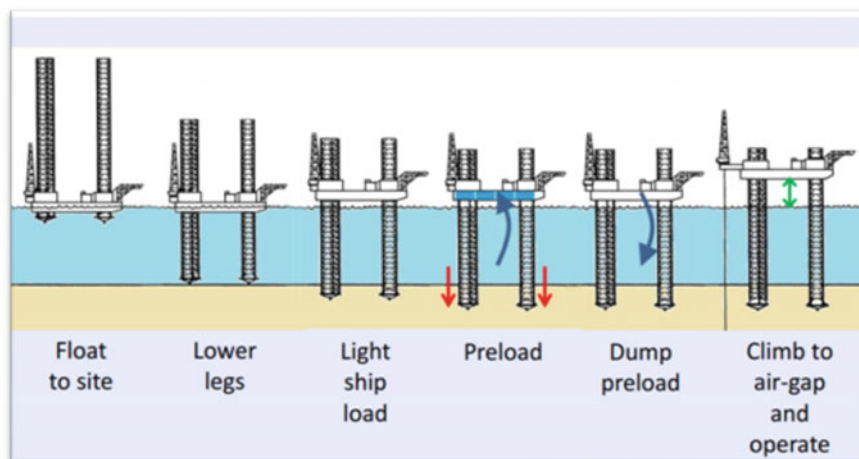
When using spud can for independent legs, the supported jack-ups can operate in regions that are more diverse: in soft and hard seafloor areas, uneven seafloor with slope, etc. For areas with pipelines, boulders or other debris, the position of the jack-up can be adjusted to avoid those obstacles. Spud cans work with lattice legs for most modern jack-up platforms. Figure 2.7 illustrate the stationing process of an independent leg supported jack-up platform.



**Fig. 2.5** Transportation of jack-up platforms: the *left* shows “wet tow” by a tug boat and the *right* one shows “dry-tow” by a semi-submersible HLV (courtesy of COSL and COSCO)



**Fig. 2.6** Leg supporting structures: “Mat” versus “Spud Can” (courtesy of Maritime Communications and CIMC)



**Fig. 2.7** The stationing operation process of an independent leg supported jack-up (after Poulos [8])



From the point of view of platform assembling, only when the topsides is jacked up to the designed working elevation with certain air-gap and locked, the platform is then fully assembled. Only starting from that moment the whole platform is ready to function. This applies to all jack-ups including drilling rigs, production platforms, offshore supporting unit as well as installation vessel for wind turbines. Therefore, the completion of platform integration should be at offshore, although it is generally accepted that the platform has already been integrated and the legs are installed into the hull openings inshore. Following the latter understanding, a jack-up is fully integrated after it left the yard and the stationing operation is the operation of self-installation. During the entire installation, no need of HLCVs and all depend on the hull and the jacking system aboard.

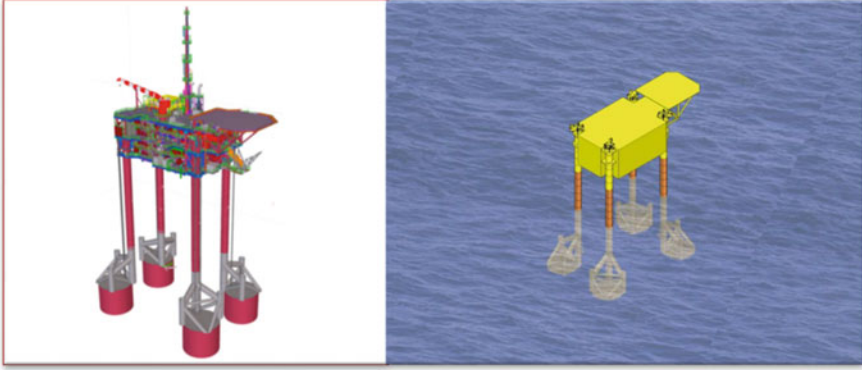
### 2.1.2 SIP II Platform [9]

The SIP II concept was developed by SPT Offshore, a Netherlands' company. The concept emphasizes that there is no need of HLCV during the offshore on-site stationing operation and the platform can be relocated with less complexity for re-use. The self-equipped jacking system can lower down the platform legs, anchor the platform with suction piles connected to the legs, and then lift the topsides up to the required elevation (Fig. 2.8).

Take the F3-FA platform as an example, there were two SIP II platforms built before it [10–12]. The platform has an integrated topsides with 5 level decks and weighing 4000 t. The topsides' dimension is 63 m  $\times$  42 m  $\times$  24 m. It was fabricated and outfitted deck-by-deck using the 'pancake' method at the yard of HFG (Heerema Fabrication Groups) at Vlissingen, Netherland. The substructure consists of four separated legs; each of them is connected to the anchoring suction pile together with a leg-stiffening frame. The configuration of the platform is illustrated in Fig. 2.9.



**Fig. 2.8** SIP II concept platforms: on the *left* is Calder SIP II platform in 30 m water depth in Irish Sea, UKCS; on the *right* is F3-FA SIP II platform in 40 m water depth near Dogger Bank in the North Sea (courtesy of SPT Offshore)



**Fig. 2.9** 3-D view of SIP II platform. The whole platform is already integrated as shown before being transported to the stationing location at the field (courtesy of iv-Gas and Oil and SPT Offshore respectively)



**Fig. 2.10** On the *left*, the fabrication of the 4000 t topsides is completed and moved out from the fabrication hall and ready for the leg installation; on the *right* shown the installation of the legs by the yard crawler cranes (courtesy of Centrica Energy)

After the 4000 t topsides was completed and moved out of the fabrication yard, the four substructure legs are attached to the topsides by the crawler cranes with capacity of 1350 t in the same HFG yard. Each of the legs is 78 m long and 3.5 m diameter and weighs 350 t. By design, each leg would be held by a 9 m long guide sleeve fixed between the top and intermediate deck levels at each corner. A clamp was welded around each leg at the topsides cellar deck level (see Fig. 2.10).





**Fig. 2.11** For each suction pile, the leg-stiffening frame was already welded to it and the assembly was ready to be connected to the platform leg (courtesy of Han Heilig, publisher of Offshore Holland, the Netherlands)

The concept of SIP II, by design, is to connect the legs with corresponding suction piles before the platform to be transported to offshore field, but not on the land.

First, each of the suction piles would be welded with the leg-stiffening frame of tubular members ready for attaching to the legs. This operation is completed on land at the HFG construction yard at Vlissingen and the pile assemblies were ready to be connected to the platform legs, which are already integrated into the topsides (Fig. 2.11).

The connection of the leg and the leg stiffening frame/suction pile assembly is carried out in the water after the topsides being loaded out to the transportation barge, which was BOA barge BB35. Considering the transportation and stationing operation at site including the environmental condition, the grillage on BB35 is 6.5 m high by design and it weighs 850 t. The total weight of the grillage and the topsides with four legs reached 6200 t. To cope with the constraint of maximum bending moment of the hull of BB35, the topsides assembly was first loaded out to the Heerema's barge H-451 and then be moved to BB35 (Fig. 2.12).



**Fig. 2.12** Loadout of F3-FA topsides. On the *left*, it shows the topsides was being loaded out to the transportation barge at the fabrication yard. On the *right* the topsides was first moved on board Heerema barge H-541 and then positioned on Boa Barge 35 (courtesy of ©Heerema Fabrication Group)



**Fig. 2.13** Suction bucket with leg stiffening frame on the top is lifted by Matador 3 and put in position to be connected to the platform leg (courtesy of ©Heerema Fabrication Group)

Then, the suction pile assembly will be connected to the bottom of each leg with the assistance of the sheerleg crane Matador 3 of Bonn & Mees and the strain jacks temporarily installed on the topsides. Each pile assembly weighs 900 t (Fig. 2.13).

The leg stiffening frames together with suction piles are welded to the bottom of the corresponding legs. The frame helps to align the suction pile edge with the leg and make better load distribution. The attachment of the heavy suction piles helps to improve the transportation stability and raise no issues for transportation operation (Fig. 2.14).



**Fig. 2.14** After the leg stiffening frame together with the suction pile is welded to each leg and the platform is ready to sail to the offshore site. It can be seen in the *right* that the whole 13 m long suction pile is submerged in the water (courtesy of iv-Oil and Gas)



**Fig. 2.15** SIP II platform being transported to the field. The limited transportation weather window is  $H_s = 4.0$  m (courtesy of BOA Group)

After all the sea-fastening structures in place, the total transportation weight on the BB35 barge reaches 10,150 t. Thanks to the large and heavy suction piles assembly, the transportation stability was very high—in the real transportation journey when caught by the wave with the maximum wave height of 6 m, the barge's roll angle was less than  $2^\circ$  (Fig. 2.15).

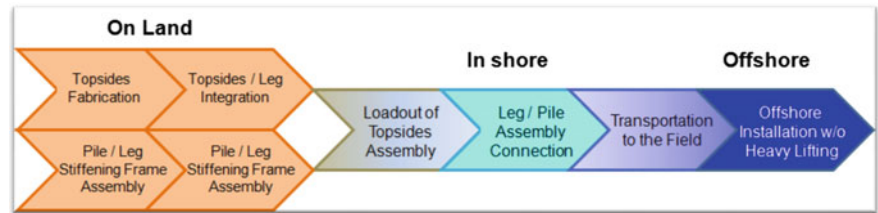


**Fig. 2.16** Stationing operation at site. The center is a photo showing the BB35 with the F3-FA platform aboard during operation. The *left* illustrates the operation of the leg lowering; the *right* illustrates the completion of the F3-FA platform and BB35 being sailing away (courtesy of SPT Offshore)



**Fig. 2.17** The F3-FA platform after the topsides & legs locked. The strain jacks can still be seen (courtesy of SPT Offshore)

Once arrived at the station location in the field, the sea-fastenings on the legs were quickly removed. The legs together with the suction piles were then lowered towards the seabed by the temporarily equipped hydraulically operated strand jacks on board. After the piles reach the bottom of the sea and penetrate the soil about 4 m by its own weight, the pumping system starts to work and empty the water inside the piles. The 13 m long piles will penetrate into the seabed by suction force, becoming the anchors to hold the platform in position and support the topsides

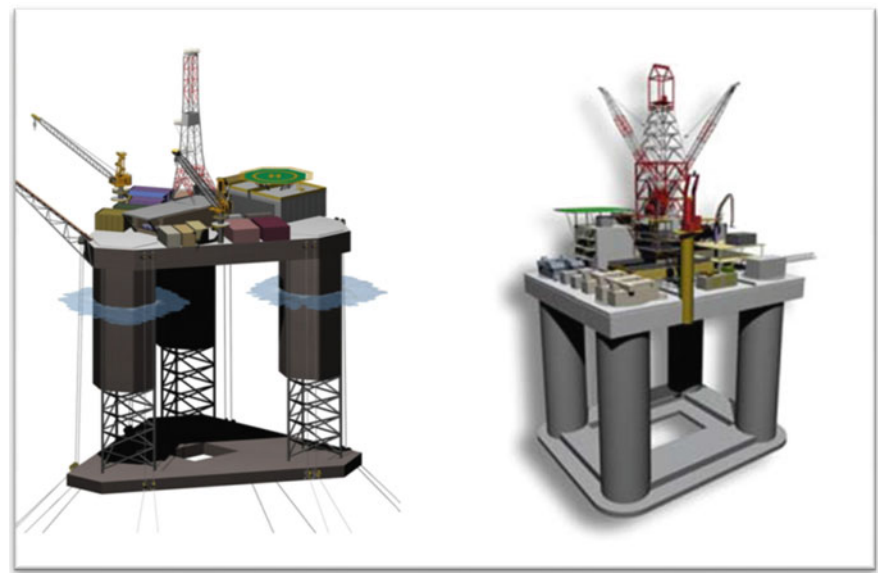


**Fig. 2.18** The F3-FA platform from construction to offshore installation

weight. The pile installation only took 6 h. Going through the process, the weight of the platform is gradually passed to the piles until 100% is done (Fig. 2.16).

After the completion of the weight transfer, the welded connection between the topsides and the grillage was cut to make it ready for the separation of BB35. It was followed by the topsides’ lifting up using the strand-jack system. With enough opening, BB35 was safely removed. The topsides and the legs will be locked together by super-bolts when it reaches the designed height (Fig. 2.17).

To summarize briefly, the design of SIP II is different from jack-ups in stationing operation. The topsides does not provide buoyancy as a floater hull at any stage of the installation. It is capable of self-installing in the sense of without using HLCVs. Temporarily equipped strain jack system was used for lowering legs as well as lifting up the topsides. A suitable transportation vessel is necessary. The platform is



**Fig. 2.19** The EDPs—three leg version and four leg version (credit to EDP concept development team)



reusable, but would not move as frequently as jack-up drilling platforms. The construction and the process of stationing operation is illustrated in Fig. 2.18.

However, the seabed soil conditions must be carefully examined for the feasibility of using suction piles. Especially, when consider the re-use of the platform in different offshore sites. Other factors such as the water depth, the variation of air gap requirement, as well as the environmental loading conditions may also have impacts on the design of supporting legs and suction piles.

### 2.1.3 EDP [13–15]

The concept of EDP (Extended Draft Platform) by Technip is an example of self-installation deepwater floating production platform. There are several versions of EDP concept (see Fig. 2.19) during the development. As can be seen from Fig. 2.19, an EDP platform comprises a topsides box, three or four columns and a heave plate attached to the columns.

EDP platforms are designed for deepwater application, either as the drilling rigs or as drilling/production platform. It can also be used for ocean science. The initial intention of development was for a deepwater dry tree semisubmersible to meet the strict motion requirement as well as cost-effectiveness offshore installation. It was evolved from the Technip's TPG 3300 and CSO-Aker's DPS 2001 concepts, while the heave plate concept was from truss spar. During the concept development stage, beside intensive analyses and model testing on the platforms' in-place performance, efforts had been on the mechanism of draft changing, topsides lifting up, etc., to make the self-installation offshore successful.

The TPG3300s idea of self-installing by moving the legs stems from TPG500 jack-up platform. The topsides also plays the role of a floating hull, although the lower pontoon also provides buoyancy. These kinds of characteristics naturally passed to the EDP concept (Fig. 2.20).

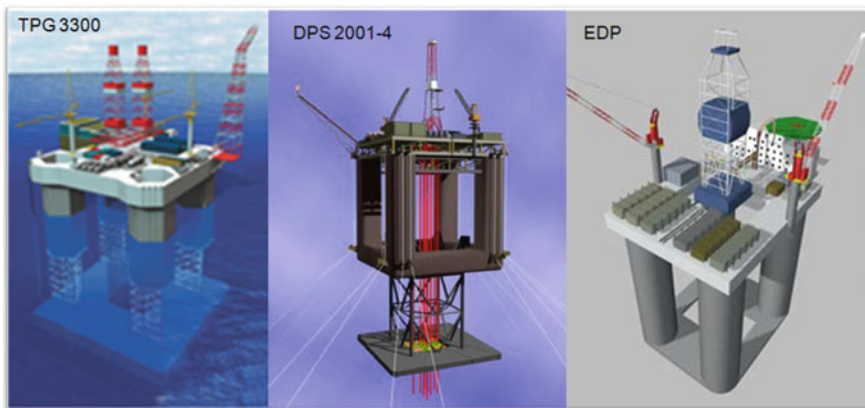
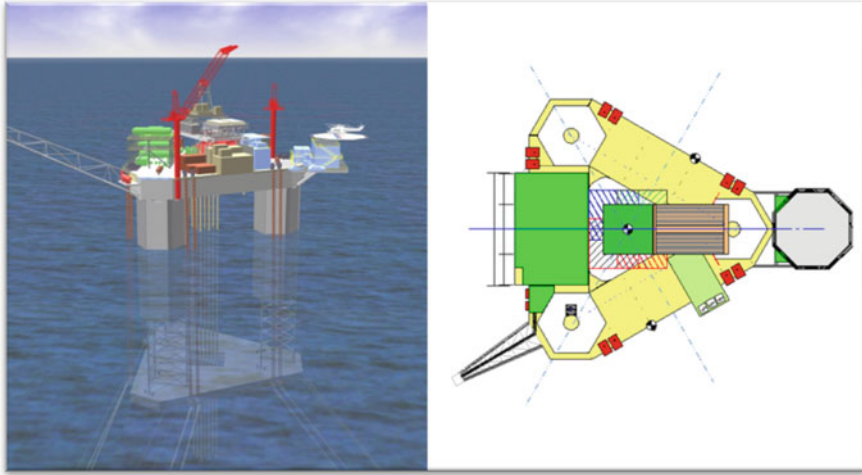
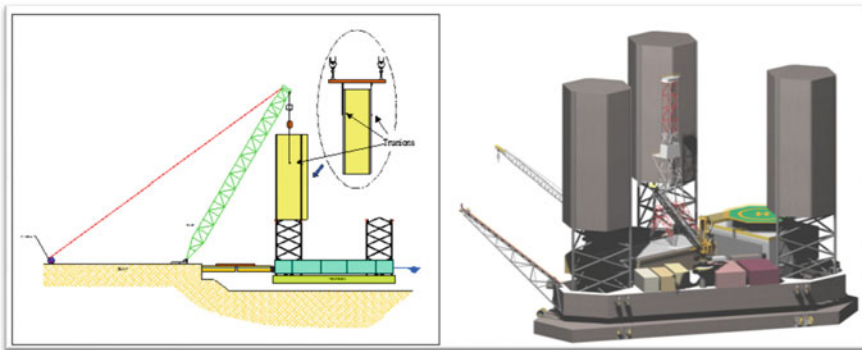


Fig. 2.20 EDP concept evolution (credit to EDP concept development team)





**Fig. 2.21** The three leg EDP example (credit to EDP concept development team)



**Fig. 2.22** Example of EDP platform integration (credit to EDP concept development team)

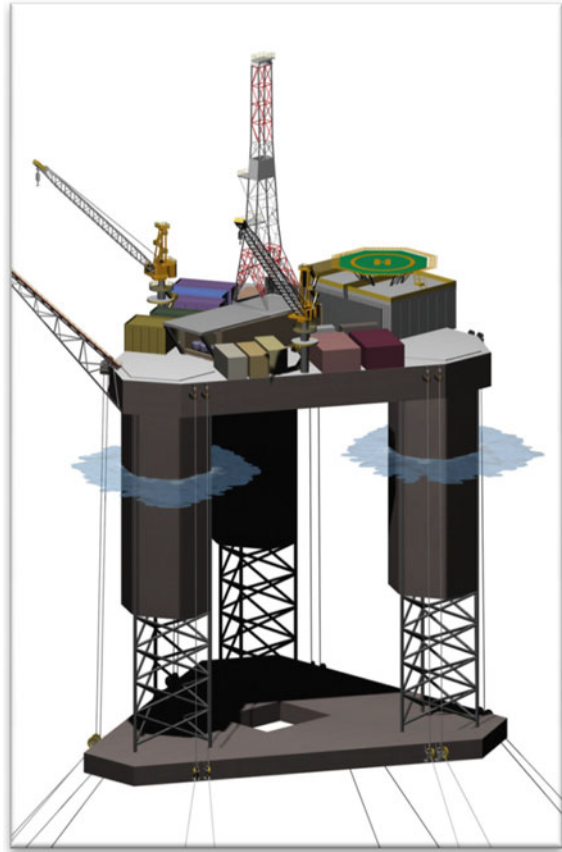
Look at the example of a three leg EDP shown in Fig. 2.21, the topsides is almost the same of a jack-up design. The position of the three legs are also similar, but not separate to each other—they sits on the heave plate, which helps to reduce the heave motion when the platform stationed in the deepwater.

However, the EDP is no longer a jack-up, but a deep draft semisubmersible in place. The function of the legs is no longer only providing supports to the payloads, but also providing stability when the EDP floats working in the field. The integration of the topsides and the legs is completed inshore in the assembling yard as the following (Fig. 2.22):



**Fig. 2.23** Brief process of the offshore stationing operation

**Fig. 2.24** An EDP platform after installation (credit to EDP concept development team)



- After putting together the topsides, heave plate and the lattice section of the legs at the fabrication yard, then transport the integrated structure to the assembling yard to get the top columnar section, and the topsides modules installed.
- The whole platform is then ready for transportation to the offshore side. It can be wet towed.

When the integrated EDP platform arrives at the stationing location, a preset mooring system should be in place. The brief stationing operation is summarized in Fig. 2.23.

The EDP platform is then ready for the offshore HUC operation with minimized workshop, since most of the commissioning work has been completed inshore (Fig. 2.24).

The stationing process of the EDP platform is similar to but different from either jack-up or SIP II. Comparing to jack-up platforms, the operations of the leg part are different, while comparing to the SIP II, the transportation barge is not involved during the offshore operation although the dry tow transportation to the site can be an option. However, for all of them one thing is in common, that is no need of the heavy lifting vessel on site and all the equipment for the stationing operation is on board the platform. They all are self-installable in this sense.

## 2.2 Inshore Integration [16]

As discussed in Chap. 1, for fixed platform, GBS and non-FPSO floaters especially in deepwater, generally the topsides and the substructures are fabricated separately and then integrated. After the introduction of self-installable platforms, the discussion is now focused on the platform integration operations. Considering the project as well as the operation involvement, it is well understood that the better option is to have least installation related work and HUC to be completed offshore. In this section, the discussion will be focus on the inshore platform integration. Methods with potential for inshore integration will be discussed at the relatively high level.

Inshore integration is not a simple process, a comprehensive plan and careful execution with systematic safety checking such as stability, structural integrity, etc. are essential.

- First, the integration or mating site for inshore platform integration needs to be carefully selected (Fig. 2.25).



**Fig. 2.25** The integration site should be carefully selected for successful mating operation. On the *left* is the topsides installation by heavy lifting for WHO DAT topsides. On the *right*, it shows the topsides of Statfjord B being carried out on barges near the mating site ready for floatover (courtesy of KOS and StatOil)

No matter the mating operation is by crane lifting or other methods. The site should be a sheltered water area to avoid strong impacts from severe weather. At the same time, the location should provide adequate space including sufficient water depth for:

- Temporarily stationing the substructure
- Allowing the maneuvering of the vessel carrying the topsides or the construction vessels including the crane vessels
- Making possible the operation less complex and highly effective.

Not so many locations meet the requirement, only some Norwegian fjords and some locations at the west coast of Scotland can qualify.

The ideal mating site for condeep is at the fjord with a relatively narrow inlet but a large water area and deep enough. At the same time, the environment is benign making the operation safer and smooth. No wonder, most of the inshore mating sites for condeeps are along the Norwegian coast [17].

- Secondly, the access and exit of the transportation route should also carefully examined and the transportation analyses need to be carried out for the safety and effectiveness.



**Fig. 2.26** Condeep Statfjord B was towed to the integration site at Yrkje Fjord in Vindafjord. (Courtesy of Statoil)

Take condeep Statfjord B as an example, after the GBS hull had been completed at Gands Fjord off Stavanger, it was towed at the draft of 62 m to the mating site at Yrkje Fjord in Vindafjord. The towing weight was 634,000 tonnes and the tow width was 135 m. The minimum water depth along the route is more than the required 70 m, but at the passage near the mouth of the Grands Fjord, the channel width was only 280 m, therefore needs extreme caution of navigation. Towing effectiveness was also a concern. Since the deep draft of the condeep and the short towing lines for the narrow shipping channel, propeller backwash was very strong, which reduced the net towing power drastically. Based on the experience, pushing tugboats were used instead (Fig. 2.26).

For the case of exit towing channel consideration, Chevron's DDS (Deep Draft Semisubmersible) platform Blind Faith is a good example. The hull of Blind Faith platform was fabricated at Verdal in Norway and the topside was constructed at GIF yard at Houma, Louisiana. The integration site was chosen at the integration yard belonging to KOS at Ingleside, Texas, where is not far from the platform's stationing location in Mississippi Canyon Area block 650 in GOM, approximately 140 nm south-east of New Orleans. The hull of the platform was transported to the integration yard being equipped with the cranes capable of lifting the integrated topside by a single lift.

The integrated semisubmersible platform was then wet towed to the offshore field. Because the limited water depth of the transportation route, the inshore towing draft could not go beyond 6.1 m, the transportation stability could not meet the requirement at this transit draft. Fortunately, by closely following the weight control record, this potential issue was identified earlier. There was already a developed plan in place to addressing the issue. The idea was to attach specifically designed portable sponsons temporarily to the platform hull columns to increase the GM value of the platform during the inshore towing. After the platform reached the location where the platform draft could be increased by ballasting, the four sponsons, each of them attached to one of the four columns, were released. The platform was then further ballasted down to the offshore towing draft and towed to the offshore field (Fig. 2.27).



**Fig. 2.27** Temporary sponsons for handling inshore towing stability issue. The *left* shows the sponsons are installed at quay; the *middle* shows the platform under tow with sponsons attached. The *right* shows one of the sponsons was just separated from the hull column (credit to the Blind Faith T&I project)

- During the platform integration, platform's loading and environmental conditions keep changing, though some of them are temporary, checking of safety such as stability of the platform, overloading, etc. as well as the integrity of the structures are necessary for each operation steps.

In the following, several approaches in inshore platform integration are discussed with examples.

### ***2.2.1 Inshore Topsides Integration by Heavy Lifting***

The topic of the method of integrating the platform at assembly yard was already touched when discussing the topsides design. Nowadays, for large offshore projects, integration of the separately fabricated topsides and corresponding structure become an important step of platform construction. The completed topsides and substructures built at different construction site will meet at a selected yard with high capacity cranes or a sheltered inshore site with HLCVs to achieve the platform integration by heavy lifting. This approach is not only applicable to floaters such as semisubmersibles and TLP's, but also worked for GBS platforms. The operation can be carried out at the quay of the integration yard or in a carefully selected sheltered waters. The topsides can be modularized or integrated. The results are all the same: the whole platform is fully integrated and ready for transit to the field where the platforms are positioned by either connected to the preset mooring system or being ballasted down and sitting on the seabed followed by the offshore HUC with minimized work scope.



**Fig. 2.28** Condeep Statfjord A and the installation of topsides modules (courtesy of Statoil and Norwegian Petroleum Museum)



- GBS platforms

For deep draft GBS platforms, the preferred option of platform integration is inshore to take the advantage of avoiding impacts of the severe weather, especially in the earlier time before the innovation of floatover technology.

Statfjord A is one of the condeep built for the North Sea, which belongs to the early generation of GBS. In Fig. 2.28, the left is an effect picture of condeep Statfjord and the right picture shows the installation of the modules on the topsides. When the hull of the condeep was towed to the mating site, it would be ballasted down to have only 5–6 m of the columns above the sea surface and the module support structure (frame) was then installed on the column tops. Following that, the crane vessel lifted the modules and installed them on the topsides. The topsides installation of Statfjord A condeep was in 1977. For condeep Statfjord A, the three (3) living quarter modules were 40 m high and weighed about 1000 ton each. Each module could not be lifted by a single crane but required three (3) crane barges working in concert, not because of the weight but the height and the configuration.

Following the completion of the modules' installation, as much HUC work as possible can be performed inshore and make the offshore HUC work scope minimized.

- TLPs

For large TLPs, the platform integration is carried out inshore for the same reasoning. The integration can be at the quay of the integration yard or in the sheltered waters using heavy lifting vessel. As examples, brief discussions of two cases of Shell's TLP platforms are in the following.

- Mars TLP [18, 19] (Fig. 2.29).

Shell and BP's Mars TLP was deployed in the Mars field in GOM with water depth about 900 m (2940 ft) in 1995. Total weight of the platform was 36,500 tons. 55% of the total development cost of \$1.2 billion was spent on the fabrication and installation.

The 15,650-ton hull of the Mars TLP consists of pontoons and four circular steel columns, which was built in Belleli SpA, Taranto, Italy, and delivered on Aug. 31, 1995. It was then “dry-towed” approximately 6500 nautical miles to Aker Gulf Marine's fabrication yard at Ingleside, Texas, riding on



**Fig. 2.29** Shell TLP Mars integration. The *left* photo shows the Mars' hull being carried by Mighty Servant 2 of Dockwise; the center shows the installation of modules; on the *right*, the integrated platform was wet-towed to the field (courtesy of Shell)

Dockwise semisubmersible heavy lifting vessel Mighty Servant 2 for platform integration. The journey took 22 days.

Compared with the cost of topsides/hull mating for Auger TLP at open sea, Shell chose to perform the platform integration for Mars inshore at the yard near Corpus Christi.

The yard is equipped with shore-based twin boom heavy lifting facility—SLD (Specialized Lifting Device) which is capable of lifting objects up to 4000 short tons. The topsides of Mars consists of five (5) main modules (process, power, quarters, drilling, and wellbay) and each module was built and commissioned by the corresponding contracted fabricator before being transported to the integration yard. During each lift, the hull need to be so positioned that the module-carrying vessel could be under the SLD to make the lifting safe and smooth.

Then the necessary HUC work was completed at the integration site. Comparing to working offshore, there was no need for extra helicopters, supply boats, and marine equipment. In addition, the possibilities of delays caused by weather were greatly reduced. As discussed earlier, by integrating the platform inshore, the offshore HUC work was minimized and the cost was drastically reduced, even if the topsides was of modularized design.

The integrated platform was then transported to the site by wet-tow using four ocean-going tugboats. It took seven days for travelling the 400 miles to the field.

– Ursa TLP

Shell's Ursa platform is a third generation design of TLP and was deployed on Mississippi Canyon Block 809 with the water depth being approximately 1158 m (3800 ft). The fabrication started in 1996.

Similar to Mars, the TLP hull also consists of four circular steel columns connected by a ring pontoon. The hull, weighing 28,600 tons, was built at Belleli Offshore.

The total weight of Ursa TLP was 97,500 tons and the total steel weight is 63,300 tons. The topsides of Ursa consists of six (6) modules: wellbay, living quarters, power, drilling and two processes. J. Ray McDermott built all the modules. The total weight of the topsides was 22,400 tons (Fig. 2.30).

The platform integration site was chosen at the Caracas Bay of the Curacao Island, Netherlands Antilles, which was off the coast of Venezuela. The integration site is located off the hurricane zone and the water depth is enough for Ursa TLP module installation. The other favored factor is that Heerema's SSCV Balder was just there for routine maintenance and available for the integration operation.

The Ursa hull itself was much larger than Ram Powell and twice the size of the Mars TLP. Although there were limited port facilities on the Curacao Island, the staff and equipment needed for the integration project had to be either flown in or shipped across the GOM. With the detailed



**Fig. 2.30** The *left* photo shows the Ursa hull being transported from Italy to the integration site offshore Venezuela on barge H-851. On the *right*, the HMS's SSCV was lifting modules during the installation. The sheltered waters were calm (courtesy of HMC)

project execution planning and joined efforts, the integration was completed ahead of time and good preparation led to the big time saving for offshore tendon installation.

From the above discussion, it is convincible that the inshore platform integration is a better choice for conventional TLP platforms, even using heavy lifting of modularized installation.

- Semisubmersibles

With the introduction of the integrated deck concept, quite a few semisubmersible FPS's (Floating Production Structure) were integrated inshore using floatover method, which will be discussed in later subsection. Here the integration of the hull and topsides of Chevron's DDS production platform Blind Faith is presented as an example of using heavy lifting for inshore integration (Fig. 2.31).



**Fig. 2.31** The platform integration of Chevron Blind Faith DDS. The topsides is an integrated topsides. HLD (Heavy Lifting Device) lifted the integrated topsides from the transportation barge (*left*) and put on the hull (*right*) (courtesy of Rigzone and KOS)

As mentioned earlier, Blind Faith platform is a DDS with draft of 100 ft. The total displacement of it was 40,000 tons and the topsides was an integrated topsides fabricated in GIF in Louisiana. The hull was built in Aker's yard in Verdal, Norway. Integration yard of KOS near Corpus Christi, Texas was selected as the site for topsides mating. The crane through one single lift successfully installed the 7000-ton topsides.

For this kind of integrated topsides, there should be no certain preference between inshore and offshore installation. Saving on offshore HUC is the same. Selection of the integration site is decided case-by-case with consideration of multi-factors including availability of lifting equipment, schedule, Mob/Demob cost, environmental condition, etc.

### ***2.2.2 Inshore Platform Integration by Floatover***

Floatover technology has been a well-accepted offshore installation option in offshore oil and gas industry and becoming popular. In the offshore industry, floatover installation technology links to open water on-site platform topsides installation. Most of the completed projects using floatover methods were fixed-platforms. However, the first application of floatover technology, an innovation by Larry Farmer and Phil Abbott of Brown & Root in later 1970s, was to the platform integration of steel GBS Maureen platform in the North Sea. Following that floatover technology were widely applied to inshore platform integration for various kinds of offshore platforms including GBS, TLP, and Semisubmersibles. The following are some examples.

- **GBS**

Before the first floatover method application on the Maureen steel GBS in the early 1980s, the topsides installation of the condeeeps in the North Sea were carried out by modularized operation. At that time, the integrated deck concept was still in the development stage and the floatover technique had not been invented. The matting of the MSF deck with a few modules on the concrete base was carried out by floating the deck over the shafts of the already ballasted down platform base, just as shown in Fig. 2.32 of the mating of Statfjord A platform. Starting in 1980s, concepts of integrated topsides and floatover have been widely used for GBS platforms including condeeeps and CGBSs (Concrete GBS). Since all the GBS topsides are huge and very heavy, the floatover operation generally needs multi barges involvement instead a single barge. Take Statfjord B platform, which started production in 1982, as an example. It was the first four-shaft condeeep and the first platform using inshore floatover method for platform integration. Similar to the mating operation of Statfjord A



**Fig. 2.32** Mating operation of Statfjord A. The topsides was not an integrated topsides, a few modules were installed on the MSF which is carried by two tankers and then floated over the shafts of the base which was only a few meters above the water surface (courtesy of Norwegian Petroleum Museum)

platform, the shafts only have 6 m above the surface of the water, but the operation was then a floatover process.

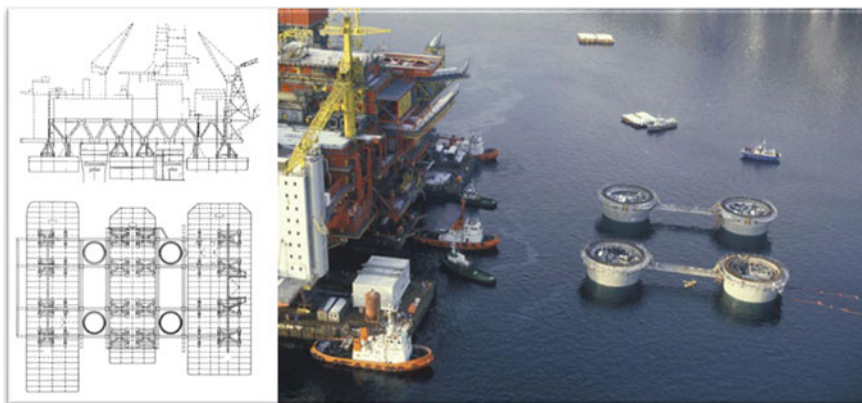
The differences were:

- The topsides was an integrated topsides, not a MSF deck with a few module installed. The topsides comprises of several decks including cellar, module, weather and upper weather decks; altogether 28,900 m<sup>2</sup> space were provided. All the modules made both in Norway or in other countries were already installed on the topsides and connected.
- The completion of the mating was by simultaneously de-ballasting the concrete base and ballasting the barges, which is a typical operation process of floatover platform integration).

Challenges in the operation were obvious: not only the huge topsides weighed more than 40,000 tons, but also the ballasting/de-ballasting performance control was quite complicated. Figure 2.33 shows that four (4) barges with different sizes were involved, a good planning and an accurate execution of the plans on coordination of water pumping for each corresponding tank at any moment was a key for the success (Fig. 2.34).

Another example is the CGBS Hibernia platform, which was deployed in Grand Banks of Newfoundland, 195 miles east southeast of St. John's, Canada

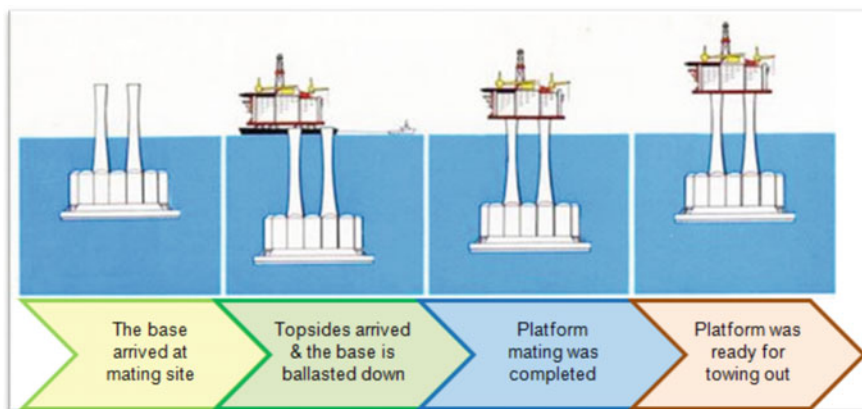




**Fig. 2.33** Statfjord B platform integration was the first inshore floatover integration (photo shows the floatover of Statfjord C which has the same design of Statfjord B), this operation used more than two barges (credits of drawing go to Aker Maritime [9], photo courtesy of Statoil)

(Fig. 2.35). The platform is a huge CGBS weighing approximately 1.2 million tons and more than 219 m high after being completed. The topsides consists of five (5) main modules, which were built globally. All the modules were assembled and installed on the topsides in Bull Arm. The integrated topsides weighed 37,000 tonne. The base of the platform weighed 550,000 tonne [20, 21] (Fig. 2.36).

The platform integration was carried out inshore using floatover method. The integration site in the middle of Bull Arm where is near the base construction site. Two giant barges formed a catamaran carrying the huge and heavy



**Fig. 2.34** Illustration of the platform integration process of Statfjord B





**Fig. 2.35** Hibernia platform (courtesy of HMDC)



**Fig. 2.36** Hibernia platform integration. The base structure of Hibernia is shown on the *left* and the *right* shows the topsides was transported by two giant barges to the integration site (courtesy of HMDC)



**Fig. 2.37** The topsides of Conoco (UK) Ltd's Hutton TLP was under construction at Ardersier Yard (courtesy of Oilrig-Photos)

topsides. The operation was successful and the experience accumulated will benefit the future same kind of projects.

- **TLP**

In the early section, examples of TLP platform inshore integration by heavy lifting were presented. The operations were very successful. Not so many cases of TLP platform integration using floatover can be found. One of the possible reasons might be that the stability of the floating TLP is sensitive to the floating draft before it is anchored by the tendons. The Conoco Hutton TLP was integrated using inshore floatover method [22] (Fig. 2.37).

The Conoco Hutton TLP was the first production TLP ever built for the Hutton field in the North Sea where the water is not deep—only 148 m. The concept development was by Vickers Offshore since 1974. The topsides and the hull of Hutton TLP were fabricated at separate yards in parallel. The Hutton topsides, an integrated topsides, was designed by Brown & Root and fabricated at the McDermott Ardersier yard in Scotland. The hull was built in the drydock at the nearby Highland Fabricator's Nigg yard in the north of Scotland.

The 17,600-ton topsides and the 22,000-ton six (6) columned hull were integrated by floatover method in 1984, following the success of Maureen steel GBS platform. The mating site was at the Moray Firth off Findhorn, the east coast of Scotland. The site was close to both fabrication sites and no need for a long distance towing operations. Aker Offshore carried out the floatover

operation at the mating site off the east coast of Scotland. The Moray Firth mating site is exposed to the North Sea, environmental conditions were a challenge for the mating operation. Engineers conducted analyses to simulate the relative motion of the operation and it turned out that the relative motion was much lower than the operation limit.

One thing worth noticing, i.e., although the operation has been called floatover, it was actually a bit different from the original HIDECK floatover concept. It was NOT the same for the Maureen platform floatover in achieving the mating contact between the two parts of the platform. The TLP hull was ballasted down to the designed draft for mating, instead of moving the topsides over the hull; the floating hull was aligned with the topsides and de-ballasted up. After the contact, the rising hull lifted the topsides from the transportation barge and then complete the mating by welding (Fig. 2.38).

The integrated Hutton TLP was towed to the stationing site in July, 1984; the hooking up with tendons only took three days. The first oil was produced twenty-five (25) days after its arriving. The success of the Hutton TLP platform integration fully demonstrated the advantages of integrated deck and inshore platform integration.

- Semisubmersible

It should be natural to consider integration semisubmersible platform by floatover method. A semisubmersible is stable by design when floating as an integrated platform. The inshore platform integration of Statoil Kristin semisubmersible is a good example (Fig. 2.39).

Aker Kvaerner and GVA designed Kristin production platform, which is a semisubmersible with four (4) columns. Fabrications of the topsides and the hull were in separate construction yards. Samsung Heavy Industries in South Korea built the 14,450-tonne hull. Fabrication of the integrated topsides weighing no less than 19,000-tonne was at Aker Stord. The mating site was in the Aker Stord's harbor and the completed hull was transported to the mating site by the Dockwise heavy lift vessel Mighty Servant 1. The topsides was on the semisubmersible heavy lifting vessel BOA Barge BB19.

The integration went smoothly and it took only one hour and forty-two minutes (1:42) to complete the mating of the topsides and the hull. After that, the extensive welding was carried out. The platform integration was quite impressive.

However, for quite a few semisubmersible platforms including drilling rigs, the topsides is often built in the yard with large drydock facility. The platform hull and topsides are also built separately. The integration of the topsides and the hull happened in the drydock by a method similar to but different from the floatover. See the discussion of this method in the next section.



**Fig. 2.38** The Conoco's Hutton production TLP was integrated using floatover method (courtesy of Conoco)



**Fig. 2.39** Inshore deck floatover installation of semisubmersible platform Kristin (courtesy of Statoil)

### 2.2.3 *Moving-in-Under [23–25]*

This is the method having been applied in the semisubmersible platform integration in the docking facility of the fabrication yards for various kind of platforms. There has not been a unified name for the method, and just name it “Moving-in-under” in this book. In the following, the discussion will be on the platform integration of a semisubmersible.

By applying this method, the topsides, an integrated topsides, will be elevated up to a height mechanically in a drydock to create enough space for the semisubmersible hull to move in beneath the topsides. The topsides and the hull columns will be aligned and then the topsides will be lowered in a controlled manner to complete the mating with the hull. In this section, we will present two different approaches with a few examples.

The first approach is to lift up the topsides with a giant crane capable of handling very heavy topsides, as it happened at the yard of CIMC Raffles, in Yantai, Shandong, China. The second approach is to use gantry-lifting systems to elevate the topsides in the drydock and then make it possible for the hull to move in beneath and aligned with the topsides.

- Approach of using heavy lifting derrick over the dock

This approach is specifically to the platform integration of floaters with integrated topsides. It should be noticed that there is the limit of the total height of the integrated platform. The advantages are:

- A single lift operation
- Making it possible to parallel fabricate the hull and the topsides
- Shortening project schedule and improve utilization of resources
- Safe with good quality.

Obviously, the high capacity crane and related rigging are the key factors. These facilities need a big investment and good maintenance during the service life. The realization of the above-mentioned advantages very depends on the backlog of the fabrication projects.

The best examples are the platform integration operations performed by Yantai Raffles’ yard using its Taisun Crane with safe lifting capacity of 20,133 tonne (Fig. 2.40).

The maximum lifting height is 80 m for the Taisun crane, which is enough for semisubmersibles, and FPSO’s to complete the mating operation. Since the performance is in the drydock, the working environment is very favorable. This technology has been recognized by the industry. Its record of topsides installation has been 17,000 tonne up to now.

- Approach of using jacking systems

The concept is the same in creating mating room by elevating the topsides to a needed height but without using the huge derrick on the drydock walls. The





**Fig. 2.40** The 14,000 tonne integrated topsides of the COSL Pioneer drilling semisubmersible had been lifted and the hull was moving in underneath (courtesy of CIMC Raffles)



**Fig. 2.41** P-55 platform integration in the drydock of Rio Grande yard (courtesy of Petrobras)



temporarily erected gantry tower lifting system was the key for the integration operation. A few examples are presented for illustration.

- P-55 semisubmersible production platform (2012)

The Petrobras P-55 semisubmersible platform had its topsides and hull constructed separately but simultaneously. The integrated topsides or the deckbox was fabricated in the RIO Grande yard. It weighed 17,000 tonne. The hull was fabricated in the Suap yard (Fig. 2.41).

The drydock of the Rio Grade yard, where the topsides was fabricated, was selected as the integration site. The Mammoet Gantry System was setting up in the dock for the topsides lifting. The gantry system consisted of twelve (12) towers connected to twenty-four (24) hydraulic jacks, each with a capacity of 900 tonnes. When setting up, six (6) towers on each side of the dock will be erected. Twenty-four (24) sets of fifty-four (54) steel wire ropes were used to lift the structure. For P-55 platform integration, the 17,000 tonne topsides would be lifted up to the height of 47.6 m above the drydock bottom (Fig. 2.42).

For this case, the topsides height reached almost 50 m. Theoretically speaking, the jacking height should be able to be adjusted by the gantry system when higher elevation is needed. The topsides lifting and mating site preparation took six (6) days following the procedure below:



**Fig. 2.42** The topsides and the hull were aligned and ready for mating (courtesy of Petrobras)

- First, the topsides was lifted up to a height of 20 cm for testing and final weighing.
- Then, it was lifted to the height of 15.4 m above the bottom of the dock. The grillage and fenders for the hull floating in were put in place at the same time.
- The topsides will be lifted further and be ready for the hull to move in.

The hull was then to be floated in with the drydock being flooded to the depth of 13.8 m through the water collection pipeline and the floating gate being opened.

After floating the P-55 hull into the dock, the flooding gate was closed. Then the water depth inside the dock was drained to 7.2 m. The topsides was then lifted to the maximum design height of 47.6 m and the hull was aligned underneath the topsides. After final adjustment, the topsides was lowered down by the jacking system and the mating process was completed. Following that, the entire platform landed on the grillage through draining the dock.

The total integration process only lasted two (2) weeks, which was a better, and cost-effective approach comparing to the conventional construction of semisubmersible. This approach may not be as effective as the directly lifting by the huge crane like happened in the drydock of the Yantai Raffles' yard in both the mating operation and the drydock usage, but there was no need of the large permanent investment on the super crane. Other yards have also chosen similar approach.

– Aker H-6e drilling rig

Aker H-6e drilling rig is the six (6th) generation rig capable of working in Arctic severe environment. The hulls of the first two (2) rigs were built in the yard of the Drydocks World in Dubai, UAE. For each platform, the hull was wet-towed to the Aker Stord yard for integration, where the topsides was fabricated in the drydock.



**Fig. 2.43** Aker H6-e semisubmersible drilling rig was integrated at the drydock of Aker Stord yard (courtesy of Aker Solutions)



**Fig. 2.44** Both of the topsides and the hull were built in the drydock of the Drydocks World yard at Dubai, the topsides was fabricated in the drydock (courtesy of Drydocks World and ALE)

In Fig. 2.43, the eight (8) SMLTs (Sarens Modular Lifting Tower) were erected in place in the drydock. The topsides was already lifted up by the gantry lifting system. On each of the eight (8) towers, there are four (4) standard strand jacks. The whole lift system is capable of handling the weight of 144,000 tonne and withstanding a full Norwegian winter storm. The 10,700 tonnes topsides of the



**Fig. 2.45** The topsides of the Dolwin Beta was lowered on the columns of the semisubmersible look-like GBS hull, the ALE's gantry system can be seen clearly (courtesy of Drydocks World and ALE)



**Fig. 2.46** Both the drydocks are open to the sea. On the *left*, it can be seen that three (3) tugs are used to push the hull to move in underneath the elevated topsides (courtesy of Aerophoto.no and Drydocks World separately)

semisubmersible drilling rig “Aker Spitsbergen” was lifted up to 34 m high and the hull was moved in underneath the topsides. The mating was successful.

– Dolwin Beta HVDC (High Voltage Direct Converter)

The Dolwin Beta platform serves as part of the offshore windfarm. The total weight of it is 23,000 tonne. From the structure of the hull and the topsides, it was often taken as a semisubmersible platform, however from the function offshore, it is really a GBS.

The construction of Dolwin Beta was the same as the floating platforms. The topsides and the hull were fabricated separately and then the two were mated at the shipyard.

The 10,000-tonne topsides was built in the drydock of the Drydocks World yard at Dubai. The gantry system used for the topsides jacking up was by the Netherland Company ALE. The system was designed combining several different standard gantry systems. It consisted of six (6) consoles as shown in Fig. 2.44. Three (3) of them forming a row on each side of the dock with two (2) ALE’s Laced Tower system at the ends of the row and an A-Frame structure in the middle. Four (4) strand jacks were installed on each tower unit with the minimum lifting capacity of 500 t for each strand jack. All the tower units were sitting on the bottom of the dock and the standing stability was assured (Fig. 2.45).

After the completion of the topsides, it was lifted up to the height of more than 50 m from the bottom of the dock. The final height before the mating reached 52.8 m. The hull was then floated in carefully in between the gantry towers and underneath the topsides. The topsides lowering and mating operation was controlled by the gantry system similar as discussed earlier.

From the three cases presented above, it can be seen that the gantry systems played a vital role in the operation, though their designs were different. Not only the system lifting capacity is critical, but also the standing stability and controlling system of the jacking motion and the safety under the operational environment all

create challenges for the execution. It is not difficult to understand that the lifting operation needs the coordinated actions at all the towers during the jacking up process. At the same time, the drydocks as the mating sites in the shipyards are all quite open to the sea; therefore, the weather condition is a factor non-negligible. All the integrated operation efforts are for assuring the accurate alignment between the topsides and the hull (Fig. 2.46).

One point worth noting: behind all the successful inshore mating operation, there were intensive efforts in the concept development as well as careful planning with details. Engineering supports through thorough investigation of technical issues and creating solutions by analysis and design are vital. All the plans, procedures and operation manuals should go through seriously and strictly checking before formally issued and strictly followed during the execution.

## 2.3 Offshore Integration

For fixed platforms or CGBS in shallow water or compliant towers in relatively deepwater, the substructures are first installed at the stationing location and then the topsides is installed on the substructure at the site. Therefore, the offshore platform integration is inevitable.

For single columned floaters such as Spars or the MinDoc platform, the hull arrives at the offshore field first. Operations of upending, hooking-up with the preinstalled mooring system and the topside installation will follow. This is also a process of offshore integration. As discussed earlier, both minimizing the work scope of the offshore HUC and reducing the duration of the offshore integration process are the key factors contribute to the project cost saving and improvement of the operation safety. The development of integration methods and corresponding equipment including the installation vessels has always been focusing on the same goal.

For the existing installations of offshore platforms, most of them were installed using heavy lifting vessels either by a single lift of integrated topsides or by modules. Floatover method, which includes variations stemming from the initial invention of HIDECK, is the other option and gaining some kind of moment in recent years in certain area such as South East Asia, especially for heavy topsides installation. Brief discussion on these two options will be carried out here and leave more detailed discussion on the floatover technology in the following chapters.

### 2.3.1 *Topsides Installation by HLCV [26, 27]*

The topsides of platforms vary in dimension, weight and configuration and the environment such as the water depth, wind/wave/current conditions, neighbor existing structures, etc. at the platform stationing location are project dependent.



Therefore, the selection of the installation vessel and the creation of the installation plan should start very early with the project. It is not so easy to hold a suitable vessel with a very long lead-time. On the other hand, as discussed in Chap. 1, changing the installation method in the later stage of a project is very costly and sometimes is not feasible.

- Single lift operation

Since the earlier years of the offshore industry, topsides of fixed platforms were installed by crane barges. The ideal situation was to have a crane barge available with the capacity of lifting the topsides in one piece (Fig. 2.47).

When the topsides becoming larger, heavier, the existing crane vessels could not install the topsides by a single lift. One of the solution is to make a multiple lifting operations by modules. The other is to build large capacity crane vessels. At the same time in the 1970s, the concept of integrated topsides appeared which created the demands for larger capacity HLCVs. Since 1979, several huge SSCV's (Semi-Submersible Crane Vessel) were built and joined the global HLCV fleet. They are Balder and Hermod of HMC (Heerema Marine Contractor), following them in the middle of 1980s, came the largest SSCV Thialf of HMC and the Saipem 7000 of Saipem S.p.A (Fig. 2.48).

Both giant crane vessels are huge in size: 201.6 m (L) × 88.4 m (B) × 49.5 m (D) of Thialf and 198 m (L) × 87 m (B) × 43.5 m (D) of Saipem 7000. Thialf's displacement is 198,750 t, while Saipem's is 172,000 t. The designed lifting capacity of Thialf is 14,200 tonnes at 42 m and the capacity of Saipem 7000 is 14,000 tonnes at 31.2 m. However, Saipem 7000 when she succeeded the installation of the 12,150 tons Sabratha deck in the Mediterranean Sea created the record of lifting the heaviest objective.



**Fig. 2.47** The topsides of a fixed platform was installed by a crane barge (courtesy of CNOOC)



**Fig. 2.48** World largest SSCV's. On the *left* is the largest SSCV Thialf (originally DB-102 of McDermott) of HMC. On the *right* is the second largest SSCV Saipem 7000 of Saipem S.p.A (courtesy of HMC and Saipem)

All these large SSCV's are designed multifunctional and most suitable to large deepwater projects. They can handle most of the heaviest structural objects and can perform subsea installation for very deepwater.

However, the offshore operation accomplishment does not only depend on the weight lifting capacity, but also on other factors such as the water depth, structure size and configuration, oil field environment, etc. Therefore, less capacity HLCVs with shallow draft are also important members in the global heavy lifting fleet. They have played important roles in the offshore installation including the single lift topsides installation for both fixed platforms and spars (Fig. 2.49).

In the offshore industry, the designed platform topsides weight and size have been engaged in the development of HLCV's lifting capacity in a spiral cycle. When the heavy lifting side sees the potential or trend of topsides going bigger, higher capacity vessels are designed and built; on the other side, when higher



**Fig. 2.49** HLCVs. On the *left* is Blue Whale of COOEC hoisting the largest offshore oil wellhead platform module in Bohai Sea China. On the *right* is the McDermott DB-50 equipped with DP system (courtesy of CNOOC and McDermott)



**Fig. 2.50** In early 2009 HMC installed the integrated topsides of the Perdido with a 9773 ton single lift by their SSCV Thialf, a record for the US part of the GOM. The living quarter was then put on the topsides. It took two weeks to complete the installation (courtesy of HMC and Shell)

capacity HLCVs are available or under construction, larger or heavier topsides design will appear. Both sides keep the same focus in mind, i.e., to make the single lift installation of the integrated topsides successful and safe.

Sometimes, limited capacity of the installation vessel may inspire the engineers to make creative efforts in the optimization of the topsides design. The completion of the Shell Perdido spar platform is a good example (Fig. 2.50).

When the project started, the SSCVs were considered as the topsides installation vessel and the integrated topsides design weight was set to be under 10,000 tonnes. The single lifting operation assured the reduction of the platform offshore integration duration and the integrated topsides design minimized the offshore HUC work scope.

- Installation by modules

When the topsides offshore installation cannot be completed by a single lift operation, the topsides will be fabricated into several installation modules, which can be installed one-by-one using HLCVs.

Platforms such as fixed platforms and compliant towers and spars with large topsides often perform topsides installation by modules. The module here means the installation modules, which may not be the same as the equipment modules fabricated by the vendors.

The Chevron TOL (Tombua Landana) compliant tower in West Africa is an example for the modularized topsides installation. The topsides of the compliant tower was an integrated design according to Chevron, but the installation was carried out by SSCV Thialf by modules in the order of the MSF, the CM (Center Module), the WM (West Module), the EM (East Module), the FB (Flare Boom) and the LQ (Living Quarter) (Fig. 2.51).

Installation of the topsides of spars by multiple lifting happened in most of the spar projects. One of them was the Genesis spar platform.

The topsides of the Genesis spar was installed by multiple lifting including production deck, east and west drilling/utility modules, a living quarter package,



**Fig. 2.51** The Center Module was lifted and put on the MSF of the Chevron TOL (Tombua Landana) compliant tower platform in offshore Angola (courtesy of Chevron)



**Fig. 2.52** The McDermott DB-50 was preparing to lift up the lower deck of the Genesis spar topsides (courtesy of McDermott)



**Fig. 2.53** Bottom Feeder with lifting capacity of 4000 tons (*left*) and VB 10,000 with lifting capacity of 7500 tons (*right*) (courtesy of Versaba, Inc.)

and a drilling rig. McDermott's DB-50 equipped with DP system was used for the installation (Fig. 2.52).

For multiple lifting operation, to reduce the installation duration without interruption is critical and challenging. Knowledge and information of the weather at the site play an important role and carefully developed installation plan and procedure must be strictly followed.

- “Bottom Feeder” and VB 10,000 (Fig. 2.53)

A different kind of heavy lifting vessel VB 10,000 by Versaba, Inc. worth mentioning here. The vessel concept started from “Bottom Feeder” in the middle of 2000, which was designed for the platform decommissioning tasks. The rigid frame trusses are mounted on specially designed barges forming a catamaran, which can accommodate the environment at the working site. There is enough space created under the frame trusses and between the barges, therefore the two formed gantry system is capable of removing certain sized topsides of platforms by a single lift.

VB 10,000 was the further development from the successful Bottom Feeder. Although the vessels were initially designed for platform decommissioning, it has easily to be agreed that they could also be used for platform topsides installation. In fact, VB 10,000 has been proposed for fixed platform topsides installation projects. As pointed out earlier, the challenge of the single lift of the topsides comes not only from its weight and weight distribution, but also from the size and the configuration. Because of the limited space bounded by the frame trusses, sometimes, the lifting height and the weight balance control may cause the capacity reduction.

### 2.3.2 Offshore Topsides Installation by Floatover

When discussing offshore topsides installation by floatover methods, it naturally focuses on the integrated topsides. As mentioned in the above section, integrated



topsides single lift operation has been the favored in the platform installation projects. Depending on the size of the platform, an integrated topsides may either be a whole topsides with all the equipment installed on it or the MSF with key production and processing equipment included. So far, the HLCVs still have a majority share of the integrated deck installation market in competition with other options.

However, under either of the following situations, the floatover method will be the first choice:

- Suitable vessel not available or the mob/demob cost too high  
It should be noted that the majority of the medium-to-large capacity HLCV's generally be spotted working or temporarily stationing in areas like the North Sea and GOM where the infrastructures are established and more activities are going on. For projects in remote areas, it's hard to make the planning of the offshore operations based on the needed HLCV's, especially when considering the uncertainties of the development of the projects.
- The topsides design or the field environment make the application impossible  
Sometimes, the platform topsides is too heavy to be lifted by an HLCV. The obvious example is the huge CGBS. In addition, when the topsides may not too heavy, but the water depth prevents the HLCVs with the requested capacity to work at the installation field.

When talking about floatover methods, the most important equipment are the vessels and the rigging designed for a specific project. These vessels play the role of transportation of the topsides for installation and the mating of the topsides and the substructures. There is a larger room for selecting the suitable vessels and the cost will be lower including mob/demob.

Furthermore, as shown in earlier examples in inshore condeep topsides integration, floatover operation can be performed with multi-vessels and can even consider using of piggyback arrangement. In addition, floatover method works in



**Fig. 2.54** SHWE platform integration in Bay of Bengal, Myanmar. The weight of the topsides is 26,000 Mt carried by the COOEC barge HYSY 229 (courtesy of Dockwise)



**Fig. 2.55** Corocoro CPT (Central Production Facility) project was in the 5 m water depth field (courtesy of ConocoPhillips)

very shallow water environment and one example will be presented for illustration later.

- Fixed platform topsides installation

In recent years, quite a few of the floatover topsides installations have been very quite successful, most noticeable area is the South Eastern Asia. Projects such as Bayu Undan, Angel, Wheatstone, Malampaya, SHWE, etc. all created some kinds of records at their installation time. The accomplishment of these projects were very impressive especially considering the large integrated topsides, high air-gap request for some project, the long journey in open sea for the topsides transportation, etc. The safe and cost-effective operations sufficiently demonstrated the advantages of floatover technology and the application of the floatover technology to offshore platforms has been gaining momentum, more fixed platform projects are in the list for future floatover operation.

The SHWE is one typical project in the South Eastern Asia area. The platform had a huge integrated topsides and the floatover topsides installation method was chosen from the beginning of the projects. The transportation/floatover vessel availability is high and the fleet has been growing.

The floatover operation of SHWE platform topsides integration is illustrated in Fig. 2.54. The water depth at the field is 110 m; the jacket was designed considering the one barge floatover topsides installation operation. HHI fabricated both the 22,000 t jacket and the 26,000 t topsides. In the early December of 2012, the topsides arrived at the site riding on barge HYSY229 provided by COOEC (China Offshore Oil Engineering Co. LTD) after a journey around 4000 n.m. from Ulsan, South Korea. The barge was built for large jacket launch and floatover operation and has a bottle shaped hull. The total weight carried by HYSY229 was about 31,000 t including the DSF (Deck Supporting Frame). The operation had no surprise and was successful.

There are also successful floatover installation examples in other areas, e.g., Technip have completed more than six (6) floatover projects applying their UNIDECK floatover technology, including four (4) fixed platform topsides



**Fig. 2.56** Sakhalin II project PA-B platform floatover topsides installation (courtesy of Posh Terasea Offshore Pte Ltd.)

installation in the West Africa and the weights of the topsides ranging from 9500 to 18,000 t.

It is also notices that it is not difficult to find the vessels suitable for performing floatover operation in the very shallow waters. The example for Venezuelan Corocoro CPF (Central Production Facility) project is a good demonstration. The topsides weighs 7400 Mt and the water depth was only 5 m. BOA barge BB29 was selected as the transportation and floatover vessel (Fig. 2.55).

The above examples are all single vessel floatover operations, which happened with very high percentage in the total real floatover cases. For some platforms, especially the jacket of the platform was not initially designed to suit the single vessel floatover operation, catamaran floatover technique then can be considered to avoid the jacket redesign. An example of spar topsides floatover operation using catamaran floatover technique will be presented later.

- CGBS floatover topsides installation offshore

In the earlier discussion, the *inshore* floatover platform integration of CGBS platforms was illustrated by the Herbinia platform example. Here is an example of *offshore* CGBS topsides floatover installation. The installation of the topsides of the PA-B (Piltun-Astokhskoye-B) was in the Sea of Okhotsk, northeast of Sakhalin Island, Russia. As shown in Fig. 2.56, the 29,600 Mt topside was built in Koje, Korea by SHI (Samsung Heavy Industries) and was carried by the “T” shaped (or bottle shaped) barge TCB2 and transported to the field where the concrete base was already settled down. The floatover operation was completed



**Fig. 2.57** The hull and topsides mating operation for Shell Auger TLP. McDermott's Intermac 650 carried the topsides weighing 24,000-tons. The top of the TLP column was 7 m (23 ft) above the water surface. The two derrick barges were not only standing by, but also assisting the mating operation (courtesy of Shell and McDermott)

with the TCB2 on 5th of July, 2007. It was also a record-breaking success [28, 29].

- Floaters

When discuss the floating platform integration by offshore floatover, it generally means single columned floaters such as the spar's for which the hull needs to be wet towed to the field and then upended to be ready for the integration with the topsides. TLP and Semisubmersibles would get the floatover integration inshore. Shell's Auger TLP was a special case. The platform integration site was at Galveston Block A206 of GOM, approximately 70 miles south southeast of Freeport, TX. The mating site is not the TLP stationing location. The place was not inshore, but could be considered near shore. The water depth at the mating site is 73 m (240 ft). However, the area is not a sheltered coastal region and the operation was during the hurricane season.

The Shell Auger TLP was the first TLP platform in the GOM. The TLP platform was to be stationed in the Block 426 of Garden Banks of GOM. The water depth of the station area is 870 m (2860 ft). The 21,500-ton Auger TLP hull was fabricated primarily at Taranto, Italy. After the completion, it was wet-towed to the GOM over a long journey more than 6880 nm. The topsides was built at McDermott's Morgan City yards with the total weight of 24,000 tons. The floatover method was chosen and the operation vessel was McDermott's Intermac 650, which carried the integrated topsides to the mating site and



**Fig. 2.58** Murphy's Kikeh truss spar platform integration offshore Malaysia in November, 2006 was the first open water catamaran floatover operation and was successful (courtesy of Technip)

performed the single vessel floatover operation. During the mating, the TLP hull was de-ballasted making the columns rise and attach the topsides' legs. Derrick barges DB-16 and DB-28 were on site to assist the mating operation (Fig. 2.57). The platform integration was successfully completed in October 1993. Then the integrated TLP was towed to Freeport for inshore HUC. After that, the TLP was towed to the stationing area where it was hooked up with the pre-installed LMS (Lateral Mooring System) and the tendons were installed. The Shell Auger TLP is the only TLP with LMS and completing the topsides/hull mating in open water during hurricane season. Actually, the operation arrangement was not as initially planned but took place in dealing with the delay in the schedule. Tremendous efforts were made in the management and planning supported by intensive engineering efforts. In preparation of the topsides/hull integration operation, an Offshore Procedure Manual and a Weather Contingency Manual were developed with very detailed instructions. Although the operation succeeded, the open water floatover hull/platform integration did not become the favored choice for TLP. Inshore integration using heavy lifting equipment have been applied of the other Shell TLPs in the record.

For floaters like Spars, on-site topsides installation is inevitable. Among the proposed methods, catamaran floatover method has been commonly accepted as the favored one. However, there had no completed open water catamaran floatover operation before Murphy's Kikeh truss spar installation. The Hibernia CGBS platform integration with catamaran floatover operation was aforementioned, but that was inshore within the sheltered waters. Kikeh spar was deployed 75 miles northwest of the island of Labuan, offshore Sabah, East Malaysia with the water depth of 1341 m (4400 ft). The truss spar hull and topsides were fabricated at the Malaysian Shipyard and Engineering Sdn Bhd Facilities in Johor Bahru, Malaysia. The topsides was not so heavy—weighing 4000 Mt [30].

The team from Technip conducted the topsides installation. The mating site was the stationing area where the spar hull was upended and hooked up with the



pre-installed mooring system. Different from the single vessel floatover operation, the topsides was not directly loaded out from the yard to the floatover vessels, but first onto a transportation vessel. Then the topsides was later transferred to the floatover vessels at a pre-selected location to form a catamaran. The detailed discussion on the catamaran floatover methods will be included in Chap. 6.

For Kikeh project, the chosen transportation barge was UH336 of Uni-Bulk Services with the specified deadweight of 11,000 Mt. Twin barges of Swiber Offshore—Swiber 252 and Swiber 253 were used as the floatover barges with the deadweight of 5332.3 Mt. The site of topsides transferring from UH336 to the twin barges was in the harbor of Labuan. The site was sheltered. After the completion and with the favored environment, the catamaran was towed 59 nm (110 km) to the spar stationing site for the mating. At the site the significant wave height  $H_s$  was 0.7 m and the corresponding swell period was seven–eight seconds. The floatover operation went smoothly and was successful (Fig. 2.58).

### 2.3.3 Challenges and Development

For offshore floatover installation, as previously mentioned, the catamaran method is no doubt an option to supplement the single vessel floatover method, which is considered mature in operation. Comparing to single vessel floatover, more technical and operational challenges exist for the catamaran floatover technique.

First, the selection of the two floatover-barges is not simple, beside the examination each barge for hydrostatic, hydrodynamic and structural properties, the behavior of the catamaran during the transportation and the floatover operation need thorough and seriously engineering analyses to assure the safety of the operation



**Fig. 2.59** Example of vessel concepts for catamaran. On the *left* is a conceptual design of OCDV (Offshore Construction and Decommissioning Vessel) by Master Marine AS. On the *right* is the catamaran vessel concept from student team of the University of California, Berkeley in 2002 (courtesy of Master Marine AS and UC Berkeley, Ocean Engineering) [31, 32]



**Fig. 2.60** The largest vessel in the world so far—Pioneer Spirit of Swiss Company Allseas (courtesy of Allseas and gCaptain)

and the cost-effectiveness. In most cases, the engineering modification of the vessels and the heavy rigging design are necessary.

Secondly, the extra step of topsides transferring brings about more challenges for engineering and operation. In catamaran floatover operation, transferring the topsides from the transportation barge to floatover barges was a critical step. Transferring site selection and engineering simulation of the operation are vital. On the operation side, carefully created procedures and operation manuals with details of systematic instructions based on engineering studies and real practice experiences are the key for success.

The mating process for catamaran floatover is also more complicated because of the involvement of multi-body motions.

In dealing with the aforementioned challenges, one way is to conduct thorough engineering simulations and to optimize the operation procedures with adequately prepared equipment as well as contingency plans. Success can be expected with the accurate execution of the installation plan. The success of Kikeh spar is a good example, which can encourage more applications of the open water catamaran floatover.

At the same time, it should be noted that in offshore industry there have been intensive efforts in develop new method to use one vessel to carry out the catamaran floatover tasks considering both simplicity, safety and cost-effectiveness.

Some of the activities started actually from searching the solution of the platform decommissioning. As estimated, there are more than 80,000 aging platforms waiting for removal. Although the decommissioning process can be thought the reverse of the installation, but it is not practical. Some real decommissioning projects have been carried out and there have been various approaches to make the operation safe, environment friendly and economic, but there is no simple solution. For fixed platform decommission, an ideal solution is to remove the topsides and the jacket by single lift without using huge HLCV's.

Many efforts have been focusing in the development of new type of vessels, which are capable of performing the topsides catamaran floatover operation in the open sea and can perform decommissioning of platforms by a single lift. Examples

include cantamaran vessel concept by UC Berkeley, OCDV(Offshore Construction and Decommissioning Vessel) by Master Marine AS (Fig. 2.59), MPU Heavy Lifter by MPU Offshore Lift ASA, DSIV Technip, etc. They will be revisited with detail in later chapters.

The goal of the concept development is straightforward: the vessels based on these concepts can be designed for real isolation and decommissioning projects. Of course, there are other factors having impacts on the investors.

One vessel launched in 2014 drew the attention in the shipbuilding, oil & gas and energy industry. She is the Allseas' new vessel "Spirit Pioneer" which was originally named "Pieter Schelte" and was recognized as the largest vessel built in the world so far. "Spirit Pioneer" is a multi-functioned vessel of 382 m (1252 ft)  $\times$  123.75 m (406 ft)  $\times$  30 m (98 ft). The vessel was designed to remove and decommission of the topsides of Shell's Brent platforms with weight ranging from 16,000 to 30,000 tons and the Brent Alpha's steel jacket. At the bow of the vessel there is a slot of 122 m (400 ft)  $\times$  59 m (194 ft), equipped with eight (8) sets of horizontal lifting beams for a single lift of topsides weighing up to 48,000 tons. Two tilting lift beams at the stern can be used for the installation and decommissioning of jackets weighing up to 25,000 tons. The main construction of Spirit Pioneer was done at Daewoo shipyard, Korea and completion was in the Netherlands (Fig. 2.60).

There is also the large deck space for offshore onboard operation. The stability and motion property are outstanding and she is capable of performing the offshore operation under the condition of  $H_s = 3.5$  m. The decommissioning of Shell Brent platforms will start in the future, and at that time, the experiences of using Spirit Pioneer could affect the direction of the development of platform integration methodology.

## 2.4 Summary

Bases on the discussion with the examples of offshore installation practice, the following conclusions can be drawn:

- For floaters, if possible, the inshore platform integration is preferred. There are multiple factors in choosing between applying heavy lifting and floatover methods. Modularized lifting operations are still used and the decision will be made by the specific projects.
- Although there have only been about 30 offshore floatover operation completed in the world, the momentum has been building up, especially for heavy topsides weighing more than 10,000 Mt. There is still room for floatover technology development, including new vessel and equipment development.

Detailed discussion on floatover technology is in next chapter.

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