Regulations and Cost Estimation for the Decommissioning of a Sample Fixed Offshore Platform in Brazil

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***Abstract*— Fixed offshore platforms become economically unfeasible when the production phase ends or maintenance and operation costs exceed the returns. In addition, aged fixed platforms pose an environmental threat since the risk of accidents increases over time and therefore need to be decommissioned. Due to the long history of offshore oil and gas exploration in the Gulf of Mexico, the experience in the United States has led to industry wide standards for decommissioning offshore facilities. This paper describes the decommissioning activities for fixed offshore platforms including subsea installations at the seabed. The regulations of the United States are compared to the current set of regulations valid for the coast of Brazil. This paper further evaluates cost estimation assessments and identifies the principle components. The summarized cost studies provide the basis for the decommissioning of a sample fixed offshore platform located in the Campos Basin, offshore Rio de Janeiro, Brazil.**

***Index Term*— Fixed offshore platform, Decommissioning, Cost evaluation**

I. Introduction

THE need to decommission a fixed offshore platform becomes inevitable if the design life has been exceeded [1] and the structure poses a risk of structural failure. In addition, decommissioning is initiated if the oil field is depleted and the facilities are of no further use, or if the oil production is no longer profitable and operating costs exceed the returns on a permanent basis.

Decommissioning comprises terminating oil and gas operations and returning the field in compliance with regulations required by the local jurisdiction [2]. The decommissioning of a fixed offshore platform covers several activities and requirements that are not unanimously defined. In general, the decommissioning process contains the planning and execution of the removal and disposal of the offshore and subsea facilities [3].

This paper focusses on the decommissioning of fixed offshore platforms. Reference [4] lists a total of 68 operating fixed platforms in Brazil in 2016 with the majority scheduled for decommissioning in the next decade. Only a few small fixed platforms have been decommissioned in Brazil so far and the decommissioning procedure is therefore not well-established.

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As a consequence, the decommissioning of aged fixed platforms has become a major concern for the Brazilian oil and gas industry. It is of keen interest to further specify the procedure and estimate the cost of the decommissioning of fixed platforms.

The legal requirements established in Brazil are defined by the Agência Nacional do Petróleo (ANP) and are in the initial stages of development. In comparison, the Unites States Code of Federal Regulations (CFR) contains a comprehensive set of decommissioning regulations. The CFR [2] is the main code referenced by the related literature because the Gulf of Mexico (GOM) has had, by far, the largest number of concluded decommissioning projects [5]. This paper provides an example of the decommissioning procedure of a fixed offshore platform and the associated facilities as well as the estimation of the corresponding financial expenses.

II. Main Procedure and Regulations

The main activity types involved in the decommissioning of fixed offshore platforms can be summarized by the following categories [2]:

- Application and decommissioning approval
- Permanent well plugging and abandonment (P&A)
- Pipeline decommissioning
- Removal of the platform and associated facilities
- Site clearance

Each category is associated to a set of decommissioning procedures and requirements that have to be adjusted on a case to case basis. The mandatory decommissioning regulations have the following objectives ([2],[6]):

- Provide decommissioning guidance
- Guarantee safe and efficient procedures
- Prevent unnecessary risks associated with environmental hazards

Federal, state and local authorities, as well as environmental agencies, require specific forms of application and approval procedures for decommissioning projects, which can vary for different countries [7]. In Brazil the national oil and gas agency ANP is responsible for the approval of decommissioning projects. The ANP ([6],[8]) mentions only general documentation requirements and related legal steps to be taken in Brazil. In comparison, the CFR provides all the required information to the public. The CFR [2] requires defining and planning the entire procedure of the decommissioning activities based on specified forms and tables.

Prior to the execution of a decommissioning project it is imperative to perform all necessary planning and engineering work ([7],[6]). The obligations of all parties involved in the decommissioning process need to be identified and the current condition and configuration of the field and installations assessed. The performance of all engineering analyses is mandatory to plan smooth and efficient operations. Finally, the bidding procedures can be initiated to select subcontractors for the individual activities considering the availability of vessels and specialized equipment services as well as locations for disposal.

A. Well Plugging & Abandonment

1) Well Plugging Procedures

The oil and gas field well is the principal source of contamination as hydrocarbons or drilling mud could spill out. Therefore, the objective is to permanently plug the well to guarantee no leakage when the field is decommissioned [9]. Well plugging is one of the major and most delicate tasks during the decommissioning process, which is instructed by the governmental authorities ANP [10] in Brazil and the Bureau of Safety and Environmental Enforcement (BSEE) in the Unites States [2].

Prior to the actual plugging procedure the current condition of the wells and their specifications have to be determined [2]. As part of the planning procedure, the review of all related documents that contain information about well depths, location of the perforations, deployment of the production liners as well as the condition of the wellheads and Blowout Preventers (BOPs) is required. If considered necessary, additional inspections with the use of remotely operated vehicles (ROVs) might be performed to ensure smooth operations during the well plugging [7]. Once the information is gathered, the approach on how to plug and abandon the wells can be specified. Each and every well requires an individual examination of the applied procedure. Should there be temporarily plugged wells in a given field, these must be permanently plugged during the decommissioning phase.

Furthermore, it is necessary to stop the production of hydrocarbons and omit secondary recovery techniques [11], such as water injection or gas lift, before plugging operations can be initiated. It is also recommended to clean the wellbore and to retrieve downhole equipment, such as liners, including packers, that have been previously installed in the casing string to facilitate plugging operations [7].

The plugging of a well consists mainly of the following steps:

- Placing mechanical plugs by wireline operations into the casing string
- Pumping cement down the casing string
- Filling spaces between cement layers with drilling mud.

Mechanical or wireline plugs are usually placed by wireline operations into the casing string and temporarily seal the flow of hydrocarbons. Mechanical plugs are usually utilized for the repair or substitution of the BOP´s. For the purpose of well abandonment, deployed mechanical plugs additionally serve as a support for the cement layer that will be placed on top. Cement is pumped down to form the permanent plug. The plugging procedure is repeated for all critical zones in the wellbore. Remaining space in the casing string between cement plugs can be filled with drilling mud for further safety. The use of drilling mud requires special attention, since it contains toxic substances [12]. After the well has been plugged, additional pressure tests guarantee, that no leakage will occur. Therefore, the plug needs to resist a specified maximum pressure rate [2].

The CFR [2] considers several cases of well configurations for the plugging requirements. The Brazilian regulations [10] also present different permanent plugging criteria based on the type of well completion. Summarizing the well plugging requirements in the ANP [10] and CFR [2] are very similar but those of the CFR [2] provide a more detailed and particular list of possible scenarios.

For the procedure of well abandonment a distinction has to be made between wells located directly below the platform and wells nearby, although the plugging requirements remain the same. The conductor pipes directly connect the topsides with the platform wells and are much easier to access than subsea or satellite wells.

2) Platform Well Plugging & Abandonment

Platform wells neither have a wellhead nor a Christmas tree installed at the seabed as in the case of subsea and satellite wells. Instead, the conductor extends the casing string from the wellbore up to the topsides where a dry tree is installed on top. The P&A procedure basically consists of the plugging procedure explained in the previous section and the following removal of the conductors, which is addressed separately in the following section.

The required equipment for well P&A needs to be able to perform wireline operations and cement pumping or mud drilling through the conductors as well as lifting operations. The capability of the existing topsides equipment needs to be evaluated. Some platforms have a fixed topsides derrick, plus available pumps and wirelines. For the majority of the cases the available equipment is not entirely appropriate for the purpose of well P&A and additional machinery is necessary. The use of integrated systems placed on topsides is a convenient and cost-effective method, referred to as rig-free technology. Rig-free systems eliminate the use of costly drilling rigs, which are often placed adjacent to the fixed platform by jack-up platforms. Instead, the integrated system itself allows to perform wireline, cementing and pumping operations all in one. Using rig-free technology requires the preparation of the topsides to create enough space for the large equipment but the cost advantage can be substantial.

3) Conductor Removal

To complete the well P&A for platform wells the conductors need to be removed. Prior to the actual removal cleaning operations need to take place to make sure, that no hydrocarbons are left in the conductors. These may also include the removal of marine growth from the conductors to reduce the weight and establish a smooth conductor surface for pulling operations. The removal of the conductors requires three main steps [7]:

- Severing
- Cutting and pulling
- Offloading

Abrasive jetting tools are lowered inside the conductors to make a cut as close as possible to the seafloor or even below the mudline. The conductors are very heavy and therefore need to be held horizontally in position by the rig located on the platform. Having been severed from the downhole casing, each conductor is pulled up to a specified length by the platform rig and additional jacks and cut at the topsides forming segments of approximately 10m. The pulling and cutting procedure is repeated until the last remaining segment of the conductor can be pulled up and removed. The segments can be stored safely on deck or transferred to a vessel for further recycling onshore.

4) Wet Tree Well Plugging & Abandonment

Subsea and satellite wells require another P&A treatment since the well configurations are different and they are not easily accessible by equipment placed on the topsides of the platform. Instead, wet tree wells are connected to the platform by a system of subsea installations. The P&A procedure of wet tree wells comprises plugging operations and the removal of the wellhead systems and other related subsea installations.

For the procedure the wet tree wells need to be separated from the remaining subsea installations as a first step to facilitate plugging operations. All connected jumpers or spools, pipelines, umbilicals and risers are detached from the Christmas tree of the subsea and satellite wells using ROV operations.

In order to perform wireline and pumping operations to place a temporary and permanent plug into wet tree wells, multi-intervention vessels are employed. The cost of such a vessel is much larger than the integrated solutions that enable rig-free topsides operations. The intervention vessel positions itself above the wet tree well. A casing string is run down to the Christmas tree and connected. The hydrocarbons inside the production string are pumped back into the reservoir. A mechanical plug is placed with wireline operations into the casing string. This seal allows the removal of the Christmas tree as well as additional subsea equipment located close by as further discussed in paragraph B. With the Christmas tree removed another casing is run down to plug the well according to the stated requirements. At this stage the wellhead still sticks out of the seafloor and creates a possible obstruction. Therefore, the wellhead and the upper part of the casing string are usually removed by abrasive water jets which can cut through all layers of the casing string from the inside. Finally, a prepared cement plug is placed on top of the remaining casing string, which is aligned to the seafloor and forms the final seal.

5) Regulations for Plugging &Abandonment

The CFR [2] clearly states, that wellheads and casing strings as well as all other facilities attached to the seafloor have to be removed to at least 5m below the mudline. This means, for the case of platform wells, that the conductors need to be removed until this depth. For wet tree wells the removal of the Christmas tree, the wellhead, the upper part of the casing string and all other installations, such as the manifold, spool and PLET is mandatory.

In contrast, the ANP [10] defines the removal of all equipment related to the well and makes a differentiation between erosive and stable seafloors for water depths less than 80m. For stable seafloors the wellbore can reach up to the mudline while for erosive soils all installations need to be removed up to a depth of 20m below the mudline. Based on the ANP [10] the equipment, which would have to be removed up to a water depth of 80m, refers to:

- Conductors for platform wells
- Wellheads and wet trees for satellite wells
- Wellheads, wet trees, flexible risers and umbilicals for subsea wells.

On the other hand pipelines and other subsea installations, such as PLETs, PLEMs, manifolds, umbilicals on the seafloor, spools or jumpers can remain in place. Similarly, the ANP [8] allows leaving subsea installations in place.

For water depths above 80m no requirements are stated in the ANP [10] for the removal of installations related to a well. Therefore, this paper assumes based on the ANP [8], that for water depths greater than 80m wellheads and wet trees could actually remain in place or be placed on the seafloor adjacent to the plugged wellbores. As the ANP [8] requires the jacket removal only of the upper 55m below the water surface, this paper assumes, that this exception is not valid for the conductors. From a practical point of view a partial removal of conductors could lead to a structural failure which may lead to damage of the well plug. Therefore the requirements of the ANP [8] lead to a necessary removal of the conductors until the seabed.

B. Pipeline, Riser and Subsea Installations Decommissioning

In this section the decommissioning of pipelines, risers and subsea installations, such as umbilicals, manifolds, PLEM´s, PLET´s, optional templates and spools or jumpers is specified. These installations connect subsea and satellite wells to the fixed platform. The well P&A leaves the platform with no supply of hydrocarbons. In order to retrieve wet trees and wellheads as part of the well P&A procedure in section A.4) it is necessary to decommission all pipelines, production risers and umbilicals connected to the subsea and satellite wells as well as to the platform. The pipelines, production risers and umbilicals have to be cleaned by Pipeline Inspection Gauge (PIG) operations and flushed with seawater. Once these installations have been completely cleared of hydrocarbons and chemicals that could flow into the marine environment, it is possible to detach pipelines, risers and umbilicals from subsea structures, the wet tree wells and the platform. These operations are usually carried out by divers and ROV's. The entire subsea field is decomposed into the individual parts mentioned above.

Rigid risers are decommissioned as part of the platform removal, since they are attached to the structure. Having been severed, jumpers or spools can be retrieved by simple lifting operations, while umbilicals and flexible risers are usually removed by reeling them on a vessel. On the other side, templates, manifolds, PLEMs and PLETs pose a difficulty since they are often anchored by suction piles. These can be detached from the soil in reverse order of installation by ROV operations and retrieved. Other options are the application of cutting tools to detach the suction piles from the structure that needs to be lifted [13].

According to the CFR [2] all facilities attached to the seafloor need to be removed up to a depth of approximately 5m below the mudline [2] which includes flexible risers, umbilicals, jumpers or spools and subsea structures, such as PLEMs, PLETs, manifolds and optional templates. According to the CFR [2] pipelines do not necessarily have to be removed entirely. Pipelines, that do not entail environmental risks or form an obstacle, can be decommissioned in place [2]. The CFR [2] provides further specifications on the procedure for pipeline decommissioning in place. The CFR [2] states, that the cleaned and flushed pipelines need to be filled with seawater and all related valves have to be removed. The severed pipeline ends need to be plugged and buried approximately 1m below the seabed or secured by concrete mats or sand bags.

The ANP [6] states, that pipelines and subsea systems should be decommissioned by cleaning, cutting and plugging but does not mention the need to bury the ends of pipelines as in the CFR [2]. The ANP [8] allows the possibility to leave subsea installations, such as pipelines, umbilicals, PLEMs, PLETs, manifolds, jumpers or spools in place. On the other hand the requirements of the ANP [10] lead to a necessary removal of flexible risers and umbilicals if they are directly connected to a well and lead to the water surface. The ANP [8] is conform with this requirement because the removal of the platform implies necessarily the removal of flexible risers and umbilicals that are hanging from the topsides. Further, the ANP [6] recommends the application of established offshore industry codes but does not go into details.

C. Platform Removal

1) Platform Preparation

Platform preparation includes all necessary activities associated with shutting down and preparing the facility for removal. The procedure usually starts when all subsea facilities have been detached from the platform and the flow of hydrocarbons has stopped [7]. The activities involve inspections both above and below water to determine the structural condition of the platform and define repairs or strengthening if necessary. Corrosion or previous accidents may have caused degradation of the material or weak connections which may lead to accidents during the lifting operations. Up to a depth of 30m normal divers can remove marine growth. This may lead to a significant reduction of the weight and less lifting capacity for cranes that will be needed during platform removal. All modules need to be separated from each other by cutting all piping and cables. If the topsides are split up in several parts, it is further necessary to check, which parts need special attention in terms of cleaning operations since these might entail environmental hazards. The chemicals and materials, that might be present in the modules, need to be identified (e.g. Mercury, Asbestos, corrosion, radiological contamination) and specific treatment plans set up for these cases, especially in the cleaning procedure. Cleaning operations require flushing and emptying tanks from chemicals and hydrocarbons. Padeyes need to be installed at the lifting points of the structures or modules for lifting operations.

2) Topsides Removal

The topsides consists of several modules that are installed on different decks and connected to each other by piping. Certain equipment on the topsides can be quite valuable and other might pose a significant environmental threat that needs to be considered. Therefore, each module requires an individual evaluation and strategy for decommissioning.

Unless the topsides can be of further use, the CFR [2] requires the removal of platforms and therefore automatically of the topsides. Similar to the CFR [2], the ANP [8] requires the removal but allows the topsides to remain in place as long as the structural integrity is guaranteed by the lessees by regular inspection and repair plans. This exception allows to postpone temporarily the removal of the topsides but inevitably results in the removal at some point in time.

The following three strategies are available for the topsides removal:

a) Single lift
b) Reverse modular
c) Piece small

The first option (a) single lift is the simplest one which contains the lifting of the entire topsides as a single piece. Options (b) and (c) require cutting the topsides in smaller pieces. In reverse order of installation, each module on the topsides is lifted individually onto a barge for transport to shore. In the context of the piece small strategy the single modules are cut in even smaller components which allows the removal to take place by smaller vessels and cranes. Preparing the topsides for several cutting and lifting sequences leads to less requirements for the lifting capacity of the vessel. At the same time the duration of the removal and the work intensity involved with cleaning, separation and cutting procedures increases.

The decision, which removal strategy should be adopted, depends on the topsides configuration and the availability of capable vessels. Therefore, it is imperative to perform a full survey of the equipment and inventory of the platform. The most crucial factor to evaluate the strategies is certainly the weight of each equipment and the entire modules. Some special equipment might be worth reusing. These components should be separated and treated more carefully to avoid any damage. The cleaning and safety procedures are illustrated in more depth in [14].

3) Jacket Removal

The jacket structure needs to be removed since it forms an obstruction in the ocean. Unless the jacket can be of further use, the CFR [2] requires the removal of all platforms up to a depth of at least 5m below the mudline. This means, for the jacket, that all piles need to be cut at this depth to remove the structure. The CFR [2] contains an exception that allows the jacket to become an artificial reef which would fall under the responsibility of a federal agency.

The ANP [8] also defines the conditions for the removal of the jacket. Jackets with a dead weight of less than 4,000 tons in a water depth of less than 80m have to be completely removed. For stable soil conditions the removal until the mudline is sufficient but for erosive soils the piles need to be removed until 20m below the mudline. If the jacket weighs more than 4,000 tons or is located in a water depth greater than 80m, the ANP [8] requires only the removal of the upper 55m below the water surface and allows the remaining structure to be abandoned in place. The ANP [8] allows the jacket to remain temporarily in place as long as the structural integrity is guaranteed by regular inspection and repair plans. Similar to the CFR [2], the ANP [8] offers the option to convert the jacket into an artificial reef. The authors are not aware of any case, where this option has been adopted so far.

In general, several options are available to remove the jacket:

- Lifting the jacket as a single piece or cut into several parts to dispose onshore
- Lifting jacket as a single piece to be disposed in deep waters
- Lifting jacket with buoyancy tanks and tug to shore for disposal
- Convert jacket to artificial reef by toppling in place or cut in pieces and reposition

Lifting operations of jackets require heavy lifting vessels (HLV). Prior to lifting, the jacket needs to be detached from the seafloor. The jacket is anchored with piles to the ground. These piles can either be driven through the platform legs or as skirt piles adjacent to the platform legs. In either case the piles have to be cut to allow a safe removal of the jacket. In the case of piles, which are driven through the platform legs, cutting operations may become cumbersome since the annulus between the leg and the pile inside is often filled with grout. Piles can be cut by either explosives, saws or abrasive techniques.

Two strategies are common to lift the jacket either entirely as a single piece or in several pieces. The first option requires less preparation but an HLV with large capacity. The second option requires cutting the jacket at certain elevations either with the use of divers or ROV's. The jacket is then lifted piecewise which requires an HLV with much less capacity but longer operational time.

A special piecewise removal of the jacket structure is referred to as "hopping" [7]. In this technique the jacket is detached from the seafloor and brought to a smaller water depth to remove further sections from the top. This method reduces the need of deep sea divers or ROV operations.

An alternative to the single lift of the jacket with an HLV is the use of controlled variable buoyancy systems [15]. These systems consist of actively controlled buoyancy tanks which are attached to the jacket and cause enough uplifting force to allow the platform to be towed to the shore.

The last option is to topple the jacket on site. This procedure is described briefly by [15] who suggests cutting all piles instead of only one side which forms the fixed rotational axis. The piles of the last side of the jacket should be cut until half the diameter is reached. This approach leaves the cross section weak enough to allow a plastification of the steel to take place, which would result in a rotational hinge. The jacket should then be toppled with the use of winches. According to the ANP [8] this option is valid for Brazil if the toppled jacket remains 55m below the water surface and the jacket weighs more than 4,000tons or the water depth is greater than 80m.

The toppled jacket could serve as an artificial reef. Currently, no rig-to-reef programs in Brazil are known by the author such as the program valid for the U.S. coast [16]. The optimal depth for the jacket to serve as an artificial reef is between 30m and 60m [17]. The alternative to an artificial reef is to convey the structure for disposal to deeper seas or to shore, which both implicate transportation costs. The question whether the jacket may be disposed under water needs to be addressed by the Brazilian legislation. In comparison to the topsides, pipelines and other subsea installations, the jacket does not contain remnants of hydrocarbons or chemicals. The jacket usually consists only of steel, anodes made of aluminum for corrosion protection and paint, which contains zinc. The downside of submerged structures is, that the steel corrodes further whereas the effect on fish population has not been investigated thoroughly to form an opinion [18].

Independent of which removal concept is applied, the structural integrity of the jacket needs to be verified. During any lifting or toppling operation an already damaged joint could result in severe accidents. A careful planning and monitoring procedure needs to be established and all cases should be verified by engineering analyses.

4) Site Clearance

Once all subsea installations and the platform have been removed and the pipelines abandoned in place, the CFR requires that the field has to be cleaned from remaining debris [2]. In comparison to the CFR, the ANP [8] requires site clearance only for water depths less than 80m.

Divers and ROVs are able to scan the area around the location of previous installations and check for objects that might interfere with future work or contain environmental hazards. Another cost-effective option is to use trawls to clear the site. The CFR [2] defines radii of site clearance for different installations, such as platform wells, satellite wells, subsea structures and the platform site. Sonars are a useful technique to scan large areas and verify if all debris has been removed. Ships with equipped sonars should perform scans both prior and after the removal of the installations [7].

Although it has been recommended in [19], that a continuous monitoring of the abandoned installations be included in the decommissioning program, the exact scope has not been defined. Neither the CFR [2] nor the ANP [10] address this topic. Especially in the case of the abandoned wells, monitoring at certain time intervals should be performed to guarantee, that the plug still seals the well. The authors have not encountered any recommendations that require certain time intervals or monitoring techniques of the site after decommissioning has finished.

III. Cost Estimation Approach

This paper uses a recent study [17] of cost estimates, which determines the financial expenses for decommissioning 17 fixed offshore platforms in water depths greater than 120m in the GOM. These platforms serve as a representative set for fixed platforms in the GOM, since they cover a wide range of designs that are similar to the platforms built in the Campos Basin of Brazil.

Reference [17] determines cost estimates for the following set of activities:

- Well P&A and conductor and subsea structures removal
- Pipeline abandonment
- Umbilical and flexible riser removal
- Platform removal including preparation and site clearance

All decommissioning activities within the cost estimate of the study fulfil the assumptions listed below:

- All activities comply with the CFR
- Approaches are conventional, according to industry wide practices
- Operations are non-problematic, ordinary
- No salvage value, no sale value of equipment
- Operators do not share resources
- All required vessels, specialized equipment and services are available at location

As a consequence of the last assumption in the list, the study considers mobilization and demobilization costs only for a few days for the GOM. The availability of required vessels, specialized equipment and services is regarded valid for Brazil as well, since the oil and gas industry is well-established in the Campos Basin.

The cost estimates of [17] are defined as P50 cost estimates [20] with an accuracy of ±20% in U.S. Dollars ($) and are based on market and technology conditions of 2009.

Costs for overhead, such as planning and engineering as presented in chapter II, have a significant impact on the total decommissioning cost estimate and are explicitly mentioned in this chapter for each decommissioning activity. The assumption of non-problematic and ordinary decommissioning procedures does not necessarily turn out to be valid. As a consequence, further contingencies are added as a percentage of the activity cost. A work contingency allows taking inaccuracies into account and also not estimated issues, such as minor changes of the decommissioning procedure design or techniques, which do not generally change the concept. The work contingency covers also market variations, such as costs for required equipment or vessel rates since these factors are assumed to be constant in the estimate but undergo changes along time. Finally, a weather contingency includes the chances of schedule slips due to severe storms. All mentioned contingencies depend especially on the location, type and modifications of the offshore platform as well as on the chosen decommissioning options of platform removal, transportation and disposal [7].

Reference [21] generalized regression equations based on the results obtained in [17]. The curves furnished therein are useful to determine cost estimates for platforms which do not match exactly the properties of the 17 sample platforms of the cost study in [17].

A. *Platform Well Plugging & Abandonment*

The most important variable to determine P&A costs of platform wells is the difficulty or complexity of a well since it determines the time required to complete the activity [7]. Also the depth of the platform wells has an impact on the cost due to longer plugging operation times and additional cement volumes.

Reference [17] estimates the cost per platform well c_{pw} for the plugging and preliminary abandonment of a total number N_{pw} of at least 15 platform wells. The preliminary state corresponds to the fact that the conductors are still in place. Once these have been also removed, the platform well abandonment can be considered complete. Fig. 1 presents the costs based on an increase with water depth d. This cost estimate is based on the assumption, that a rig-less method is applied and that the wells are trouble-free plugged according to the CFR [2]. The costs include P&A work of 2-3 days for each platform well and fixed costs for mobilization, demobilization and placing a platform rig and casing jacks on topsides within 8 days. The cost estimate also contains a work provision of 15%, weather contingency of 20% and overhead costs of 8% for planning and engineering.

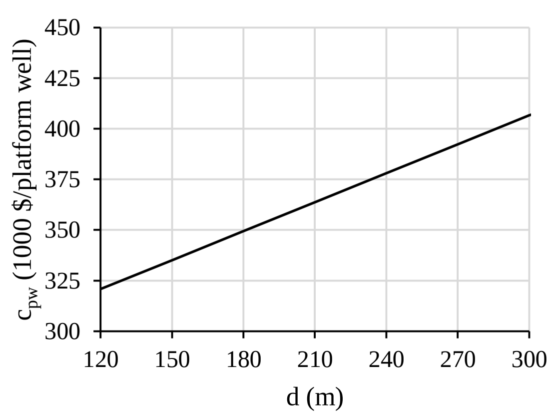

Fig. 1. P&A costs per platform well for a set of more than 15 platform wells [17]

The cost to abandon a single platform well increases with the water depth because the demand on equipment rises. On the other side, the unit cost remains nearly constant as the total number of platform wells increases if the number exceeds 15 platform wells [17].

In a different study conducted by [22] the P&A costs for platform wells are estimated based on the complexity of the wells as shown in Table I. The study assumes the use of rig-less techniques with mobilization and demobilization costs from the GOM. Difficult well completions might contain inclined wellbores, high annular pressures, parted casings or require fishing operations.

TABLE I
PLATFORM WELL DECOMMISSIONING COSTS BASED ON COMPLEXITY [22]

Well type definition by level of complexity	Average cost/well ($)
Low cost well (3 days)	140,112
Med low cost well (4 days)	170,116
Med high cost well (5 days)	224,120
High cost well (8+ days)	328,532

B. Conductor Removal of Platform Wells

To complete the preliminary abandonment of platform wells making them permanent, the conductors have to be removed. This includes severing, pulling, cutting, and offloading. Reference [17] developed unit prices per conductor c_{cond} depending on water depth d. These unit prices are applicable for platforms with at least N_{cond} =15 conductors in total. This cost estimate is based on the assumption, that the conductors are cut 5m below the mudline with abrasive cutters. The cost estimate assumes the availability of hydraulic jacks as well as a platform drilling rig and crane to pull and offload the conductors. The approach applied in [17] covers lifting the conductors in 10m segments with the drilling rig and casing jacks. The conductors are cut on topsides with saws and offloaded with the platform crane to a barge. Afterwards, the conductor segments are brought to shore for disposal. The estimate includes mobilization costs of a cargo barge, work provision of 15%, weather contingency of 20% and overhead costs of 8% for planning and engineering. Fig. 2 presents the cost for conductor removal based on an increase with water depth d.

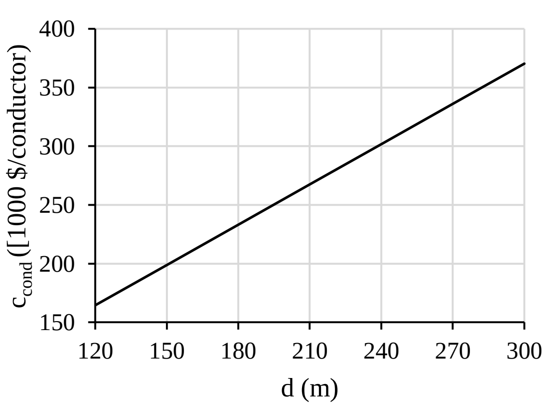

Fig. 2. Removal cost per conductor, applicable only if the total number exceeds 15 conductors [17]

The unit cost to permanently abandon a single platform well with the removal of the conductor increases with the water depth because more time is needed to lift and cut a greater number of string sections in several steps. Otherwise, the unit cost remains nearly constant with an increase in the total number of conductors if the total number of conductors exceeds 15. According to [7] it does not matter for the cost whether a conductor is removed immediately after the related platform well has been plugged or first all platform wells are plugged and then the conductors removed.

In a different study, [22] estimates the cost for the conductor removal of 23 platforms with a total of 810 conductors of the Pacific Outer Continental Shelf Region (POCSR). The cost estimate contains similar assumptions but does not include any contingencies, mobilization of cargo barges, engineering and planning costs. The study concludes, that the cost estimate can be simplified to a unit price of 945 $/m conductor length.

C. Wet Tree Well Plugging & Abandonment and Removal of Subsea Structures

Wet tree wells have a different cost estimation approach since the P&A involves vessels and associated techniques. Table summarizes a detailed cost estimate presented in [17] with the application of a semi-submersible rig and a rig-less option with an intervention vessel. The rig option requires the use of anchoring vessels with mooring lines and tug boats. The cost estimate is based on the assumption, that a total of 11 wet tree wells are plugged, each requiring 7.5 days. The mobilization and demobilization costs for the rig option cover 12.5 days and for the rig-less option 7 days. The activities and costs include the removal of the related subsea structures, such as trees, wellheads and templates [17].

TABLE II
COST ESTIMATE FOR WET TREE WELL ABANDONMENT ACCORDING TO [17]

	Duration (days)	Dayrate (Thousand $/day)	Rig (Million $)	Rig-less (Million $)
Preparation	-	-	0.345	0.345
2 anchor vessels	2x16	36	1.152	-
Anchor vessel fix costs	-	-	0.04	-
Drill rig	20.5	404	8.282	-
Vessel	14.5	180	-	2.61
Cost for P&A	-	-	0.12	0.12
Total			9.94	3.08

In general, the permanent P&A of wet tree wells is much more expensive than the P&A of platform wells due to higher vessel costs. These have a much greater impact if mobilization and demobilization require more than the assumed few days in the study of [17] for the GOM.

D. Pipeline Abandonment

The cost of pipeline abandonment depends on the complexity of the pipeline system at the seabed. Pipeline crossings require additional planning and time since more pipe sections need to be cut [7]. The decommissioning of the pipeline is usually combined with the separation from connected subsea structures, such as PLEMs, manifolds and spools or jumpers. Therefore, the time required for the decommissioning of the pipelines increases with the obstructions per pipeline. The pipeline abandonment cost usually increases with water depth because costs of diving activities and mobilization tend to rise [17]. The cost also increases with pipeline length, diameter and water depth, since a higher flushing volume is required to clean the pipeline, more time is necessary and more powerful pumps are required to accomplish the procedure. The decommissioning of pipelines requires a vessel whereas the cost varies a lot with the type of vessel utilized. In most cases a vessel is already present due to the P&A of wet tree wells.

Reference [17] estimates the cost for pipeline abandonment of the selected platforms of the study by [17] with reference to flushing volume, water depth, mobilization distance, pipeline termination point and type of vessel. Estimates are summarized in Table for representative pipeline abandonment scenarios with anchored dive boats being utilized. Anchored dive boats perform operations for water depths up to 150m. The pipelines are pigged, flushed and detached from all other subsea installations and from the platform. Pipelines are decommissioned in place by plugging and burying the ends with sand bags or concrete mats. These operations are carried out by ROV's or divers. The cost estimate also contains a work provision of 15%, weather contingency of 20% and overhead costs of 8% for planning and engineering.

TABLE III
PIPELINE DECOMMISSIONING COST SCENARIOS
BASED ON THE USE OF ANCHORED DIVE BOATS [17]

Water depth (m)	Mob. distance (km)	Pipe diam. (in)	Pipe length (km)	Volume (1000 m³)	Decom. costs (Million $)	Pipeline termination
137	254	4	2	28	0.9	In between platforms
122	226	6	31	566	1	
122	226	8	59	1926	1.3	
122	226	16	21	2662	1.4	
137	254	6	1	28	1.1	Platform to subsea installation
122	370	10	23	1133	1.8	
137	185	12	37	2662	2.6	

Reference [21] derives a linear multi-factor regression model based on the full set of representative pipeline abandonment scenarios. Equation (1) enables the estimation of the pipeline abandonment cost c_{pipe} with water depth d in meters, pipeline length L_{pipe} in km and pipeline diameter D_{pipe} in inches as relevant variables.

$$c_{pipe}\,[\$]=42968+5085\cdot d+9961\cdot L_{pipe}+43305\cdot D_{pipe} \qquad (1)$$

In a different cost assessment, [22] analyzes the pipeline decommissioning of 23 platforms of the POCSR. The total length of the pipelines sums up to 553km. This cost assessment differs in comparison to the study of [17] due to the fact, that it considers a complete pipeline removal if the water depth is less than 60m. The remaining pipelines in water depths above 60m are decommissioned in place. This paper derives from the cost assessment [22] a simplified unit price of 115,000 $/km.

E. Umbilical Removal

Umbilical length and water depth are the main criteria to define the cost of umbilical removal. The longer an umbilical is the more time is necessary to flush and reel it. For a greater water depths different vessels are necessary which also need to contain more powerful pumps for the flushing operations.

Reference [17] provides a simplified approach to determine the decommissioning cost for the complete removal. The umbilical removal cost includes flushing, cutting and reeling. The umbilicals are detached on both ends by ROVs and reeled to an anchor handling vessel. Table provides the cost estimates for water depths of 120m and 300m. The costs include weather and work contingencies but do not contain the mobilization costs of the vessel nor engineering costs. The unit cost of umbilical removal per meter length reduces with a larger total length, because fixed costs for mobilization and equipment are allocated to a greater length.

TABLE IV
COST ESTIMATE OF UMBILICALS [17]

Length (km)	2	4	6	10	20	37
Costs/length ($/m) for d=120m	42.11	23.61	17.74	12.81	9.04	7.41
Costs/length ($/m) for d=300m	55.04	30.08	21.81	15.35	10.61	8.07

In a different cost assessment [22] estimates the cost of umbilical removal with a total umbilical length of 53km for 23 fixed platforms in the POCSR. The cost estimates are very similar to the values presented in Table . The study presents a simplified unit cost value per umbilical length of 106 $/m.

F. Flexible Riser Removal

Flexible risers are connected to the platform and removed similar to umbilicals by spooling them to a reel or by removing them with heavy lift vessels. In comparison, rigid risers are connected to the jacket and considered part of the structure.

The cost of flexible riser removal c_{riser} has a value of 256 $/m which is factored by the flexible riser length L_{riser} [17]. The unit cost includes weather and work contingencies but does not include the mobilization cost of the vessel nor engineering costs. The flexible riser removal cost covers flushing, cutting at the seafloor and detaching from the platform prior to the removal.

Flexible riser removal costs increase with length. As vessel costs are not taken into account, the flexible riser removal cost is negligible compared to other decommissioning cost components if the procedure is performed from the platform or by low cost vessels.

G. Subsea Structures Decommissioning

Subsea base structures, such as PLETs, PLEMs, templates, manifolds as well as jumpers or spools need to be removed up to a depth of 5m below the mudline according to the CFR [2]. This requirement is considered very strict and needs to be discussed for other locations. In general, exceptions can be thought of, which would allow the facilities to be left in place if they are installed in a water depth where they do not pose any threat as an obstruction. Similar to the previously mentioned argument, the approach by [17] has made an exception. It is considered, that templates anchored to the seafloor are decommissioned in place but if the connection is simple and the template easy to detach, the installation is lifted to a vessel for disposal. Cutting anchored piles at the seabed results in a significant cost increase and could be avoided if the anchored facilities do not pose any environmental threat, which is generally the case. On the other hand, the removal of subsea structures is considered as part of the well P&A cost for subsea and satellite wells in section C.

H. Platform Removal and Site Clearance

Preparing the platform for removal is a task usually performed by crews on a day rate and does not require vessels or heavy equipment. The costs for the inspection of the jacket and topsides might vary due to the age of the platform. Older platforms require more inspections to determine the current structural condition of the jacket for a safe removal. The number and size of modules placed on the topsides vary significantly. Therefore, the preparation of these modules for removal requires different time frames, which need to be evaluated for each platform individually. Heavy modules, such as the living quarter or the flare tower, might require additional resources [7].

The cost of the topsides removal depends on the chosen method, whether a single or multiple lift approach is chosen. The single lift requires little preparation but much larger costs for the vessel and is the preferred option for small topsides. The topsides of a platform can become very heavy and weigh more than 10,000tons. A single lift approach is considered not adequate since few vessels are available with such capacities. Therefore, the multiple lift approach is the preferred option which requires much more preparation and more time but will probably cost less due to the lower requirements of the vessel lifting capacity. Usually, the modules are removed in reverse order of installation [7].

The applied method to remove the jacket needs to be evaluated for each case individually. Cutting the jacket in smaller pieces requires less lifting capacity of the vessel which results in lower vessel costs. At the same time additional work associated with the more detailed cutting of the jacket and underwater activities is involved. This can become quite costly depending on the water depth as divers require pressure chambers at water depths below 30m or alternatively ROVs have to be used. A single lift approach could lead to extensive costs and an increased risk of an accident if the material has degraded and connection might fail during operations. A rig-to-reef program [16] would be a very cost-effective solution for the industry since disposal, recycling and transport to shore could be avoided.

Reference [17] determines a cost table for the entire removal of 17 fixed platforms in the GOM with varying configurations of its cost factors:

- Water depth
- Total number of piles

The cost estimate for the entire platform decommissioning considers a topsides removal with multiple lifts and a jacket removal by either a single lift in place or the hopping method. Among the different methods the cheapest one is selected. The legs are assumed to be severed with explosives for diameters less than 1.5m and with abrasive cutting for diameters larger than 1.5m. The entire platform is supposed to be transported to shore via cargo barges. Several water depths and number of piles are considered. The cost estimation method assumes, that the vessels are available in the region and therefore considers mobilization and demobilization periods of only a few days. The cost estimate includes:

- Platform preparation
- Removal of modules and deck in multiple lifts
- Removal of jacket in single lift or hopping
- Transport to shore
- Site clearance

Certain activities, such as the removal of the modules or the jacket, contain weather and work contingencies, while other activities such as platform preparation or site clearance do not. All activities contain a quota of 8% for engineering costs.

IV. Cost Estimation Approach

A. Specifications of the Case Study

The case study covers a deepwater fixed oil platform that serves as a host facility for oil production. The sample platform is located approximately 100km offshore Brazil at a water depth of 125m.

The topsides structure has dimensions of 55m width and 40m length. The jacket has a width of 75m and 55m length at the bottom which reduce to 55m width and 25m length at the top. The platform has a total height of 150m and weighs about 30,000tons. The jacket weighs 9,000tons and is anchored to the seafloor with 36 skirt piles adjacent to 8 platform legs. The topsides weighs about 21,000tons whereas 1,500tons are topsides steel weight only. The deck is subdivided into 20 modules including support frames and comprise living quarter, cranes, compressors and dry trees etc. with a weight of 18,000tons as well as equipment loads, such as piping, pumps, filters, water tanks and generators, with a weight of 1,500tons.

The oil field consists of 29 well completions including platform, subsea and satellite wells. About half of the wells are drilled for oil production whereas the other half serve for water injection. All 15 platform wells are connected to the topsides by 15 conductors each with a dry tree attached to it. Eight subsea well completions are located close to the jacket base and 8 flexible risers connect the wells to the topsides. Six satellite well completions require 6 flowlines and rigid risers to access the topsides. A total of 3 manifolds surround the platform. To each manifold 2 satellite wells are connected with spools or jumpers.

The platform is connected with 4 pipelines to neighboring platforms and facilities. An export pipeline leads to shore. These longer pipelines require each a PLET to compensate deflections due to pipeline expansion. Rigid risers on the platform connect the pipeline ends to the facilities on the topsides. A total of 16 umbilicals provide simultaneously electric power, control and chemicals to all subsea installations of the field. In between the pipelines and subsea installations 17 subsea tie-in systems in the form of jumpers provide sufficient flexibility for thermal expansion. Fig. 3 illustrates all components of the oil field with further details such as the pipeline lengths.

B. Well Plugging & Abandonment, Removal of Conductors and Subsea Structures

Within the scope of the case study 15 dry tree wells will be abandoned and the related 15 conductors removed. A total of 6 satellite and 8 subsea wells have to be permanently abandoned as well.

In accordance to Fig. 1, the plugging and preliminary abandonment of a single platform well in a water depth of 125m costs approximately $321,000. For a total of 15 platform wells the cost sums up to $4,815,000. All 15 conductors are removed by severing, pulling and cutting, and offloading. The cost estimate of the conductors is based on the cost curve presented in Fig. 2 which leads to a removal cost of a single conductor in a water depth of 125m of about $170,000. Therefore, the total cost for 15 conductors results in $2.55 Million. The estimate includes the mobilization costs of the cargo barge whereas further equipment is assumed to be available. The estimate contains work provision, weather contingency and overhead costs.

Rig-less techniques are applied for the abandonment of wet-tree wells of the case study. Therefore, the procedure costs $3 Million per well which results in a total cost of $42 Million for 14 wet tree wells. The cost assessment includes the decommissioning of the related subsea structures.

C. Pipeline Abandonment

The pipelines of the case study include 6 flowlines, 1 export line and 4 lines to neighboring facilities to build a network. All pipelines have a diameter of 10in, are located in 125m water depth and decommissioned in place.

The abandonment cost for each pipeline is estimated with the regression model of [21] in Equation (1). In contrast, the application of cost Table from [17] and the calculated unit cost per km length of [22] is not appropriate since the exact configurations of the sample pipelines are not similar. The cost of a single flowline with a length of 1km is estimated at $1,122,000 and therefore $6,732,000 for a total number of 6. The cost to abandon the export line with a length of 130km is estimated with $2,407,000.

The pipelines connected to other platforms or facilities to build a network have each a length of 10km. The decommissioning in place of a single pipeline leading to neighboring facilities costs $1,211,000, whereas the cost of all 4 sums up to $4,844,000. The abandonment of all pipelines of the case study requires a financial expense of almost $14 Million. This cost includes the use of vessels, ROVs and divers. The pipelines are pigged, flushed and detached from the platform and subsea structures. The pipeline ends are plugged and buried with sand bags or concrete mats. The cost estimate also contains work provision, weather contingency and overhead costs.

D. Umbilical and Flexible Riser Removal

The case study contains 16 umbilicals which are removed in a water depth of 125m. The values presented in Table provide the basis for the estimate of several unit prices based on the cable length. The value 7 $/m leads to a removal cost of $890,000 for the sample umbilical with a length of 120km that leads to shore. A unit price of 42 $/m is applied for shorter umbilical lengths of 300m and 1.1km. The removal cost of 8 umbilicals with a length of 300m sums up to $104,000. Additionally, the removal of 3 umbilicals with a length of 1.1km results in a cost of $138,000. The unit price of 13 $/m is valid for the 4 umbilicals with a length of each 10.1km and leads to the removal cost of $516,000. The entire removal cost for the umbilicals of the case study sums up to approximately $1.65 Million. The cost includes weather and work contingencies but does not contain the mobilization cost of the vessel nor engineering costs.

The case study contains 8 flexible risers each with a length of 220m. According to the unit price of 256 $/m defined by [17], the total cost to remove all 8 flexible risers sums up $448,000. The flexible riser removal cost covers flushing, severance at the seafloor and from the platform as well as the removal by reeling on a vessel. The removal cost includes weather and work contingencies but neither mobilization cost of the vessel nor engineering costs are included.

E. Platform Removal and Site Clearance

The cost estimate in [17] provides removal costs of several platforms among which a single platform is selected with similar characteristics. The selected platform is located in a water depth of 335m, anchored with 30 piles and has a total weight of 24,558tons. In comparison to the case study of this paper, the water depth of the comparison platform [17] is greater, whereas the number of piles and the platform weight are slightly less. This paper assumes, that the weight of the platform provides a more important indicator than the water depth since it serves as the main criteria to select the appropriate HLV. The platform removal cost for the case study sums up to $43.52 Million [17]. This cost estimation assumes, that the vessels are available in the region and therefore considers mobilization and demobilization periods of a few days. The principal activities, such as modules and jacket removal, contain weather and work contingencies but all single activities listed in [17] include engineering costs.

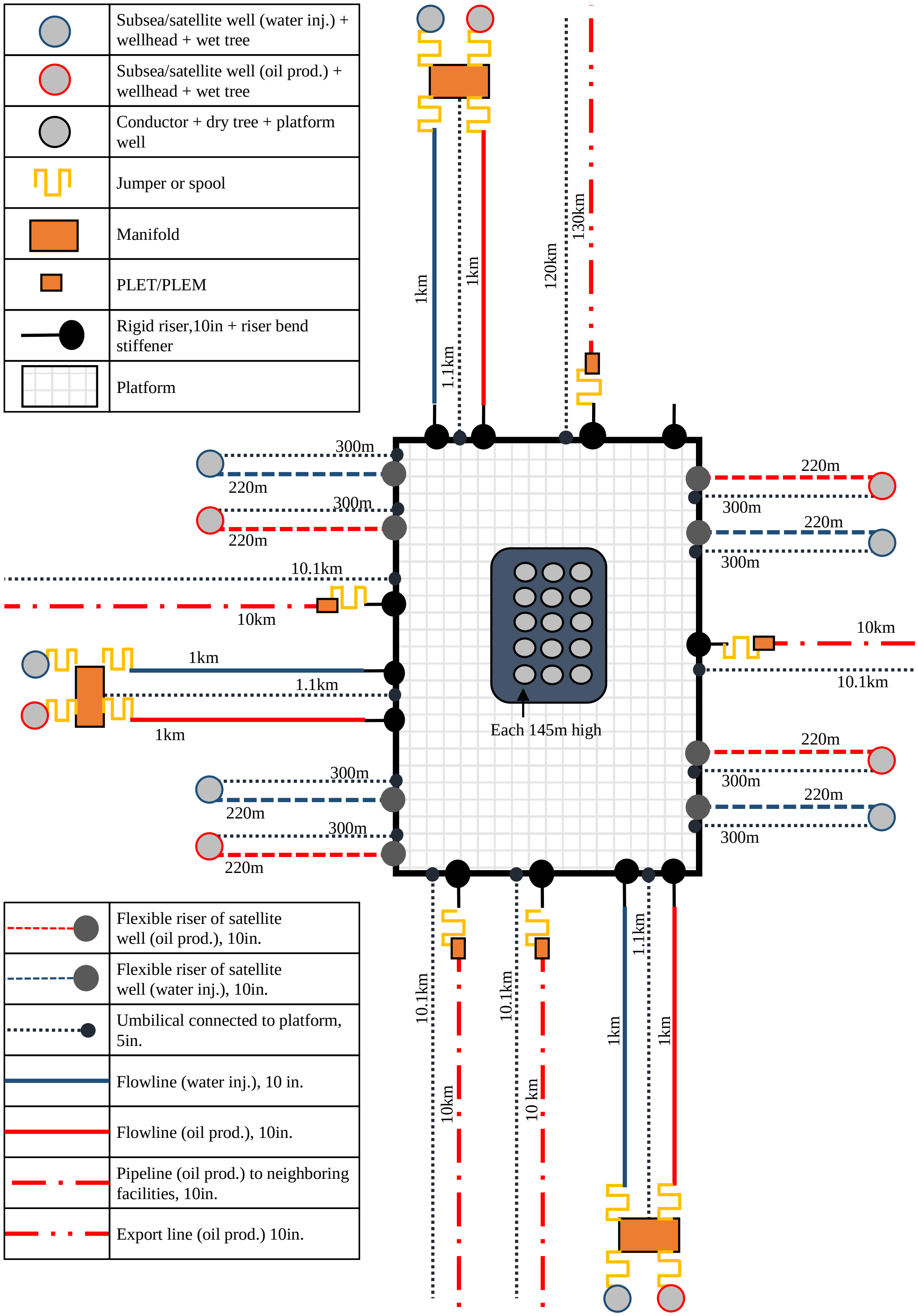

Fig. 3. Field layout of the case study

The cost estimation considers the topsides removal to be performed in reverse order of installation with multiple lifts on a vessel for transport and recycling onshore. Therefore, the topsides need to be prepared for removal by inspections, cleaning and cutting operations. The jacket is removed with the piles severed by explosives. The jacket removal is performed by the hopping method due to the heavy weight of the structure. The structure is brought onshore with a barge for recycling.

F. *Cost Estimate Summary*

Table V provides an overview of the individual costs and presents the total project cost to decommission the sample platform and its associated facilities.

TABLE V
SUMMARY OF COST ESTIMATION FOR THE CASE STUDY

Case Study Installation	Length (km)	Unit cost (Million $)	Quantity.	Total cost (Million $)
Wet tree wells and subsea structures		3	14	42
Dry tree wells		0.3	15	4.8
Conductors		0.17	15	2.6
Pipelines	10	1.2	4	4.8
	130	2.4	1	2.4
	1	1.12	6	6.7
Flexible risers	0.22	0.06	8	0.5
Umbilicals	120	0.9	1	0.9
	1.1	0.05	3	0.1
	0.3	0.01	8	0.1
	10.1	0.12	4	0.5
Platform (topsides and jacket)		43.5	1	43.5
TOTAL				**109**

The total decommissioning cost of the case study adds up to approximately $109 Million. As the base date for the cost estimate is set to 2009, the total project cost needs to be adjusted by the inflation rate of the region where the decommissioning takes place. Fig. 4 illustrates the cost breakdown structure of decommissioning the sample offshore platform and its associated facilities.

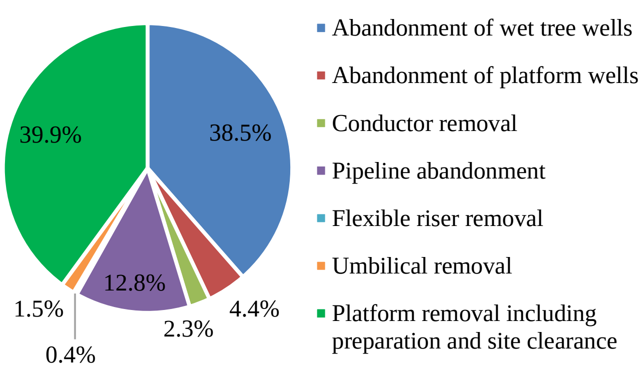

Fig. 4. Cost breakdown structure of case study

The platform removal adds significantly to the total decommissioning cost due to a large and expensive vessel that is required for the lifting procedure. The platform removal, preparation and site clearance contain a percentage of 40%. It can be further observed, that the abandonment of wet tree wells covers a large portion of 38.5%, too. Pipeline abandonment covers a percentage of almost 13% of the total decommissioning cost. Umbilical, flexible riser and conductor removal are in comparison simple activities and negligible in terms of total decommissioning cost.

V. CONCLUSION

Due to the long history of offshore oil exploration in the GOM, the experience in the United States has led to a detailed set of well-established and industry wide standards. In contrast, the current set of regulations valid for the Brazilian coast is still in the initial stages of development. Brazilian regulations should be extended to include more detailed specifications for decommissioning or officially refer to specific international regulations. The question of whether the strict requirements of the CFR are applicable to Brazil, needs to be discussed by the Brazilian authorities and the oil and gas community. Although requirements and guidelines for the decommissioning of offshore facilities are provided by the ANP, these are not sufficiently detailed and allow multiple interpretations, especially for the removal of jackets installed in deep water. A concise document containing all related information as in the CFR is not available for Brazil. The separate regulations for the decommissioning of wells and the platform by the ANP should be unified to a single code to avoid misunderstandings.

The cost estimate study by [17] provides a reliable source for the decommissioning costs of fixed offshore platforms and the associated facilities. The application of the cost tables and curves leads to a first estimate of the total decommissioning cost, which can be extensive as demonstrated for a sample platform located in Brazil. The total cost should be further adjusted by the local price level and inflation rate, which will lead to even higher expenses in the case of Brazil.

The high costs and the exceptions of the regulations in the ANP tempt lessees in Brazil to continuously postpone the decommissioning of fixed offshore platforms. This paper shows, that all alternative scenarios for the decommissioning should be evaluated, compared and discussed with the objective to optimize procedures and reduce the total cost. The oil and gas industry in Brazil needs to encourage the development of recommended practices for decommissioning procedures and cost estimates.

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