CHAPTER 6

Subsea Cost Estimation

Contents

6.1. INTRODUCTION

Subsea cost refers to the cost of the whole project, which generally includes the capital expenditures (CAPEX) and operation expenditures (OPEX) of the subsea field development, as shown in Figure 6-1.

From Figure 6-1 we can see that expenditures are incurred during each period of the whole subsea field development project. Figure 6-2 illustrates

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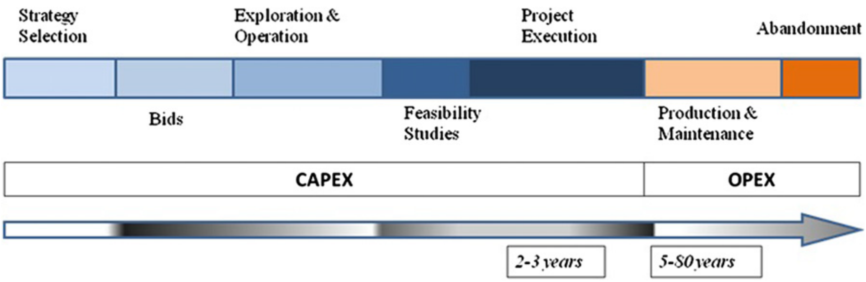

Figure 6-1 Cost of Typical Subsea Field Development

the feasibility studies in different phases of a subsea field development project. The feasibility studies are performed before execution of the project, which may include three phases as shown in the figure:

- Prefield development;
- Conceptual/feasibility study;
- Front-end engineering design (FEED).

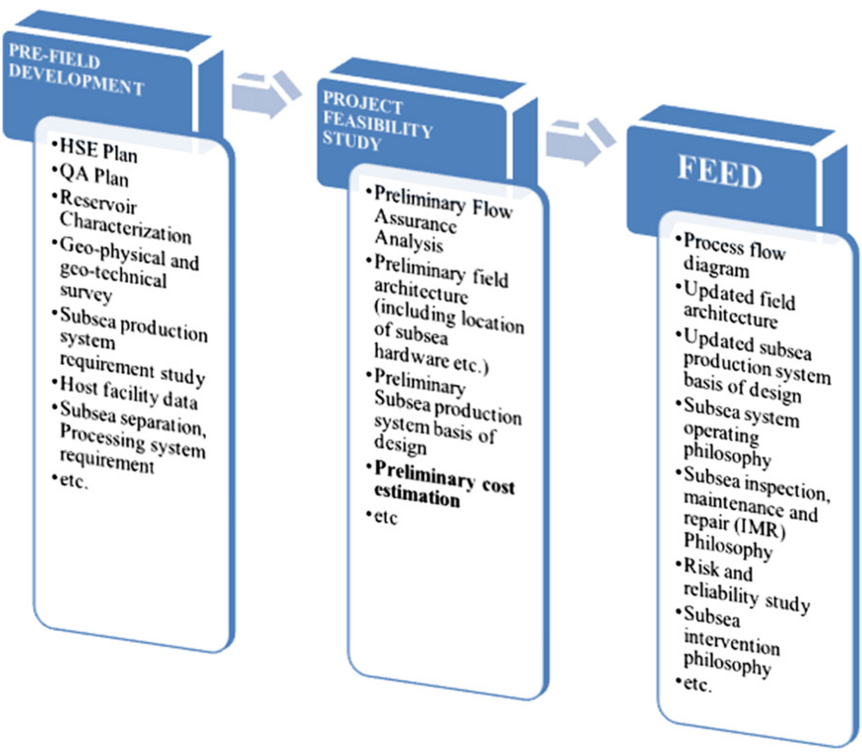

Figure 6-2 Feasibility Studies in Subsea Field Development Project

Table 6-1 Cost Estimation Classification Matrix (AACE) [1]

Estimate Class	Level of Project Definition	End Usage	Methodology	Expected Accuracy Range	Preparation Effort
Class 5	0 to 2%	Screening or feasibility	Stochastic or judgment	4 to 20	1
Class 4	1% to 15%	Concept study or feasibility	Primarily stochastic	3 to 12	2 to 4
Class 3	10% to 40%	Budget, authorization, or control	Mixed, but primary stochastic	2 to 6	3 to 10
Class 2	30% to 70%	Control or bid/ tender deterministic	Primarily 1 to 3	5 to 20	
Class 1	50% to 100%	Check estimate or bid/tender	Deterministic	1	10 to 100

Cost estimations are made for several purposes, and the methods used for the estimations as well as the desired amount of accuracy will be different. Note that for a "preliminary cost estimation" for a "project feasibility study," the accuracy will normally be ±30%. Table 6-1 shows cost estimation classifications according to Association for the Advancement of Cost Engineering (AACE):

- Level of project definition: expressed as percentage of complete definition;
- End usage: typical purpose of estimation;
- Methodology: typical estimating method;
- Expected accuracy range: typical ± range relative to best index of 1 (if the range index value of "1" represents +10/–5%, then an index value of 10 represents +100/–50%);
- Preparation effort: typical degree of effort relative to least cost index of 1 (if the cost index of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%).

This chapter provides guidelines for cost estimation during a project feasibility study, where the accuracy range is between ±30% for subsea field development projects.

6.2. SUBSEA CAPITAL EXPENDITURES (CAPEX)

Based on Douglas-Westwood's "The Global Offshore Report," [2] the global subsea CAPEX and OPEX in 2009 was about $250 billion and will

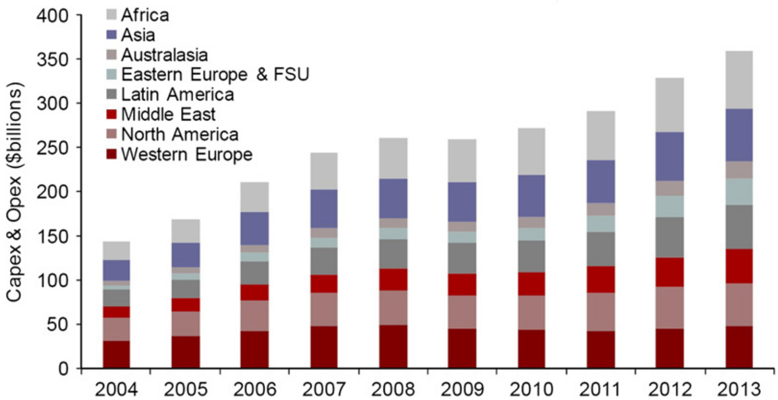

Figure 6-3 Subsea CAPEX and OPEX Distribution by Geographical Area (Douglas-Westwood [2])

be $350 billion in 2013. Figure 6-3 shows the distribution of subsea costs by geographical areas.

Figure 6-4 and Figure 6-5 show examples of the breakdown of deep-water subsea CAPEX and shallow-water subsea CAPEX, respectively. The major cost components of subsea CAPEX are equipment, testing, installation, and commissioning. The key cost drivers for subsea CAPEX are number of wells, water depth, pressure rating, temperature rating, materials requirement, and availability of an installation vessel.

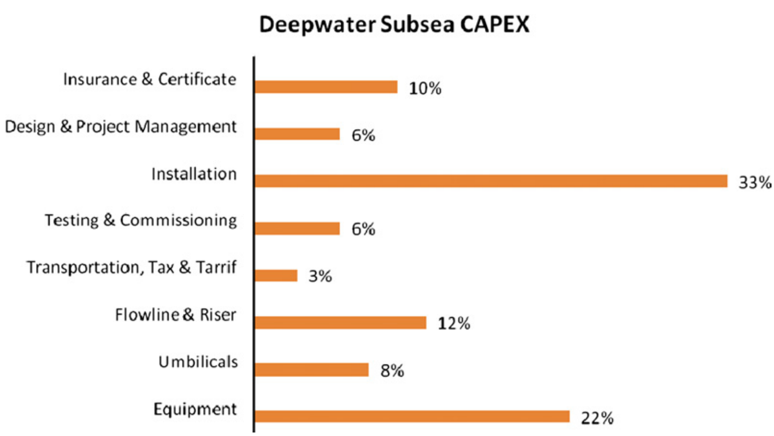

Figure 6-4 Deepwater Subsea CAPEX Breakdown

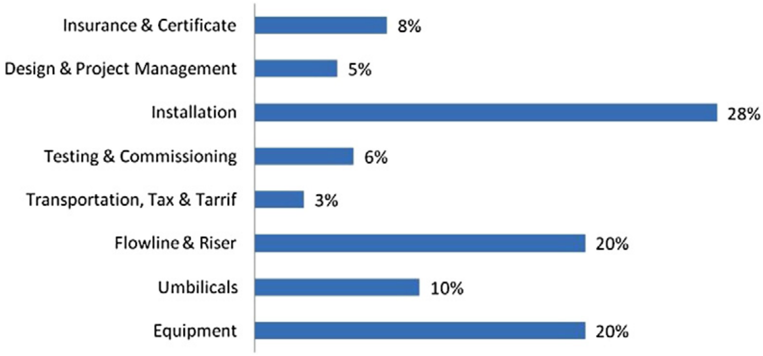

Figure 6-5 Shallow-Water Subsea CAPEX Breakdown

6.3. COST ESTIMATION METHODOLOGIES

Different cost estimating methods are used according to different phases of the project and how much data/resources have been obtained. Three methods are introduced in this book:

- Cost–capacity estimation;
- Factored estimation;
- Work breakdown structure.

The cost–capacity estimation method is an order-of-magnitude estimation method, based on similar previous cost data. This method's accuracy range is within ±30%.

The factored estimation method is based on several cost-driving factors. Each of the factors is considered as a "weight" on basic cost data. The basic cost is normally the price of a standard product based on the proven technology at that time. Accuracy can be within ±30%. This book gives upper and lower bounds for the estimated costs in Section 6.4. Note that the suggested cost-driving factors as well as recommended values for the methodology should be used within the given range and be updated based on the actual data for the time and location in question.

Another estimation method is the working breakdown structure (WBS) methodology, which is commonly used in budget estimation. This method is based on more data and details than are the two methods just mentioned. By describing the project in detail, the costs can be listed item by item, and at the end, the total costs are calculated.

6.3.1. Cost–Capacity Estimation

Cost–capacity factors can be used to estimate a cost for a new size or capacity from the known cost for a different size or capacity. The relationship has a simple exponential form:

$$C_2 = C_1\left(\frac{Q_2}{Q_1}\right)^x \tag{6-1}$$

where

C_2: estimated cost of capacity;

C_1: the known cost of capacity;

x: cost–capacity factor.

The capacities are the main cost drivers of the equipment, such as the pressure ratings, weight, volume, and so on. The exponent x usually varies from 0.5 to 0.9, depending on the specific type of facility. A value of $x = 0.6$ is often used for oil and gas processing facilities. Various values of x for new projects should be calculated based on historical project data. Let's look at the procedures for calculating x values.

Revise Equation (6-1) to:

$$x = \ln\left(\frac{C_2}{C_1}\right)/\ln\left(\frac{Q_2}{Q_1}\right) \tag{6-2}$$

The resulting cost–capacity curve is shown in Figure 6-6. The dots in the figure are the calculation results based on a database built by the user. The slope of the line is the value of exponent x.

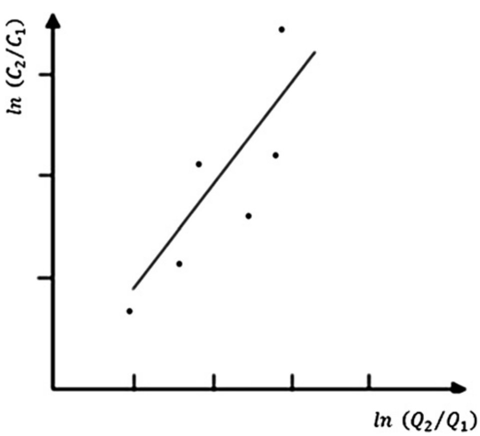

Figure 6-6 Cost–Capacity Curve

6.3.2. Factored Estimation

6.3.2.1. Cost Estimation Model

Costs are a function of many influencing factors and are expressed as:

$$C = F(f_1, f_2, f_3, \mathrm{K} f_i) \quad (i = 1, 2, 3, \mathrm{K}) \tag{6–3}$$

where

C: cost of the subsea Christmas tree;
F: calculation function;
f_i: cost factors.

Assume that:

$$C = f_1 \bullet f_2 \bullet f_3 \bullet \mathrm{K} f_n \bullet C_0 + C_{misc} \quad (i = 1, 2, 3, \mathrm{K}) \tag{6–4}$$

where

C: cost of the subsea equipment;
f_i: cost-driving factors;
C_0: basic cost;
C_{misc}: miscellaneous cost.

Equation (6–4) also shows that the cost is the product of the factors based on a fixed cost C_0. It is clear that the cost C can be estimated by multiplying the cost drivers by the basic cost, which is generally the cost of a standard product. The C_{misc} term refers to other miscellaneous costs that are related to the equipment but not typical to all types.

The basic cost C_0 is the cost of the typical/standard product among the various types of a product; for example, for a subsea Christmas tree, there are mudline trees, vertical trees, and horizontal trees. Currently, the standard product in the industry is a 10 ksi vertical tree, so the cost of a 10 ksi vertical tree will be considered the basic cost while calculating the other trees.

6.3.2.2. Cost-Driving Factors

The following general factors are applied to all subsea cost estimation activities.

Inflation Rate

Inflation is a rise in the general level of prices of goods and services in an economy over a period of time. When the price level rises, each unit of currency buys fewer goods and services. A chief measure of price inflation is the inflation rate, the percentage change in a general price index (normally the Consumer Price Index) over time. The cost data provided in this book are in U.S. dollars unless otherwise indicated, and all the cost data are based on the year 2009, unless a specific year is provided.

To calculate the cost for a later/target year, the following formula should be used:

$$C_t = C_b \bullet (1 + r_1) \bullet (1 + r_2) \bullet \mathrm{K}(1 + r_i)(i = 1, 2, 3, \ldots) \tag{6-5}$$

where

C_t: cost for target year;

C_b: cost for basic year;

r_i: inflation rate for the years between base year and target year.

For example, if the cost of an item is 100 for the year 2007, and the inflation rates for 2007 and 2008 are 3% and 4%, respectively, then the cost of that item in year 2009 will be $C_{2009} = C_{2007} * (1 + r_{2007}) * (1 + r_{2008}) = 100 * 1.03 * 1.04 = 1.0712$.

Raw Materials Price

The price of raw material is one of the major factors affecting equipment costs. Figure 6-7 shows the trends for steel and oil prices over time between 2001 and 2006.

Market Condition

Supply and demand is one of the most fundamental concepts of economics and it is the backbone of a market economy. Demand refers to how much (quantity) of a product or service is desired by buyers. Supply represents how much the market can offer. Price, therefore, is a reflection of supply

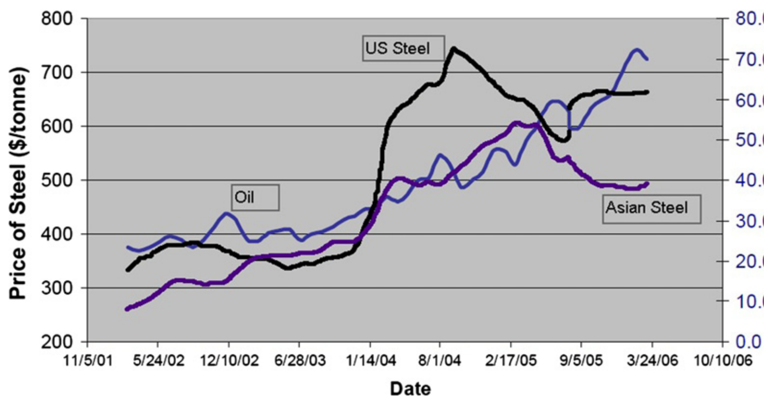

Figure 6-7 Steel and Oil Prices over Time [3]

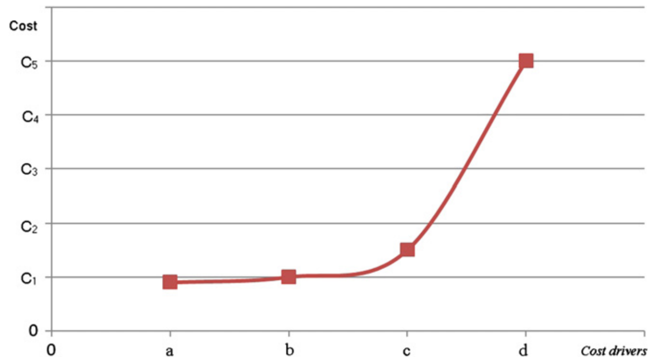

Figure 6-8 Cost Curve

and demand. The law of demand states that if all other factors remain equal, higher demand for a good will raise the price of the good.

For subsea development, the availability/supply of fabrication capacity and installation vessels is one of the major cost drivers. Tight supply will increase costs sharply, as shown in Figure 6-8.

Figure 6-8 also explains cost trends resulting from technology conditions, which influence market supply. Costs change very slowly within normal capacity, but they increase smartly after point *c* as technology's limits are reached. For example, a 10-ksi subsea Christmas tree is now the standard product in the market, so the cost of a 5-si subsea Christmas tree will not change too much. However, the 15-ksi subsea Christmas tree is still a new technology, so its costs will increase a project's cost by a large amount.

Subsea-Specific Factors

Besides the general factors just introduced, cost estimations for subsea field developments have their own specific factors:

- *Development region:* Affects the availability of a suitable installation vessel, mob/demob (mobilization/demobilization) costs, delivery/transportation cost, etc.
- *Distance to existing infrastructure:* Affects the pipeline/umbilical length and design.
- *Reservoir characteristics:* These characteristics, such as pressure rating and temperature rating, affect equipment design.
- *Water depth,* metocean *(normally refers to wind, wave, and current data) and soil condition:* Affects equipment design, installation downtime, and installation design.

For more details on these factors, see specific topics in Section 6.4.

6.3.3. Work Breakdown Structure

The work breakdown structure (WBS) is a graphic family tree that captures all of the work of a project in an organized way. A subsea field development project can be organized and comprehended in a visual manner by breaking the tasks into progressively smaller pieces until they are a collection of defined tasks, as shown in Figure 6-9. The costs of these tasks are clear and easy to estimate for the project after it has been broken down into the tasks.

The level 1 breakdown structure is based primarily on the main costs of subsea equipment, system engineering, installation, and testing and commissioning. The subsea elements are further broken down into the units of subsea Christmas trees, wellheads, manifolds, pipelines, and so on. At level 3 the breakdown reflects the equipment, materials, and fabrication required.

The cost estimation uses the elements of the WBS described. The cost of the project is estimated based on the costs established for each element, and is the sum of all elements. The material costs and fabrication costs are obtained by requesting budget prices from a selection of preapproved bidders for each type of material or work. The scope of the fabrication work provides details about the work relevant to that material. It contains the project description, a list of free issue materials,

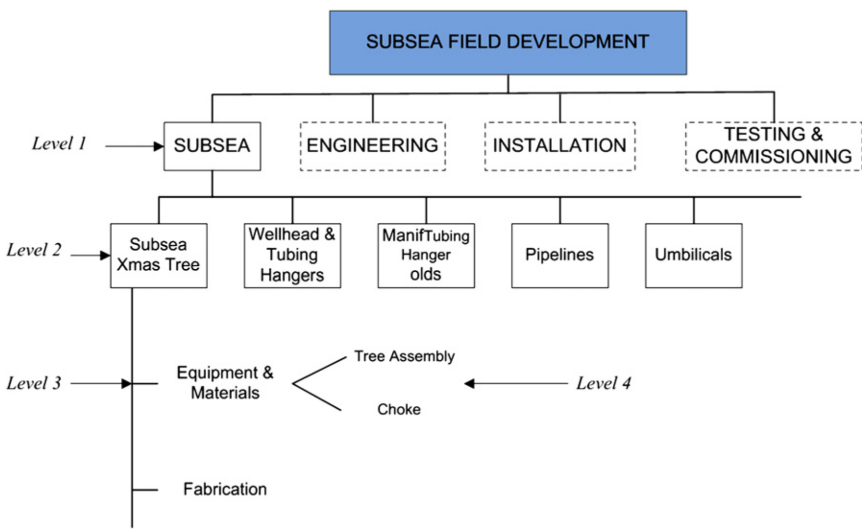

Figure 6-9 Typical WBS for a Subsea Field Development

a detailed list of work scope, and a fabrication, construction, and delivery schedule.

In some cases, the scope of work document is replaced with a drawing. The costs for the engineering elements are based on experience and knowledge of the project requirements. The man-hours required for the individual engineering activities are estimated and the cost derived by application of the appropriate man-hour rates.

6.3.4. Cost Estimation Process

Cost estimates for subsea equipment can also be obtained by combining the above two methods (factored estimation and WBS estimation). As shown in the flowchart of Figure 6-10, we first select the basic cost, which is decided based on the WBS of a standard product, and then choose the cost-driving factors. By listing the data in several tables, choosing the appropriate data, and putting them in Equation (6-4), we can arrive at the final estimation cost.

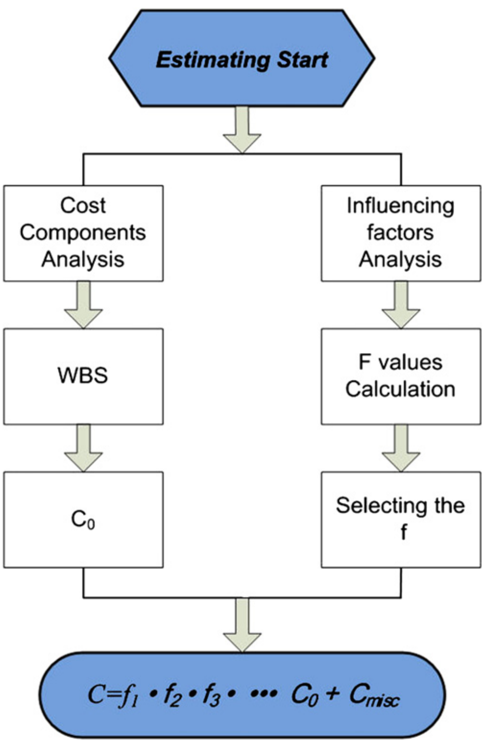

Figure 6-10 Cost-Estimating Process Flowchart

6.4. SUBSEA EQUIPMENT COSTS

6.4.1. Overview of Subsea Production System

Subsea production systems can range in complexity from a single satellite well with a flowline linked to a host facility, to several wells on a template producing and transferring product via subsea processing facilities to a host facility or directly to an onshore installation. Figure 6-11 show a typical subsea production system.

A subsea field development can include one or more of the following subsea structures or equipment:

- A wellhead with associated casing strings to provide a basic foundation structure and pressure containment system for the well;
- A subsea tree incorporating flow and pressure control valves;
- A tubing hanger, set either in the wellhead or tree, used to suspend the production tubing and/or casing;
- A manifold/template system for controlled gathering/distribution of various fluid streams;
- A structural foundation for positioning and supporting various equipment;

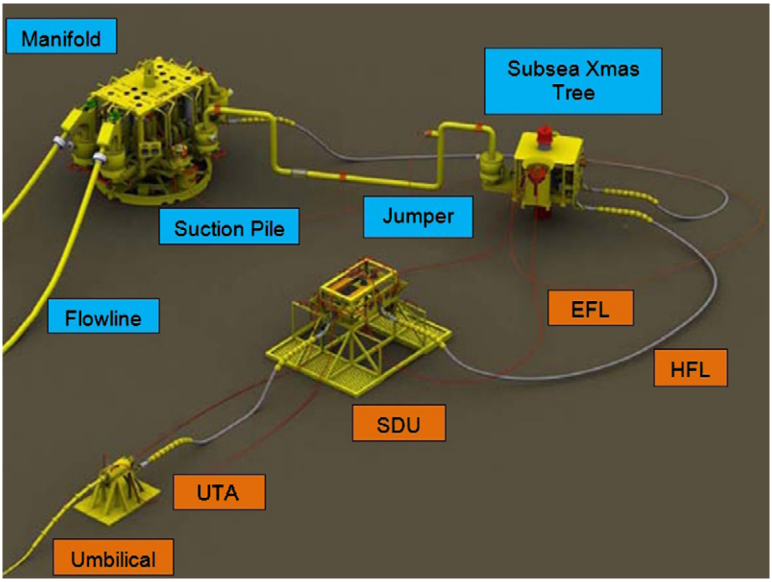

Figure 6-11 Typical Subsea Production System [4]

- A subsea production control system (SPCS) for remote monitoring and control of various subsea equipment, such as a hydraulic power unit (HPU) or subsea distribution assembly (SDA);
- A subsea control module (SCM);
- A chemical injection unit (CIU);
- An umbilical with electrical power and signal cables, as well as conduits for hydraulic control fluid;
- A UTA;
- A flying lead, which connects the UTA with other subsea structures, such as a manifold;
- One or more flowlines to convey produced and/or injected fluids between the subsea completions and the seabed location of the host facility;
- A PLET;
- A jumper, which connects the PLET with other subsea structures, such as a manifold;
- One or more risers to convey produced and/or injected fluids to/from the various flowlines located on the seafloor to the host processing facilities;
- A subsea HIPPS to protect flowline and other equipment not rated for the full shutdown wellhead pressure from being overpressured;
- An installation/workover control system (IWOCS or WOCS);
- A pigging system, including launcher and receiver;
- A boosting system, including an electrical submersible pump (ESP) and multiphase pump (MPP);
- Various connectors used to connect different subsea equipment;
- Various protection structures and foundation structures.

This book will focus on some typical and common equipment and introduce the cost estimation processes for them, instead of covering all subsea equipment costs.

6.4.2. Subsea Trees

Figure 6-12 shows a subsea tree being deployed. The cost of subsea trees in a subsea field development can simply be estimated by multiplying the unit price by the number of trees. Tree type and number are selected and estimated according to the field conditions such as water depth, reservoir characteristic, and fluid type. The unit price can be provided by proven contractors and manufacturers.

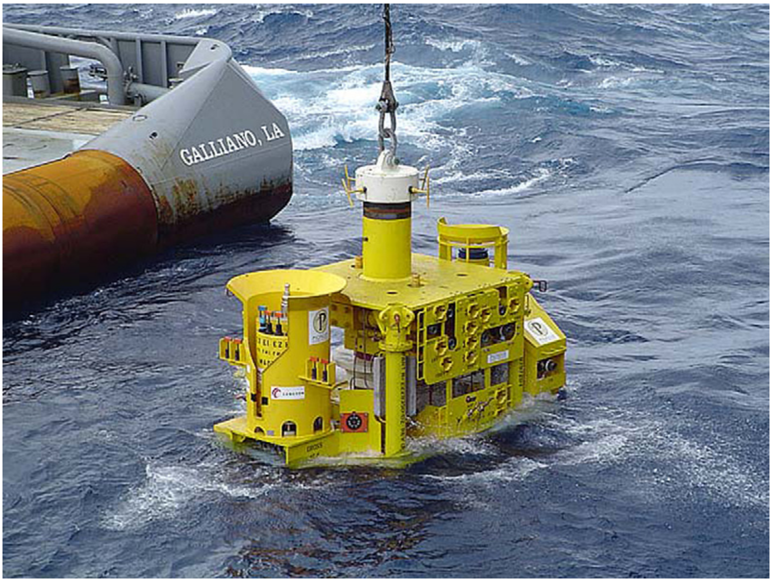

Figure 6-12 A Subsea Tree Being Deployed [5]

6.4.2.1. Cost-Driving Factors

The following factors should be considered for subsea tree selection:

- Tree type (mudline, VXT, and HXT);
- Bore size (3, 4, 5, 7, and 9 in.);
- Pressure rating (5, 10, and 15 ksi);
- Temperature;
- Water depth;
- Well type (production well, water injection well, gas injection well);
- Service type (sour, neutral, and sweet);
- Other factors (strategies for procurement, sparing, drilling, completion, workover, testing, installation, commissioning, operation, inspection, maintenance and intervention, and the experience of the operator).

After decades of experience and technology advancements, current trees are standardized to the following parameters:

- Tree type: mudline, VXT, and HXT;
- Bore size: 5 in.;
- Pressure rating: 10 ksi;
- Water depth: 3000 m (10,000 ft).

At the moment, 3000 m (10,000 ft) of water depth is the upper bound and is unlikely to be exceeded in the next few years. So the main cost drivers for a subsea tree are reduced to:

- Tree type;
- Bore size;
- Pressure rating.

The types of tree fall mainly into two categories: horizontal tree (HT) or vertical tree (VT). The main differences between HTs and VTs are the configuration, size, and weight. In an HT, the tubing hanger is in the tree body, whereas in a VT, the tubing hanger is in the wellhead. In addition, an HT is usually smaller in the size than a VT.

The bore size is standardized to 5 in., so there is very limited effect on the cost when it is smaller than 5 in., such as 4 or 3 in. A bore size larger than 5 in., such as 7 or 9 in., has a large impact on the cost.

The pressure ratings for subsea Christmas trees are 5, 10, and 15 ksi, in accordance with API 17D [6] and API 6A [7]. Different pressure ratings are used at different water depths. The technology of 5- and 10-ksi trees is common and is used in water depths greater than 1000 m. Several suppliers can design and fabricate the 5- and 10-ksi subsea Christmas tress. The main difference in the cost is determined by the weight and size. In addition, few companies can design and fabricate the 15-ksi tree, so costs increase with this tree because of market factors.

The temperature ratings of subsea Christmas trees influence the sealing system, such as the sealing method and sealing equipment. API 6A [7] temperature ratings are K, L, P, R, S, T, U, and V. Typical subsea Christmas tree ratings are LV, PU, U, and V. Many manufacturers supply the equipment with a wide range of temperature ratings so that they work in various types of conditions. The temperature ratings do not have too great an influence on the total cost of a subsea Christmas tree.

Material rating/selection depends mainly on the reservoir characteristics, but it only has limited impact on the tree procurement cost.

6.4.2.2. Cost Estimation Model

Based on the aforementioned cost-driving factors, the cost estimation model for the procurement of subsea tree can be expressed as:

$$C = f_s \cdot f_t \cdot f_p \cdot C_0 + C_{misc} \tag{6-6}$$

where

f_s: bore size factor;

f_t: tree type factor;

f_p: pressure rating factor;

C_0: basic cost;

C_{misc}: the miscellaneous cost not common to all trees.

The cost for the basic standardized tree is shown in the following tables, which include:

- Pipeline connector;
- Tree caps;
- ROV retrievable choke assembly;

but excludes:

- Tubing hanger;
- SCM;
- Junction plate;
- Sensors.

Base Cost:

Base Cost C_0 ($\times 10^6$ USD)		**min. = 2.50 | average = 2.75 | max. = 3.00**			
Pressure	10 ksi	**Bore Size**	5 in.	**Tree Type**	VXT
Material	Carbon steel (seal and gasket clad with CRA)				

Cost Factor: Tree Type

Tree Type		**Mudline VXT**	**Mudline HXT**	**VXT**	**HXT**
Cost Factor f_t	min.	0.30	0.38	1.00	1.25
	average	0.40	0.52		1.30
	max.	0.50	0.68		1.35

Cost Factor: Bore Size

Bore Size		**3 in.**	**4 in.**	**5 in.**	**7 in.**	**9 in.**
Cost Factor f_s	min.	0.90	0.95	1.00	1.15	1.30
	average				1.18	1.35
	max.				1.20	1.40

Cost Factor: Pressure Rating

Pressure Rating		**5 ksi**	**10 ksi**	**15 ksi**
Cost Factor f_p	min.	0.95	1.00	1.15
	average			1.18
	max.			1.20

Cost Factor: Miscellaneous (Insulation)

C_{misc} ($\times 10^3$ USD)	min. = 100 | average = 200 | max. = 300

6.4.3. Subsea Manifolds

Several concepts are applied to manifolds and associated equipment in a subsea field development. Figure 6-13 shows the installation of a subsea manifold from the moon-pool of the installation vessel. Some fields use templates instead of manifolds. Actually the templates have the functions of a manifold. PLET/PLEMs are subsea structures (simple manifolds) set at the end of a pipeline that are used to connect rigid pipelines with other subsea structures, such as a manifold or tree, through a jumper. This equipment is used to gather and distribute the production fluids between wells and flowlines.

The costs of this type of equipment are mainly driven by the cost of the manifold, because it generally makes up about 30% to 70% of the total equipment cost, depending on the type and size of the field.

6.4.3.1. Cost-Driving Factors

The cost drivers for a subsea manifold are:

- Manifold type;
- Number of slots (2, 4, 6, 8, 10);
- Pressure rating;
- Temperature rating;
- Pipe size;
- Material class.

Figure 6-13 Subsea Manifold [8]

Manifolds are usually designed with 2, 4, 6, 8, and sometimes 10 slots. The number of slots mainly influences the size and weight of the structure, as does the pipe size. In addition, the size of the manifold affects the installation.

Pressure ratings, usually 5, 10, and 15 ksi, mainly influence the pipe wall thickness and the selection of the valves. Temperature ratings and material class ratings are selected depending on the fluid characteristics. Temperature influences the selection of the sealing material in the valves.

Both temperature ratings and material class ratings have limited effects on procurement costs.

6.4.3.2. Cost Estimation Model

The cost of a typical manifold can be expressed as follows:

$$C = f_s \cdot f_n \cdot f_t \cdot C_0 + C_{misc} \tag{6-7}$$

where

C: cost of the manifold;
f_t: manifold type factor (cluster, PLEM);
f_n: number-of-slot factor;
f_s: pipe size factor;
C_0: basic cost;
C_{misc}: miscellaneous cost not common to all manifolds.

The effects of pressure rating are incorporated into the pipe size factor:

Base Cost

Base Cost C_0 ($\times 10^6$ USD)	**Min. = 2.0 | Avg. = 3.0 | Max. = 4.0**				
Number of Slots/ Headers	4	**Type**	Cluster	**OD**	10 in.
Base Materials	Carbon steel		Pressure		10 ksi

Cost Factor: Manifold Type

Manifold Type		**PLEM**	**Cluster**
Cost Factor f_t	Min.	0.50	1.00
	Avg.	0.60	
	Max.	0.70	

Cost Factor: Number of Slots (for Cluster Manifold)

Number of Slots		**2**	**4**	**6**	**8**	**10**
Cost Factor f_N	Min.	0.55	1.00	1.10	1.30	1.70
	Avg.	0.70		1.30	1.50	2.00
	Max.	0.85		1.50	1.70	2.30

Cost Factor: Pipe Size

Pipe Size (OD)		8 in.	10 in.	12 in.	16 in.	20 in.
Cost Factor f_s	Min.	0.90	1.00	1.02	1.10	1.15
	Avg.	0.93		1.05	1.15	1.25
	Max.	0.96		1.08	1.20	1.35

Cost Factor: Miscellaneous (Such as Insulation)

C_{misc} ($\times 10^3$ USD)	min. = 150 | average = 250 |max. = 350

6.4.4. Flowlines

Flowlines are used to connect the wellbore to the surface facility and allow for any required service functions. They may transport oil or gas products, lift gas, injection water, or chemicals and can provide for well testing. Flowlines may be simple steel lines, individual flexible lines, or multiple lines bundled in a carrier pipe. All may need to be insulated to avoid problems associated with cooling of the production fluid as it travels along the seafloor.

The cost of flowlines is usually calculated separately from the costs for other subsea equipment. The estimation can be simply arrived at by multiplying the length of the line and the unit cost. Installation costs are discussed in Section 6.5.

6.4.4.1. Cost-Driving Factors

The main cost drivers for flowline procurement are:

- Type (flexible, rigid);
- Size (diameter and wall thickness, based on pressure rating and temperature rating);
- Material class;
- Coating;
- Length.

The steels applied in the offshore oil and gas industry vary from carbon steels (API standards Grade B to Grade X70 and higher) to exotic steels such as duplex. The higher grade steel obviously commands a higher price. However, as the costs of producing high-grade steels have been reduced, the general trend in the industry has been to use the higher grade steels, typically subsea flowline grades X70 and X80 for nonsour service and grades X65 and X70 with a wall thickness of up to 40 mm for sour service.

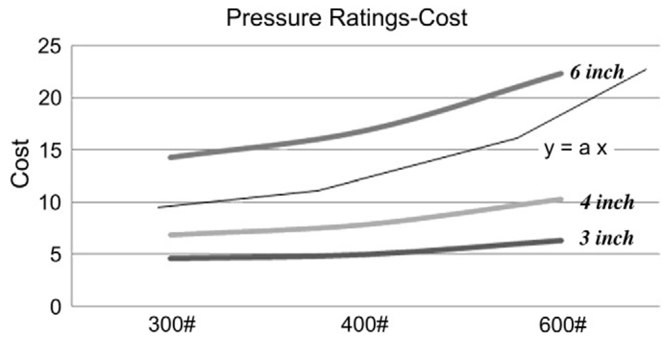

Figure 6-14 Pressure Rating–Cost Curve

Flexible flowlines make the laying and connection operations relatively easy and fast. Material costs for flexible lines are considerably higher than that of conventional steel flowlines, but this may be offset by typically lower installation costs.

High-pressure ratings require high-grade pipe materials, thus the cost of steel increases for high-pressure projects. However, the increase in grade may permit a reduction of pipeline wall thickness. This results in an overall reduction of fabrication costs when using a high-grade steel compared with a low-grade steel. The pressure rating–cost curve is shown in Figure 6-14.

The factor of pressure rating is combined into pipe size factor.

6.4.4.2. Cost Estimation Model

Costs for flowlines in a subsea field can be expressed as:

$$C = f_t \cdot f_s \cdot C_0 \cdot L + C_{\text{misc}} \tag{6-8}$$

where

f_t: flowline type factor;

f_s: size factor;

C: basic cost per unit length (meter);

L: total length of the flowline (meter);

C_{misc}: miscellaneous cost associated with the flowline.

The effects of pressure ratings and temperature ratings are incorporated into the size factor Note that for flexible pipe, the normal temperature rating is $\leq$65°C (150°F). For a temperature rating > 65°C (150°F), the price increases dramatically.

Base Cost for Unit Length (meter)

Base Cost C_0 (USD/meter)	min. = 165 | average = 230 | max. = 295
Parameters:10-in. OD, 10 ksi (ANSI 2500), API 5L X65, rigid pipe	

Base Cost C_0 (USD/meter)	min.= 1970 | average = 2300 | max. = 2620
Parameters: 5.625-in. OD, 6 ksi (ANSI 1500), flexible pipe. *Note:* Flexible pipe has a big discount for length.	

Cost Factor: Size

Rigid Size		4 in.	10 in.	12 in.	16 in.	20 in.
Cost Factor f_s	P90	0.15	1.00	1.20	1.60	2.20
	P50	0.25		1.30	1.80	2.60
	P10	0.35		1.40	2.00	3.00

Flexible Size		4 in.	6.625 in.	8 in.	10 in.
Cost Factor f_s	P90	0.50	1.00	1.10	1.70
	P50	0.65		1.25	1.90
	P10	0.80		1.40	2.10

Cost Factor: Miscellaneous (Coating)

Coating (USD/meter)		4 in.	10 in.	12 in.	16 in.	20 in.
Cost Factor C_{misc}	P90	150	360	400	480	590
	P50	180	460	500	600	720
	P10	210	560	600	720	850

6.5. TESTING AND INSTALLATION COSTS

6.5.1. Testing Costs

Testing is a key part of subsea field development. It ensures that all equipment meets the design specifications and functions properly, both individually and as a whole system. It also ensures quality, controls costs, and maintains the schedule. Therefore, testing needs to be planned at a very early stage of the project, and testing requirement needs to be written in the contract or purchase order specifications. Poor planning for the testing phase will delay the observation of nonconformities, affect the project schedule, and may cause major problems or delays.

Testing includes a factory acceptance test (FAT), extended factory acceptance test (EFAT), and system integration test (SIT). The intents of these tests are as follows:

- Confirm that each individual assembly is fit for its intended purpose and complies with its functional specifications, as set by vendor and operator.
- Verify that each individual assembly interfaces and operates properly with other components and assemblies of the system.
- Demonstrate that assemblies are interchangeable, if required.
- Demonstrate the ability to handle and install the assemblies under simulated field conditions, if possible.
- Provide video and photographic records, if possible.
- Document the performance.
- Provide training and familiarity.

A FAT is concerned with confirming the mechanical completion of a discrete equipment vendor package prior to release from the manufacturing facility for EFAT or SIT testing. A FAT is intended to prove the performance of the discrete component, subassembly, or assembly. On completion of the FAT, a system-level EFAT is performed on the subsea equipment.

The cost for FAT testing is normally included in the equipment procurement cost. The cost of an EFAT, when needed, is normally negotiated between the vendor and the operator.

System integration can be broadly described as the interface between various subsea systems. To ensure the whole system is interfacing properly and functioning properly, a SIT is needed. The cost for a SIT includes the following items:

- Tooling rent;
- Personnel (coordinator, technician, etc.);
- Support;
- Spare parts (may be included in the procurement cost).

The estimated costs for a key subsea equipment SIT are listed in Table 6-2.

6.5.2. Installation Costs

Installation costs for a subsea field development project are a key part of the whole CAPEX, especially for deepwater and remote areas. Planning for the installation needs to be performed at a very early stage of the project in order to determine the availability of an installation contractor and/or

Table 6-2 SIT Costs

SIT Cost ($\times 10^3$ USD) (per tree, including tooling/support)	Min.	Avg.	Max.
Tree and tubing hanger	100	200	300
Manifold	150	200	250
PLEM	50	100	150
Jumper	25	50	75
Umbilical	100	200	300
IWOCS	100	200	300
Connectors	8	10	12

installation vessel, as well as a suitable weather window. Also, the selection of installation vessel/method and weather criteria affects the subsea equipment design.

The following main aspects of installation need to be considered at the scope selection and scope definition stages of subsea field development projects:

- Weather window;
- Vessel availability and capability;
- Weight and size of the equipment;
- Installation method;
- Special tooling.

Different types of subsea equipment have different weights and sizes and require different installation methods and vessels. Generally the installation costs for a subsea development are about 15% to 30% of the whole subsea development CAPEX. The costs of subsea equipment installation include four major components:

- Vessel mob/demob cost;
- Vessel day rate and installation spread;
- Special tooling rent cost;
- Cost associated with vessel downtime or standby waiting time.

The mob/demob costs range from a few hundred thousand dollars to several million dollars depending on travel distance and vessel type.

The normal pipe-laying vessel laying speed is about 3 to 6 km (1.8 to 3.5 miles) per day. Welding time is about 3 to 10 minutes per joint depending on diameter, wall thickness, and welding procedure. Winch lowering speeds range from 10 to 30 m/s (30 to 100 ft/s) for deployment (pay-out) and 6 to 20 m/s (20 to 60 ft/s) for recovery (pay-in).

For subsea tree installation, special tooling is required. For a horizontal tree, the tooling rent cost is about USD $7000 to $11,000 per day. For

Table 6-3 Day Rates for Different Vessel Types

Vessel Type	Minimum Day Rate ($ 000s)	Average Day Rate (in 000s)	Maximum Day Rate (in 000s)
MODU-jack-up	200	350	500
MODU < 1500 m (5000 ft)	700	900	1100
MODU > 1500 m (5000 ft)	750	950	1050
Pipelay, shallow water	200	400	600
Pipelay, deepwater	800	1000	1200
HLV	250	400	550
MSV	40	80	120
AHV/AHT	70	85	100
OSV	20	30	40
Simple barge	10	15	20
ROV	35	50	65

Table 6-4 Typical Subsea Structure Installation Duration (5000 ft/1500 m WD)

Tasks	Days
Preinstallation preparation	3–5
Sea fastening	5–7
Setup mooring	8–10
Installation (lifting, lowering, positioning, and connecting)	
Subsea tree	1–3
Manifold	1–3
Flowline (10 km)	4–8
Umbilical (10 km)	4–8
Jumper	1–2
Flying Lead	1–2

a vertical tree, the tooling rent cost is about USD $3000 to $6000 per day. In addition, for a horizontal tree, an additional subsea test tree (SSTT) is required, which costs USD $4000 to $6000 per day. Tree installation (lowering, positioning, and connecting) normally takes 2 to 4 days.

Table 6–3 shows the typical day rates for various vessels, and Table 6–4 lists some typical subsea equipment installation duration times.

6.6. PROJECT MANAGEMENT AND ENGINEERING COSTS

Project management and engineering costs are highly dependent on the charge rate for each discipline's managers and engineers. The charge rate is driven by market conditions. For North America and Europe, on average, the hourly management rate ranges from \$150 to \$300, and the hourly engineering rate ranges from \$100 to \$250.

The costs of management and engineering for equipment fabrication and offshore installation are normally included in the equipment procurement expenditure and installation contract cost.

The costs of management and engineering for an EPIC firm normally adds up to about 5% to 8% of the total installed CAPEX.

6.7. SUBSEA OPERATION EXPENDITURES (OPEX)

An offshore well's life includes five stages: planning, drilling, completion, production, and abandonment. The production stage is the most important stage because when oil and gas are being produced, revenues are being generated. Normally a well's production life is about 5 to 20 years.

During these years, both the planned operations and maintenance (O&M) expenditures and the unplanned O&M expenditures are needed to calculate life cycle costs. OPEX includes the operating costs to perform "planned" recompletions. OPEX for these planned recompletions is the intervention rig spread cost multiplied by the estimated recompletion time for each recompletion. The number and timing of planned recompletions are uniquely dependent on the site-specific reservoir characteristics and the operator's field development plan.

Each of the identified intervention procedures is broken into steps. The duration of each step is estimated from the historical data. The non-discounted OPEX associated with a recompletion is estimated as:

$$\text{OPEX} = (\text{Intervention duration}) \times (\text{Rig spread cost})$$

Figure 6-15 shows a distribution for the typical cost components of OPEX for a deepwater development. The percentage of each cost component of the total OPEX varies from company to company and location to location. Cost distributions among OPEX components for shallow-water development are similar to those for deepwater developments, except that the cost of product transportation is significantly lower.

6.8. LIFE CYCLE COST OF SUBSEA SYSTEM

Many cost components/aspects must be considered to determine the most cost-effective subsea system for a particular site. The risks associated with

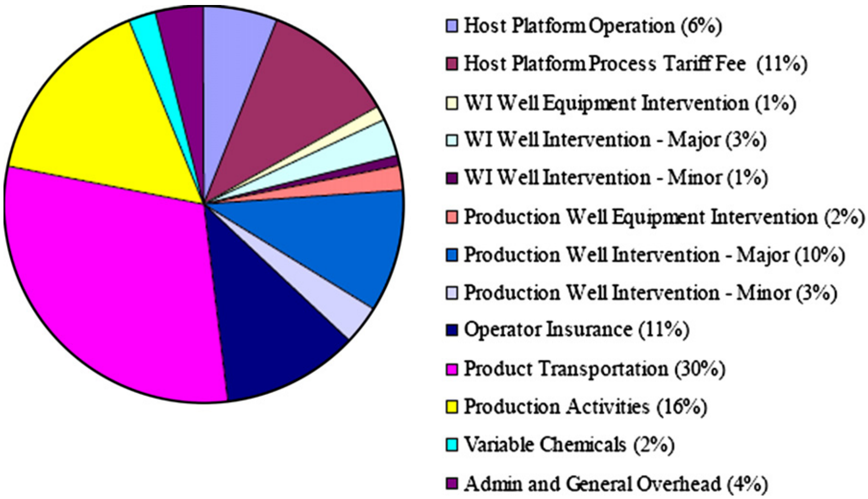

Figure 6-15 Typical Cost Distribution of Deepwater OPEX [9]

blowouts are often an important factor during drilling/installation. Another often overlooked important factor is the cost of subsea system component failures. As oil exploration and production moves into deeper and deeper water, the costs to repair subsea system component failures escalate dramatically.

Therefore, besides CAPEX and OPEX, two other cost components are introduced for determining the total life cycle cost of a subsea system [9]:

- *RISEX:* risk costs associated with loss of well control (blowouts) during installation, normal production operations, and during recompletions;
- *RAMEX:* the reliability, availability, and maintainability costs associated with subsea component failures.

Let's also revisit the definitions of CAPEX and OPEX at this time:

- *CAPEX:* capital costs of materials and installation of the subsea system. Materials include subsea tress, pipelines, PLEMs, jumpers, umbilicals, and controls systems. Installation costs include vessel spread costs multiplied by the estimated installation time and for rental or purchase of installation tools and equipment.
- *OPEX:* operating costs to perform well intervention/workovers. The number and timing of these activities are uniquely dependent on the site-specific reservoir characteristics and operator's field development plan.

The life cycle cost (LC) of a subsea system is calculated by:

$$LC = CAPEX + OPEX + RISEX + RAMEX \qquad (6\text{–}9)$$

6.8.1. RISEX

RISEX costs are calculated as the probability of uncontrolled leaks times assumed consequences of the uncontrolled leaks:

$$RI = PoB \cdot CoB \qquad (6\text{–}10)$$

where

RI: RISEX costs;

PoB: probability of blowout during lifetime;

CoB: cost of blowout.

Blowout of a well can happen during each mode of the subsea system: drilling, completion, production, workovers, and recompletions. Thus, the probability of a blowout during a well's lifetime is the sum of each single probability during each mode:

$$PoB = P(\mathrm{dri}) + P(\mathrm{cpl}) + P(\mathrm{prod}) + \sum P(\mathrm{wo}) + \sum P(\mathrm{re} - \mathrm{cpl}) \qquad (6\text{–}11)$$

The cost of a subsea well control system failure (blowout) is made up of several elements. Considering the pollution response, it is likely to be different among different areas of the world. Table 6–5 shows this kind of costs in the industry from last decades.

6.8.2. RAMEX

RAMEX costs are related to subsea component failures during a well's lifetime. A component failure requires the well to be shutdown, the workover vessel to be deployed, and the failed component to be repaired. Thus, the main costs will fall into two categories:

- The cost to repair the component, including the vessel spread cost;
- The lost production associated with one or more wells being down.

Actually, the repair cost of a failed component is also a workover cost, which should be an item of OPEX. Normally, however, only the "planned" intervention/workover activities are defined and the cost estimated. With "unplanned" repairs, RAMEX costs are calculated by multiplying the probability of a failure of the component (severe enough to warrant a workover) by the average consequence cost associated with

Table 6-5 Cost of Blowouts in Different Geographic Areas [9]

Area	Type of Incident	Date	Cost* ($ MM)	Type of Damage
North Sea	Surface blowout	09/1980	16.1 13.9	Cost of cleanup Redrilling costs
France	Underground blowout on producing well	02/1990	9.0 12.0	Redrilling costs Cost of cleanup
GoM	Underground blowout	07/1990	1.5	Cost of cleanup
Middle East	Underground blowout when drilling	11/1990	40.0	
Mexico	Exploration and blowout	08/1991	16.6	Operator's extra expenditure
North Sea	Blowout of high-pressure well during exploration drilling	09/1991	12.25	Operator's extra expenditure
GoM	Blowout	02/1992	6.4	Operator's extra cost
North Sea	Underground blowout during exploration drilling	04/1992	17.0	Operator's extra expenditure
India	Blowout during drilling	09/1992	5.5	Operator's extra expenditure
Vietnam	Surface gas blowout followed by underground flow	02/1993	6.0 54.0	Redrilling costs Cost of the well
GoM	Blowout	01/1994	7.5	Operator's extra expenditure
Philippines	Blowout of exploration well	08/1995	6.0	Cost of the well
GoM	Surface blowout of producing well (11 wells lost)	11/1995	20.0	Cost of wells and physical damage costs

* *Note:* The costs are based on the specific years. If considering the inflation rate, see Section 6.3.2.

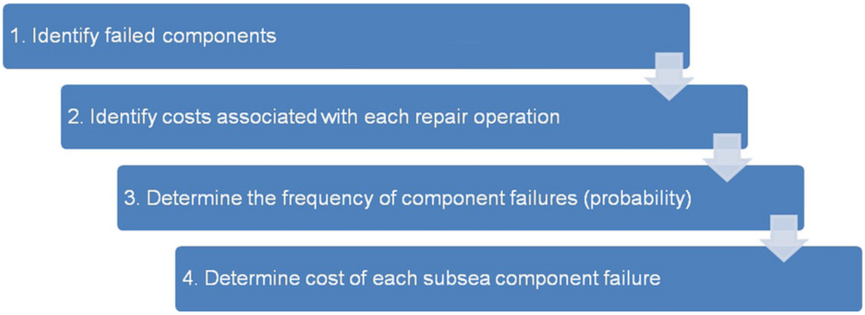

Figure 6-16 RAMEX Cost Calculation Steps

the failure. The total RAMEX cost is the sum of all of the components' RAMEXs:

$$\mathrm{RA} = C_r + C_p \tag{6–12}$$

where

RA: RAMEX cost;

C_r: cost of repair (vessel spread cost and the component repair/change cost);

C_p: lost production cost.

The procedures for calculating this cost are illustrated in the Figure 6–16.

The vessel spread costs are similar to the installation vessel costs; see Section 6.5.2. For more information about failures of subsea equipment, see Chapter 11.

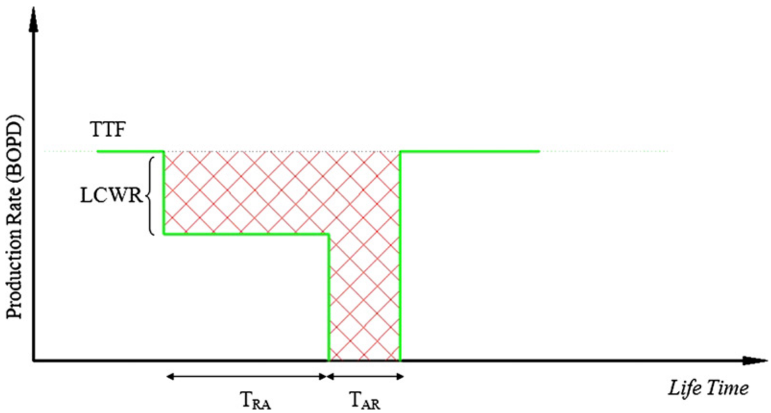

Figure 6-17 Costs Due to Lost Production Time [10]

Figure 6-17 illustrates the costs that arise as a result of lost production time where TTF is time to failure, LCWR is lost capacity while waiting on rig, T_{RA} is the resource's availability time (vessel), and T_{AR} is the active repair time.

The mean time to repair is dependent on the operation used to repair the system. A repair operation is required for each component failure. Each operation will have a corresponding vessel, depending on the scenario (subsea system type or field layout; see Chapter 2).

From Figure 6-17, we can clearly see the production lost cost: the loss of oil or gas production. Note that this cost is the sum of all of the individual subsea wells.

6.9. CASE STUDY: SUBSEA SYSTEM CAPEX ESTIMATION

Too often, only CAPEX is estimated in detail on a sheet listing items one by one (the WBS method). OPEX, RISEX, and RAMEX, in contrast, depend largely on reservoir characteristics, specific subsea system designs, and operating procedures. The flowchart shown in Figure 6-18 details the CAPEX estimation steps in a feasibility study for a subsea field development. Note that the data provided in this flowchart should be used carefully and modified if necessary for each specific project.

We look now at an example of CAPEX estimation using the WBS method and the steps illustrated in Figure 6-18.

Field Description

- Region: Gulf of Mexico;
- Water depth: 4500ft;
- Number of trees: 3;
- Subsea tie-back to a SPAR.

Main Equipment

- Three 5-in. × 2-in.10-ksi vertical tree systems;
- One manifold;
- Two production PLETs;
- One SUTA;
- 25,000-ft umbilical;
- 52,026-ft flowline.

Calculation Steps

- See Table 6-6.

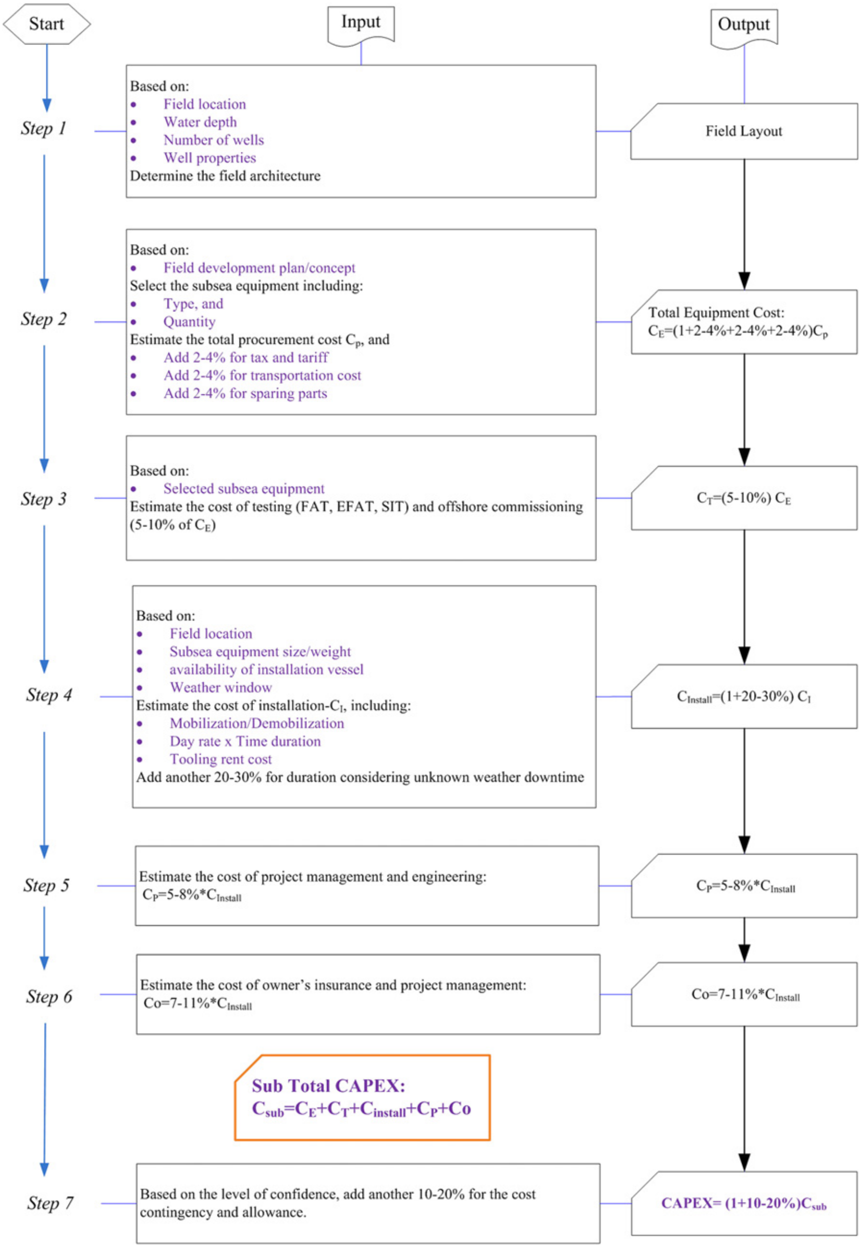

Figure 6-18 CAPEX Calculation Steps

Table 6-6 CAPEX Estimation Example (2007 Data)

1. Subsea Equipment Cost

Subsea Trees		Unit	Cost
Subsea Tree Assembly		**3**	**$4,518,302**
(each)	5-inch × 2-inch 10-ksi vertical tree assembly	1	included
	Retrievable choke assembly	1	included
	Tubing hanger 5-in. 10 ksi	1	included
	High-pressure tree cap	1	included
	5-in. tubing head spool assembly	1	included
	Insulation	1	included
Subsea Hardware			
Subsea Manifold			
	(EE trim)	1	$5,760,826
Suction Pile			
	Suction pile for manifold	1	$1,000,000
Production PLET		2	$3,468,368
Production Tree Jumpers		3	$975,174
Pigging Loop		1	$431,555
Production PLET Jumpers		2	$1,796,872
Flying Leads			$1,247,031
	Hydraulic flying lead SUTA to tree		
	Electrical flying lead SUTA to tree		
	Hydraulic flying lead SCM to manifold		
	Electrical flying lead SUTA to manifold		
Other Subsea Hardware			
Multiphase Flow Meter		1	$924,250
Controls			
Topsides Equipment		1	$2,037,000
	Hydraulic power unit (include gas lift outputs)	1	$569,948
	Master control station (with serial links to OCS)	1	$204,007
	Topside umbilical termination assembly (TUTA) (split)	1	$156,749
	Electrical power unit (incl. UPS) (*Note:* Check capacity of existing UPS.)	1	included above
Tree-Mounted Controls		3	$5,108,940
Manifold Equipments		1	$1,104,163
SUTA		1	$2,764,804

Table 6-6 CAPEX Estimation Example (2007 Data)—cont'd

1. Subsea Equipment Cost			
	Subsea Trees	**Unit**	**Cost**
Umbilicals			
Umbilical			$11,606,659
	25,000ft Length		
Risers			
Riser			$6,987,752
	Prod. 8.625-in. × 0.906-in. × 65 SCR, 2 × 7500 ft		
Flowlines			
Flowline			$4,743,849
	Dual 10-in. SMLS API 5L X-65, flowline, 52,026 ft		
		Total Procurement Cost	**$54,264,324**
2. Testing Cost			
Subsea Hardware FAT,EFAT			$27,132,162
Tree SIT & Commissioning			$875,000
Manifold & PLET SIT			$565,499
Control System SIT			$237,786
		Total Testing Cost	**$28,810,447**
3. Installation Cost			
Tree	3 days × $1000k per day		$3,000,000
Manifold & Other hardware			$48,153
Jumpers	(1 day per jumper + downtime)		$32,102
ROV Vessel Support			$1,518,000
Other Installation Cost			$862,000
Pipe-lay	52,0260ft		$43,139,000
		Total Installation Cost	**$63,179,032**
4. Engineering & Project Management Cost			
		Total Engineering Cost	**$4,738,427**
5. Insurance			
		Total Insurance Cost	**$6,002,008**
		Sub-Total of CAPEX	**$156,994,238**
6. Contigency and Allowance			
		Total Allowance Cost	**$12,559,539**
Total Estimated CAPEX: $169,553,778			

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