KERSTIN ELLWANGER

DECOMMISSIONING OF A FIXED OFFSHORE PLATFORM MAIN PROCEDURE AND COST EVALUATION

Dissertação apresentada ao Programa de Pós-Graduação em Engenharia Civil da Universidade Federal Fluminense, como requisito parcial para obtenção do Grau de Mestrado em Engenharia Civil.

Area de Concentração:
Gestão, Produção e Meio Ambiente

Orientador: Prof. Élson Antonio do Nascimento, D.Sc.
Co-Orientador: Prof. Dr.-Ing. Nelson Szilard Galgoul

Niterói
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RESUMO

As plataformas marítimas fixas se tornam economicamente inviáveis quando a sua fase de produção se esgota ou quando seus custos de operação e manutenção excedem o retorno correspondente. Além disso as plataformas envelhecidas que operaram por várias décadas representam elevado risco ambiental, visto que o risco de acidentes cresce com o tempo, pelo que precisam ser descomissionadas. Este estudo descreve as atividades de descomissionamento de plataformas marítimas fixas, incluindo instalações submarinas de fundo. As regras válidas nos Estados Unidos são comparadas àquelas contidas nas normas atualmente vigentes no Brasil. Além disso este estudo discute a estimativa de custos correspondentes e identifica os principais itens que entram em sua composição, tais como a remoção da plataforma e tamponamento dos poços satélites. Os preços contidos nestes estudos servem de base para o estudo de descomissionamento de uma plataforma marítima fixa na costa brasileira, tomada como exemplo.

Palavras chaves: Platformas Marítimas Fixas, Descomissionamento, Avaliação de Custos

ABSTRACT

Fixed offshore platforms inevitably become economically unfeasible when their 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 increase over time and have to be decommissioned. Due to the long history of offshore oil exploration at the Gulf of Mexico, the experience in the United States has led to industry wide standards for decommissioning offshore facilities. This study 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 study further evaluates cost estimation assessments and identifies the principle components, such as platform removal and subsea well plugging and abandonment. The cost studies provide the basis for the decommissioning of a sample fixed offshore platform located offshore Brazil.

Keywords: Fixed Offshore Platform, Decommissioning, Cost Evaluation

CONTENTS

LIST OF FIGURES

LIST OF TABLES

SYMBOLS

ANP	Agência Nacional do Petróleo
BOP	Blowout Preventer
c_{cond}	Cost per Conductor
$C_{platform\&site}$	Cost per Platform & Site Clearance
c_{pipe}	Cost per Pipeline
c_{pw}	Cost per Platform Well
c_{riser}	Cost per Riser
c_{umb}	Cost per Umbilical
CAPEX	Capital Expenditure
CFR	Code of Federal Regulations
d	Water Depth
D_{pipe}	Diameter of Pipeline
GOM	Gulf of Mexico
HLV	Heavy Lift Vessel
l_{pipe}	Length of Pipeline
l_{riser}	Length of Riser
l_{umb}	Length of Umbilical
N_{cond}	Number of Conductors
N_{pw}	Number of Piles
N_{pw}	Number of Platform Wells
OCS	Outer Continental Shelf
OPEX	Operational Expenditure
PIG	Pipeline Inspection Gauge
PLEM	Pipeline End Manifold
PLET	Pipeline End Termination
POCSR	Pacific Outer Continental Shelf Region
ROV	Remote Operated Vehicle

1 INTRODUCTION

1.1 THE NEED TO DECOMMISSION

The last downfall of oil prices has led to a decline in the international oil and gas industry. As a result several investments in new and ongoing projects have stopped for the time being due to financial unfeasibility. Hence, the operating companies are faced with a financial revaluation of their currently operating offshore platforms. Among these, several platforms have become unprofitable, especially aged ones. In the latter case the offshore platform has operated for some decades and does not produce any longer sufficient hydrocarbons from the oil field to assure the financial feasibility of keeping the platform operating. At the same time aged offshore platforms have become an environmental risk since the harsh marine environment causes the material to degrade which increases the risk of a structural failure. The life cycle of an offshore platform is usually supposed to end after a specified design life of 20-30 years (API, 2007). Therefore, especially at the later stages of the life cycle maintenance and repair costs start to increase up to a level, where expenditure exceeds income. In addition, a structural failure can have a large impact due to environmental hazards and judicial consequences.

The decommissioning of a fixed offshore platform covers several activities and requirements that are not unanimously defined. Decommissioning comprises terminating oil and gas operations and returning the field to a condition that meets the regulations required by local jurisdiction (CFR, 2015). The decommissioning process contains the planning and execution of removing and disposing the offshore facilities, which are of no further use for its current purpose (JAHN, COOK, & GRAHAM, 2008). The need to decommission an offshore platform becomes inevitable if the design life of an offshore structure has been exceeded, the oil field is completely exploited, or oil production is no longer profitable. In particular, the risk of a structural failure has to be specified and taken into account by the lessees to support the decision making process of initiating the decommissioning phase.

Figure 1 shows the typical phases of the life cycle of an oil and gas field (WOOD, 2005). The life cycle begins with the exploration of the field and ends with the decommissioning of the platform and its associated facilities. After the oil and gas field has been discovered, scanning techniques are applied and test drills are made to provide a first indication of the capacity of recoverable reserves. During the field appraisal the forecasts of capacities are improved through information from additional wellbores. The entire field layout is specified including the number and location of wells, type of platform, subsea installations and connection to existing facilities. Up to this stage money has been spent and invested on the project without receiving any revenues. During the field development the oil production begins and first revenues are generated. This change is characterized by a less negative cash flow followed by a decreasing amount of required capital expenditure (CAPEX). At some point in time first returns are made and investments are recovered. The ongoing oil production leads to a falling pressure in the reservoir which results in a gradually decreasing production rate and cash flow. A decision has to be made whether enhanced recovery techniques are applied by further investments to produce more hydrocarbons. Artificial lift may give a last increase in the production which decays rapidly and is not always applicable or feasible in a field. When the field is completely exploited or the operational expenditure (OPEX) exceeds revenues on a permanent basis, the decommissioning phase is initiated. The removal and abandonment of the platform and its associated facilities go along with a final negative cash flow due to the decommissioning costs. This study addresses the required decommissioning activities of the last phase of the life cycle as well as the incurred costs (Figure 1).

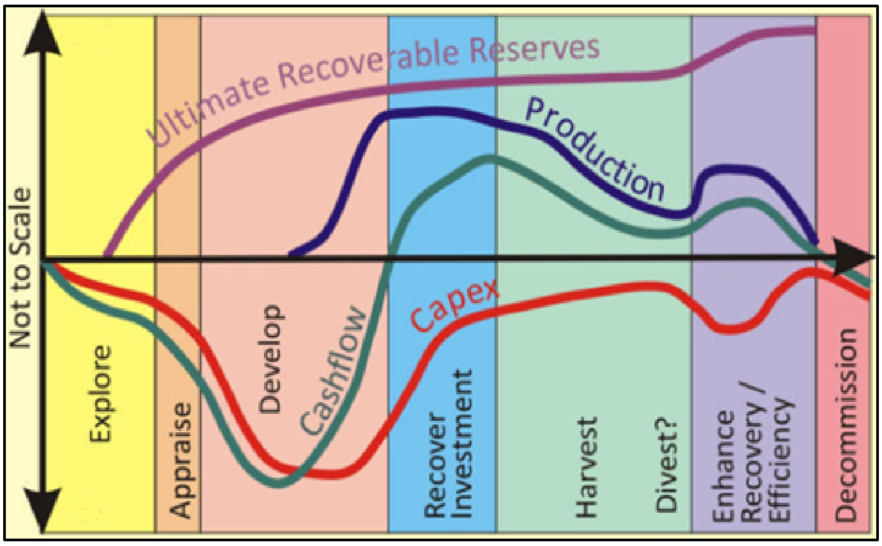

Figure 1: Life cycle of an oil and gas field (WOOD, 2005)

1.2 OVERVIEW OF HISTORICAL DECOMMISSIONING

In 1947 the first offshore platform was installed in the Gulf of Mexico Outer Continental Shelf (OCS) whereas the earliest decommissioning was registered in 1973 (Figure 2). From these dates on hundreds of platforms have been installed and removed in the Gulf of Mexico OCS only. The U.S. Department of the Interior (2003) presents the development and increase of installed and removed platforms in the Gulf of Mexico OCS. The graph illustrates converging numbers of installations and decommissioning in the last two decades. One possible explanation is the increased exploration in deepwater regions where the use of fixed platforms is no longer sufficient and floating platforms are necessary. This has led to a larger number of platforms being decommissioned than built (Figure 2).

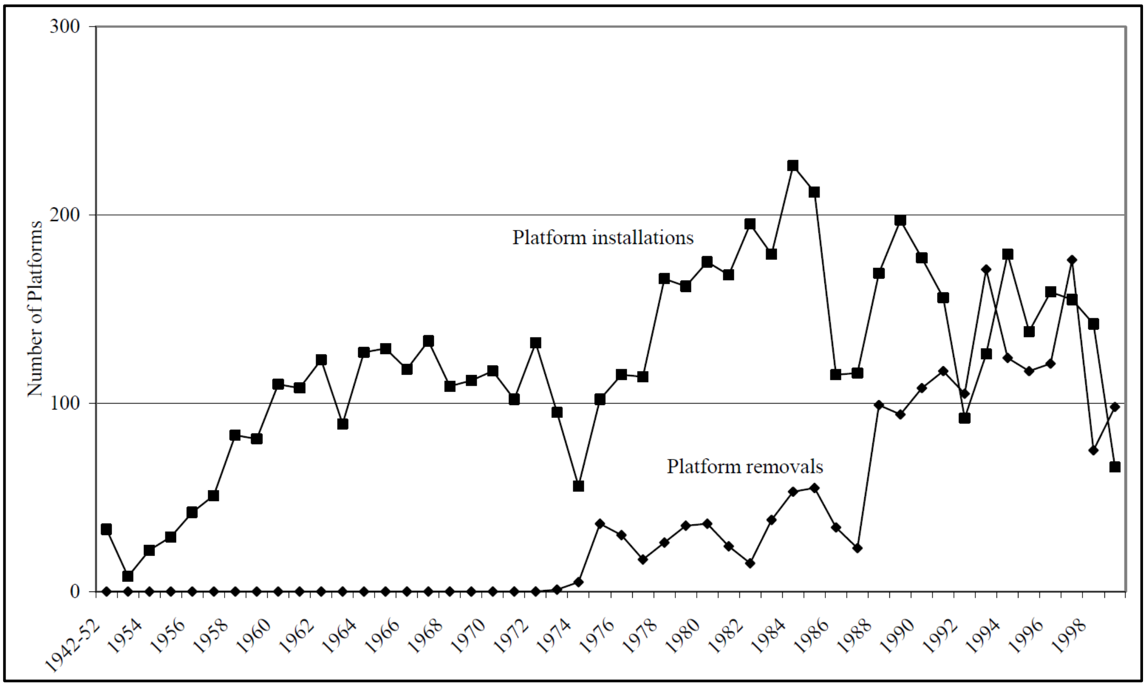

Figure 2: Installed and removed platforms at the Gulf of Mexico Outer Continental Shelf (U.S. DEPARTMENT OF THE INTERIOR, 2003)

A total of about 4,100 offshore structures have been decommissioned in the Gulf of Mexico since the beginning and up to 200 offshore structures are removed per year (TSB OFFSHORE, 2015). Over the last 20 years approximately 3,300 platforms were removed in the Gulf of Mexico with a great portion in a water depth less than 60m and the remaining amount in a water depth between 60m and 120m. Only 16 platforms were decommissioned in a water depth greater than 120m.

The Gulf of Mexico contains with 4,000 offshore structures the greatest number of operating platforms. By comparison, in Europe are only approximately 400 operating platforms installed (BEMMENT, 2001) and only very few platforms have been decommissioned until now (EKINS, VANNER, & FIREBRACE, 2005). In the North Sea, where the majority of the platforms in Europe is located, approximately 30 have been decommissioned (BEMMENT, 2001). Figure 3 presents the distribution of operating platforms worldwide. Among 340 operating platforms in South America, the majority belongs to Brazil.

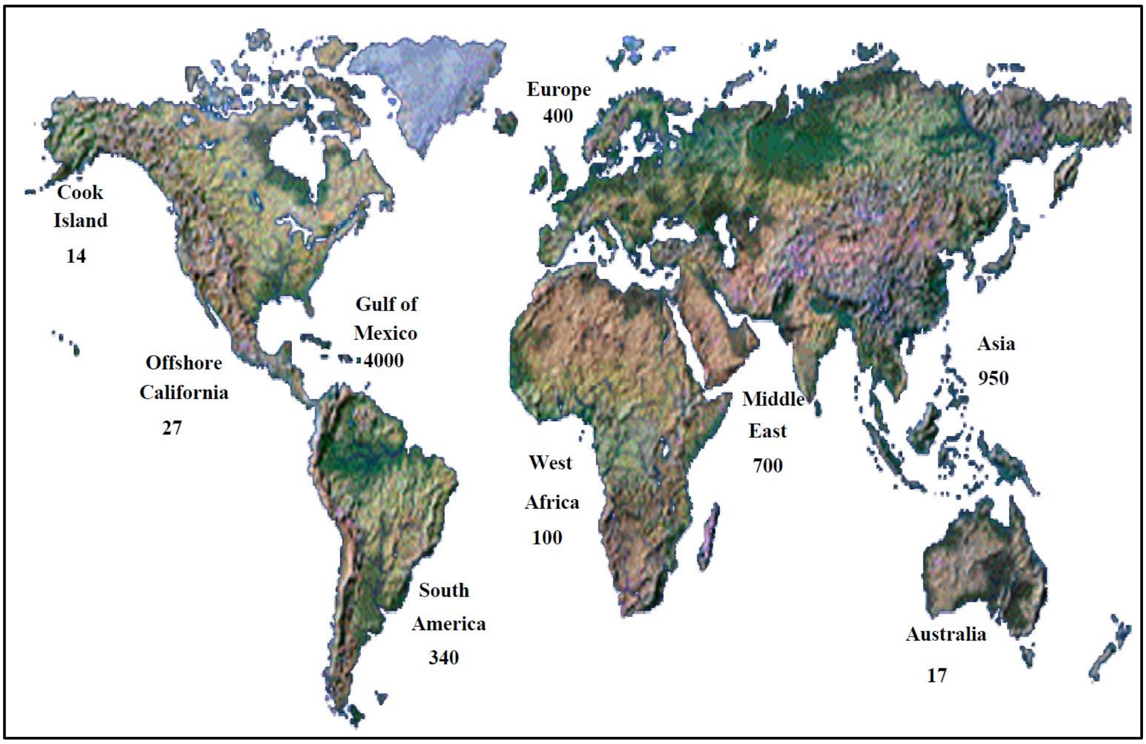

Figure 3: Distribution of offshore installations worldwide (TSB OFFSHORE, 2000)

This study focusses only on the decommissioning of fixed offshore platforms which are the oldest operating structures that will require decommissioning activities in the near future. The MARINHA DO BRASIL (2016) lists a total of 68 operating fixed platforms in Brazil whereas the majority is scheduled for decommissioning in the next decade. Only a few small fixed platforms have been decommissioned in Brazil and decommissioning is so far not well-established and needs to be further specified. Therefore, this subject is extremely relevant since the decommissioning of aged platforms has become a major concern for the Brazilian oil and gas industry. It is also of keen interest to estimate the costs for the decommissioning of deepwater fixed platforms which is a very cost-intensive procedure.

1.3 OBJECTIVES

The objective of this study is to provide an overview of the most common procedures to decommission a fixed offshore platform and its associated facilities in compliance with current practice and regulations. Beyond that, this study presents an example for the estimation of the corresponding financial expenses involved with the decommissioning procedure based on recent literature studies.

The remainder of this document is organized as follows. Chapter 2 provides an overview of typical installations related to an offshore field development based on a fixed platform including a brief description. Chapter 3 explains the commonly applied techniques to decommission each installation deployed in the oil or gas field. In addition, the relevant national and international regulatory requirements applied to Brazil and the United States are explicitly discussed. Chapter 4 covers the financial aspect of decommissioning and introduces an approach to estimate the costs of decommissioning deepwater fixed platforms based on recently developed cost curves and tables. In Chapter 5 a detailed case study is defined to demonstrate the implementation of the cost estimate for the decommissioning procedure. Furthermore, the costs of all required activities of the sample platform and its associated facilities are separately estimated to give an idea of how expensive the procedure can become. Finally, Chapter 6 concludes and provides recommendations for future work.

2 INSTALLATIONS DEPLOID AT OFFSHORE OIL AND GAS FIELDS

2.1 OVERVIEW

Every oil and gas field is unique in terms of the existing natural resources and the deployed equipment to produce the hydrocarbons. Yet, there are certain installations that recur. The fields that are discussed in this study contain a fixed offshore platform as host facility (Figure 4) and are therefore restricted to water depths of below 300m. Fields that are located in greater water depths generally require the use of floating platforms. The decommissioning procedure for these kind of platforms is different from those of fixed platforms and not further discussed in this study. This chapter introduces the main facilities of an oil and gas field and briefly explains the function. Also the installation method is mentioned to allow a further discussion of the decommissioning activities explained in Chapter 3.

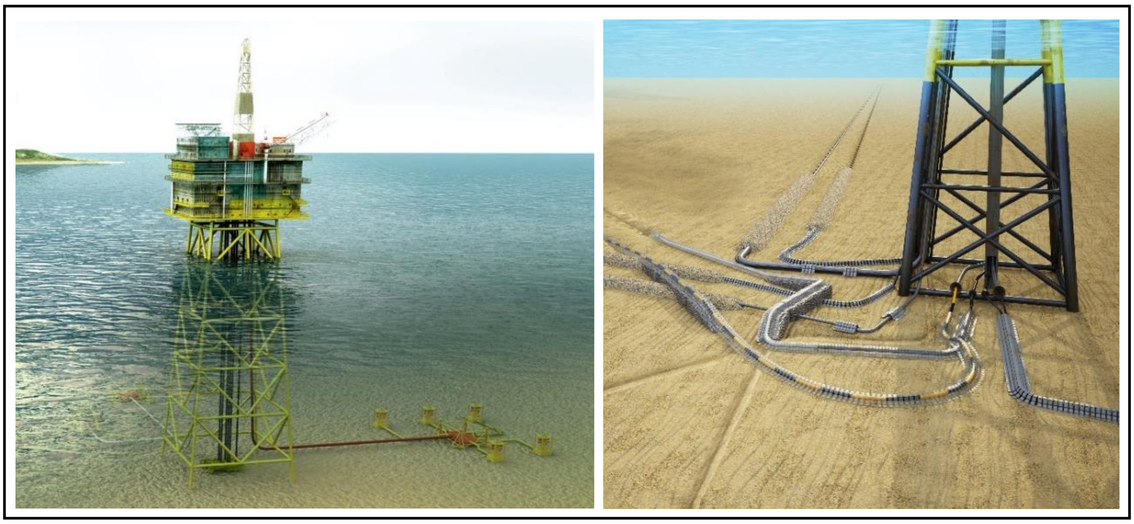

Figure 4: Typical field layout (XODUS, 2016)

2.2 JACKET OF FIXED OFFSHORE PLATFORM

The fixed platform serves as a central facility for the field that processes the extracted hydrocarbons that are transported from the single wells around and directly below the platform. Typical fixed offshore platforms are installed in water depths of at least 40m up to about 200m at the coast of Brazil. For calmer seas even larger platforms are possible that reach heights up to 300m, known as compliant towers. The jacket structure usually consists of welded steel pipes that create a truss which is fixed to the seabed through piles. The circular shape of the pipes is necessary to reduce the impact that the current and waves have on the structure.

The installation procedure varies for each platform and only the most general form is explained in this study. The jacket is constructed onshore at a shipyard in several steps. Pipes are welded to large segments and assembled together. Then the jacket is pushed on a barge by jacks and made ready for transport. Therefore, the jacket is fixed to the barge by welded connections which is referred to as sea-fastening. Figure 5 shows a constructed jacket located on a barge ready for transport offshore.

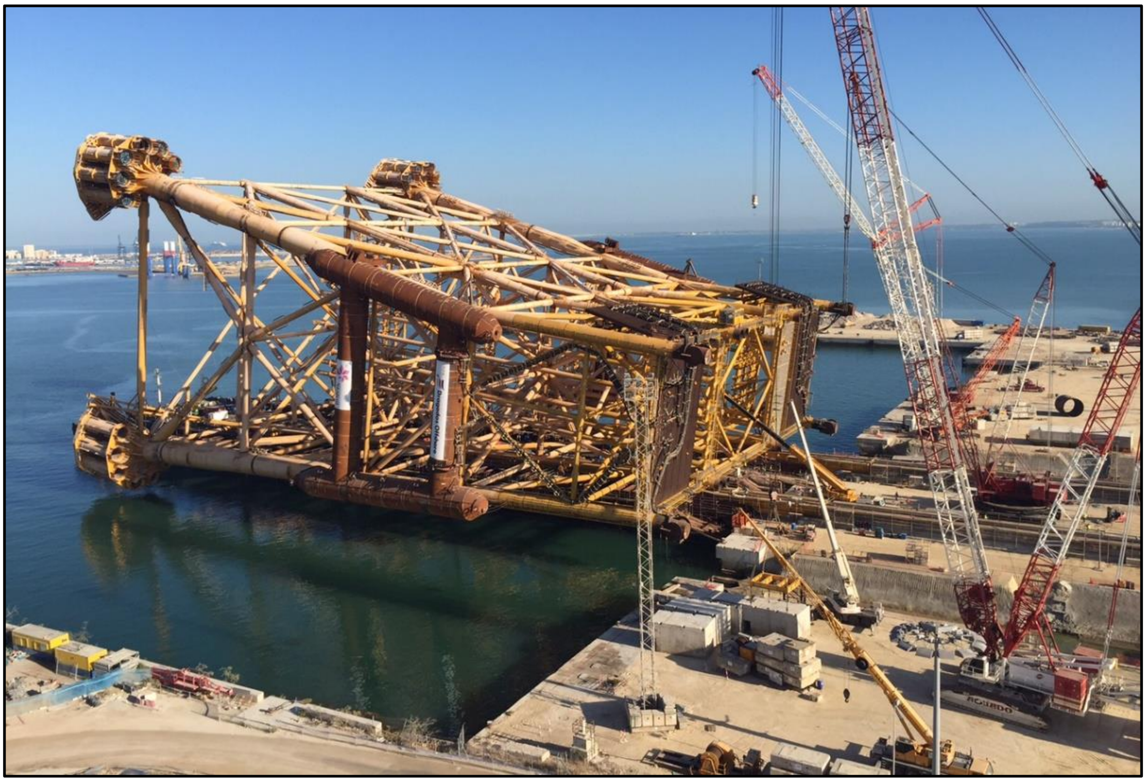

Figure 5: Jacket positioned on a barge and prepared for transport (SUBSEA WORLD NEWS, 2015)

The barge moves to the designated oil and gas field for installation. At destination all welded connections between jacket and barge are removed and buoyancy tanks are attached to the structure. To move the jacket into the water for the installation at the seabed, tanks of the barge are filled up with water so that the barge starts to incline. When the barge has reached a certain angle, the jacket automatically slides along the barge into the water which is shown in Figure 6. The jacket floats in the water due to the previously installed empty buoyancy tanks.

Figure 6: Launching of a jacket off a barge (SUBSEA WORLD NEWS, 2015)

In a predefined sequence the buoyancy tanks are filled with water to allow a verticalization of the jacket, the so-called upending. During this procedure it is necessary to secure the jacket with an offshore crane with sufficient capacity. Figure 7 illustrates a moment of this procedure with the jacket upending and secured by an offshore crane. Having been filled with water, all buoyancy tanks are separated and removed from the jacket.

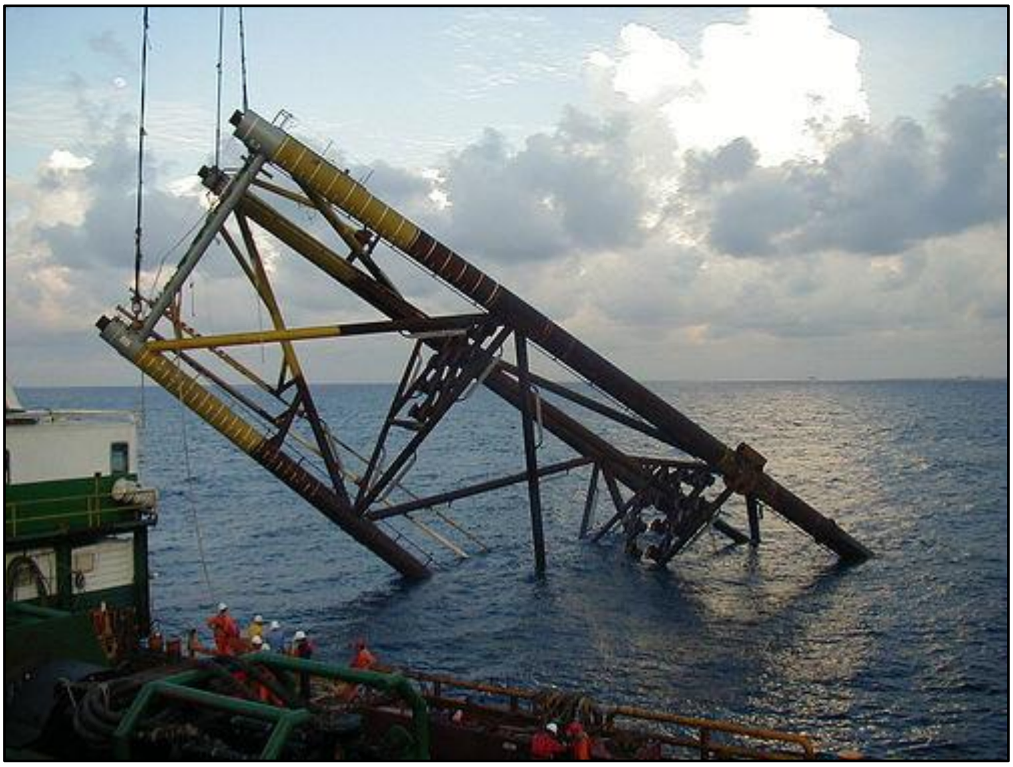

Figure 7: Jacket upending

In the next stage the crane positions the jacket that is completely vertical above the final designation at the seafloor and starts to lower it. Piles have been rammed into the seabed to serve as guides for installation. Mud-mats provide sufficient resistance to guarantee that the jacket does not sink too much into the soil. The crane connections are removed and the jacket is stable for calm seas and the temporary state.

There are in general two methods to anchor the jacket to the ground. Platforms which were installed in the 70s, 80s until the beginning of the 90s are anchored by piles driven through the main jacket legs. In this method the sequence of welding pile segments at deck and hammering them down through the platform legs into the soil is repeated until the jacket is fixed. As a consequence the piles have a smaller diameter than the legs and shear keys welded inside the legs provide sufficient guidance for the piles to remain at the center of the leg. Once the planned depth has been reached the space between the piles and platform legs are filled with grout to provide additional stiffness. The hammer could only operate above waters and therefore this technique was preferred.

Since the 1990s further development of hammers enabled a hammering under water. This allows an anchoring of the structure with skirt piles adjacent to the platform legs. Instead of hammering the piles through the legs, this development allows hammering the piles through the skirts. The piles are lowered down through the skirts which serve as a guide. The deadweight of the piles is sufficiently large to allow a substantial penetration into the soil with a remaining portion sticking out of the skirts. The hammer is placed on top of the piles by an offshore crane and drives the piles further down into the soil. Once the final depth has been reached, the space between the skirts and the piles is filled with grout. It is also common to have several skirts connected to the platform leg which allow the use of more piles with less depth. Fixed at the seafloor, the jacket can resist the environmental loads and has sufficient resistance towards large dead weight which will act once the topsides is installed.

2.3 TOPSIDES OF FIXED OFFSHORE PLATFORM

The topsides is the upper part of the platform above the sea level and consists of welded steel profiles that do not necessarily have to be tubular. The topsides is usually constructed at shore and contains the equipment required for oil production. The equipment is built in modules that contain steel frames. These modules are connected to the topsides by piping and other connections and could be separated again for the decommissioning of the platform. Figure 8 depicts several modules that are commonly installed on topsides, e.g. production module, helideck and flare boom. Having been finally assembled, the topsides is lifted by a crane to a barge and fastened by welded steel pipes. Similar to the jacket the vessel transports the topsides to the designated oil and gas field where the jacket has already been installed.

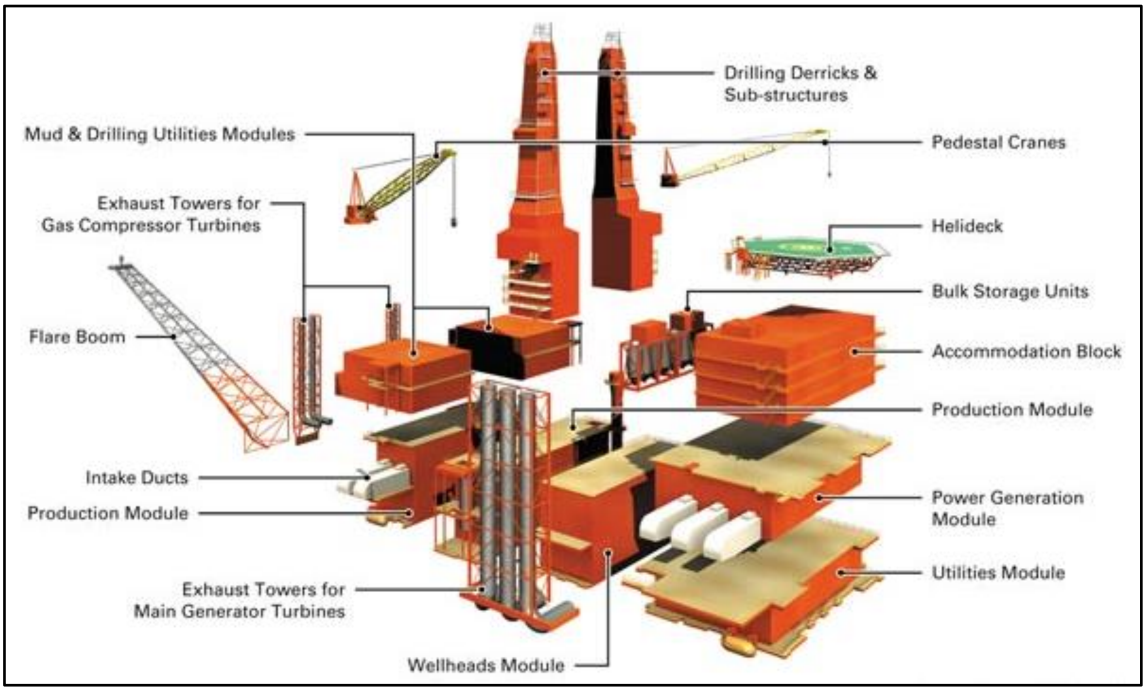

Figure 8: Typical topsides configuration (OFFSHORE TECHNOLOGY, 2016)

The most common procedure to install the topsides is to use an offshore crane that lifts the entire topsides in a single step and places it on top of the jacket. The topsides contains supports that slide into the main legs of the jacket and guarantee a safe installation. The top part of the legs are then welded to the topsides supports which provides sufficient strength. Once the mating has been achieved, the crane is detached from the topsides. The entire fixed platform stands on its own and the platform installation process is completed.

2.4 CONDUCTORS

Once the mating of the jacket and the topsides has been achieved, the conductors need to be installed. Conductors are empty pipes at full length that run down from the main deck into the soil and serve as a guide for the drill bit.

There are different methods how drilling operations can take place. The most common option is that a Jack-up platform is used to perform the drilling operations and no drill tower is available on the platform. The Jack-up is positioned adjacent to the fixed platform and the derrick is cantilevered to the drill holes on the main deck. The drill is lowered down to the mudline elevation and usual drilling operations are carried out which consists of a series of lowering casing strings and cementing jobs. After drilling operations have been established, the conductors are filled with several layers of casing strings and concrete. The weight of this conductor can be substantial. Removing the conductors is one of the tasks that need to be performed in the decommissioning phase which is discussed in Chapter 3.

2.5 RISERS

Produced hydrocarbons from subsea or satellite wells are transported to the topsides through risers. Processed oil from the platform is further transported to shore or other offshore facilities that are connected through a network of pipelines. Small diameter steel pipes are installed over the height of the platform and are referred to as rigid risers. Flexible risers can also be used to connect surrounding wells with the platform.

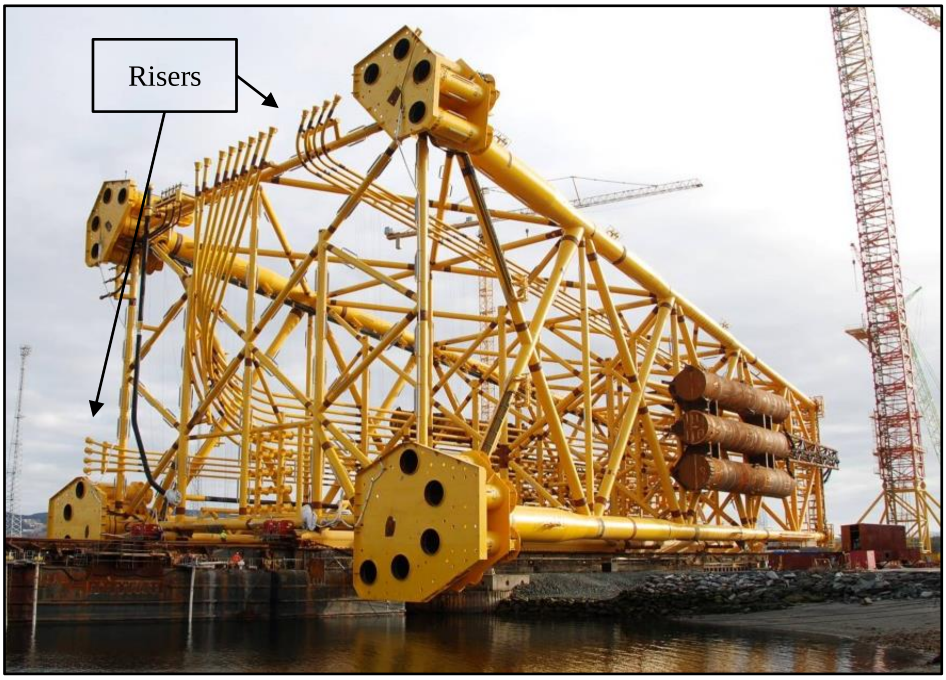

Figure 9: Rigid risers at jacket (OFFSHORE ENERGY TODAY, 2016)

2.6 WELL COMPLETIONS

Wells that are directly located below the platform and connected to the topsides by conductors are referred to as platform wells or dry tree wells.

Wells that are located close to the platform are referred to as subsea wells and are often connected to the platform by flexible risers. Wells that are connected to the platform by pipelines including a set of attached subsea structures as shown in Figure 10 are called satellite wells. Subsea and satellite wells are wet tree completions. Wet tree wells cannot be drilled from the platform and require drilling vessels that position themselves above these wells.

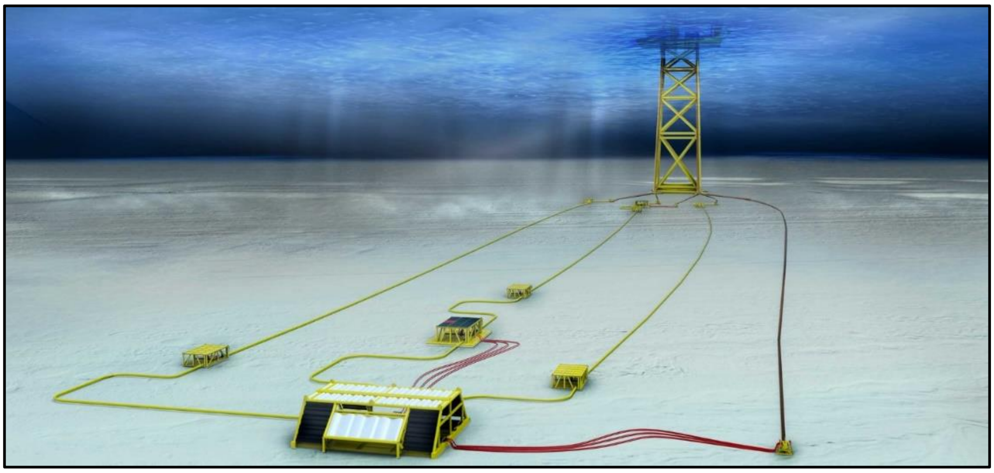

Figure 10: Satellite well connected to the fixed platform by subsea installations (OIL&GAS EXPERT GRAPHICS, 2016)

In comparison to platform wells subsea and satellite wells have a significant impact on the decommissioning costs because they are not accessible from the platform and the decommissioning procedure is more complicate as explained in section 3.3.

2.7 SUBSEA INSTALLATIONS

If the distance of a satellite well to the platform is too large, additional equipment has to be installed at the seafloor to transport the hydrocarbons to the facility. Figure 11 shows a brief overview of the main subsea installations required to produce hydrocarbons from a wet tree well. These subsea installations include wet trees, jumpers, manifold, PLET and pipelines. Produced hydrocarbons from the satellite wells pass through a wet tree and jumper into a manifold. Having passed through the manifold, the hydrocarbons continue through a jumper connected to a PLET and are transported by pipelines either to a facility or to shore (Figure 11).

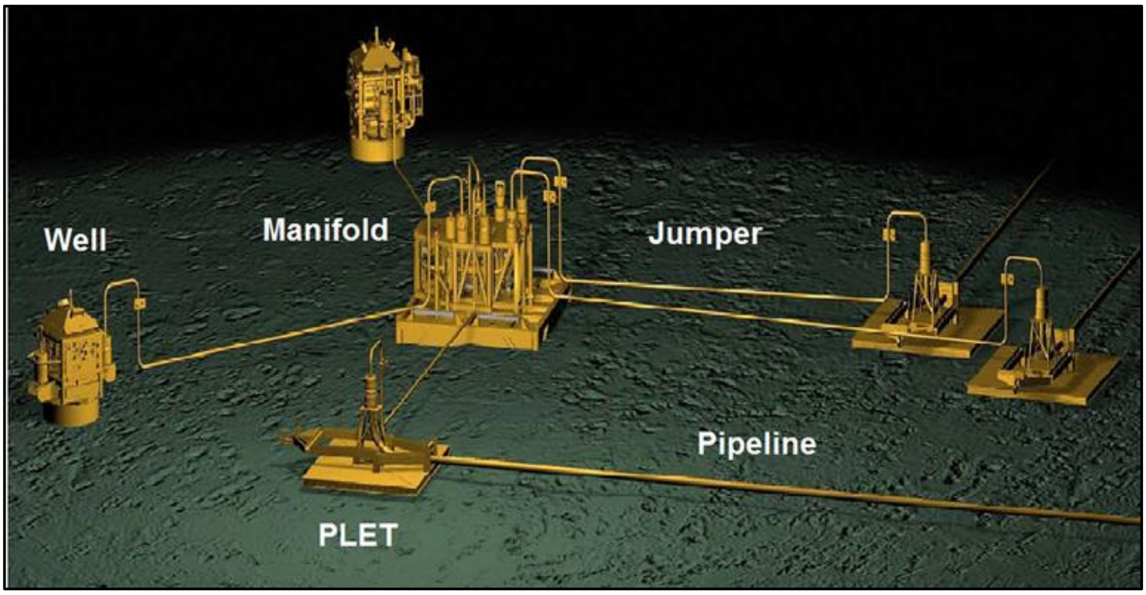

Figure 11: Subsea installations involved with wet tree wells (OIL & GAS TECHNOLOGIES, 2016)

On top of the wellhead a Christmas tree is placed. The Christmas tree of a subsea or satellite well is referred to as a wet tree and consists of a set of valves to control the flow pressure of the hydrocarbons from the well. A Blow-Out-Preventer (BOP) is part of the Christmas tree assembly and contains a set of shear blades. These are able to cut the production tubing and seal the well if the well pressure exceeds a specific limit. Therefore, the BOP is a safety precaution and prevents an environmental damage.

Satellite wells are connected to a manifold through jumpers. Jumpers are simple pipes that work as a spring between subsea installations because the produced hydrocarbons from the well may have a high temperature which causes the pipe to expand. In order to prevent any damage at the connection flanges, the jumpers form a spring that reduces the rotation at the connection flanges. The manifold works as a central hub for all adjacent wet tree wells. It contains a set of valves and monitoring devises which allow a controlled flow into the pipeline network. The installation of manifolds is a difficult task since they can easily weigh up to a few hundred tons. In addition, the conditions under which an installation or a removal can take place have to be studied well. As the shape of the manifold mobilizes a significant amount of water during the installation procedure, the additional water mass can lead to a rupture of the lifting cable.

Having been passed through the manifold, produced hydrocarbons are transported through another jumper to the Pipe-Line-End-Termination (PLET). A PLET is another valve mounted on a steel frame that is fixed to the seabed by suction piles or shear walls. The PLET forms a fixed point and connects the manifold to the network of pipelines that either end onshore or lead to the host facility.

Devices away from the platform have to be supplied with electrical power, control data or chemicals by umbilicals. An umbilical usually consists of a flexible pipe that contains several inner tubing for the different cables as illustrated exemplarily in Figure 12.

Figure 12: Different kind of umbilical configurations (TECHNIP, 2016)

The method for installing all the subsea equipment mentioned above varies from case to case depending on the weight of the subsea structure, the water depth and the environmental conditions. For the removal of these structures it is imperative to understand the procedure of installation in order to reverse it if necessary.

3 DECOMMISSIONING ACTIVITIES AND REGULATIONS

3.1 GENERAL ASPECTS OF THE PROCEDURE

The lessee of an oil and gas field is obliged to perform the decommissioning. Both decommissioning procedures and scope are not unanimously defined in the literature. The regulatory requirements for the decommissioning differ between the national legislations as in the cases of Brazil (ANP, 2002), the United States (CFR, 2015) and the United Kingdom (PETROLEUM ACT, 1988). The legal requirements for Brazil are defined by the Agência Nacional do Petróleo (ANP) and compared to the Code of Federal Regulations (CFR). The CFR contains a comprehensive set of decommissioning regulations and is the main code referenced by the literature. Other regions such as the North Sea (PETROLEUM ACT, 1988) have different legislations but are mainly referring to the CFR since the Gulf of Mexico has had by far the largest number of concluded decommissioning projects.

The principal types of activities involved with the decommissioning of fixed offshore platforms can be summarized in the following categories (CFR, §250.1703, 2015):

- Application and decommissioning approval
- Permanent well plugging and abandonment
- Removal of the platform and its associated facilities
- Pipeline decommissioning
- Site clearance

Every category contains a set of decommissioning procedures and requirements that have to be adjusted to a project on a case to case basis and are further explained in this chapter. The mandatory regulations for decommissioning have the following objectives (CFR, §250.170, 2015):

- Provision of guidance for the execution of decommissioning
- Guarantee of safe and efficient procedures
- Prevention of unnecessary risks associated with environmental hazards

The form of the application and approval procedure for decommissioning projects requested by federal, state and local authorities as well as environmental agencies vary a lot for each country (GEBAUER, et al., 2004). In Brazil the national oil and gas agency ANP is responsible for the approval of decommissioning projects. In comparison to the ANP the CFR has made the entire procedure available to the public. In general the CFR requires that the entire procedure of the decommissioning activities is defined, planned and presented in specified forms and tables. Required documentation and related legal steps in Brazil are beyond the scope of this study. Instead, this study focusses on the main constructive steps that are involved in the decommissioning process.

3.2 ENGINEERING AND PLANNING

Precedent to the execution of a decommissioning project it is imperative to perform all necessary planning and engineering work which basically include the following activities:

- Identifying the obligations of all parties involved in the decommissioning process
- Performing all engineering analyses (reliability analysis, risk assessment, installation method, removal procedure)
- Planning all operations (definition of required vessels, checking availability of vessels, specify local particularities)
- Establishing bidding procedures to select subcontractors for the individual activities

Oil and gas fields often have multiple shareholders that are responsible for the decommissioning and need to be included in the procedure. In addition, other parties are involved, such as operators of the platform and owners of the pipeline network to which the platform is connected.

All available information from these different parties need to be gathered and checked for relevance to perform the engineering analyses and select decommissioning methods. Especially information from inspection and maintenance reports are highly important. These reports may include damages of facilities installed at the field that occurred due to an accident or the deterioration (e.g. corrosion) of the material along time. These flaws in the structure or equipment should be taken into account in the decommissioning process and need to be validated in the planning phase to avoid redundant and costly adjustments at later stages. Problems and risks that could occur during operations need to be identified and alternatives established to avoid unnecessary delays.

Once an overview of the individual activities exists, the availability of vessels and specialized equipment needs to be established. All locations, where the removed facilities might be disposed, need to be identified. Based on the gathered information the scope of each bidding contract is defined which finally leads to the selection of subcontractors.

3.3 WELL ABANDONMENT

The well of an oil and gas field is the principal source for 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 development is decommissioned (DNV, 2016). The well abandonment is one of the major and most delicate tasks during the decommissioning process and is instructed by governmental authorities, such as ANP (2002), CFR (CFR, §250.1700-§250.1723, 2015) and NORSOK (2012).

Prior to the actual abandonment procedure the current condition of the wells and their specifications have to be determined (CFR, §250.1712, 2015). As part of the planning procedure in section 3.2 it is required to review all related documents that contain information about well depths, location of perforations, deployment of production liner as well as the condition of wellheads and BOP's. If considered necessary, additional inspections with the use of ROV's might be performed to ensure smooth operations during the well abandonment (GEBAUER, et al., 2004). Once the information is gathered, the approach on how to plug and abandon the wells can be specified whereas each well requires an individual examination of the applied procedure.

Furthermore, it is necessary to stop the production of hydrocarbons prior to the well abandonment. In the majority of the cases the wells of the field have already produced for a few decades. As a consequence, the reservoir pressure is at a low level and not sufficient to transport the hydrocarbons to the surface. In this case, secondary recovery techniques are usually applied, such as water injection or gas lift (LYONS, PLISGA, & LORENZ, 2016), which need to be omitted. Before well abandonment operations can be initiated, it is recommended to clean the wellbore and remove downhole equipment to facilitate plugging operations (GEBAUER, et al., 2004).

In general, the abandonment of a well principally consists of the following techniques:

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

Mechanical or wireline plugs temporarily seal the casing string from any flow of hydrocarbons and are usually utilized for repair or substitution of the BOP. For the purpose of well abandonment mechanical plugs additionally serve as support for the cement layer that will be placed on top. For the placement of the mechanical plug through wireline operations it is helpful to retrieve all liners including packers that have been previously installed in the casing string. The cementing can be repeated several times as required and 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 (SMITH, PERRY, STEWART, HOLLOWAY, & JONES, 1990). After the well has been plugged, additional pressure tests provide a guarantee that no leakage will occur. Therefore, a maximum pressure rate is specified that needs to be resisted (CFR, §250.1715, 2015).

For the decommissioning procedure a distinction has to be made between wells located directly below the platform and wells close by. Platform wells are connected through the conductor pipes directly to the platform and thus are much easier to access than subsea or satellite wells. As a consequence, different procedures exist to abandon both types of wells while the requirements for plugging remain the same as shown in this section. In some cases temporarily plugged wells exist at the field which need to be permanently plugged as well.

The abandonment of a platform well basically comprises the techniques introduced above. Existing production liners including packers are usually removed from the casing string, a temporary plug is deployed and cement is pumped down to form the permanent plug. Voids can be optionally filled with drilling mud for further safety. To complete the platform well abandonment, the conductors and the dry tree have to be removed which is explained separately in section 3.4. The capability of the existent equipment on topsides to perform wireline operations, pumping cement or drilling mud needs to be evaluated. Some platforms have a fixed derrick on topsides, pumps and wirelines available. For the majority of the cases the equipment is not entirely appropriate for the purpose of well abandonment and additional machinery is necessary. The use of integrated systems placed on topsides is a convenient and cost-effective method and referred to as rig-free technology. Rig-free systems make the use of costly drilling rigs redundant that are often placed by Jack-up platforms adjacent to the fixed platform. 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 so that there is enough space for the large equipment but the cost advantage can be substantial.

Subsea and satellite wells require other treatment of abandonment since the configuration is different and they are not easily accessible through equipment placed on the topsides. Figure 13 shows exemplarily one possible solution to permanently plug a subsea or satellite well using a combination of mechanical or wireline plugs and cement. Prior to the plugging (Figure 2, left) the well consists of a casing string with liner, wellhead and Christmas tree. The plugged well (Figure 2, right) consists of a series of cement layers separated through mechanical or wireline plugs. The top part of the casing string, the entire wellhead and the Christmas tree are removed and a cement plug at the top forms the last seal.

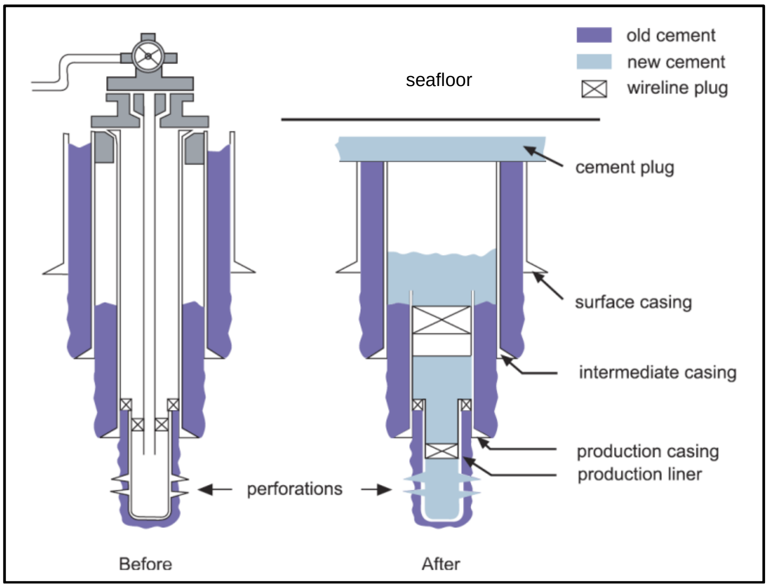

Figure 13: Permanent plugging of wet tree wells with cement (JAHN, COOK, & GRAHAM, 2008)

As a first step of the abandonment of wet tree wells all connected pipelines need to be detached from the Christmas tree as explained in section 3.5. In order to perform wireline operations to place a temporary and permanent plug into wet tree wells, multi-intervention vessels are employed. The costs of such a vessel are much larger than integrated solutions that enable rig-free operations. The intervention vessel positions itself above the subsea or satellite well. A casing string is run down to the Christmas tree where it is connected. Potential liners located in the casing string are usually removed through wireline operations. The hydrocarbons inside the production string are pumped back into the reservoir. A mechanical plug is placed through wireline operations at the bottom of the casing string. This seal allows the removal of the Christmas tree as well as additional subsea equipment located close by. With the Christmas tree removed another casing is run down that allows pumping down cement to form the permanent plug. The latter procedure can be repeated several times as required. Remaining space in the casing string between cement plugs can be filled with drilling mud for further safety. The casing string has to be removed to at least 5m below the mudline (CFR, §250.1716, 2015). Finally, a prepared cement plug is placed on top of the remaining casing string which is aligned to the seafloor.

The following paragraphs explain the requirements of a permanent plug with the focus on offshore wells. The Brazilian regulations (ANP, 2002) differentiate the criteria of a permanent plug based on three types of well completions independent whether these are platform, subsea or satellite wells:

a) Open holes
b) Liners
c) Perforations

Figure 14 presents well completions with open holes. This option is usually chosen when no supporting casing is necessary in the production layer since the soil formation is strong enough not to collapse.

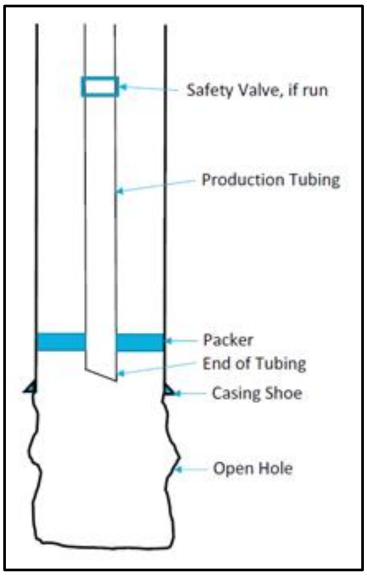

Figure 14: Well completion with open hole (LYONS, PLISGA, & LORENZ, 2016)

According to the ANP (2002) open hole layers are permeable and have several requirements for plugging. The first requirement shown in Figure 15, left, depends on the location of the permeable layer where oil has been produced. The cement plug should extend to at least 30m below the permeable layer and 30m above it. Considering the length of the permeable layer the cement plug reaches a significant length. This requirement is the same as stated in the CFR (§250.1715, 2015). In case that there is less than 30m space below the open hole, the ANP (2002) accepts the cementing until the end of the wellbore. The second condition to place the plug is based on the position of the casing shoe. The ANP (2002) requires a length of the cement plug of at least 30m below the casing shoe and a total length of 60m. Again, this requirement is the same as stated in the CFR (§250.1715, 2015).

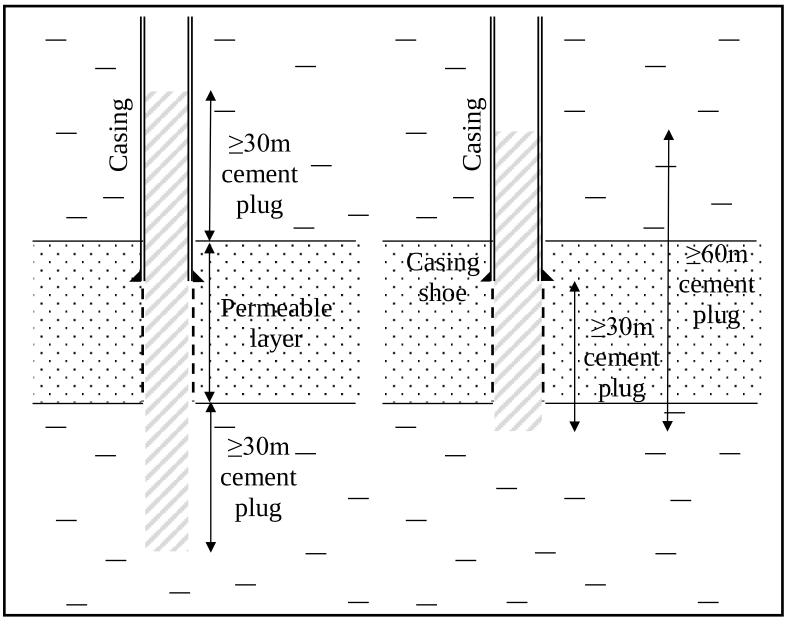

Figure 15: Permanent plugging of well completions with open hole (ANP, 2002)

The examples shown in Figure 15 might lead to the conclusion that the second requirement is automatically fulfilled with the first. This is not always the case as indicated by Figure 16, where the casing shoe ends in the solid formation. In these cases a layer of 30m above the permeable layer might not be sufficient to fulfill the requirement of a total length of 60m.

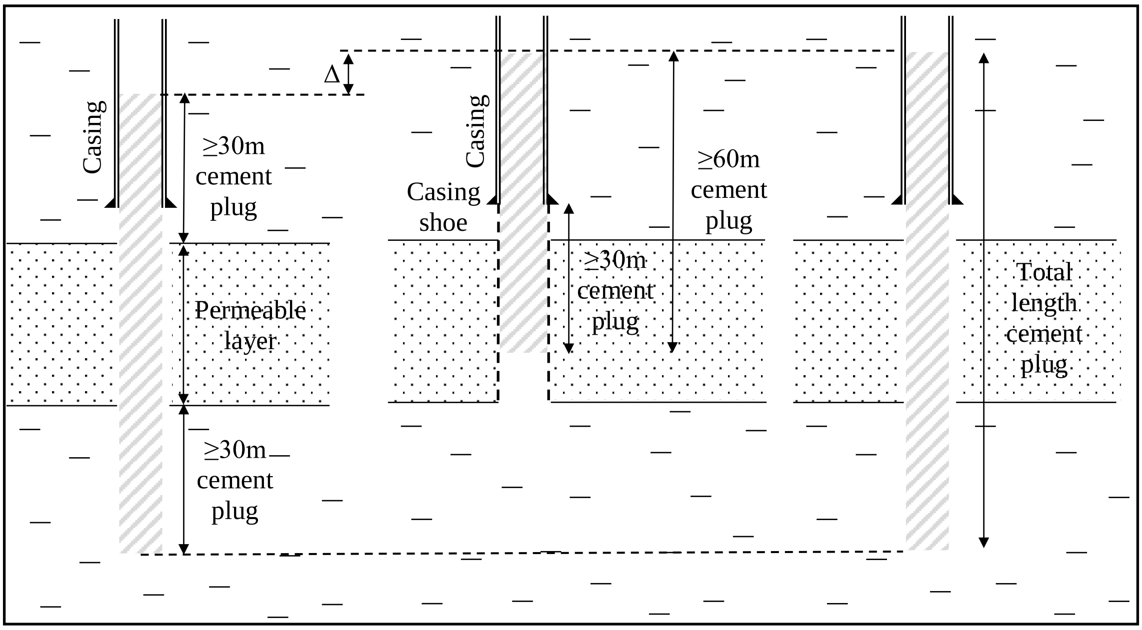

Figure 16: Fulfillment of all conditions permanent plugging of well completions with open hole (ANP, 2002)

In certain soil conditions the permeable layer might be very porous as to make the cementing difficult to achieve. Both the ANP (2002) and CFR (2015) allow for these cases the use of mechanical plugs for open hole completions, but with slightly different configurations. Figure 17 shows the requirements of both codes for the plugging with the use of mechanical plugs. While the ANP (2002) asks for the mechanical plug to be placed directly at the casing shoe, the CFR (2015) requires a distance of 15m to 30m between casing shoe and mechanical plug on top of which a cement layer finishes the seal. The length of the cement layer also differs between the regulations, the CFR (2015) asks for 15m while the ANP (2002) asks for twice the length.

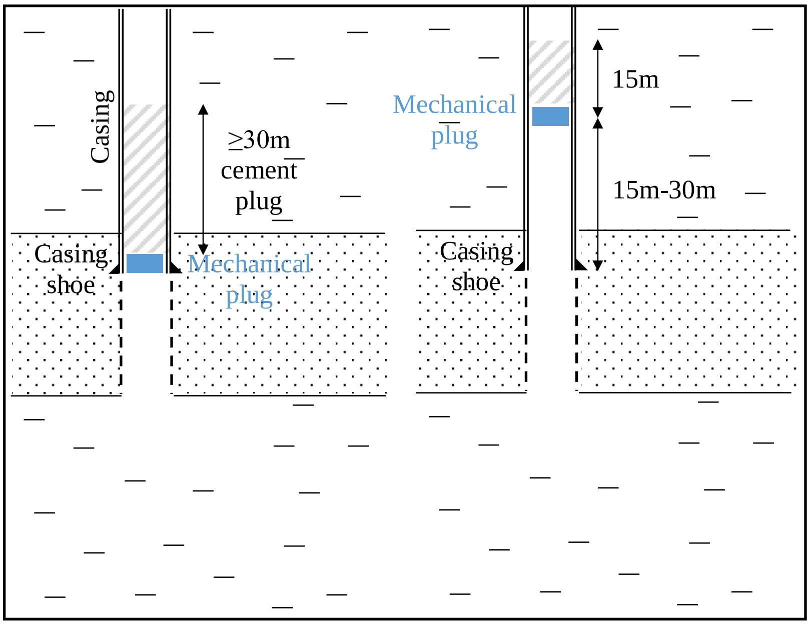

Figure 17: Plugging of well completions with open hole (ANP, 2002) and (CFR, 2015)

Liners are usually used for cost reduction in order to avoid unnecessary cementing of the casing and can be a convenient and economic solution for well completion. In certain cases it is not possible or desired to remove the liners. In these situations it is necessary to know at which depth the liner string starts and where it is supported in the casing. Figure 18 shows a sample completion with a string of liners. The hydrocarbons flow through the production liner into the tie-back stub liner, then to the tie-back casing which ultimately leads to the platform. It is necessary to place a plug in a manner that guarantees a complete seal of the wellbore.

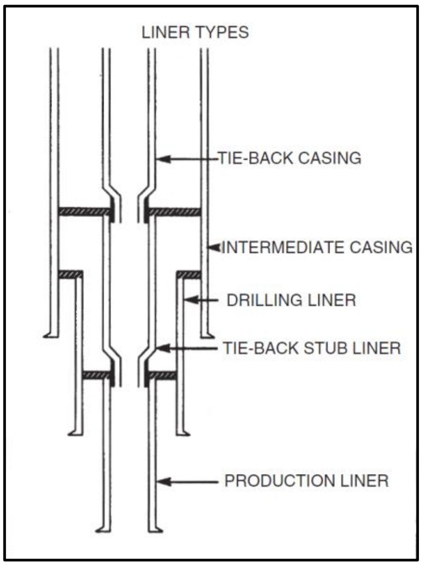

Figure 18: Liner types (NEALON & DOMINIQUE, 2006)

In the case of a well completion with liners, the ANP (2002) requires a cement plug of at least 30m in length being placed above the liner. Usually the liner is located at the permeable layer. Since the configuration of the liner string differs from case to case and can become complicate to plug, the Brazilian regulations recommend placing the plug above the liner to avoid cementing the liner itself. For the cement job to take place a temporary plug has to be placed at the top of the liner to make sure that the cement does not flow down. Figure 19 shows a schematic of the required plugging requirements.

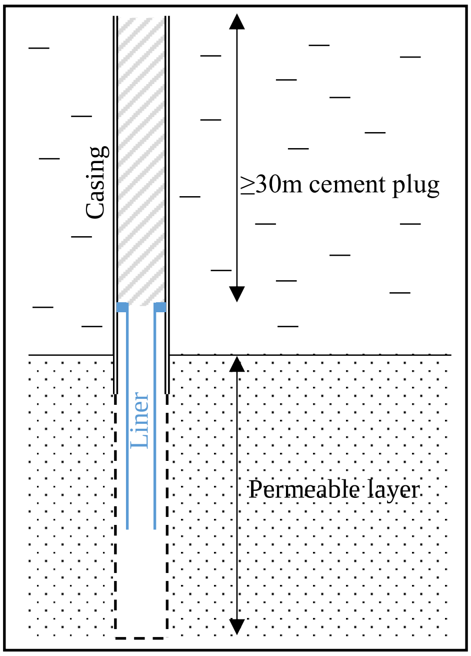

Figure 19: Plugging of well completions with liners (ANP, 2002)

Perforated casings are the most common form of well completion in the offshore industry. In comparison with the previous methods perforations are commonly used when several layers are produced. Perforating guns shoot bullets into the casing string that penetrate all layers and allow oil or gas to run into the production tubing.

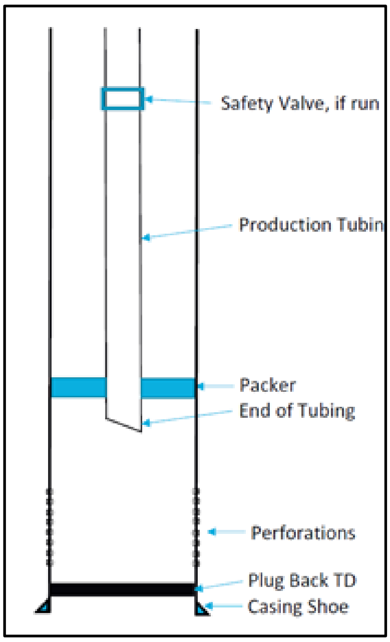

Figure 20: Well completion with perforations (LYONS, PLISGA, & LORENZ, 2016)

For the plugging of perforated well completions the ANP (2002) uses the perforations interval as the main criteria for the location of the permanent plug. In the previous completions the location of the actual permeable layer serves as reference. The location of the perforation intervals is usually recorded during drilling and perforation operations. Figure 21 visualizes the first set of requirements of the ANP (2002). As a first rule the cement plug should be placed 30m below the bottom end and 30m above the top end of the perforation interval. In some cases it is possible that a mechanical plug already exists below the perforation interval. This plug can be used as a support of the cement column and to reduce the required bottom length of the cement layer. At the wellbore end it may be the case that the remaining wellbore below the perforation interval is less than 30m deep. In this case the ANP (2002) allows the cementing up to the end of the wellbore even if the final length from the bottom of the perforation interval to the wellbore end is less than 30m. In the CFR (§250.1715, 2015) the left and center case of Figure 21 are listed as well but the CFR (2015) does not mention the specific case of Figure 21, right, where the wellbore ends shortly after the perforation interval.

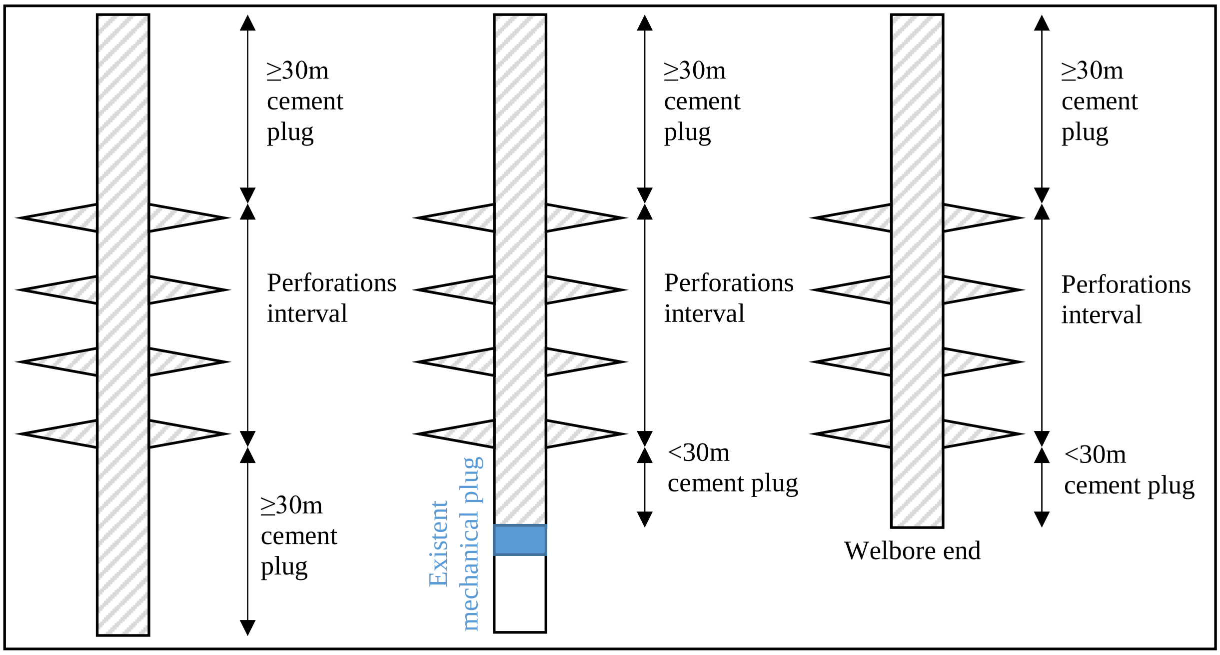

Figure 21: Plugging requirements for well completions with perforations (ANP, 2002) and (CFR, 2015)

Further, the ANP (2002) allows different plugging options when it is more convenient to avoid cementing the perforation interval. These options are illustrated in Figure 22. The first option allows the use of a permanent mechanical plug that should be placed at less than 30m above the perforation interval, in combination with a cement column of 30m height on top of it. The second option allows avoiding a mechanical plug, instead the cement layer should be increased from 30m to 60m.

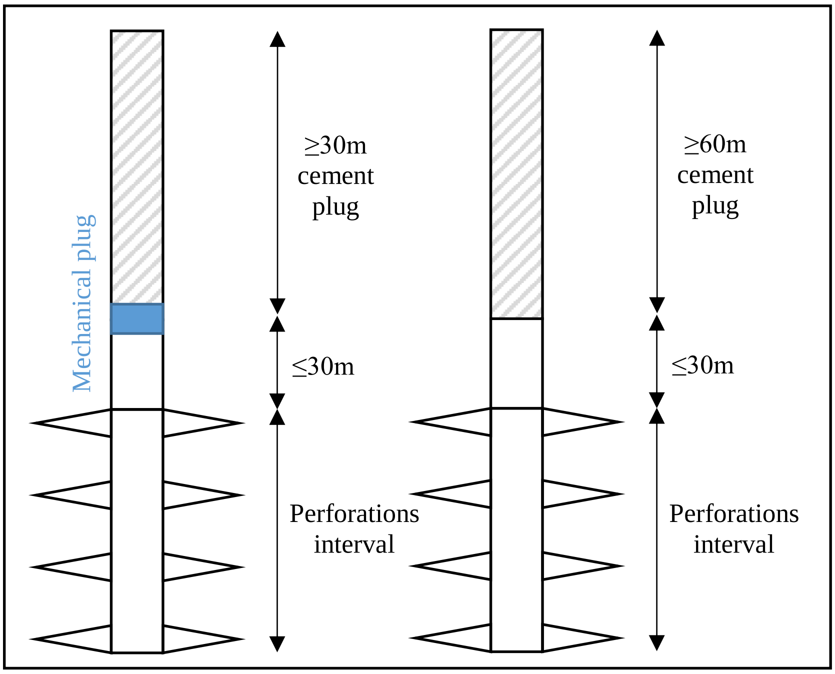

Figure 22: Plugging requirements for well completions with perforations (ANP, 2002)

For the top perforation layer closest to the mudline, the ANP (2002) has additional plugging requirements as presented in Figure 23. Similar to the requirements shown in Figure 22 the top layer needs to be plugged according to the two options shown in Figure 23. The options have the constraint that either the mechanical plug or the bottom layer of the cement column should be located at approximately 20m above the top end of the perforation interval.

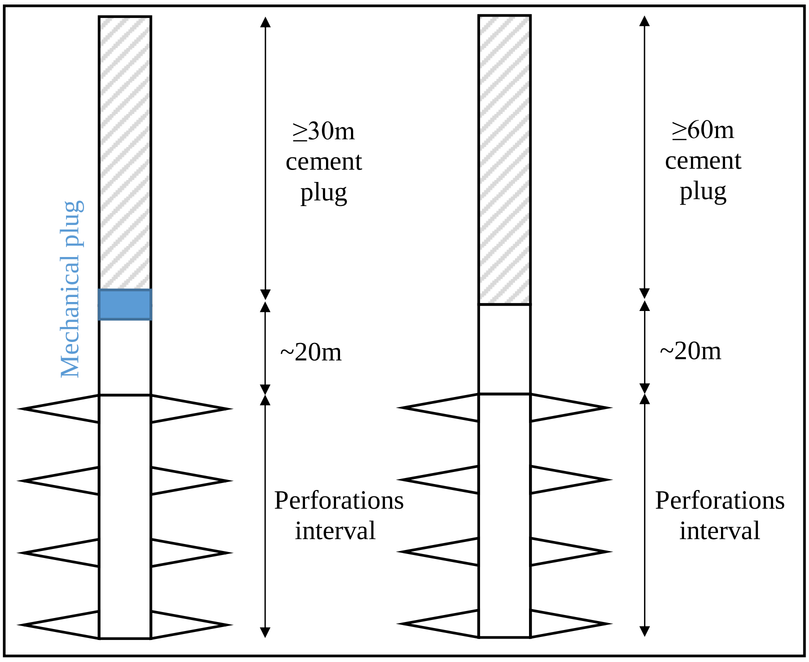

Figure 23: Plugging requirements for well completions with perforations at the top interval (ANP, 2002)

Typical well completions with the use of perforations usually consist of several layers of oil producing intervals as illustrated in Figure 24. When drilling operations start the first producing layer is perforated and production begins. Once the layer does not provide sufficient oil, drilling operations continue to reach the next hydrocarbon containing layers in greater depth. This procedure is repeated until the wellbore is completely exploited or further drilling operations become too costly. In terms of well abandonment each perforation interval needs to be permanently plugged according to the previous descriptions. Moreover, the intervals in between the temporary plugs need to be filled with drilling mud as stated by the ANP (2002). The mud provides additional stability of the wellbore and works as an additional seal to prevent any flow of hydrocarbons along the casing.

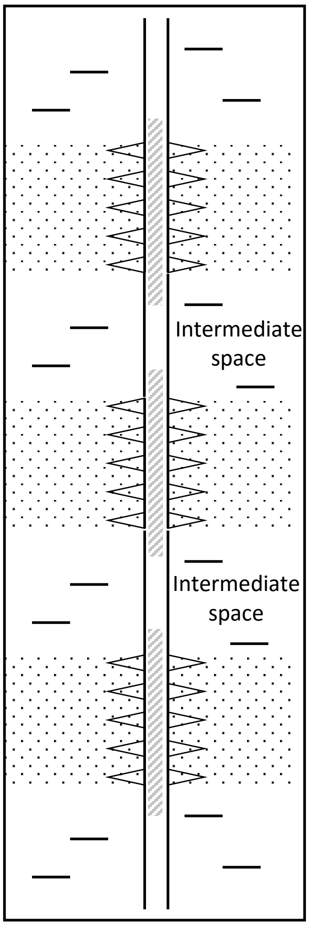

Figure 24: Repeated producing layers with perforations (ANP, 2002)

Close to the mudline an additional cement plug is required by the ANP (2002). The plug is divided in two segments. The lower segment needs to be placed in the interval between 100m and 250m below the mudline. The cement plug has to have a length of at least 30m. The second and final cement column needs to have a length of at least 60m and be placed as close as possible to the surface. The ANP (2002) requires an additional mechanical plug placed below the top cement columns. The CFR (§250.1715, 2015) states very similar requirements as shown on the right of Figure 25. The size of the plug in the CFR (2015) is smaller which is supposed to be at least 45m and the distance to the mudline should have a maximum value of 45m. Further conditions as explained in section 3.4 require a removal of the top 5m to completely seal off the wellbore. This depth needs to be taken into account for placing the highest cement column according to both the ANP (2002) and CFR (2015).

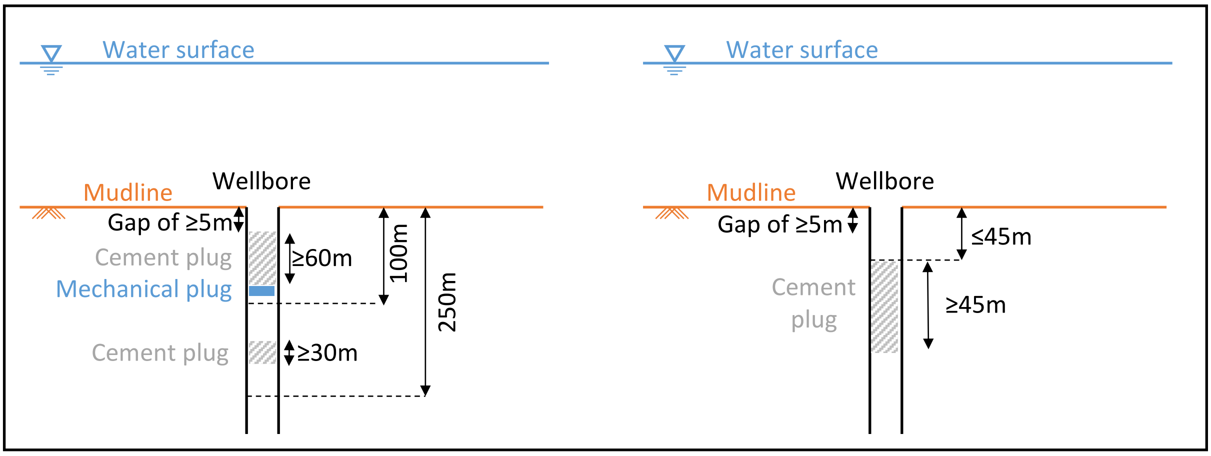

Figure 25: Plugging requirements for well completions for casings close to mudline (ANP, 2002) and (CFR, 2015)

The CFR (§250.1715, 2015) contains more cases than the Brazilian regulations (ANP, 2002) as can be observed in an excerpt shown in Table 1 which explains the required plugging specifications based on several scenarios.

Table 1: Well plugging requirements for several scenarios according to the CFR (2015)

If you have...	Then you must use . . .
(1) Zones in open hole,	Cement plug(s) set from at least 100 feet below the bottom to 100 feet above the top of oil, gas, and fresh-water zones to isolate fluids in the strata
(2) Open hole below casing,	(i) A cement plug, set by the displacement method, at least 100 feet above and below deepest casing shoe;
	(ii) A cement retainer with effective back-pressure control set 50 to 100 feet above the casing shoe, and a cement plug that extends at least 100 feet below the casing shoe and at least 50 feet above the retainer; or
	(iii) A bridge plug set 50 feet to 100 feet above the shoe with 50 feet of cement on top of the bridge plug, for expected or known lost circulation conditions
(3) A perforated zone that is currently open and not previously squeezed or isolated,	(i) A method to squeeze cement to all perforations;
	(ii) A cement plug set by the displacement method, at least 100 feet above to 100 feet below the perforated interval, or down to a casing plug, whichever is less; or
	(iii) If the perforated zones are isolated from the hole below, you may use any of the plugs specified in paragraphs (a)(3)(iii)(A) through (E) of this section instead of those specified in paragraphs (a)(3)(i) and (a)(3)(ii) of this section.
	(A) A cement retainer with effective back-pressure control set 50 to 100 feet above the top of the perforated interval, and a cement plug that extends at least 100 feet below the bottom of the perforated interval with at least 50 feet of cement above the retainer;
	(B) A bridge plug set 50 to 100 feet above the top of the perforated interval and at least 50 feet of cement on top of the bridge plug;
	(C) A cement plug at least 200 feet in length, set by the displacement method, with the bottom of the plug no more than 100 feet above the perforated interval;
	(D) A through-tubing basket plug set no more than 100 feet above the perforated interval with at least 50 feet of cement on top of the basket plug; or
	(E) A tubing plug set no more than 100 feet above the perforated interval topped with a sufficient volume of cement so as to extend at least 100 feet above the uppermost packer in the wellbore and at least 300 feet of cement in the casing annulus immediately above the packer.
(4) A casing stub where the stub end is within the casing,	(i) A cement plug set at least 100 feet above and below the stub end;
	(ii) A cement retainer or bridge plug set at least 50 to 100 feet above the stub end with at least 50 feet of cement on top of the retainer or bridge plug; or
	(iii) A cement plug at least 200 feet long with the bottom of the plug set no more than 100 feet above the stub end.
(5) A casing stub where the stub end is below the casing,	A plug as specified in paragraph (a)(1) or (a)(2) of this section, as applicable.
(6) An annular space that communicates with open hole and extends to the mud line,	A cement plug at least 200 feet long set in the annular space. For a well completed above the ocean surface, you must pressure test each casing annulus to verify isolation.
(7) A subsea well with unsealed annulus,	A cutter to sever the casing, and you must set a stub plug as specified in paragraphs (a)(4) and (a)(5) of this section.
(8) A well with casing,	A cement surface plug at least 150 feet long set in the smallest casing that extends to the mud line with the top of the plug no more than 150 feet below the mud line.
(9) Fluid left in the hole,	A fluid in the intervals between the plugs that is dense enough to exert a hydrostatic pressure that is greater than the formation pressures in the intervals.
(10) Permafrost areas,	(i) A fluid to be left in the hole that has a freezing point below the temperature of the permafrost, and a treatment to inhibit corrosion; and
	(ii) Cement plugs designed to set before freezing and have a low heat of hydration.
(11) Removed the barriers required in §250.420(b)(3) for the well to be completed	Two independent barriers, one of which must be a mechanical barrier, in the center wellbore as described in §250.420(b)(3) once the well is to be placed in a permanent or temporary abandonment.

It can be summarized, that for plugging and abandonment of wells the requirements in the ANP (2002) and CFR (2015) are very similar but that the CFR (2015) provides a more detailed and particular list of possible scenarios.

3.4 WELLHEAD, TREE AND CONDUCTOR REMOVAL

For the removal of the wellhead, tree and conductor it has to be distinguished between the case of platform wells and subsea or satellite wells. The removal of a subsea or satellite wellhead requires several tasks. As a first step, it is necessary to disconnect the pipelines, risers and spools from the Christmas tree through ROV operations. The ROV's are used a second time to unlock the connection between Christmas tree and wellhead. The Christmas tree is retrieved by lifting operations as part of section 3.5 and leaves the wellhead completely isolated and accessible for its removal. At this stage the wellhead still sticks out of the seafloor and creates a possible obstruction. Therefore, the CFR (§250.1716, 2015) requires the removal of all subsea installations up to a depth of at least 5m below the mudline. As a consequence, the last section of the casing in the wellbore needs to be removed as well. Among the various methods the most common procedure is to use abrasive water jets which cut through all layers of the casing from the inside as shown in Figure 26.

Figure 26: Cutting operation by abrasive water jet (PROSERV OFFSHORE, 2009)

The wellhead and the Christmas tree are lifted separately to a vessel. The wellhead in Figure 27, right, still shows the support of the Christmas tree which was previously removed.

Figure 27: Wellhead sliced by abrasive water jet (left) and wellhead removal (right) (MCGENNIS, 2007)

Platform wells are treated differently since there is neither a wellhead nor a Christmas tree installed on the seabed. Instead, the conductor extends the casing string from the wellbore beyond the seafloor up to the topsides and needs to be removed. In this case the dry tree is placed on the topsides on top of the conductors and removed as part of the platform decommissioning in section 4.7. Prior to the conductor removal cleaning operations need to take place to make sure that no hydrocarbons are left in the conductors. The cleaning operation may also include the removal of marine growth to simplify pulling operations.

The removal of the conductors requires three main steps (GEBAUER, et al., 2004):

- Severing
- Cutting and pulling
- Offloading.

Abrasive jetting tools are lowered inside the conductors (Figure 28, left) to make a cut as close as possible to the mudline. Figure 28, right, shows a conductor which has been cut underwater.

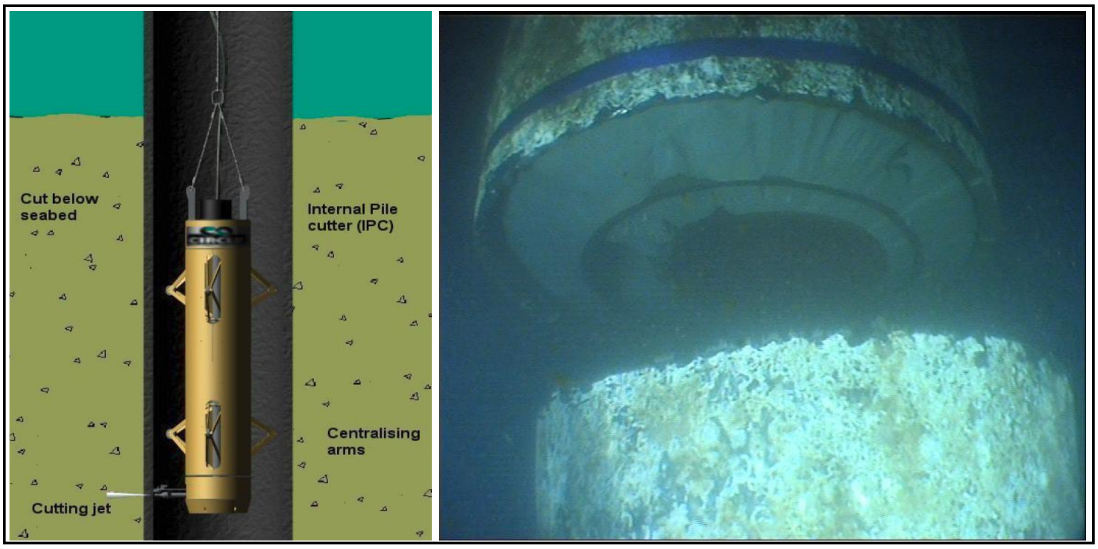

Figure 28: Abrasive water jet instrument (PROSERV OFFSHORE, 2009) and underwater conductor cut (CLAXTON ENGINEERING, 2015)

The conductors are very heavy and therefore need to be held horizontally in position by the rig that is located at the platform. Once the conductors are severed from the casing up to at least 5m below the mudline according to the CFR (§250.1716, 2015), the conductor is pulled up by the platform rig or additional jacks until a specified length and cut on topsides. The conductors are cut into segments of approximately 10m by saws as shown in Figure 29. The pulling and cutting procedure is repeated until the last remaining segment of the conductor can be pulled up and stored at the deck. The segments can be stored safely on the platform or lifted to a vessel for further recycling on shore.

Figure 29: Cutting conductor in segments at topsides (CLAXTON ENGINEERING, 2015)

Similar to the casing of wet tree wells, casings of platform wells need to be removed to at least 5m below the mudline in compliance with the CFR (§250.1716, 2015). In contrast, the ANP (2002) defines the removal of all equipment directly connected 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. For water depths above 80m no requirements are made for the removal of subsea installations related to a well. Therefore, this study assumes that for these water depths wellhead and could actually remain in place or placed at the seafloor adjacent to the plugged wellbore while the conductors are removed mandatorily as part of the platform decommissioning.

3.5 PIPELINE, RISER, UMBILICAL AND SUBSEA STRUCTURES DECOMMISSIONING

Subsea and satellite wells are connected to the platform through pipelines, such as flowlines and umbilicals and subsea installations. The decommissioning of these structures is specified in this section. The well plugging leaves the platform without any supply of hydrocarbons. Before removing the wellhead as explained in the previous section, it is necessary to decommission all pipelines connected to the platform. The pipelines have to be cleaned by Pipeline Inspection Gauges (PIG) operations and flushing. Once the pipelines have been completely cleared of hydrocarbons and chemicals that could flow into the marine environment, it is possible to detach the pipelines and subsea structures from both the well or Christmas tree and from the platform. These operations are usually done with divers and ROV’s.

The entire subsea field is decomposed in the individual parts, such as Christmas trees, drilling templates, PLETs, PLEMs, manifolds, jumpers, spools, risers, umbilicals, flowlines and pipelines. According to the CFR (§250.1725, 2015) all subsea structures need to be removed which contain Christmas tree, PLET, PLEM, risers, umbilicals, flowlines, spools, jumpers and manifolds. Umbilicals can be reeled to a vessel. Subsea structures pose a difficulty since they are usually anchored by suction piles. These can be detached from the soil through reverse installation since the CFR (§250.1728, 2015) requires that all subsea structures need to be removed up to a depth of approximately 5m below the mudline. Other options would be the application of cutting tools to detach the suction piles from the structure that needs to be lifted (MINERALS MANAGEMENT SERVICE, 2005).

According to the CFR (§250.1750, 2015) pipelines do not necessarily have to be removed entirely. Pipelines that do not entail environmental risks or form an obstacle and can be decommissioned in place in compliance with the CFR (§250.1751, 2015). The CFR (§250.1751, 2015) provides further specifications on the procedure for pipeline decommissioning in place. The CFR (2015) states that the cleaned pipeline needs to be filled with seawater. Both ends of the pipeline need to be detached from subsea structures (PLET, PLEM). The ends need to be plugged and buried approximately 1m below the seabed or secured by concrete mats.

The author did not find any Brazilian code that specifies whether pipelines or subsea structures have to be removed or if the option exists to leave them in place. The ANP (2015) provides only a vague description of the decommissioning requirements and states that the usual codes of the offshore industry should be applied but does not go into detail. If removal of subsea equipment is desired, ROV operations are necessary in combination with a crane vessel that can lift all subsea structures and bring it to the shore for disposal.

3.6 PLATFORM PREPARATION AND TOPSIDES REMOVAL

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 (GEBAUER, et al., 2004). 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 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.

The topsides consists of several modules that are installed on different decks and are connected to each other by piping. Certain equipment on the topsides can be quite valuable and others might pose a significant environmental threat that needs to be considered. Therefore, each module requires an individual evaluation and strategy for decommissioning. The usual procedure is to detach each module by cutting all piping and cables. Afterwards, cleaning operations are necessary which require flushing and emptying tanks from chemicals and hydrocarbons.

The removal of the topsides requires lifting operations. For these to take place padeyes need to be installed at the lifting points. 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 is a lifting of the entire topsides as a single piece. According to the options (b) and (c) the topsides is cut in smaller pieces. The reverse modular removal separates each module on the topsides which is lifted individually on a barge for transport onshore. 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 small vessels and cranes. The more lifting sequences are conducted, the less capacity is needed for the vessel. At the same time the duration of the removal and the work intensity involved with cleaning, separation, and cutting procedures increases. Figure 30 shows an example with several individual modules of the topsides, which can be removed separately.

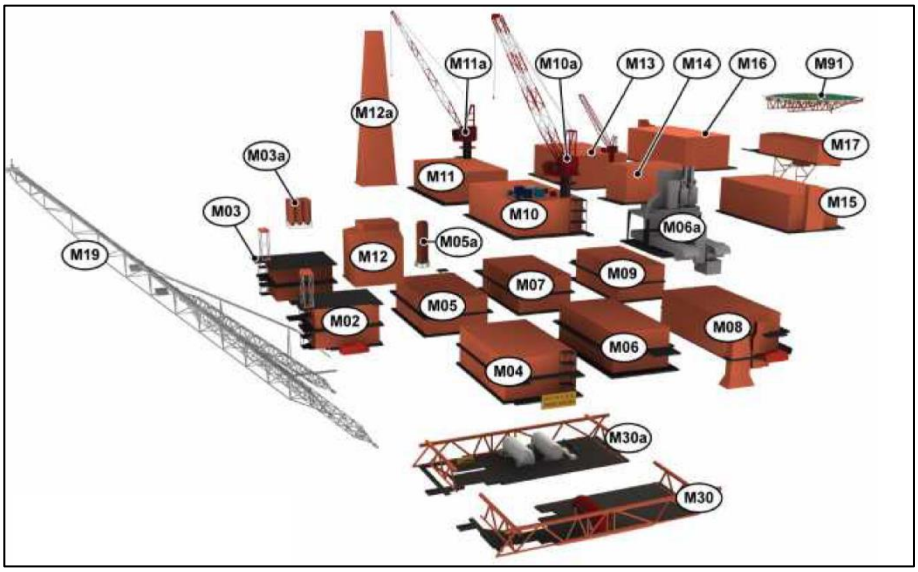

Figure 30: Individual modules of a typical topsides configuration (CNR INTERNATIONAL, 2014)

Figure 31, left, shows the lifting of a topsides where all modules have previously been removed while Figure 31, right, illustrates a single lift with the entire equipment and modules still in place.

Figure 31: Types of topsides removal, in various steps (left) (BYRD, MILLER, & WIESE, 2014) and single lift with all modules still in place (right) (DECOM NORTH SEA, 2014)

The decision of which removal strategy should be adopted depends on the configuration of each topsides 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 each strategy is certainly the weight of each equipment and the entire modules. If the topsides is 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. Some special equipment might be worth for reuse. These components should be separated and treated more carefully to avoid any damage. The cleaning and safety procedures are illustrated in more depth by OIL & GAS UK (2008).

3.7 JACKET REMOVAL

The jacket structure needs to be removed since it is an obstruction in the ocean. The requirements for the removal differ between the CFR (2015) and ANP (2002). The CFR (§250.1703, 2015) states that the objective of the decommissioning is to remove all platforms up to a depth of approximately 5m below the mudline (CFR, §250.1728, 2015). This means for the jacket that all piles need to be cut at this depth before the structure is removed. It has to be stated that the legislation incorporates an exception (CFR, §250.1730, 2015) that allows the structure to become an artificial reef which would fall under the responsibility of a federal agency. The ANP (2002) does not specifically mention the removal of the jacket structure but states that for water depth up to 80m all installations need to be removed. This study interprets from this condition that for the coast of Brazil that if the jacket is removed up to a depth of 80m, it poses no further threat and fulfills the requirements of the ANP (2002). This would mean that jackets do not necessarily need to be removed entirely and the top 80m below the water surface would be sufficient. The majority of the platforms located at the Campos Basin are installed at water depth above this mark, and leaving the bottom segment in place could lead to a significant reduction of the workload.

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

1. Lifting jacket as a single piece or cut in several parts and bring onshore for disposal
2. Lifting jacket as a single piece and dispose in deep waters
3. Lifting jacket with buoyancy tanks and tugging to shore
4. 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 through piles to the ground. These piles can either be driven through the platform legs or as skirt piles adjacent to the platform legs. In some cases both types of piles exist. 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 as explained in section 3.4.

There are two strategies for lifting the jacket either entirely as a single piece or in several pieces. The first option requires less preparation but a HLV with a 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 as shown in Figure 32 which requires a HLV with much less capacity but a longer duration of the entire procedure.

Figure 32: Jacket removal in various steps (DECOM NORTH SEA, 2014)

A special piecewise removal of the jacket structure is referred to as “hopping”. In this technique the jacket is detached from the seafloor and brought to smaller water depth to remove further sections from the top as they stand out of the water as demonstrated in Figure 33. This method makes the use of deep sea divers or ROV operations obsolete.

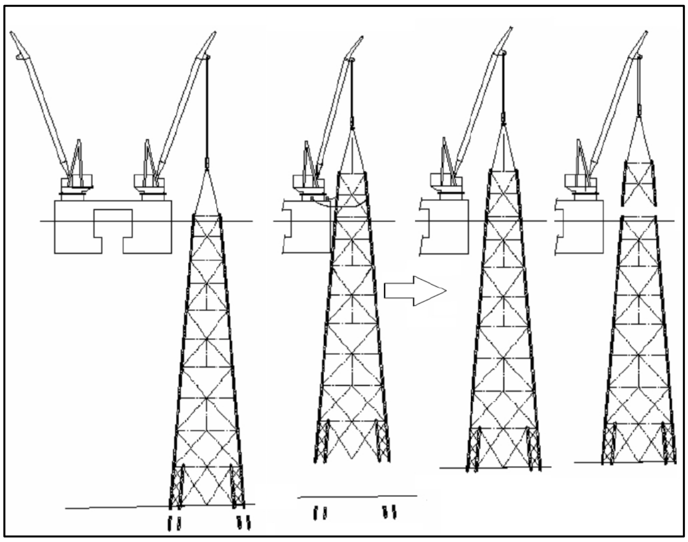
Figure 33: Jacket removal through hopping (TSB OFFSHORE, 2000)

An alternative to the single lift of the jacket with HLV is the use of controlled variable buoyancy systems (GERWICK, 2007). These system consist of actively controlled buoyancy tanks which are placed at the jacket and cause enough uplifting force to allow the platform to be towed to the shore as shown in Figure 34.

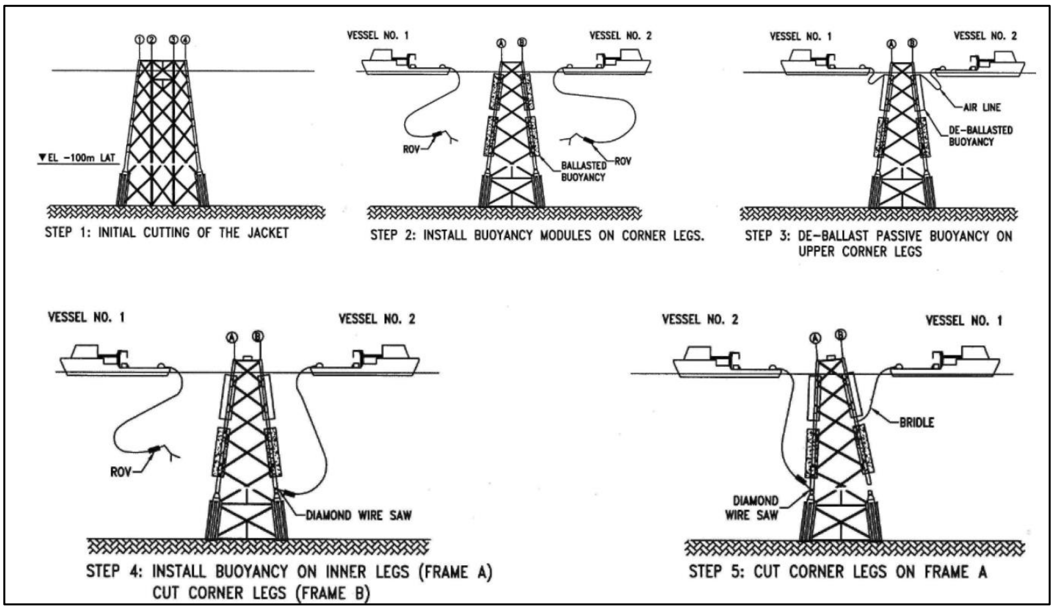

Figure 34: Jacket removal with buoyancy tanks (PROSERV OFFSHORE, 2009)

The connection of the tanks can be achieved through clamps as shown in Figure 35. These methods are still under investigation and require further testing before they can be applied (GEBAUER, et al., 2004).

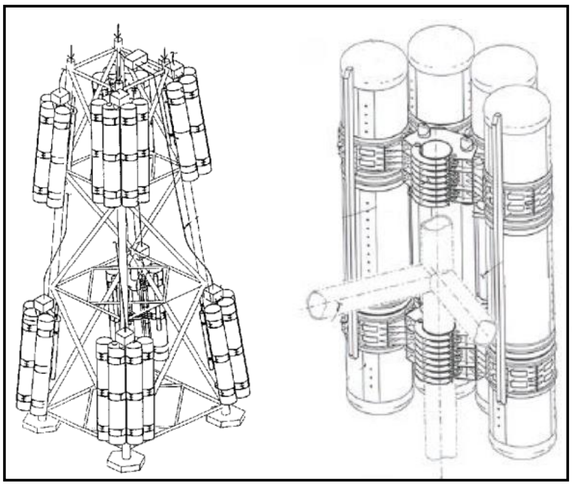

Figure 35: Buoyancy tanks clamped at jacket legs (TSB OFFSHORE, 2000)

The last option is to topple the jacket on site as illustrated in Figure 36. This option is valid if the requirements of a distance 80m from water surface to the highest point of the toppled jacket is fulfilled according to the ANP (2002). The procedure for toppling the jacket is described briefly by GERWICK (2007), who suggests cutting all piles instead of one side, which will form the fixed rotational axis. The piles of the last side of the jacket should be cut until half the diameter is reached. This 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.

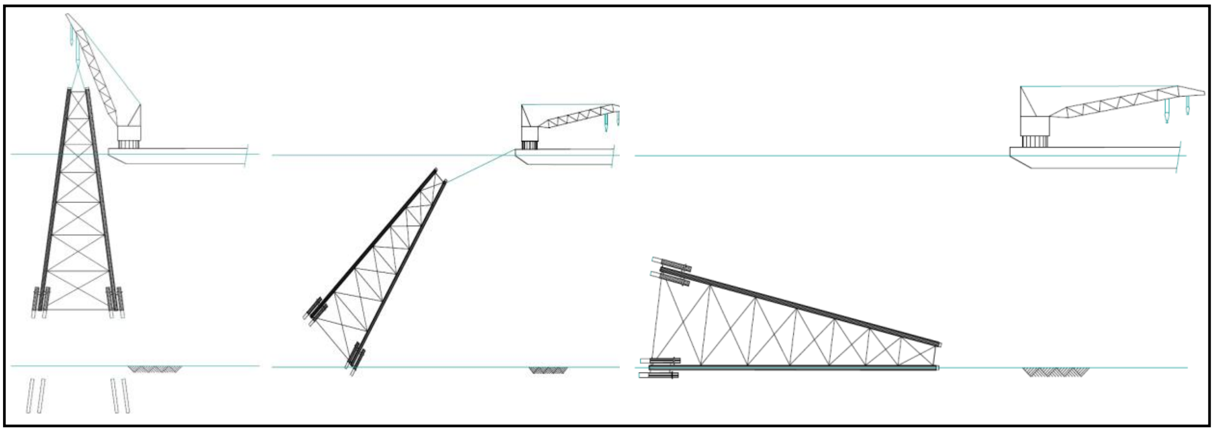

Figure 36: Toppling on site of jacket (PROSERV OFFSHORE, 2009)

The toppled jacket could serve as an artificial reef. Currently, there are no rig-to-reef programs in Brazil known by the author such as the program valid for the US coast (NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION, 2007). The optimal depth for the jacket to serve as an artificial reef is between 30m and 60m (PROSERV OFFSHORE, 2009). The alternative to an artificial reef is to convey the structure to deeper seas or to shore, which both implicate larger transportation costs. The question whether the jacket may be disposed under water needs to be addressed by Brazilian legislation. In comparison to the topsides, pipelines, and subsea structures the jacket does not contain remnants of hydrocarbons and 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 (MACREADIE, FOWLER, & BOOTH, 2011).

Independent which removal concept is applied, the structural integrity of the jacket needs to be verified as explained in section 3.6. 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 analyzed by engineering analyses.

3.8 TRANSPORT AND DISPOSAL

The topside modules, the steel frame of the topsides, the jackets, piles, pipelines, risers and subsea structures need to be disposed. In the previous sections some options were shown that allow a disposal offshore (e.g. jacket) or that some installations may be left in place (e.g. pipelines). The remaining installations need to be treated onshore for recycling or disposal.

The large jacket structures are particularly difficult to handle since a lot of work and machines are necessary to cut the structure into pieces at a shipyard as shown in Figure 37. Therefore, a disposal offshore or a rig-to-reef option should be the preferred choice.

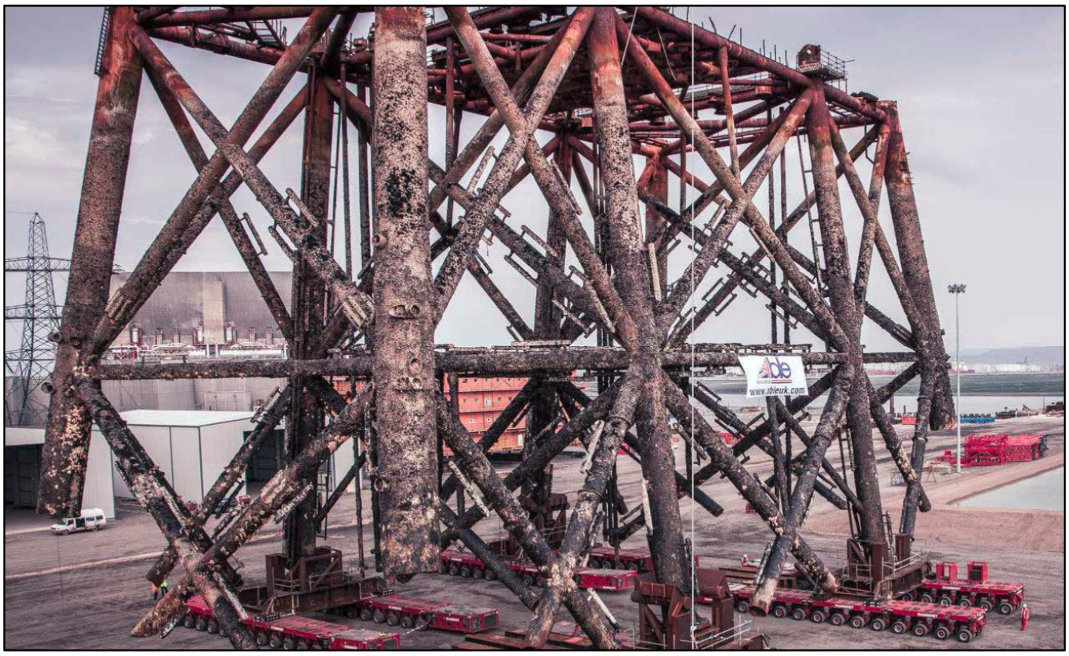

Figure 37: Dismantling of a jacket onshore (DECOM NORTH SEA, 2014)

The topsides structure is smaller than the jacket but requires similar attention and time for dismantling it. The sequence in Figure 38 shows a few steps needed to cut the topsides into pieces. Similar to the jacket structure the option should be evaluated if other solutions exist where this work could be avoided. The argument exists that the steel could be sold to reduce the costs of the procedure. A case study of Chevron from 1996 presented by GEBAUER (2004) shows that in a case of a platform decommissioning the overall expenditures to cut the steel exceeded the gains of selling the steel with a factor of 4. Therefore, this argument is not considered valid and the selling of steel not a valuable source of income.

Figure 38: Steps of dismantling topsides (Images courtesy of Veolia Environmental Services)

Subsea structures as manifolds and umbilicals may contain useful materials that might be worth to recycle. The equipment is usually not worth selling due to its age and condition. An exception is the Christmas tree which may be used for other wells (PROSERV OFFSHORE, 2009). Again, it should be taken into consideration if the option exists to leave the equipment on the seafloor after cleaning has taken place.

3.9 SITE CLEARANCE

Once all subsea structures have been removed and the pipelines buried, the field has to be cleaned from remaining debris. Divers and ROV’s 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 more cost-effective option is to use trawls to clear the site. The CFR (§250.1741, 2015) defines radii for different installations.

Table 2: Radii of site clearance for different installations based on the CFR (2015)

Installation	Radius [m]
Platform well	90
Satellite well	180
Platform site	400
Subsea structures (PLEM, manifold etc.)	180

Sonars are a useful technique to scan large areas to verify that all debris has been removed. Ships with equipped sonars should perform scans both prior and after the removal of the installations (GEBAUER, et al., 2004). Figure 39 shows a sonar scan which is able to identify several objects left behind on a decommissioning site.

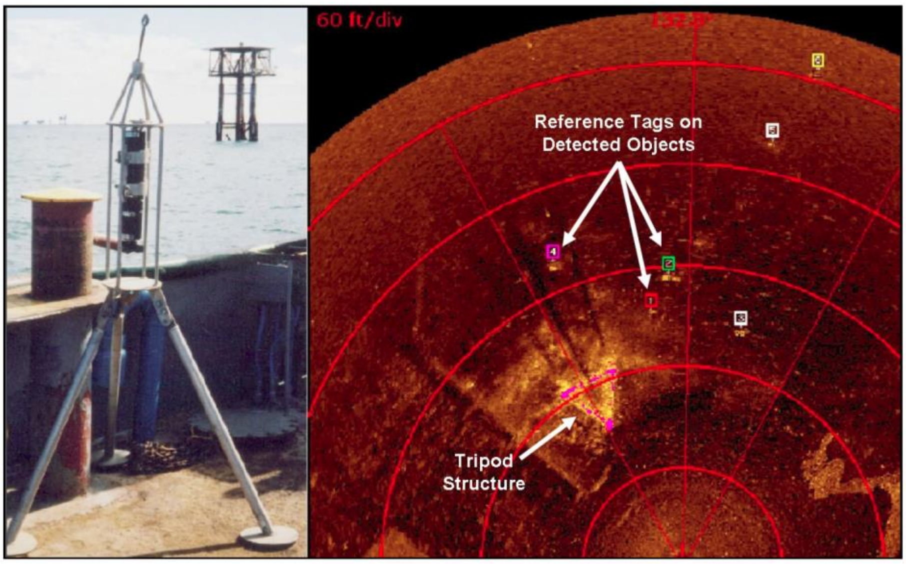

Figure 39: Sonar scan of a subsea field to detect remaining objects (MINERALS MANAGEMENT SERVICE, 2005)

3.10 MONITORING

Although it has been specified in OSPAR (1998) that a continuous monitoring of the abandoned installations should be included in the decommissioning program, the exact scope has not been defined. Neither the CFR (2015) nor the ANP (2002) address this topic. Especially in the case of the abandoned wells a monitoring in certain time intervals should be applied to guarantee that the plug still seals the well. The author did not encounter any specifications in the codes that require certain time intervals or techniques for monitoring the site after decommissioning has finished.

4 DECOMMISSIONING COST ESTIMATION APPROACH

4.1 GENERAL ASPECTS OF THE APPROACH

This study uses recent publications of cost estimates to determine the financial expenses of decommissioning fixed offshore platforms and its associated facilities. PROSERV OFFSHORE (2009) developed cost estimate curves and tables for several decommissioning activities performed in the Gulf of Mexico OCS in a recent market research. Based on the results of PROSERV OFFSHORE (2009), KAISER & LIU (2014) generalized regression equations for estimating the expenses of future projects. Where appropriate, comparisons are made to the latest cost estimation updates of a study for decommissioning activities related to the Pacific Outer Continental Shelf Region (POCSR) (TSB OFFSHORE, 2015).

On behalf of the Minerals Management Service (MMS) of the POCSR, a first study was established by a selected Offshore Decommissioning Cost Team (OFDC). The study focusses on the estimation of the decommissioning costs for the complete removal of all 23 fixed oil and gas platforms in the POCSR (GEBAUER, et al., 2004). The scenarios developed in the study contain the decommissioning between 2 and 6 platforms at once, combined to a total of 6 projects. The entire decommissioning plan is set up to be conducted within a time frame of 15 years. The purpose of the POCSR research was to support the Federal bonding decision to ensure compliance with the OCS oil and gas regulations for decommissioning activities of the lessees. Moreover, these cost estimates serve as a benchmark for the POCSR. MMS assigned PROSERV OFFSHORE to review and update the cost estimates due to their experience in managing decommissioning projects and conducting technical and engineering studies together with cost assessments for decommissioning platforms (PROSERV OFFSHORE, 2010), (TSB OFFSHORE, 2015). Periodical adjustments of the cost estimates allow for technological progress as well as changes in market conditions and regulatory requirements. It is pointed out, that the MMS was changed to the Bureau of Safety and Environmental Enforcement (BSEE) in 2011 and PROSERV Offshore to TSB Offshore. Cost estimates for the POCSR study are provided for the following categories:

- Project management, planning and engineering
- Permitting and regulatory compliance
- Complete platform removal including preparation
- Well plugging and abandonment

- Conductor removal
- Mobilization and demobilization of heavy lift vessels or derrick barges
- Pipeline and umbilical decommissioning
- Transportation to shore and disposal
- Site clearance
- Work and weather contingency factors

The general assumptions defined for the cost estimation of TSB OFFSHORE (2015) can be summarized as follows. The approach assumes, that all decommissioning activities within the cost estimate fulfill the regulations of the Bureau of Ocean Energy Management (CFR, 2015). The decommissioning activities are supposed to be unproblematic, ordinary and based on conventional approaches according to industry wide practices. No salvage value of steel or sale value of equipment, umbilicals, and wellheads and other parts is regarded to offset costs incurred by the decommissioning. The cost estimates are based on market and technology conditions of 2014. The study considers mobilization and demobilization costs of heavy lift vessels from Southeast Asia. Further, the study assumes that specialized equipment and services are mobilized from the GOM. Another significant assumption is the fact that several platforms are decommissioned in a combined project, which means that mobilization and demobilization costs are shared among the platforms. The study considers weather contingency of 5%-15%, work provision of 15% and management, planning, engineering costs of an additional 8%.

MMS assigned PROSERV OFFSHORE (2009) to conduct an additional market research for the decommissioning of deepwater oil and gas platforms in the Gulf of Mexico OCS. Having developed cost algorithms for the complete removal of Gulf of Mexico platforms, PROSERV OFFSHORE (2009) published a set of constructed decommissioning cost estimates for several required activities. The study is based on the decommissioning of fixed and floating offshore platforms installed in the Gulf of Mexico in water depths greater than 120m. The study covers a total of 111 structures. For the purpose of this study the focus is set on fixed offshore structures, which sum up to a total of 70 platforms of the 111 in total. Among these 70 fixed platforms PROSERV OFFSHORE (2009) selects a representative set of 17 platforms which cover a wide range of designs and characteristics. The aim was to reduce the workload and develop detailed cost estimates that can serve as a benchmark based on characteristics such as facility type and water depth. PROSERV OFFSHORE (2009) determines cost estimates for the following set of activities:

- Well abandonment
- Conductor removal
- Pipeline abandonment
- Umbilical removal
- Flexible riser removal
- Platform removal including and site clearance

The total decommissioning costs consist of the costs of each of the 6 categories which are explained in sections 4.3 - 4.7. It is pointed out, that these categories cover most of the aspects of the previous list defined by the OFDC (GEBAUER, et al., 2004) that is slightly different.

The assumptions defined for the cost estimation of PROSERV OFFSHORE (2009) are similar to the ones defined in the study of TSB OFFSHORE (2015). The approach assumes equal to TSB OFFSHORE (2015), that all decommissioning activities within the cost estimate fulfill the regulations of the Bureau of Ocean Energy Management (CFR, 2015). The decommissioning activities are supposed to be unproblematic, ordinary and based on conventional approaches according to industry wide practices. Additionally, no salvage value of steel or sale value of equipment, umbilicals, and wellheads and other parts is regarded to offset costs incurred by the decommissioning.

In contrast to TSB OFFSHORE (2015) the study of PROSERV OFFSHORE (2009) assumes that all required vessels, specialized equipment and services are available at the GOM. It is considered, that operators do not share any resources and neither experience nor innovation lead to a decommissioning cost reduction.

The cost estimates of PROSERV OFFSHORE (2009) are defined as P50 cost estimates with an accuracy of ±20% in U.S. Dollars [$] and are based on market and technology conditions of 2009-2010. The P50 cost estimate is defined as the expected cost with a 50% chance to result in higher and lower final costs. If all assumptions turn out to be valid and market and technology conditions used for the estimate are appropriate, the cost estimate should represent the expected costs. The level of accuracy assumes an even spread around the expected cost. The stated accuracy of ±20% signifies that an optimistic cost estimate can be 20% lower than the P50 value and a conservative cost estimate 20% higher. TSB OFFSHORE (2015) does not provide any information on the accuracy of the cost estimates.

Costs for overhead, such as planning and engineering as presented in section 3.2, could have a significant impact on the total decommissioning cost estimate and explicitly mentioned in sections 4.3 to 4.8. Equal to the POCSR study, a percentage of 8% is included in each previously specified decommissioning category of PROSERV OFFSHORE (2009). Moreover, the assumption of unproblematic 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 costs. Equal to TSB OFFSHORE (2015) a work contingency of 15% is considered to allow for inaccuracies and not estimated issues such as minor changes of design or techniques in the decommissioning procedure which do not generally change the concept. Also a variation of market conditions is covered like costs for required equipment or vessel rates since these factors are assumed to be constant in the estimate but undergo changes. Finally, a higher weather contingency of 20% for the GOM is included as well to consider schedule slips due to severe storms. All mentioned percentages 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 (GEBAUER, et al., 2004).

This study uses in addition a paper from KAISER & LIU (2014) who used the cost estimate from PROSERV OFFSHORE (2009) to derive regression curves to allow a simplified cost estimation of future decommissioning project costs. These regression models are introduced in sections 4.3 to 4.8 if they are considered as beneficial in comparison to the cost curves and tables of PROSERV OFFSHORE (2009).

4.2 RELEVANT COST FACTORS

Prior to introducing the detailed cost estimation approach for the single decommissioning activities, key variables are presented, that mainly affect the order of magnitude of decommissioning costs (GEBAUER, et al., 2004). Among several, important cost factors are the water depth of the offshore platform and the size and weight of the structure. Independent of well-developed cost estimation approaches, water depth and weight can be employed as a reliable indicator in determining decommissioning costs of pending projects.

Water depth serves as a basis for further indicators for increasing decommissioning costs. Greater water depth usually implies a larger distance to shore, greater structure sizes and weights and therefore additional logistical and organizational difficulties. These circumstances lead to larger uncertainties in the project costs where for instance severe weather conditions may cause substantial delays. For deepwater lifting operations of larger structures specialized vessels are necessary to perform these activities which in turn are less available. Additionally, engineering and scheduling have to meet the requirements for particular activities performed in deepwater. It can be stated that the decommissioning costs increase steeply with the distance from shore.

Next to the previously mentioned key variables water depth and structure weight further cost factors may significantly affect the project costs (GEBAUER, et al., 2004). The relevance of further cost factors depends on the specific decommissioning activities, e.g. the number of wells for estimating the costs of well plugging and abandonment. These factors are addressed explicitly for each decommissioning activity in sections 4.3 to 4.7.

Furthermore, the magnitude of decommissioning costs depends also on external cost factors for the project and affect each activity only indirectly. These factors are used to be economical and fixed values in terms of a base date as assumed in the previous section. Examples are the intensity of competition in the industry and corresponding price levels.

4.3 WELL ABANDONMENT AND CONDUCTOR REMOVAL

The most important variable to determine plugging and abandonment costs of platform wells is the difficulty or complexity of a well since it determines the time required to complete the activity (GEBAUER, et al., 2004). Also the depth of the platform wells impact the costs due to longer plugging operation times and additional cement volumes.

PROSERV OFFSHORE (2009) estimated the costs 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 are also removed, the platform well abandonment can be considered as complete. The costs are presented in Figure 40 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 (2015) as described in section 3.3. The cost estimate also contains a work provision of 15%, weather contingency of 20% and overhead costs of 8% for planning and engineering.

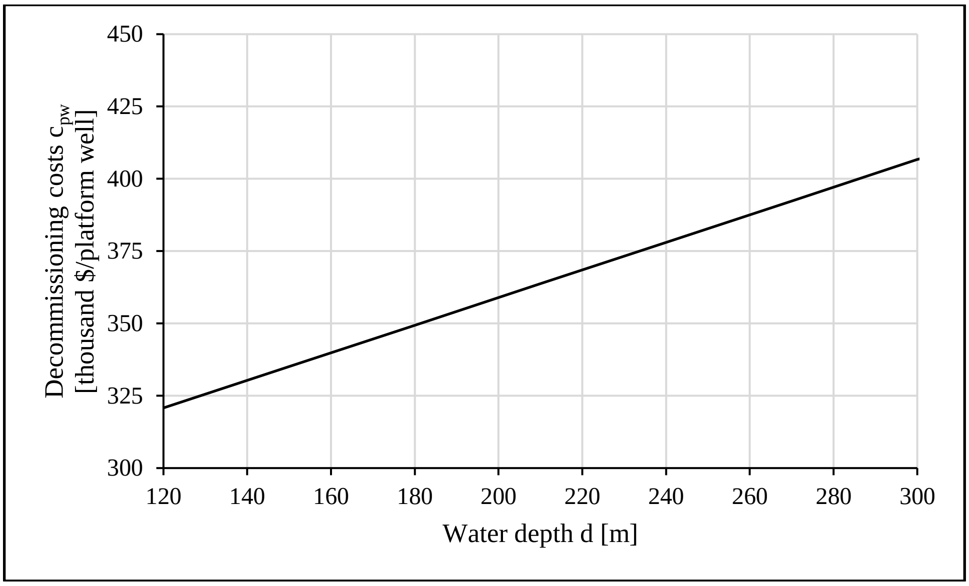

Figure 40: Plugging and abandonment cost per platform well applicable only if the total number exceeds 15 platform wells (PROSERV OFFSHORE, 2009)

The costs to abandon a single platform well increase 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 (PROSERV OFFSHORE, 2009).

Based on cost curves developed by PROSERV OFFSHORE (2009), KAISER & LIU (2014) generalized a two-factor regression model to estimate the costs to preliminary abandon a single platform well $c_{pw.}$ These costs are calculated with water depth d and the total number of dry tree wells N_{pw} as linear and exogenous variables in Equation (1).

$$c_{pw}\ [\$/\text{platform well}] = 406911 + 492 * d - 3284 * N_{pw} \tag{1}$$

Equation (1) is rather limited and considers few input parameters. Other parameters that are in detail explained in section 3.3 are not taken into account, such as the number of oil producing soil layers, the amount of cement needed to perform all plugging operations, the complexity and type of well completions and the operational time.

In a different study conducted by TSB OFFSHORE (2015) the well plugging and abandonment costs for platform wells are estimated based on the complexity of the well. The study assumes the use of rig-less techniques with mobilization and demobilization costs within the GOM. Difficult well completions might contain inclined wellbores, high annular pressures, parted casings or require fishing operations.

Table 3: Well decommissioning costs based on complexity (TSB OFFSHORE, 2015)

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

To complete the preliminary abandonment of platform wells to permanent ones, the conductors have to be removed which includes severing, pulling and offloading. PROSERV OFFSHORE (2009) developed unit prices per conductor c_{cond} depending on water depth d. These unit prices are applicable for cases with at least N_{cond} =15 conductors in total. This cost estimate is based on the assumption that the conductors are cut at 5m below the mudline using 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 this study is to lift the conductors in 10m segments with the drilling rig and casing jacks. The conductors are cut on topsides with saws and are offloaded with the platform crane to a barge. Afterwards, the conductor segments are brought to shore for disposal. The mobilization costs of the cargo barge are included. The cost estimate also contains a work provision of 15%, weather contingency of 20% and overhead costs of 8% for planning and engineering. These costs are presented in Figure 41 based on an increase with water depth d.

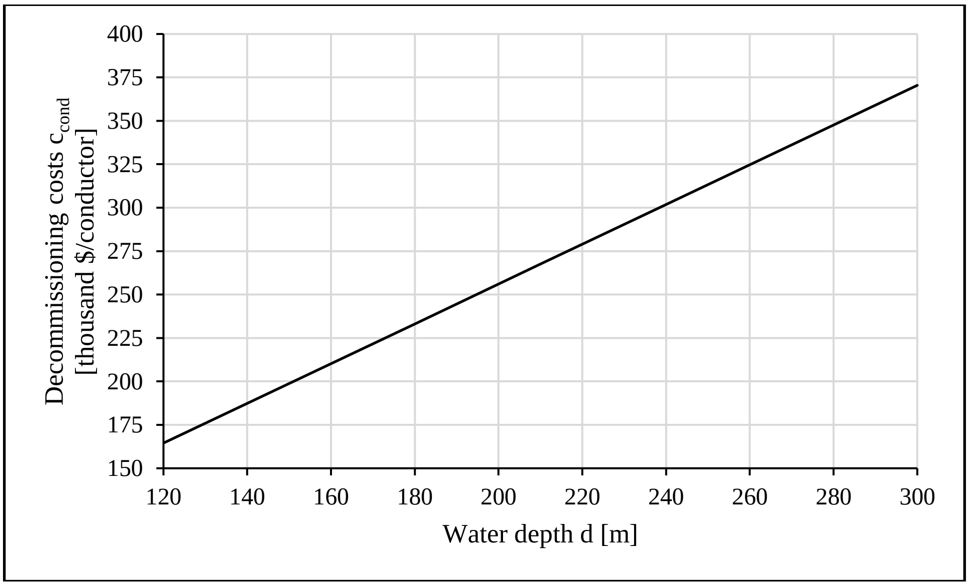

Figure 41: Conductor removal, applicable only if the total number exceeds 15 conductors (PROSERV OFFSHORE, 2009)

The unit cost to permanently abandon a single platform well by 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 remain nearly constant with an increase in the total number of conductors if the total number of conductors exceeds 15. According to the OFDC (GEBAUER, et al., 2004) it does not matter for the costs whether a conductor is removed immediately after the related well has been plugged or first all wells are plugged and then the conductors removed.

A linear two-factor regression model is generalized by KAISER & LIU (2014) based on the cost curves of PROSERV OFFSHORE (2009). The removal cost per conductor c_{cond} is obtained with water depth d and the total number of conductors N_{cond} as explanatory variables in Equation (2).

$$c_{cond}\ [\$/\text{conductor}] = 64437 + 1145 * d - 785 * N_{cond} \tag{2}$$

On a different study conducted by TSB OFFSHORE (2015) the costs for the conductor removal of 23 platforms of the POCSR was estimated which contained a total of 810 conductors. The cost estimate has 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.

Wet tree wells have a different cost estimation approach since vessels and associated techniques are involved. Table 4 summarizes a detailed cost estimate presented in PROSERV OFFSHORE (2009) for the option 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. The costs of Table 4 do not occur for intervention vessels that can keep their position through dynamic positioning systems. The cost estimate is based on the assumption that a total of 11 subsea wells are plugged. The cost assessment includes the decommissioning of the related subsea structures. It is assumed that subsea structures anchored to the seafloor are decommissioned in place. If the connection is simple and the subsea structure easily to detach, the installation is lifted to a vessel for disposal (PROSERV OFFSHORE, 2009).

Table 4: Cost estimation schematic for well abandonment according to PROSERV OFFSHORE (2009)

	Duration	Dayrate	Rig	Rig-less
		[1000 $/day]	[Million $]	[Million $]
Preparation work	-	-	0.345	0.345
2 anchor vessels	2 x 16 days	36	1.152	-
Anchor vessel fix costs	-	-	0.04	-
Drill rig	20.5	404	8.282	-
Intervention vessel	14.5	180	-	2.61
Fix costs for plugging and abandonment	-	-	0.12	0.12
Total			9.94	3.08

The cost to permanently plug and abandon a single subsea or satellite well including wellhead and wet tree removal is assumed to be fixed by KAISER & LIU (2014). The unit cost is only dependent on the chosen technology to perform the activity. It is distinguished between rig-less techniques and rig techniques. The unit costs to permanently plug and abandon a single wet tree well using rig-less techniques is approximately $3 Million whereas the unit cost using rig techniques results in $10 Million.

In general, permanent plugging and abandonment of wet tree wells is much more expensive than abandonment 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 PROSERV OFFSHORE (2009) for the GOM.

4.4 PIPELINE ABANDONMENT

The costs of pipeline abandonment depend on the complexity of the pipeline system at the seabed. Pipeline crossing requires additional planning and time since more pipe sections need to be cut (GEBAUER, et al., 2004). The removal of the pipeline is usually combined with the removal of connected subsea structures, such as spools or jumpers, PLET’s and PLEM’s. Therefore, the time required for the decommissioning of the pipelines increases with the obstructions per pipeline. Pipeline abandonment costs usually increase with water depth because costs of diving activities and mobilization tend to rise (PROSERV OFFSHORE, 2009). The costs also increase with pipeline length, diameter and water depth since 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 require a vessel whereas the costs vary a lot with the utilized type of vessel. In most cases a vessel is already present because of the plugging of the wet tree wells.

PROSERV OFFSHORE (2009) estimates the costs for pipeline abandonment of the selected platforms of the GOM study with reference to flushing volume, water depth, mobilization distance and type of vessel. The pipelines are detached from all other subsea installations and from the platform. These operations are carried out by ROV's or divers. Pipelines are decommissioned in place through plugging and burying the ends with sand bags or concrete mats. The operations below water are performed by anchored dive boats for water depths up to 150m. Estimates were summarized to representative pipeline abandonment scenarios for different types of vessels being utilized. The cost estimate also contains a work provision of 15%, weather contingency of 20% and overhead costs of 8% for planning and engineering.

Table 5: Pipeline decommissioning cost scenarios (PROSERV OFFSHORE, 2009)

Water depth [m]	Mobilization distance [km]	Pipeline diameter [in]	Pipeline length [km]	Volume [1000 m³]	Decommissioning costs [$]	Pipeline termination
137	254	4	2	28	$871,826	Pipeline between platforms
122	226	6	31	566	$980,068	
122	226	8	59	1926	$1,287,956	
122	226	16	21	2662	$1,404,745	
137	254	6	1	28	$1,115,536	Pipeline between platform and subsea installation
122	370	10	23	1133	$1,814,937	
137	185	12	37	2662	$2,554,483	

KAISER & LIU (2014) derive a linear multi-factor regression model. Equation (3) enables the estimation of pipeline abandonment costs c_{pipe} with water depth d, pipeline length l_{pipe} and pipeline diameter D_{pipe} as relevant cost factors.

$$c_{pipe}\,[\$] = 42968 + 5085 * d + 9961 * l_{pipe} + 43305 * D_{pipe} \quad (3)$$

In a different cost assessment conducted by TBS OFFSHORE (2015) the pipeline decommissioning is analyzed for 23 platforms of the POCSR. The total length of the pipelines sums up to 553km. This cost assessment differs in comparison to the previous ones due to the fact that it considers a complete pipeline removal if the water depth is less than 60m which comprises about 19% of the entire length. The remaining pipelines in water depth above 60m can be decommissioned in place. This study derives from the cost assessment (TSB OFFSHORE, 2015) a simplified unit price of 115,000 $/km.

4.5 UMBILICAL REMOVAL

The costs for the decommissioning of umbilicals is mainly based on the length and water depth. The longer an umbilical is the more time is necessary to flush and reel it. For a greater water depth different vessels are necessary which also need to contain more powerful pumps for the flushing operations.

PROSERV OFFSHORE (2009) provide a simplified approach to determine the decommissioning costs for complete removal. The umbilical removal costs include flushing, cutting and reeling. The umbilicals are detached on both ends by ROV's and reeled to an anchor handling vessel. Table 6 provides the cost estimate for water depths of approximately 120m and 300m. The costs include weather and work contingency 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 6: Cost estimate of umbilicals (PROSERV OFFSHORE, 2009)

Length [km]	2	4	6	10	20	37
Costs/length [$/m] for 120m water depth	42.11	23.61	17.74	12.81	9.04	7.41
Costs/length [$/m] for 300m water depth	55.04	30.08	21.81	15.35	10.61	8.07

KAISER & LIU (2014) derive a two-factor regression to estimate the removal cost for a single umbilical c_{umb} per length by a nonlinear relationship between the cost factors water depth d and length l_{umb} according to Equation (5). Equation (4) allows the calculation of a unit cost per meter of umbilical length.

$$c_{umb\ per\ m}\ [\$/m] = 15.77 * d^{0,31} * l_{umb}^{-0,85} \qquad (4)$$

$$c_{umb}\ [\$/umbilical] = 15.77 * d^{0,31} * l_{umb}^{-0,85} * l_{umb} \qquad (5)$$

In a different cost assessment TBS OFFSHORE (2015) conducted an estimate for the removal costs of umbilicals with a total length of 53km of 23 fixed platforms in the POCSR. The cost estimates are very similar to the values presented in Table 6. The study presents a simplified unit cost value of 106 $/m umbilical length.

4.6 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 costs for flexible riser removal c_{riser} is assumed to be a unit cost of 256 $/m which is factored by its length l_{riser} (PROSERV OFFSHORE, 2009). The unit cost includes weather and work contingency but does not include the mobilization costs of the vessel nor engineering costs. The flexible riser removal costs cover flushing, cutting at the seafloor and detaching from the platform prior to the removal.

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

4.7 DECOMMISSIONING OF SUBSEA STRUCTURES

Subsea base structures, such as PLET/PLEM, manifolds need to be removed up to a depth of 5m below the mudline according to the CFR (2015). 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 located at a water depth where they do not pose any threat as an obstruction. Similar to the previously mentioned argument, the approach by PROSERV OFFSHORE (2009) has made an exception as well for subsea templates which can remain in place if they are anchored to the seafloor. Cutting anchored piles at the seabed result in a significant cost increase which could be avoided if the anchored facilities do not pose any environmental threat which is generally the case.

4.8 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 inspection 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 needs to be evaluated for each platform individually. Heavy modules, such as the living quarter or the preparation of the flare tower, might require additional resources (GEBAUER, et al., 2004).

The costs for topsides removal depend 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 10,000t. 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 the inverse order of the installation (GEBAUER, et al., 2004).

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 are involved. This can become quite costly depending on the water depth as divers require pressure chambers at water depth below 30m or alternatively ROV’s 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 (NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION, 2007) would be a very cost-effective solution for the industry since disposal, recycling and transport to shore could be avoided.

PROSERV OFFSHORE (2009) developed 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 through either single lift in place or hopping method. Among the different methods the cheapest one is selected. The legs are assumed to be severed through explosives for diameters less than 1.5m and through 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 (inspections, flushing, cleaning, cutting between modules)
- Removal of modules and deck in multiple lifts
- Removal of jacket in single lift or through hopping
- Transport to shore (modules, deck, jacket)
- Site clearance (survey of work area, inspection, cleaning, verification)

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

Table 7: GOM platform removal cost estimates (PROSERV OFFSHORE, 2009)

Platform	Water depth [m]	Number of piles	Deck & jacket weight [t]	Costs [$]
SP 49 C	122	9	4570	$6,020,616
HI A 389 A	125	20	4146	$4,581,874
EC 381 A	136	8	4554	$6,734,501
MC 20 A	146	20	9476	$10,230,640
EW 826 A	147	20	12746	$17,920,870
WC 661 A	148	4	3112	$4,638,561
SMI 205 B	159	8	5215	$7,396,079
MC 365 A - Corral	189	8	6381	$8,707,836
GC 6 A	190	12	17237	$9,122,286
GB 172 B - Salsa	211	12	11108	$10,246,070
EW 873 - Lobster	236	20	19899	$10,021,430
EB 165 - Snapper	263	20	22528	$39,186,120
EB 159 - Cerveza Ligera	282	12	20313	$26,559,480
EB 160 - Cerveza	285	24	25218	$34,910,432
MC 194 A - Cognac	313	36	74389	$63,470,620
MC 109 A - Amberjack	335	30	24558	$43,519,160
GC 65 A - Bullwinkle	396	44	49375	$78,508,472

Based on Table 7 KAISER & LIU (2014) develop a linear two-factor regression model to estimate the costs for platform decommissioning. The cost estimate considers the complete removal of the platform $C_{platform\&site}$ with the cost factors water depth d and total number of piles N_{piles} as exogenous variables according to Equation (6).

$$C_{platform\&site}\ [\$/\text{platform}] = 14459 * d + 1241298 * N_{piles} \tag{6}$$

The platform removal cost increases with water depth and total number of piles. Both variables imply larger and heavier jackets that have to be lifted and removed by adequate vessels and cutting additional piles requires more time to remove the entire platform.

A separate cost assessment for 23 platforms in the POCSR conducted by TSB OFFSHORE (2015) shows in Table 8 the decommissioning costs covering platform preparation, platform removal and site clearance.

Table 8: POCSR platform removal cost estimates (TSB OFFSHORE, 2015)

Platform	Water depth [m]	Number of piles	Topsides & jacket weight [t]	Costs [$]
Gina	29	6	1006	$ 3,422,358
Hogan	47	12	3672	$ 8,767,762
Edith	49	12	8038	$ 10,506,551
Houchin	50	8	4227	$ 8,566,014
Henry	53	8	2832	$ 5,242,140
A	57	12	3457	$ 5,354,675
B	58	12	3457	$ 5,354,674
Hillhouse	58	8	3100	$ 5,924,170
C	59	12	3457	$ 5,424,011
Gilda	62	12	8042	$ 8,773,636
Irene	74	8	7100	$ 8,887,917
Elly	78	12	9400	$ 9,810,046
Ellen	81	8	9600	$ 8,047,107
Habitat	88	8	7564	$ 8,567,397
Grace	97	20	8390	$ 13,661,512
Hidalgo	131	16	21050	$ 36,590,064
Hermosa	184	16	27330	$ 45,142,123
Harvest	206	28	29040	$ 47,946,469
Eureka	213	24	29000	$ 52,861,989
Gail	225	20	29993	$ 49,518,354
Hondo	257	20	23550	$ 44,620,504
Heritage	328	34	56196	$ 69,254,262
Harmony	365	28	65089	$ 76,589,144

The platform removal costs in Table 8 do not contain mobilization and demobilization costs for the heavy lift vessel nor the costs for the cargo barges compared to the costs listed in Table 7. On the other hand, the study for the GOM considers a few days of mobilization costs while the costs for the POCSR would increase drastically due to the less availability of lifting vessels and cargo barges. In addition, the costs of Table 7 are based on the year 2009 while the costs provided in Table 8 contain more recent values from 2014. Both Table 7 and Table 8 are not directly comparable since the basis differs. Nevertheless, both tables provide an overview of the expected costs for the platform removal.

4.9 INDICATORS OF COST MAGNITUDE

Although the decommissioning of a fixed platform consists of a typical set of required activities, the costs between single projects vary a lot since the conditions and modifications are never the same. Therefore, the results of the latest cost estimates for decommissioning POCSR platforms are presented to serve as a benchmark for the cost estimation of the case study performed in Chapter 5.

Based on the cost assessment developed by the OFDC (GEBAUER, et al., 2004), PROSERV OFFSHORE (2010) and TSB OFFSHORE (2015) recently reviewed and updated the cost estimates for the complete removal of all 23 offshore oil and gas platforms in the POCSR. As introduced in 4.1 the constructed scenario considers 6 different decommissioning projects within 15 years whereas 2-6 individual platforms are removed at the same time. The cost estimates are mainly based on compiled information from literature review, collected cost data from different sources as well as technical and financial experience of decommissioned platforms in the GOM. Overall decommissioning costs for each POCSR platform of the study are estimated by calculating the costs for each activity involved in the decommissioning process.

Figure 42 presents a cost breakdown structure of the total costs for all 23 platforms of the study by several determined decommissioning activities. The example illustrates the order of magnitude of the costs for each activity with respect to the total costs. It can be stated, that the platform removal adds significantly to the total costs due to the expensive rates of heavy lift vessels required for lifting operations.

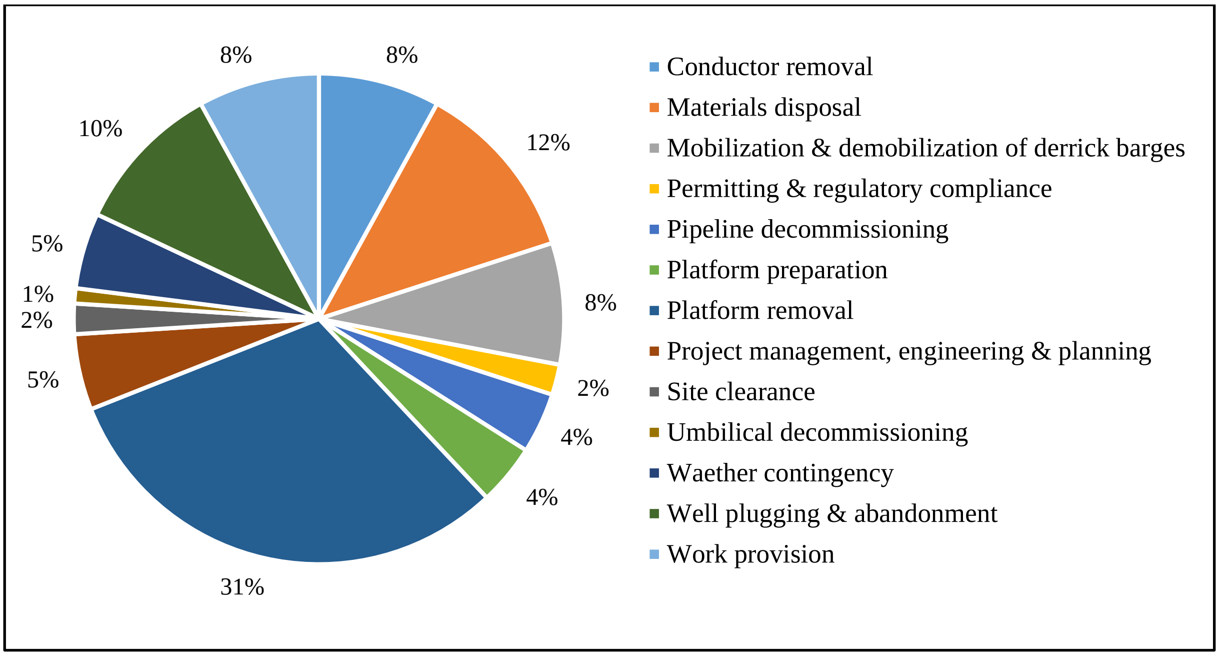

Figure 42: Cost breakdown structure of decommissioning activities (TSB OFFSHORE, 2015)

In contrast, the general scale of total decommissioning costs of a single project can be investigated by global cost factors as introduced in section 4.2. Figure 43 and Figure 44 give a brief indication for the relationship between total project costs and key factors based on the POCSR study from TSB OFFSHORE (2015) and the GOM study from PROSERV OFFSHORE (2009). The individual cost components of the performed activities as shown in Figure 42 are hidden. Figure 43 illustrates the total decommissioning costs for POCSR platforms related to the platform weight only.

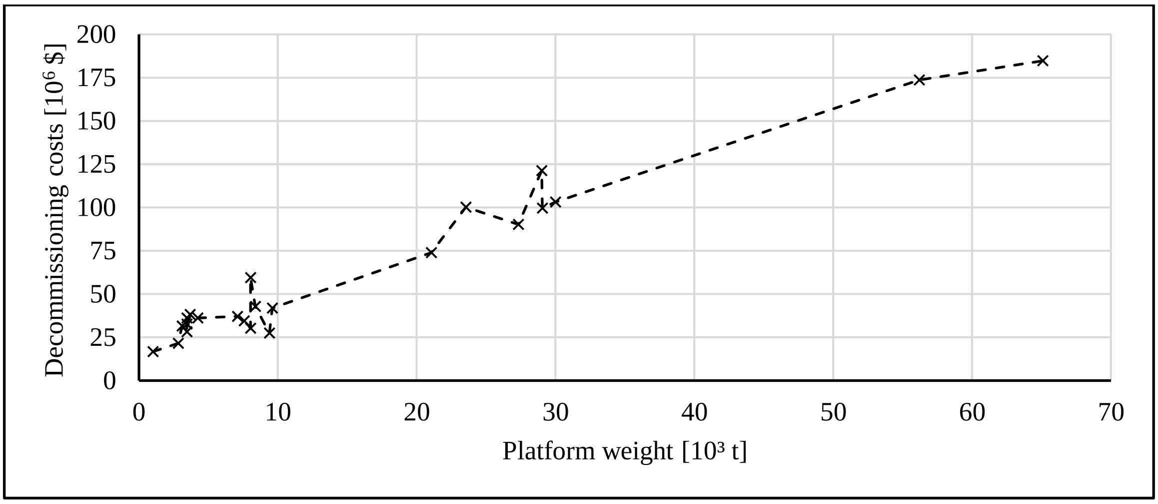

Figure 43: Estimates of total decommissioning costs including several activities for POCSR platforms (TSB OFFSHORE, 2015) based on platform weight

Figure 44 depicts the relation between total decommissioning costs for POCSR platforms and water depth.

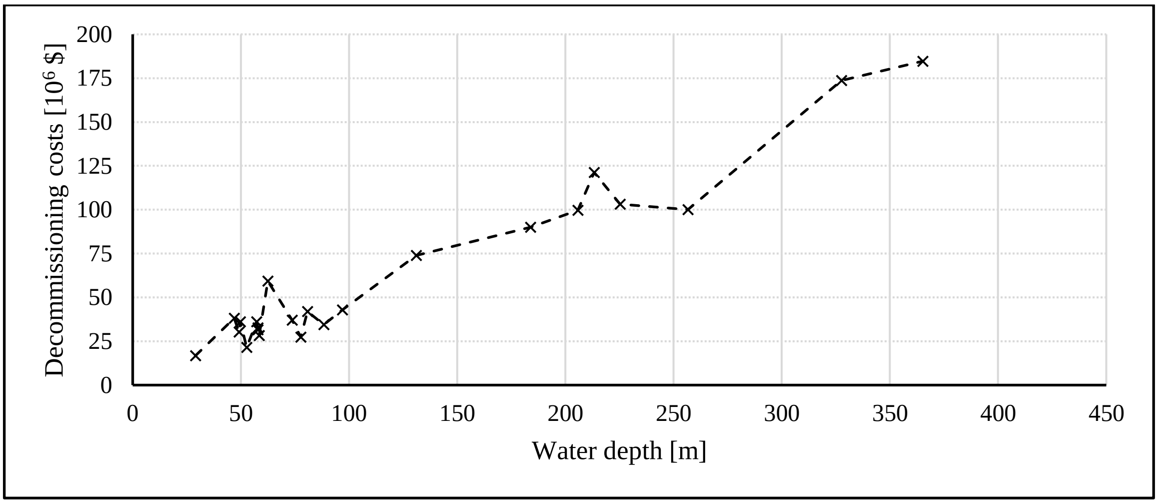

Figure 44: Estimates of total decommissioning costs including several activities for POCSR (TSB OFFSHORE, 2015) platforms based on water depths

Figure 43 and Figure 44 show that the total decommissioning costs have the tendency to increase with water depth and platform weight. Therefore, water depth and weight can be employed as a reliable indicator to roughly estimate decommissioning costs of pending projects as mentioned in 4.2.

5 DECOMMISSIONING ACTIVITIES AND COST ESTIMATION APPLIED TO A CASE STUDY

5.1 CASE STUDY SPECIFICATIONS

In this subchapter a case study is defined including all basic information about an oil field development to allow a concretization of the decommissioning procedure and cost estimation. The following specifications of the case study are compatible with the regulatory requirements of the CFR (2015) which are followed to simulate an entire decommissioning project. At this preliminary phase it is not possible to estimate the costs in detail but roughly for decommissioning the main activities as a first idea. The configuration of the sample platform and its associated facilities generally meet the assumptions of the previously described cost estimation approach in Chapter 4 which thus is applied.

The case study covers a deepwater fixed oil platform that serves as host facility for oil production. The sample platform is supposed to be located approximately 100km offshore Brazil where the water depth is about 125m. Figure 45 shows exemplarily the sample offshore platform.

Figure 45: Top view of sample platform (PETROBRAS S.A., 2016)

The topsides dimensions of the platform are 55m width and 40m length while the jacket dimensions at the bottom are 75m width and 55m length and at the top 55m width and 25m length. The platform has a total height of 150m and weighs in total about 33,000t. The jacket weighs 9,000t and is anchored to the seafloor through 36 skirt piles adjacent to 8 platform legs with a weight of 3,000t. The topsides altogether weighs about 21,000t whereas 1,500t are topsides steel weight only. The deck is subdivided into 20 modules including support frames and comprise e.g. living quarter, cranes, compressors and dry trees etc. with a weight of 18,000t as well as equipment loads, such as piping, pumps, filters, water tanks and generators, with a weight of 1,500t.

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. 15 platform wells are located directly below the platform and are connected to the topsides by 15 conductors each with a dry tree on topsides. 8 subsea well completions are located close to the jacket base and therefore are connected to the topsides by 8 flexible risers. 6 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 through spools or jumpers. The platform is connected through 4 pipelines to neighboring platforms and facilities to build a network. An export pipeline leads to the shore. These longer pipelines require each a PLET to compensate deflections due to pipeline expansion. Rigid risers at the platform connect the pipeline ends to the facilities on topsides. A total of 16 umbilicals provide simultaneously electric power, control and chemicals to all subsea installations of the oil field. In between the pipelines and subsea installations 17 subsea tie-in systems as spools or jumpers provide sufficient flexibility due to thermal expansion. All components of the oil field development are summarized in Table 9 and are illustrated in Figure 46 which both include further details such as the pipeline lengths.

Table 9: List of installations at the oil field of the case study

CASE STUDY INSTALLATIONS		
14 wellheads	6 satellite wellheads	located on top of the satellite wells: 3 oil production wells + 3 water injection wells
	8 subsea wellheads	located on top of the subsea wells: 4 oil production wells + 4 water injection wells
29 well trees	15 dry trees	located on the platform on top of all 15 conductors; is part of the modules located on topsides
	6 wet trees	located on the seafloor on top of the satellite wellheads
	8 wet trees	located on the seafloor on top of the subsea wellheads
15 conductors	For oil production and water injection of platform wells; all conductors are each connected to one dry tree; length of each: 145m; total weight: 2000t	
20 riser	12 rigid riser	1 free; 1 for export line; 4 for further network connections; 6 for satellite wells (3 oil production + 3 water injection); each with a length of 130m, diameter 10"
	8 flexible riser	directly connected to the 8 subsea wells (4 water injection + 4 oil production); each with a length of 220m, diameter 10"
16 umbilicals (grouped)	1 umbilical	for export line, length: 120km, diameter 5"
	3 umbilicals	to manifold of subsea wells, length 1.1km, diameter 5"
	8 umbilicals	connected to satellite wells, length: 300m, diameter 5"
	4 umbilicals	for further network, length: 10.1km, diameter 5"
11 pipelines	6 flowlines	from platform seafloor to manifold (subsea wells): 3 for water injection + 3 for oil production, length: 1km, diameter 10"
	1 export line	connects platform with onshore destination, length of 130km, diameter 10"
	4 network line	to neighboring platforms / network, length: 10km, diameter 10"
17 subsea tie-in systems	12 spools/jumper	related to 6 flowlines of satellite wells
	1 spool/jumper	related to 1 export line
	4 spools/jumper	related to 4 network lines
8 subsea base structures	3 manifolds	each for 2 satellite wells
	5 PLET	each for export and network lines
1 platform	1 topsides	topsides steel weight: 1500t 20 modules e.g. living quarter, helideck, cranes, flare, compressors, filter; weight 18000t (whereas heaviest module weight is 1100t) equipment loads: e.g. piping, pumps, filters, water tanks, generators, safety boats; weight: 1500t
	1 jacket	8 legs that are not anchored, weight: 9000t
	36 skirt piles	Anchored with 36 skirt piles, weight: 3000t

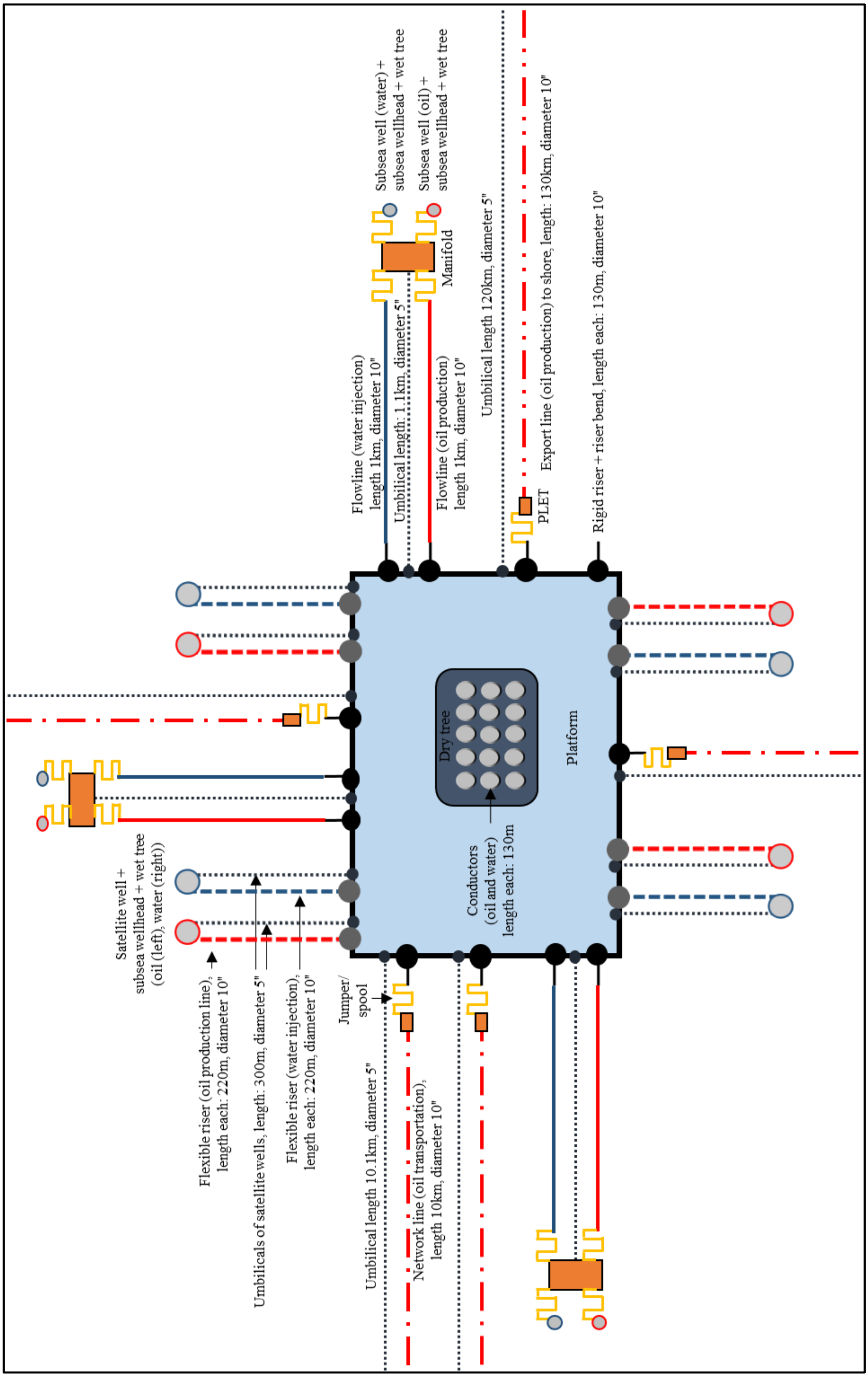

Figure 46: Layout of the case study´s oil field development: platform, well completions, conductors, risers, umbilicals, pipelines (export, network, flow), manifolds, PLETs and jumpers or spools

5.2 WELL ABANDONMENT AND CONDUCTOR REMOVAL

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

All wells are plugged according to the specifications in section 3.3 with the use of cement layers. The permeable layers are assumed to be all perforated. The cost estimation approach of TSB OFFSHORE (2014) is not applied because the definition of the individual well depth and well complexity is difficult to estimate and can vary significantly among different field layouts. On the other hand, the cost estimation for platform wells of PROSERV OFFSHORE (2009) based on Figure 40 and for wet tree wells referred to a unit price by KAISER & LIU (2014) is much more general, easier to adapt and therefore applied. As a consequence, the number of cement layers is not relevant for the well abandonment cost estimation as the applied approaches do not consider the depth and complexity of the wells as an input parameter. The cost estimate of all kind of wells is based on the assumption that the wells are trouble-free plugged according to the CFR (2015) as presented in section 3.3

In accordance to Figure 40, the plugging and preliminary abandonment of a single platform well in a water depth of 125m cost approximately $321,000. For a total of 15 platform wells the costs sum up to $4,815,000. This cost estimate is based on the assumption that a rig-less method is applied as explained in section 4.3. The cost estimate of $4,815,000 contains a work provision of 15%, weather contingency of 20% and overhead costs of 8% for planning and engineering.

It is assumed that subsea and satellite wells can be permanently abandoned through rig-less techniques. Therefore, the unit cost of $3 Million is used to estimate the total costs for 14 wet tree wells, which sums up to $42 Million. The cost assessment includes the decommissioning of the related subsea structures as wet tree and wellhead.

In order to complete the platform well abandonment 15 conductors are removed by severing, pulling and offloading. The cost estimate of the conductors is based on the cost curve presented in Figure 41 (PROSERV OFFSHORE, 2009). The removal costs of a single conductor in a water depth of 125m is $170,000. Therefore, the total costs for 15 conductors are calculated as $2,550,000. This cost estimate is based on the assumption that the conductors are severed at 5m below the mudline according to the CFR (2015) using abrasive cutters, pulled in 10m segments with the drilling rig and casing jacks and are offloaded with the platform crane to a barge for transportation to shore. The estimate includes the mobilization costs of the cargo barge whereas further equipment is assumed to be available. The estimate contains a work provision of 15%, weather contingency of 20% and overhead costs of 8% for planning and engineering.

5.3 PIPELINE ABANDONMENT

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

The costs for each pipeline are estimated with the regression model of KAISER & LIU (2014) of Equation (3). In contrast, the application of cost Table 5 from PROSERV OFFSHORE (2009) and the calculated unit cost per km length of TSB OFFSHORE (2015) has not been successful since the exact configurations of the sample pipelines are not present.

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 calculated to be $2,407,000. The pipelines connected to other platforms or facilities have a length of each 10km. The decommissioning in place of a single pipeline for network costs $1,122,000 whereas the costs of all 4 sum up to $6,732,000. The abandonment of all pipelines of the case study requires a financial expense of almost $14 Million. These costs do include the use of an anchored dive boat, ROV’s and divers. The pipelines are cleaned, flushed and detached from the platform and subsea structures. The pipeline ends are plugged and buried with sand bags or concrete mats according to the CFR (2015) as presented in section 3.5. The cost estimate also contains a work provision of 15%, weather contingency of 20% and overhead costs of 8% for planning and engineering. Jumpers or spools, PLETs and manifolds are removed as well or if anchored are abandoned in place.

5.4 UMBILICAL REMOVAL

In the context of the case study, a total number of 16 umbilicals is removed with different lengths in a water depth of 125m. To estimate the removal costs of the sample umbilicals the cost Table 6 of PROSERV OFFSHORE (2009) is used. The calculated unit prices for a water depth of 120m and different umbilical lengths are applied and regarded as a proper estimate. The unit price of 7 $/m is applied to obtain the removal cost of $890,000 for the sample umbilical with a length of 120km that leads to the shore. To calculate the removal cost for a single umbilical with a length of 300m and 1.1km, 42 $/m is assumed to be an appropriate unit price. The removal of an umbilical with a length of 300m costs $13,000 whereas a number of 8 sums up to $104,000. Additionally, the removal of an umbilical with a length of 1.1km costs $46,000 and results in a cost of $138,000 for a total of 3. The unit price of 13 $/m is selected to calculate the removal costs of $129,000 for an umbilical with a length of 10.1km whereas the costs sum up to $516,000 for a total of 4. The entire removal costs for the umbilicals of the case study are approximately $1.65 Million. These costs cover flushing, cutting and reeling the umbilicals utilizing ROV's and an anchor handling vessel. The costs include weather and work contingency but do not contain the mobilization costs of the vessel nor engineering costs.

5.5 FLEXIBLE RISER REMOVAL

The case study covers a number of 8 flexible risers each with a length of 220m. According to the unit price of 256 $⁄m defined by PROSERV OFFSHORE (2009) in section 4.6, the cost to remove a single flexible riser is assumed to be a $56,000. The total costs for 8 flexible risers are therefore $448,000. The flexible riser removal costs cover flushing, severance at the seafloor and from the platform as well as the removal through reeling on a vessel. The removal costs include weather and work contingency but neither mobilization costs of the vessel nor engineering costs.

5.6 PLATFORM REMOVAL AND SITE CLEARANCE

The removal of the sample platform of 33,000t, anchored through 36 skirt piles in a water depth of 125m, is a delicate task due to the great size and weight of the facility. A total of 20 modules with an entire topsides weight of 21,000t have to be removed and another 12,000t of the jacket need to be lifted. To determine the costs of platform removal, which includes preparation, topsides and jacket removal and site clearance, both cost Table 7 and Table 8 are considered.

According to the cost Table 7 the GOM platform MC 109 A – Amberjack is considered as a proper indication for the costs of decommissioning the sample platform. Amberjack is located in a water depth of 335m, anchored through 30 piles and has a total weight of 24,558t. In comparison to the case study, the water depth of Amberjack is greater whereas the number of piles and the platform weight is less. This study assumes that the weight of the platform provides a much more important indicator than the water depth since it serves as the main criteria to select the appropriate derrick barge. The platform removal cost for the case study is assumed to be approximately $43.52 Million with reference to Amberjack. This cost estimation assumes that the vessels are available in the region and therefore considers mobilization and demobilization periods only of a few days. Only certain activities, such as modules and jacket removal, contain weather and work contingencies but all required activities include a fraction of 8% for engineering costs. 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 will be prepared for removal through inspections, cleaning and cutting operations. The jacket is removed with the piles severed through explosives until 5m below the seabed according to the CFR (2015). The removal is performed by the hopping method due to the heavy weight of the structure. The jacket is brought onshore with a barge for recycling.

Referring to Table 8, the POCSR platform Harvest gives a good indication of the decommissioning costs of the sample platform. Harvest is located at a water depth of 206m, anchored to the seabed through 28 piles and weighs 29,040t in total. The total decommissioning cost of Harvest is estimated at $47.95 Million and can be regarded as a cost indication for the sample platform as well. This cost does not contain mobilization or demobilization costs for the heavy lift vessel, costs for the cargo barges nor work and weather contingencies and engineering work.

The costs for the removal of Amberjack and Harvest cannot be directly compared because the GOM study considers vessel rates for a few days, contingencies and overhead costs and the POCSR does not. In addition, the platform removal cost of Amberjack is based on the year 2009 while the costs for Harvest contain more recent numbers from 2014. Nevertheless, both platforms provide a good example for the platform removal costs of the sample platform and are in a similar cost range.

5.7 COST ESTIMATE SUMMARY

This section presents a summary of the cost estimates for each decommissioning activity of the case study as determined in the previous sections 5.2-5.6. Table 10 provides an overview of the individual costs with reference to the approach that has been utilized and presents the total project cost to decommission the sample platform and its associated facilities.

Table 10: Summary of cost estimation for the case study

Case Study Installation	Activities	Applied approach	Length [km]	Unit cost [$]	No.	Quantified costs
Wet tree well completion	Permanent abandonment	Fixed cost per wet tree well for rig-less techniques according to KAISER & LIU (2014): $3,000,000		$3,000,000	14	$42,000,000
Dry tree well completion	Preliminary abandonment	Cost per dry tree well according to Figure 40		$321,000	15	$4,815,000
					29	$46,815,000
Conductor	Removal	Removal cost per conductor according to Figure 41		$170,000	15	$2,550,000
Pipeline	Abandonment in place including jumper/spool removal	Pipeline abandonment costs according to Equation (3)	10 130 1	$1,211,000 $2,407,000 $1,122,000	4 1 6	$4,844,000 $2,407,000 $6,732,000
					11	$13,983,000
Flexible riser	Removal	Fixed cost per meter length of flexible riser according to PROSERV OFFSHORE (2009): 256 $/m	0.22	$56,000	8	$448,000
Umbilical	Removal	Appropriate removal cost per meter length of umbilical according to Table 6	120 1.1 0.3 10.1	$890,000 $46,000 $13,000 $129,000	1 3 8 4	$890,000 $138,000 $104,000 $516,000
					16	$1,648,000
Manifold and PLET	Removal / Abandonment	Part of related pipeline abandonment if anchored				
Platform (topsides and jacket)	Preparation, complete removal and site clearance	Appropriate removal costs according to Table 7		$43,519,000	1	$43,519,000
TOTAL						**$108,963,000**

The total decommissioning costs of the case study add up to approximately $109 Million. As the base date for the cost estimate is set to 2009, the total project costs need to be adjusted by the inflation rate of the region where the decommissioning takes place. Figure 47 illustrates the cost breakdown structure of decommissioning the sample offshore platform and its associated facilities.

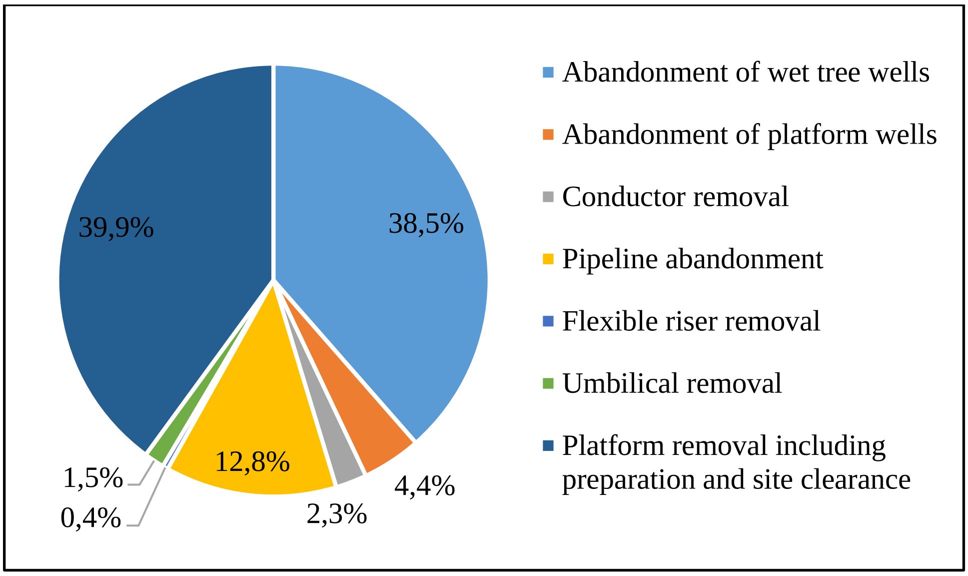

Figure 47: Cost breakdown structure of the case study

The platform removal adds significantly to the total decommissioning costs due to large and expensive equipment that is required for the lifting and removal procedure. The platform removal, preparation and site clearance percentage of 40% agrees with the one obtained in the POCSR study as shown in Figure 42 where the three activities are listed separately. It can be observed that the abandonment of wet tree wells cover a large portion of 38.5% of the total decommissioning costs. In contrast, the wet tree well abandonment does not occur in the POCSR example because the fixed platforms of the study produce hydrocarbons only from platform wells. Pipeline abandonment covers a percentage of almost 13% of the total decommissioning costs. Umbilical, flexible riser and conductor removal are in comparison simple activities and are negligible in terms of total decommissioning costs.

5.8 SCHEDULING

An accurate time schedule requires the definition of several boundary conditions, such as the availability of vessels and subcontractors for each decommissioning activity. The planning phase requires months of preparation by an entire team of engineers and is therefore not applicable within the scope of this study. In order to provide a general impression of how long each procedure takes, the project planning of two platforms similar to the sample platform in size and weight are presented. The Gantt charts show that the entire decommissioning project might take 5 to 6 years.

Figure 48 provides time intervals for each activity with an earliest starting point and the most probable time interval of the activity. From a planning point of view several activities can take place in parallel. Cleaning and preparation activities usually do not interfere with other activities which require additional equipment or vessels. As explained in Chapters 3 and 4 the first steps involve the plugging of both platform and wet tree wells. Figure 48 illustrates the long duration of the well abandonment and the importance of reducing vessel costs as much as possible through rig-less techniques.

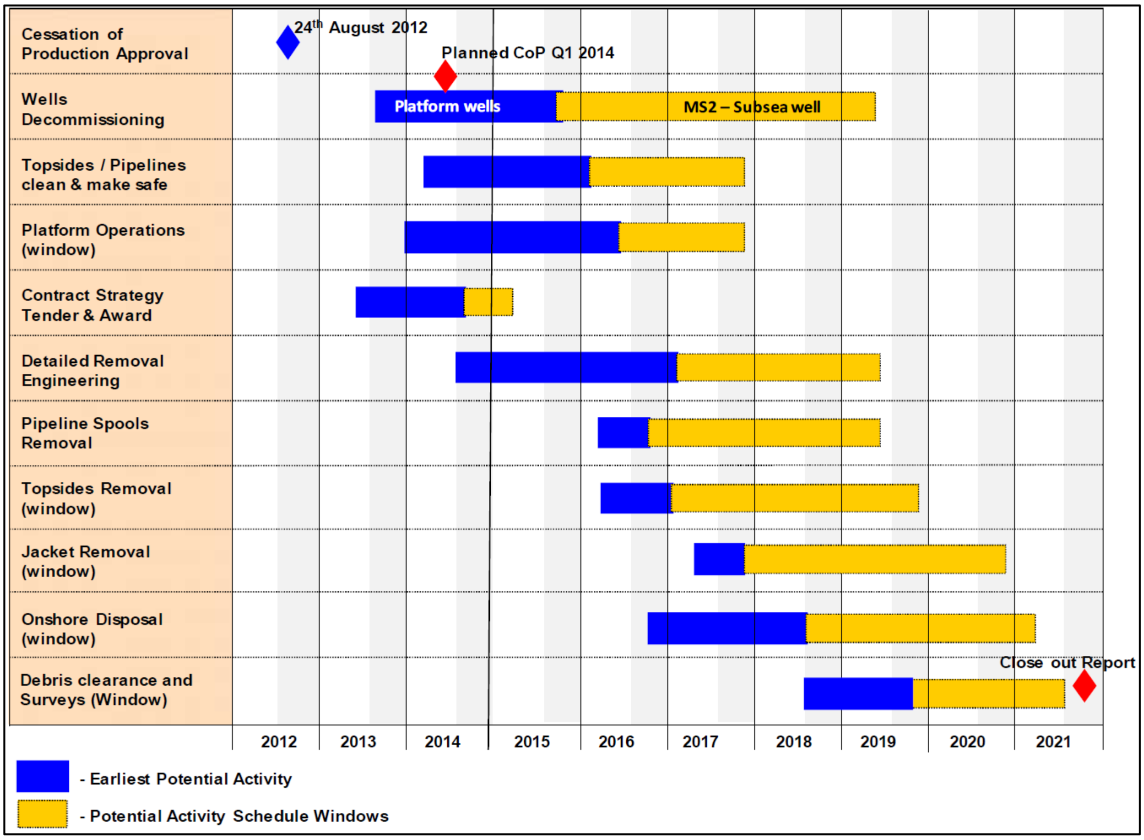

Figure 48: Example 1 Gantt chart (CNR INTERNATIONAL, 2014)

In comparison, Figure 49 shows different durations for each activity. The well plugging and abandonment activities require less time than for instance the separation of the topsides into individual modules. The different time schedules show how different the approaches can be depending on the conditions and specifications of the field layout.

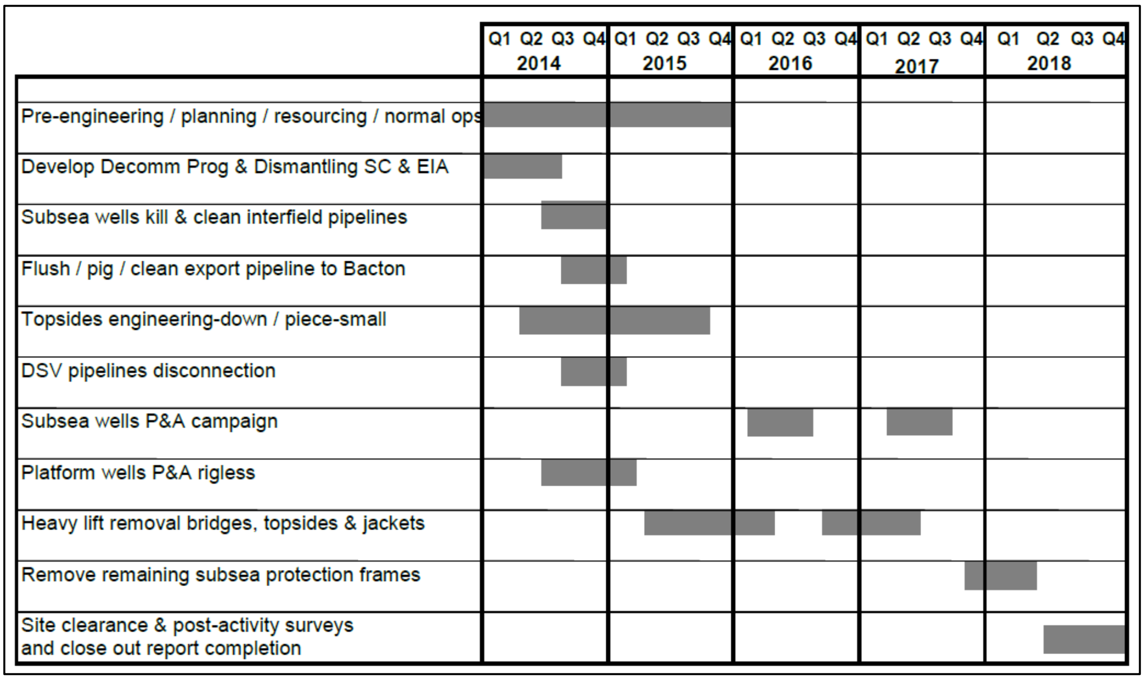

Figure 49: Example 2 Gantt chart (PERENCO UK LTD., 2015)

6 CONCLUSIONS AND OUTLOOK FOR FUTURE WORK

Due to the long history of offshore oil exploration at the Gulf of Mexico, 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 by further specifications for decommissioning or officially refer to international regulations. Although certain aspects of decommissioning oil and gas fields are well established by the ANP such as the well plugging and abandonment, other aspects are neglected, such as the requirements for subsea structures removal or the platform itself.

The cost estimate of the sample platform shows a slightly different distribution of the decommissioning costs in comparison to the comprehensive study for the POCSR. The case study contains a significant number of wet tree wells which leads to a sharp increase in the decommissioning costs of the well plugging and abandonment. Nevertheless, the cost estimation leads to reasonable results of the total costs that are within the margin that can be estimated by the cost factors water depth and platform weight. The cost assessment is therefore considered a valid solution to determine a first estimate.

The estimation of decommissioning costs for fixed platforms reveals the magnitude of the costs that the lessees have to face. The high costs tempt lessees to continuously postpone the decision and expenditures to decommission the platforms. This study shows that all alternative scenarios for the decommissioning should be evaluated, compared and discussed with the objective to reduce the costs and optimize procedures and risks.

The question of whether the strict requirements of the CFR are applicable to Brazil, needs to be discussed by the Brazilian legislation and the oil and gas community. In specific the requirement to remove all subsea installation and the platform up to 5m below the mudline needs to be addressed. If the subsea installations do not pose any obstruction or environmental risk, the decommissioning costs could be significantly reduced through abandonment in place. A rig-to-reef program similar to the one established in the United States provides an alternative to reduce transportation and disposal costs. Other options, as the use of buoyancy tanks, the hopping method or a combination should further be discussed and costs estimated. The lessees need to evaluate if the mobilization costs of vessels could be reduced if several platforms are included in a plugging and abandonment program similar to the study presented of the POCSR.

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