Life Cycle Cost

Subsea Production System

Second Edition

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J. Koto

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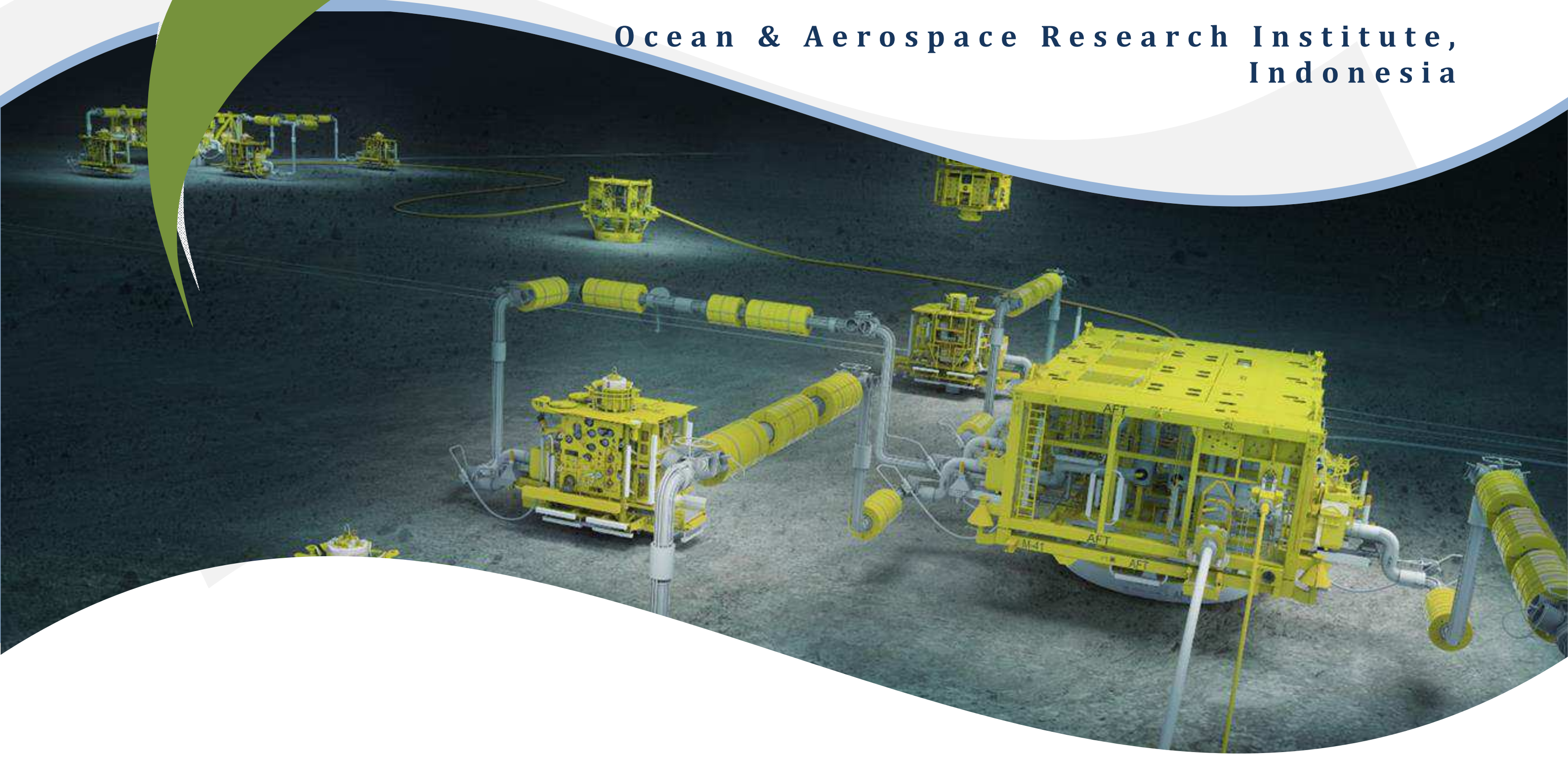

Preface

بسم الله الرحمن الرحيم

This book introduces subsea cost model in chapter 1, life cycle cost of subsea production system such as CAPEX, OPEX, RISKEX and RAMEX in chapter 2 and life cycle of satellite cluster subsea system in chapter 3.

In the book, many pictures and illustrations are enclosed in this book to assist the readers' understanding. It should be noted that some pictures and contents are borrowed from other companies' websites and brochures. Even though the exact sources are quoted and listed in the references, please use this book for education purposes only.

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1.0 Subsea Cost Model

1.1. Feasibility Study of Subsea Field Development

The implications of disasters and business interruptions should be incorporated into three steps. Figure.1.1 illustrates 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:

- Pre-Field development;
- Project Conceptual/feasibility study;
- Front-end engineering design (FEED)
- Engineering Procurement Construction and Installation (EPCI)

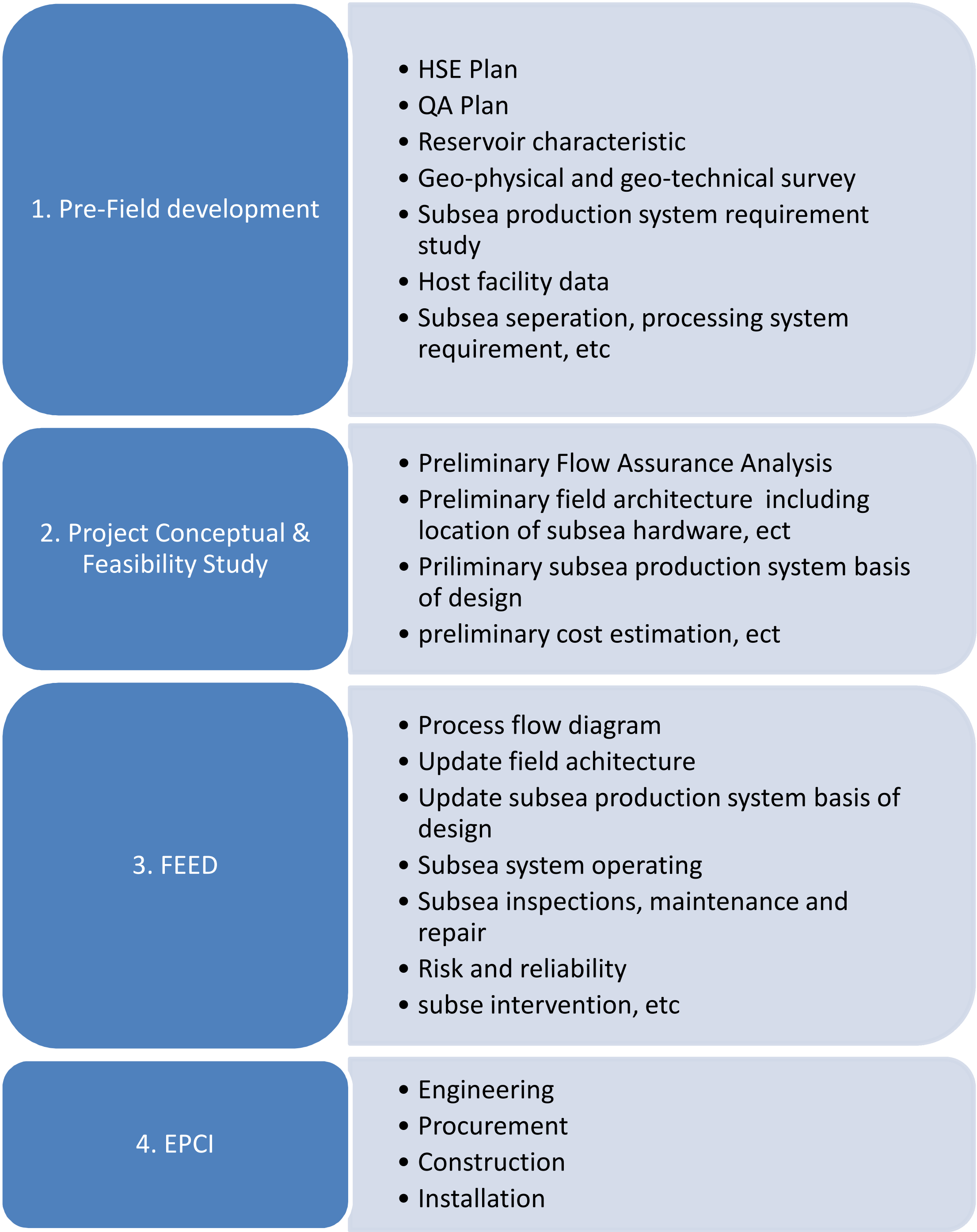


Figure.1.1: Feasibility Studies in Subsea Field Development Project.

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 “preliminary cost estimation” for “project feasibility study,” the accuracy will normally be 30%. Table.1.1 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 þ10/–5%, then an index value of 10 represents þ100/–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.

Table.1.1: Cost Estimation Classification Matrix (AACE)

Estimate class	Level of project definition (%)	End usage	Methodology	Expected accuracy range	Preparation effort
Class 1	50 – 100	Check estimate or bid tender	deterministic	1	10 - 100
Class 2	30 – 70	Control or bid tender	Primarily	1 - 3	5 to 20
Class 3	10 – 40	Budget, authorization and control	Mixed but primary stochastic	2 - 6	3 to 10
Class 4	1 – 14	Concept study or feasibility	primary stochastic	3 - 12	2 to 4
Class 5	0 – 2	Screening or feasibility	Stochastic or judgement	4 - 20	1

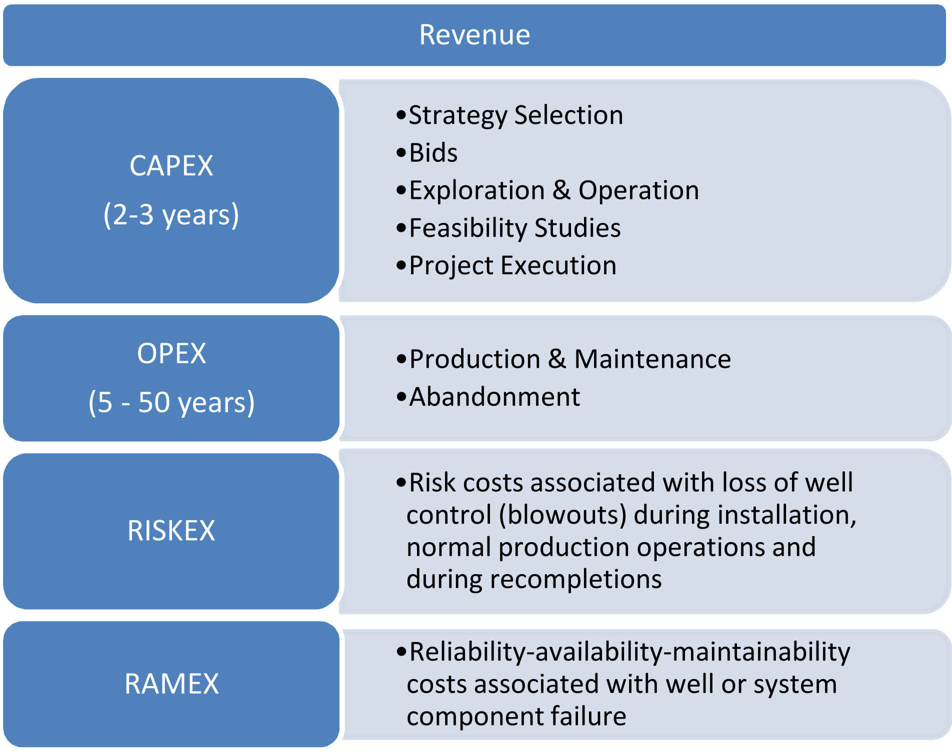
1.2 Cost Elements

The implications of disasters and business interruptions should be incorporated into business decision analyses that seek to evaluate the viability of alternative designs. Inclusion of these "unforeseen" (Risk Expenditures) RISKEX and (Reliability Availability Maintainability Expenditures) RAMEX elements with the usual Capital Expenditures (CAPEX) and Operation Expenditures (OPEX) elements results in the economic model.

The economic model of subsea system is written as:

$$Profit = \; Revenue - (CAPEX + \; OPEX + RISKEX + RAMEX) \qquad (1.1)$$

As shown in the Figure 1.1, the expenditures are incurred during each period of the whole subsea field development project.



Revenue	
CAPEX (2-3 years)	•Strategy Selection •Bids •Exploration & Operation •Feasibility Studies •Project Execution
OPEX (5 - 50 years)	•Production & Maintenance •Abandonment
RISKEX	•Risk costs associated with loss of well control (blowouts) during installation, normal production operations and during recompletions
RAMEX	•Reliability-availability-maintainability costs associated with well or system component failure

Figure.1.2: Economic Model of Typical Subsea Field Development

Chapter.2

2.0 Life Cycle Cost of Subsea System

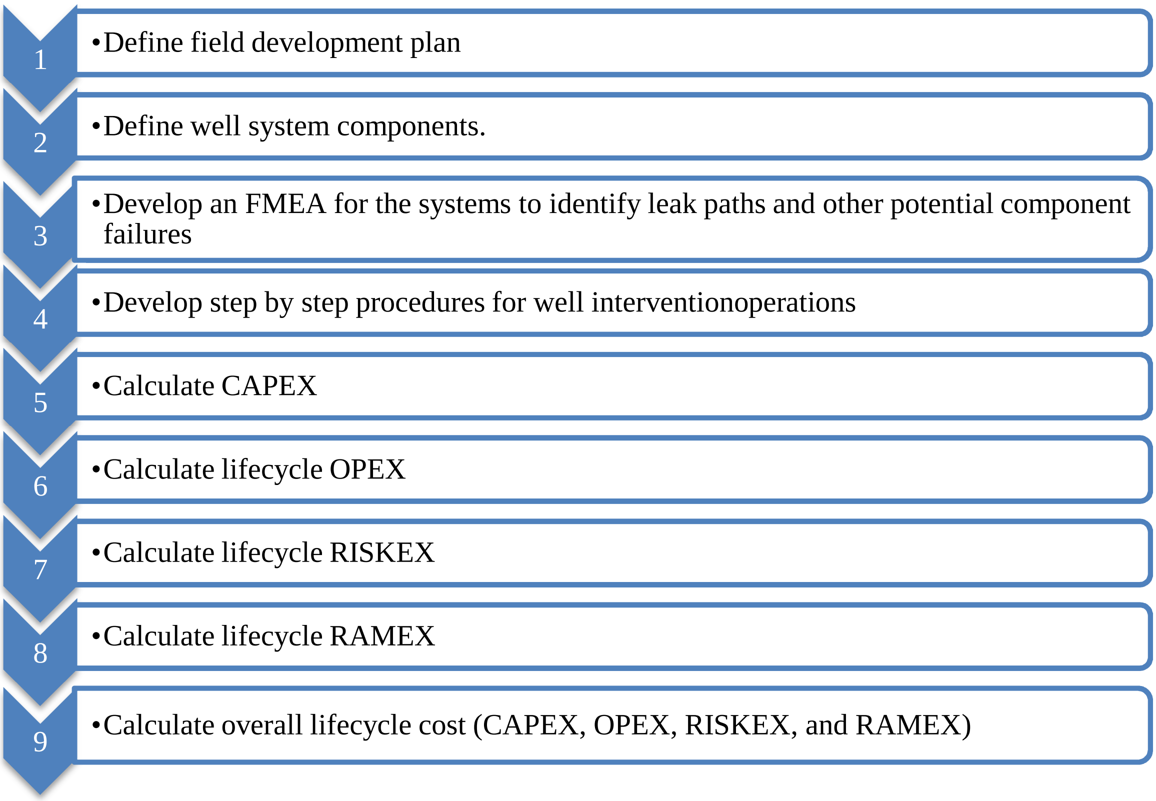
2.1 Lifetime Cost Assessment Methodology

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

- RISKEX: 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.

The lifetime cost assessment methodology consists of the following steps:



1. Define field development plan
2. Define well system components.
3. Develop an FMEA for the systems to identify leak paths and other potential component failures
4. Develop step by step procedures for well interventionoperations
5. Calculate CAPEX
6. Calculate lifecycle OPEX
7. Calculate lifecycle RISKEX
8. Calculate lifecycle RAMEX
9. Calculate overall lifecycle cost (CAPEX, OPEX, RISKEX, and RAMEX)

Figure.2.1: Lifetime Cost Assessment Steps.

2.2 Define Field Development Plan.

A realistic field description is the first and most important estimate that must be made. Data are always limited at this planning stage a project. There is often a tendency to design the development plan based on what is “hoped for” rather than on mature expert judgment of what is most likely. The following information must be estimated with as much accuracy as possible:

- Reservoir characteristics - size, shape, productive zones, fault blocks, water/gas drives, etc. that determine the number and location of wells.
- For each well - depth, formation pressure, recoverable reserves, design production rate, production profile and specific completion requirements such as type of sand control system.

In active oil provinces, it is important to consider existing infrastructure such as existing facilities to receive and process production from the wells.

2.3 Define Well System Components

It is necessary to define the components that comprise the well system. These components will form the basis of the RAMEX methodology and the leak paths used in the RISKEX calculations.

Typical down-hole completion systems and dry tree tieback riser systems were developed in the previous studies. Additional base case designs of both conventional and horizontal tree subsea systems were developed in this study. These detailed designs permitted the identification of all well-control barriers and component seals for these typical systems.

2.4 Identify Potential Component Failures With a FMEA.

A Failure Modes and Effects Analysis, FMEA, is required to identify and document the failures and potential consequences for the well tieback system. This FMEA provides the basis for developing fault trees to calculate Risk Expenditure (RISKEX) and RAMEX.

2.5 Develop Step By Step Intervention Procedures.

Operating procedures are required for initial installation of completion systems, planned workovers to new intervals as zones deplete, and unplanned interventions to repair and/or replace failed components. Initial completion procedures are used to calculate capital costs, CAPEX. Cost of planned interventions, i.e., recompletions as zones deplete, is OPEX. Cost to repair well system component failures is a major component of RAMEX. Individual steps of all operating procedures define changes in the well control barriers that provide the basis for risk costs, RISKEX.

The following procedures were developed for each dry tree tieback alternative and subsea well system:

1. Initial Installation of Fracture pack Completion
2. Initial Installation of Horizontal Lateral Completion
3. Pull completion, Install New Fracture Pack Completion
4. Pull completion, Plug Lower Zone and Install Uphole Fracture Pack Completion
5. Pull completion, Plug Lower Zone, Sidetrack and Recomplete with Fracture Pack
6. Pull completion, Plug Lower Zone, Sidetrack and Recomplete Horizontal Well
7. Repair Completion System Leaks (pull and rerun completion string)

8. Repair/replace surface or subsea tree
9. Coil tubing downhole repair

The following procedures were developed for subsea equipment repairs/replacements:

1. Repair pipeline or PLEM
2. Repair/replace flowline jumper
3. Repair/replace tree jumper
4. Repair/replace hydraulic system umbilical
5. Repair/replace electrical system umbilical
6. Repair/replace well jumper
7. Repair/replace well flying leads
8. Repair/replace well control pod
9. Repair/replace well subsea choke
10. Repair extension pipeline or PLEM
11. Repair/replace extension jumper
12. Repair/replace hydraulic extension umbilical
13. Repair/replace electrical extension umbilical
14. Repair/replace tree jumper extension

These procedures provide a broad cross section of the types of work completed during the total field lifecycle. They can be tailored easily to describe the operations for other well depths and water depths.

2.6 Subsea Capital Expenditures (CAPEX)

Based on Douglas-Westwood's "The Global Offshore Report," the global subsea CAPEX and OPEX in 2009 was about $250 billion and will be $350 billion in 2013. Figure.2.2 shows the distribution of subsea costs by geographical areas.

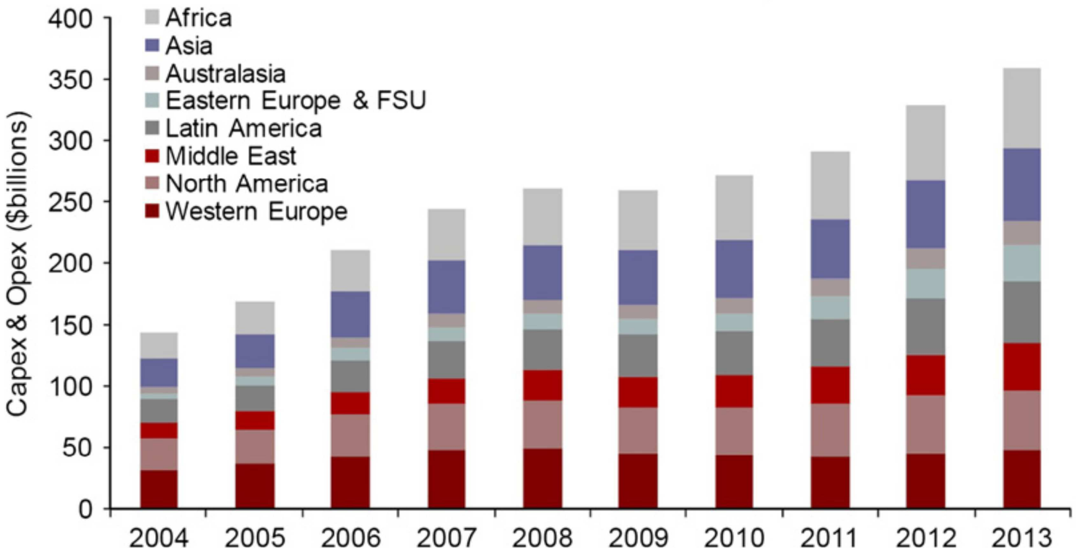


Figure.2.2: Subsea CAPEX and OPEX Distribution by Geographical Area (Douglas-Westwood)

Table.2-1 shows examples of the breakdown of deep-water subsea CAPEX and shallow-water subsea CAPEX. 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.

Table.2.1: Shallow water and deep water subsea CAPEX breakdown.

Subsea CAPEX breakdown	Deep Water (%)	Shallow Water (%)
Insurance & certificate	10	8
Design & project management	6	5
Installation	33	28
Testing & Commissioning	6	6
Transportation, Tax & Tarrif	3	3
Flowline & Riser	12	20
Umbilicals	8	10
Equipment	22	20

2.6.1 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.

2.6.1.1 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:

$$C_2 = C_1 \left(\frac{Q_2}{Q_1}\right)^x \tag{2.1}$$

Where; $C_2$is estimated cost of capacity; C_1 is the known cost of capacity; x is 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 ¼ 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 (2.1) to:

$$x = \ln\left(\frac{C_2}{C_1}\right) \Big/ \ln\left(\frac{Q_2}{Q_1}\right) \qquad (2.2)$$

The resulting cost–capacity curve is shown in Figure.2.3. 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.

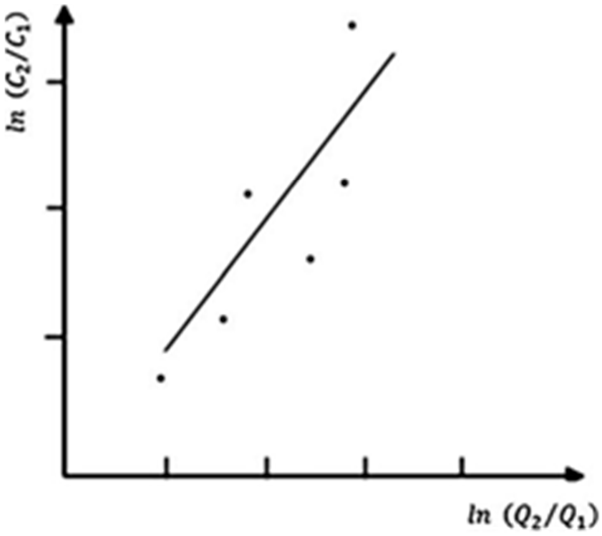


Figure.2.3: Cost–Capacity Curve

2.6.1.2 Factored Estimation

2.6.1.2.1. Cost Estimation Model

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

$$C = F(f_1, f_2, .., f_i)\ (i = 1,2,3, K) \qquad (2.3)$$

Where; C is cost of the subsea X-tree and F is calculation function; f_i is cost factors. Assume that:

$$C = f_1 \cdot f_2 \cdot, .., \cdot f_i + C_0 + C_{misc} \quad (i = 1,2,3, K) \qquad (2.4)$$

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

Equation.2-4 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 psi vertical tree, so the cost of a 10 psi vertical tree will be considered the basic cost while calculating the other trees.

2.6.1.2.2. 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:

$$C_t = C_b \cdot (1 + r_1) \cdot (1 + r_2), \cdots, (1 + r_i) \qquad (i = 1,2,3, \ldots) \tag{2.5}$$

Where; C_t is cost for target year; C_b is cost for basic year; r_i is 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:

$$C_{2009} = C_{2007} \cdot (1 + r_{2007}) \cdot (1 + r_{2008}) = 100 \cdot 1.03 \cdot 1.04 = 1.0712 \tag{2.6}$$

Raw Materials Price

The price of raw material is one of the major factors affecting equipment costs. Figure.2.4 shows the trends for steel and oil prices over time between 2001 and 2006.

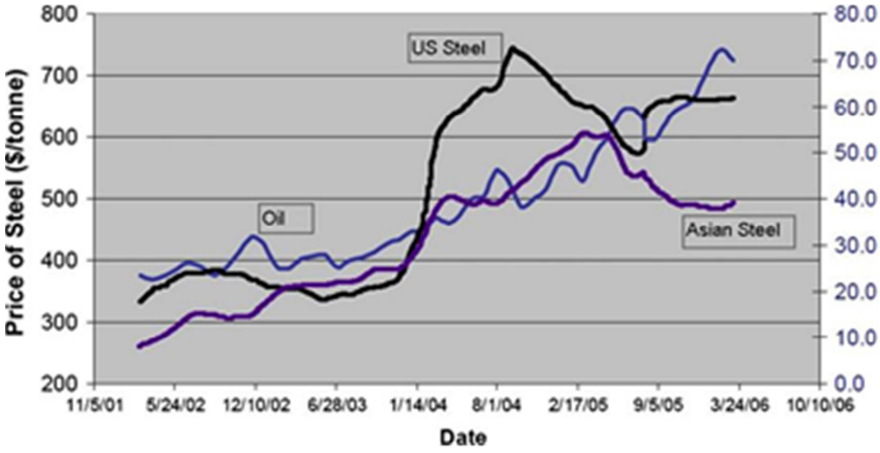


Figure.2.4: Steel and Oil Prices over Time (Douglas-Westwood)

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 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 2.5. Figure 2.5 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-psi subsea Christmas tree is still a new technology, so its costs will increase a project’s cost by a large amount.

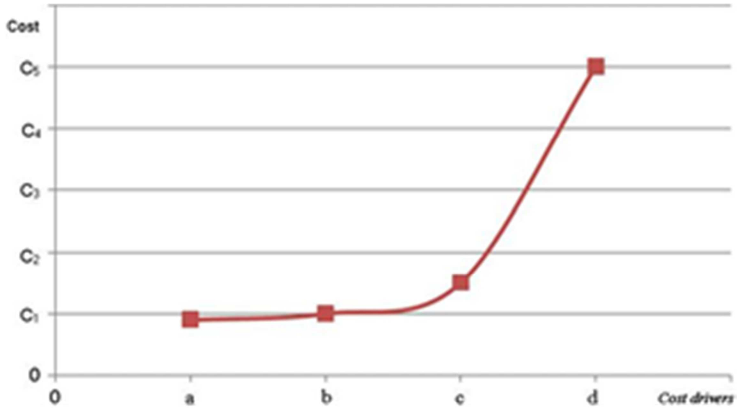


Figure.2.5: Cost versus cost drivers

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.

2.6.1.3. 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.2-6. The costs of these tasks are clear and easy to estimate for the project after it has been broken down into the tasks.

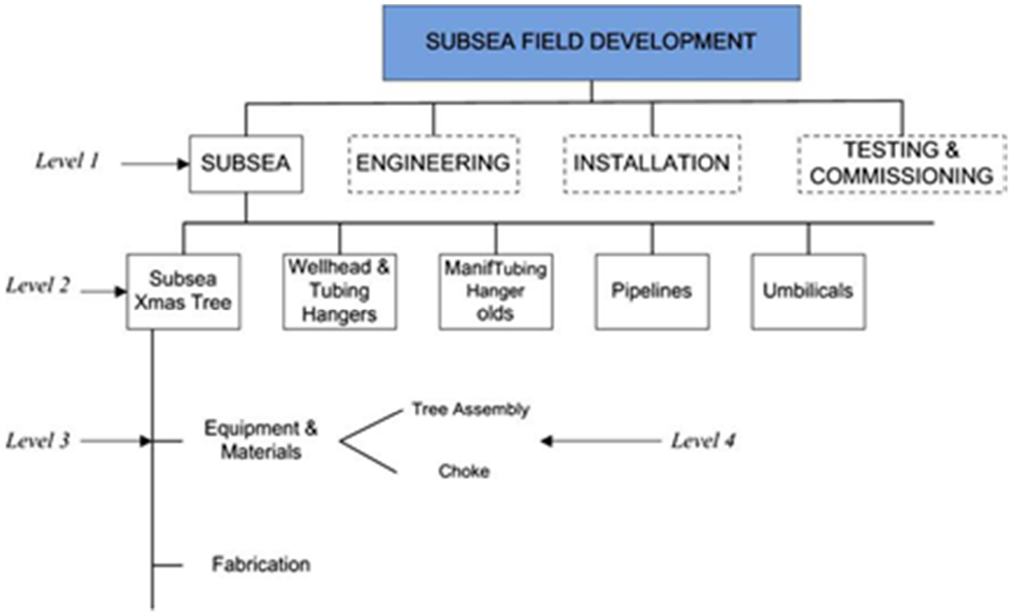


Figure 2.6: Typical WBS for a Subsea Field Development

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, 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.

2.6.1.4. 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 2.7, 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.2-4, we can arrive at the final estimation cost.

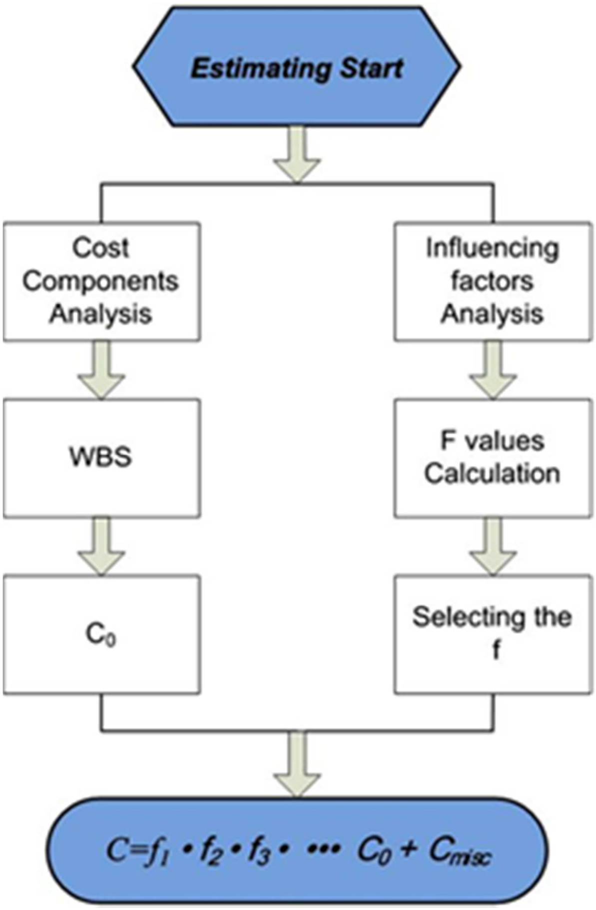


Figure.2.7: Cost-Estimating Process Flowchart

2.6.2. Subsea Equipment Costs

2.6.2.1. 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 2.8 shows a typical subsea production system.

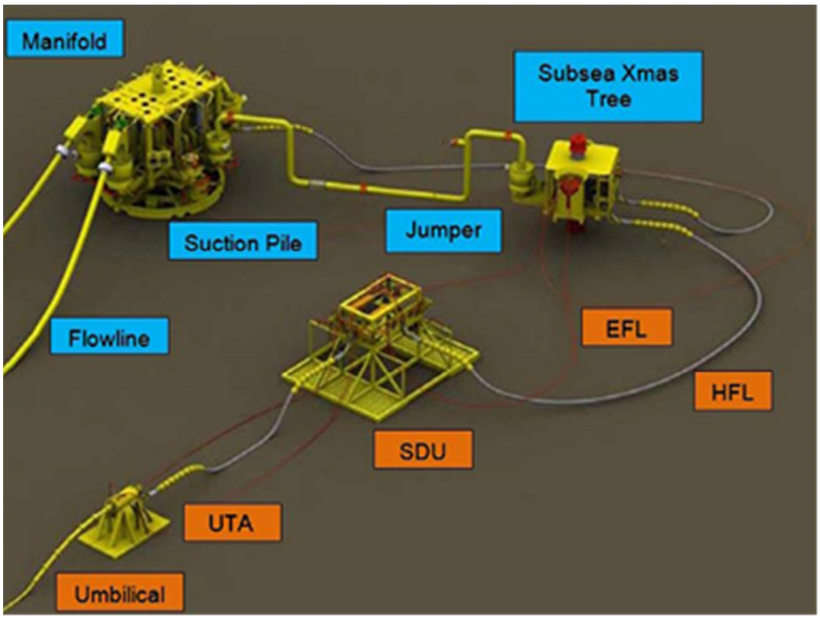


Figure 2.8: Typical Subsea Production System

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;
- 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 Umbilical Termination Assembly (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 Pipe Line End Terminations (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 High Pressure Protection Systems (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.

2.6.2.2. Subsea Trees

Figure 2.9 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.

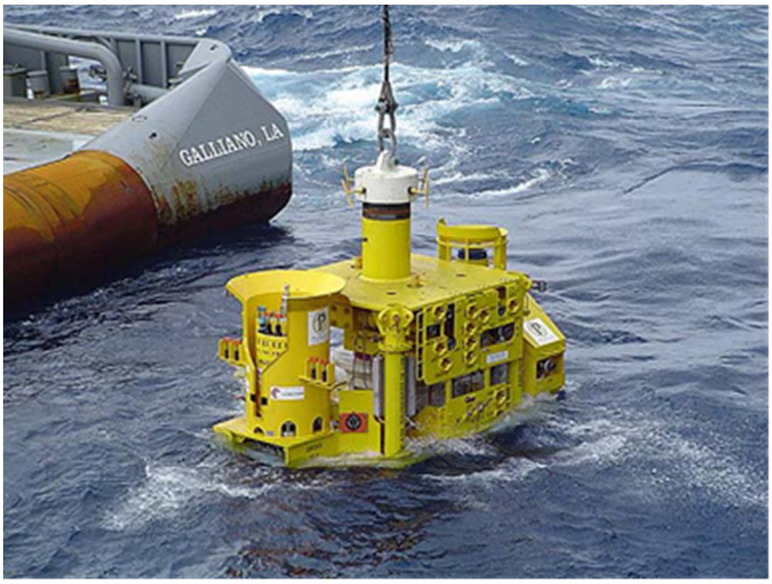


Figure.2.9: A Subsea Tree Being Deployed.

2.6.2.2.1. 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 psi);
- 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 psi;
- 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 trees are 5, 10, and 15 psi, in accordance with API 17D and API 6A. 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 trees. 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 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.

2.6.2.2.2. Cost Estimation Model

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

$$C = f_s \cdot f_t \cdot f_p + C_0 + C_{misc} \qquad (2.7)$$

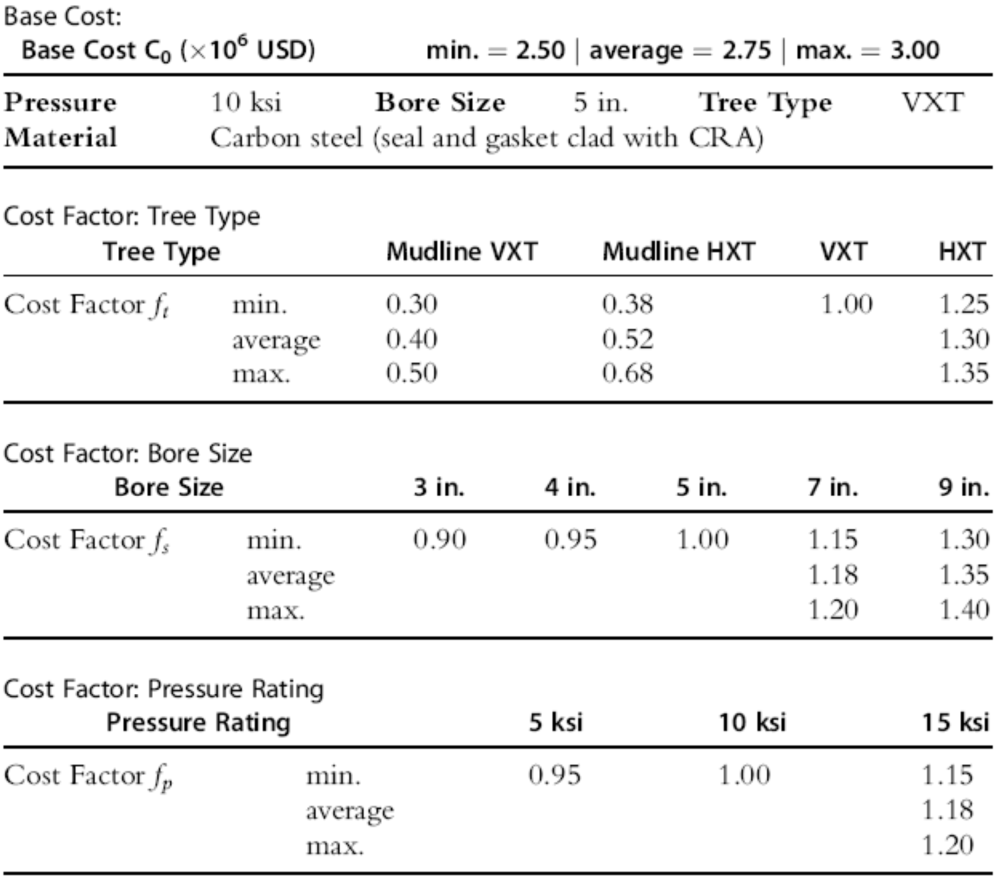
Where; f_s is bore size factor; f_t is tree type factor; f_p is pressure rating factor; C_0 is basic cost; C_{misc} is the miscellaneous cost not common to all trees.

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

- Pipeline connector;
- Tree caps;
- Remote Operating Vehicle (ROV) retrievable choke assembly

But they exclude:

- Tubing hanger,
- Subsea Control Module (SCM),
- Junction plate and
- 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

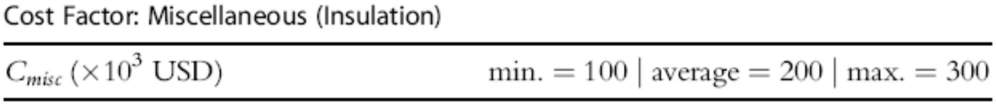
Tree Type		Mudline VXT	Mudline HXT	VXT	HXT
Cost Factor f_t	min.	0.30	0.38	1.00	1.25
	average	0.40	0.52		1.30
	max.	0.50	0.68		1.35

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

2.6.2.3. Subsea Manifolds

Several concepts are applied to manifolds and associated equipment in a subsea field development. Figur.2.10 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 (Pipe Line End Manifold) are subsea structures (simple manifolds) set at the end of a pipeline that is 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.

Figure.2.10: Subsea Manifold

2.6.2.3.1. 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.

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 psi, 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.

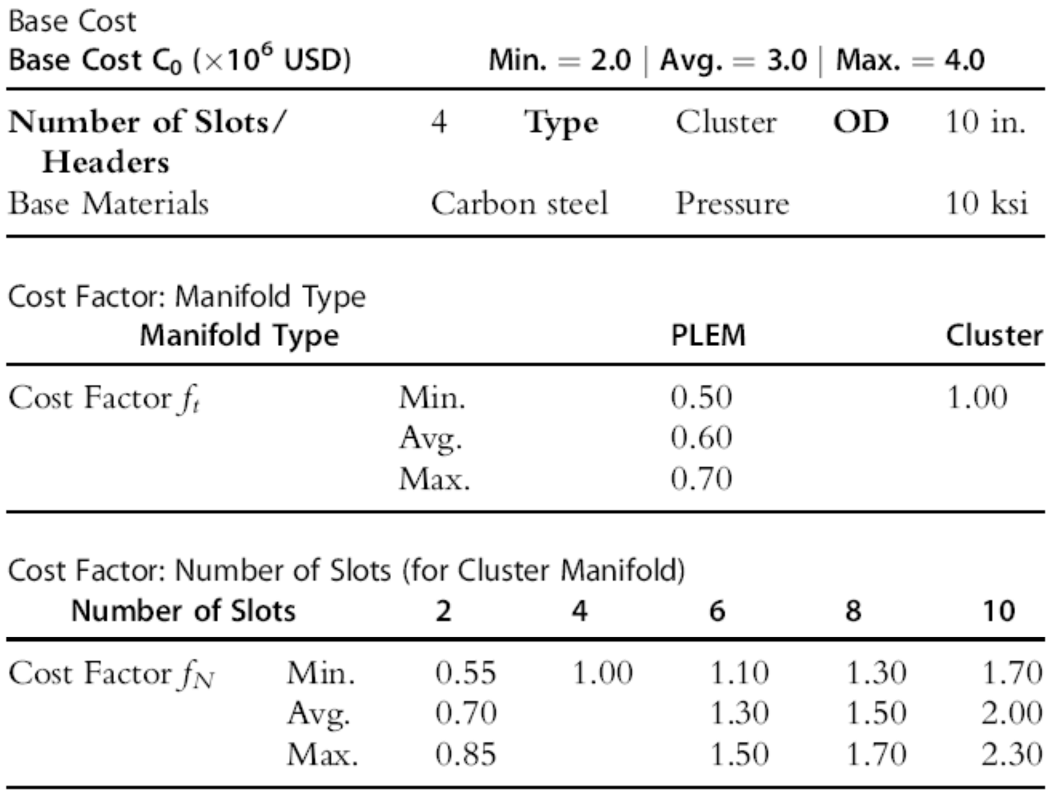
2.6.2.3.2. Cost Estimation Model

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

$$C = f_s \cdot f_t \cdot f_n + C_0 + C_{misc} \tag{2.8}$$

Where; C is cost of the manifold; f_t is manifold type factor (cluster, PLEM); f_n is number-of-slot factor; f_s is pipe size factor; C_0 is basic cost; C_{misc} is 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

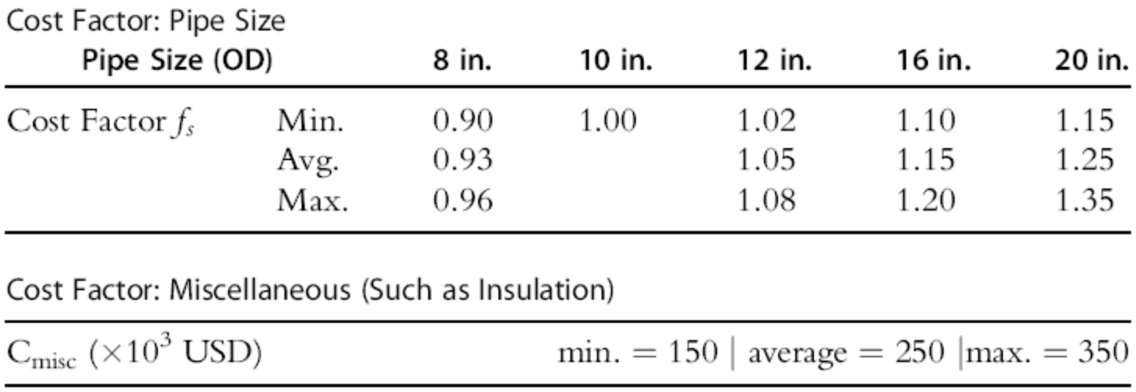
Number of Slots/ Headers	4	**Type**	Cluster	**OD**	10 in.
Base Materials	Carbon steel		Pressure		10 ksi

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

2.6.2.4. 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.

2.6.2.4.1. 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 non-sour service and grades X65 and X70 with a wall thickness of up to 40 mm for sour service.

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. These results in an overall reduction of fabrication costs when using high-grade steel compared with low-grade steel. The pressure rating–cost curve is shown in Figure 2.11.

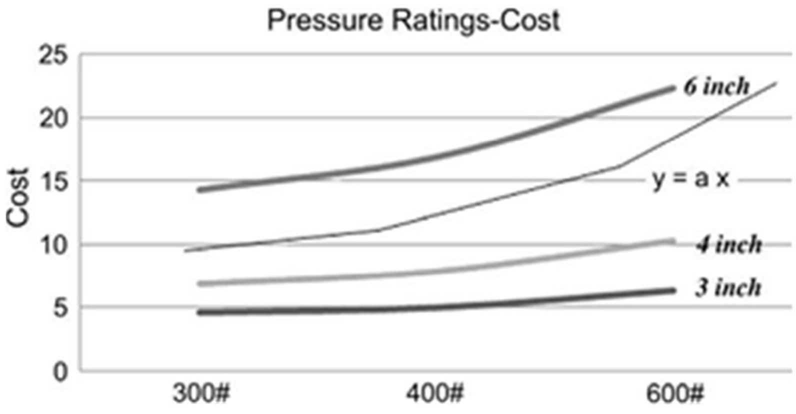


Figure.2.11: Pressure Rating–Cost Curve

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

2.6.2.4.2. Cost Estimation Model

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

$$C = f_s \cdot f_t \cdot L \cdot C_0 + C_{misc} \qquad (2.9)$$

Where; f_t is flowline type factor; f_s is size factor; $C_0$is basic cost per unit length (meter); L is total length of the flowline (meter); C_{misc} is 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 _65_C (150_F). For a temperature rating > 65_C (150_F), the price increases dramatically.

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

2.6.3. Testing and Installation Costs

2.6.3.1. 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 System Integration Test (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 System Integration Test (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 key subsea equipment SIT are listed in Table 2-2.

Table.2.2: System Integration Test (SIT) Costs

SIT Cost (_103 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
Intervention Workover Control Systems (IWOCS)	100	200	300
Connectors	8	10	12

2.6.3.2. Installation Costs

Installation costs for a subsea field development project are a key part of the whole CAPEX, especially for deep water 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 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 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 2.3 shows the typical day rates for various vessels, and Table 2.4 lists some typical subsea equipment installation duration times.

Table.2.3: 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.2.4: Typical Subsea Structure Installation Duration (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

2.6.4. 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.

2.7. 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:

$$OPEX = I_{Duration}\ x\ R_{cost}\ ¼ \tag{2.10}$$

Where; $I_{Duration}$ is Intervention duration and R_{cost} is Rig spread cost.

Table.2.5 shows a distribution for the typical cost components of OPEX for a deep-water 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 deep-water developments, except that the cost of product transportation is significantly lower.

Table.2.5: Typical Cost Distribution of Deep-water OPEX.

Subsea OPEX breakdown	Typical cost components of OPEX (%)
Host platform operation	6
Host Platform Process Tariff free	11
W1 Well Equipment Intervention	1
W1 Well Intervention -Major-	3
W1 Well Intervention -Minor-	1
Production well equipment intervention	2
Production well intervention -Major-	10
Production well intervention –Minor-	3
Operator Insurance	11
Product Transportation	30
Product Activities	16
Variable Chemical	2
Admin & general overhead	4

2.8 RISKEX of Subsea System

The RISKEX methodology developed in DTTAS /3/ was used as a basis for determining the RISKEX for the subsea completions. RISKEX costs are calculated as the probability of uncontrolled leaks times assumed consequences of the uncontrolled leaks:

$$RI_j = \sum Pob_i(avtivity - j \bullet C_i \qquad (2.11)$$

Where; RI is RISKEX costs, Pob_i (activity j) is the probability of a blowout of size i during activity j, and C_i is the cost of leak of size, i is {limited, major, extreme}.

Blowout of a well can happen during each mode of the subsea system: drilling, completion, production, workovers, and recompletions. The probability of failure of the well completion system is a function of the probability of failure during the various operating modes (drilling, initial completion, normal production, workovers and re-completions). Thus, the probability of a blowout during a well's lifetime is the sum of each single probability during each mode.

The lifetime probability of a blowout is calculated as:

$$Pob_{(BO\ during\ lifetime)} = P_{(drilling)} + P_{(initial\ compl.)} + P_{(prod)} + \sum P_{(WO)} + \sum P_{(re-compl.)} \tag{2.12}$$

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 2.6 shows this kind of costs in the industry from last decades.

Table.2.6: Cost of Blowouts in Different Geographic Areas [Mineral Management Service]

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

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2.9 RAMEX of Subsea System

Reliability, availability, and maintainability expenditures (RAMEX) are cost which is related to subsea component failures during a well's lifetime. The component failures require the well (and sometimes the entire system) to be shut-in while the component is being repaired. The costs to the operating company of these component failures fall into two categories:

- The cost to repair the component (i.e. repair vessel spread cost multiplied by duration), and
- The lost production associated with one or more wells being down.

The RAMEX of a particular component is calculated by multiplying the probability of a failure of the component by the average consequence cost associated with the failure (repair and lost production costs). The total RAMEX cost is the sum of all of the components' RAMEXs:

$$RA = Cr + Cp \tag{2.13}$$

Where; RA is RAMEX cost, Cr is cost of repair (vessel spread cost and the component repair/change cost) and Cp is lost production cost.

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 or 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 the failure.

The procedures for RAMEX calculation is performed through the following four steps, as illustrated in the Figure 2.12.

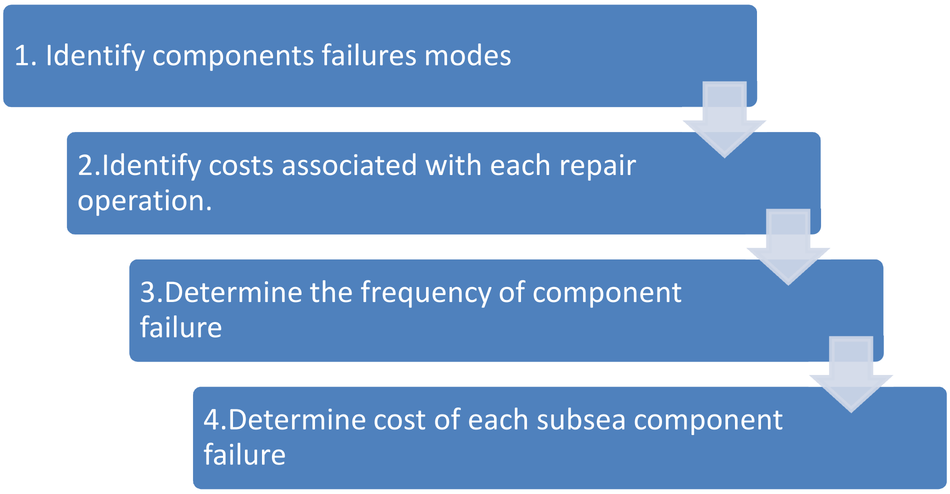


Figure.2.12: RAMEX Cost Calculation Steps.

2.9.1 Identify Components Failures Modes

A table of well system components –from the reservoir to the tubing hanger- is developed for each completion system. Failure modes such as a sand control system failure, tubing leak and SCSSV failure are determined.

Subsea completion equipment (i.e., manifolds, jumpers, etc.) can fail, resulting in production loss from one or more wells. Because these components can cause the downtime of more than one well, they are modeled separately from the downhole components. Table.2.7 lists the types of subsea repairs with the percent of wells affected.

Table.2.7: Subsea Equipment Repair Costs

Subsea Repair/Replace Type	% of wells affected
Hydraulic system umbilical (Repair/Replace)	100
Electrical system umbilical (Repair/Replace)	100
Hydraulic extension umbilical only if > 8 wells (Repair/Replace)	100
Electrical extension umbilical only if > 8 wells (Repair/Replace)	100
Repair Pipeline or PLEM/PLET	50
Flowline Jumper (Repair/Replace)	50
Extension pipeline or PLEM only > 8 wells (Repair/Replace)	50
Extension jumper only > 8 wells (Repair/Replace)	50
Tree jumper extension only > 8 wells (Repair/Replace)	a well
Tree jumper (Repair/Replace)	a well

Well Jumper (Repair/Replace)	a well
Well Flying Leads (Repair/Replace)	a well
Well control Pod (Repair/Replace)	a well
Well Choke (Repair/Replace)	a well

2.9.2 Identify costs associated with each repair operation.

An FMECA identified critical failure modes (mechanical failure, reservoir-related failures, and regulatory driven shutdowns) and determined associated consequences of failures for each well system component. This process identified which operating procedure would be used to achieve the repair. The operating procedure determined the duration of the repair activity and the type(s) of repair resource(s) required for the repair. These repair resources include platform rig, MODU, DSV, MSV, wireline or coiled tubing unit, etc. Repair resource “availability time” (i.e., how long before a resource vessel can be contracted to perform the operation) and repair resource “spread costs” are estimated based on local conditions. These are easily varied to determine their effect on the total project economics. Well production lost/deferred while waiting on repair resources and during the repair operation are dependent on the number of wells affected by the component failure and on individual well production rate(s) at the time of the failure.

2.9.3 Determine the frequency of component failure.

Component reliability data that were developed for both RISKEX and RAMEX calculations consisted of estimates of limited failures and extreme failures. For example, a tubing joint has a probability of developing limited leak due to minor damage or improper make-up and a less likely probability of an extreme failure that results in rupture or parting.

All extreme failures were assumed to necessitate a workover. However, a limited failure may or may not cause a stoppage of operations, depending on the size and nature of the failure. Small leaks often cause pressures to increase in the annulus between the tubing string and the production casing. The U.S. Minerals Management Service (MMS) permits production to continue with annulus pressure so long as the pressure build-up is within certain limits. Leaks that are sufficiently small to permit continued operations may eventually increase in size until sustained annular pressure indicates loss of a well control barrier.

2.9.4 Determine Cost of Each Subsea Component Failure.

A field development system is defined as a simplified, hierarchical network of completion components. The field development system can consist of one or more wells; the well can consist of one or more completion components.

A well is modeled as a list of completion components with their associated failure modes, corresponding consequences in terms of reduced production, and required repair resource. A well is considered to function if all of its components are functioning (in reliability theory referred to as a series structure). The type and number of completion components may vary from well to well.

The frequency of unplanned workovers can be calculated using the RAMEX methodology. Each component failure mode has a specific workover associated with its repair. Using the component failure probabilities described earlier, it is then possible to determine the frequency per year of each unplanned workover. Unplanned repair frequencies are calculated for the various types of repair operations.

RAMEX is calculated by multiplying the yearly system failure probability by the costs associated with lost production and repairing the system for the particular failure. This section will first describe the calculation of the lost production costs, then describe the repair costs.

The oil/gas production profiles vary over time. Each individual well will have a normal production rate, which sums to the normal daily field production rate. The individual well capacity can be larger than the normal rate.

The production consequence for an individual well depends on the following:

- The production rate at the time the failure occurred
- Lost capacity while waiting on repair resources
- Availability time for the repair resources
- Active repair time

The average production loss per year due to any particular component is given by the following equation:

$$PL_{year} = \frac{P_a(H)-P_a(L)}{1\,year}\,(T_{AR}+T_{RA})\,PR\;365\;days/year \qquad (2.14)$$

Where: PL_{year} is the production loss cost for a given year, $P_a(H)$ is the probability of component failure for the end of the year (e.g. 2 for year 1), $P_a(L)$ is the probability of component failure for the beginning of the year (e.g. 1 for year 1), T_{AR} is the mean time to repair a certain failure, T_{RA} is the rig availability time, PR isthe average well flow rate for that particular year.

The average production loss per year for a given well is the sum of the losses for all the well components. This concept of lost production is further illustrated in the following figure. Figure.2.13 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, TRA is the resource's availability time (vessel), and TAR is the active repair time.

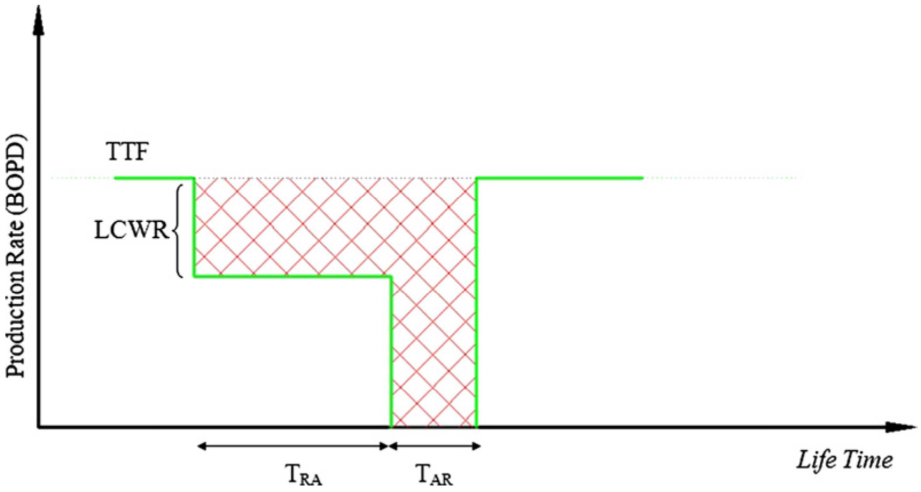


Figure.2.13: Costs Due to Lost Production Time.

The mean time to repair is dependent upon the operation used to repair the system. A repair operation is required for each component failure. Each operation will have a corresponding repair vessel, depending on the scenario (dry tree, subsea).

A field production profile prediction provides the basis for a field development plan. This field total production rate prediction is the sum of the individual well production rates.

Processing facilities capacity typically limits the field production rate during a "plateau" period when many wells are producing at near maximum rates. The production profile will normally represent a "zero equipment failure" scenario and its production volume over the planned lifetime can be regarded as "ideal recoverable reserves".

The repair costs are calculated by multiplying the yearly system failure probability by the mean time to repair the failure and the rig spread cost. For each component failure, there may be a different resource associated with the repair, and hence a different cost. The repair cost is calculated by using the following equation:

$$RC_{year} = \frac{P_a(H) - P_a(L)}{1\ year}\ T_{AR}\ RSC \tag{2.15}$$

Where: RC is resource cost associated with a particular failure, T_{AR} is the mean time to repair a particular component, RSC is resource spread cost ($/day).

The final RAMEX values are calculated by multiplying the yearly failure probability by the sum of the production costs and the repair costs for a particular failure. This is shown in the following equation:

$$RAMEX_{year} = \sum_{Component\ failrue} \frac{P_a(H) - P_a(L)}{1\ year} \{[(T_{AR} + T_{RA})]\ LP\ 365\ (T_{AR}\ RSC)\} \tag{2.16}$$

Where: $RAMEX_{year}$ = the total RAMEX of a particular system for a particular year.

The % uptime is defined as the percentage of the maximum flow that can be expected during the field’s lifetime. This percentage is calculated by dividing the welldays attributed to lost production from the total number of well-days during the field’s life.

The calculation for the % uptime of a dry tree system is shown through the following equation:

$$\%uptime_{drytree} = 1 - \frac{\sum_{x=1}^{n} \frac{LPD_x}{W_x}}{D_{total}} \tag{2.17}$$

Where: $\%uptime_{drytree}$ is the percentage of maximum flow expected from dry tree wells during the field’s lifetime, LPD_x is the days of lost production in a given year (x) for the dry trees calculated through RAMEX techniques, W_x is the number of subsea wells for a given year, D_{total} is the total number of days for a field during it’s lifetime

The calculation of the % uptime of a subsea system is shown through the following equation:

$$\%\ uptime_{subsea} = 1 - \frac{\sum_{x=1}^{n} LPSE_x + \sum_{x=1}^{n} \frac{LPSW_x}{W_x}}{D_{total}} \tag{2.18}$$

Where: $\%\, uptime_{subsea}$ is the percentage of maximum flow expected from subsea wells during the field's lifetime, $LPSE_x$ is the days of lost production in a given year (x) for the subsea equipment calculated through RAMEX techniques, $LPSW_x$ is the days of lost production in a given year (x) for the subsea wells calculated through RAMEX techniques.

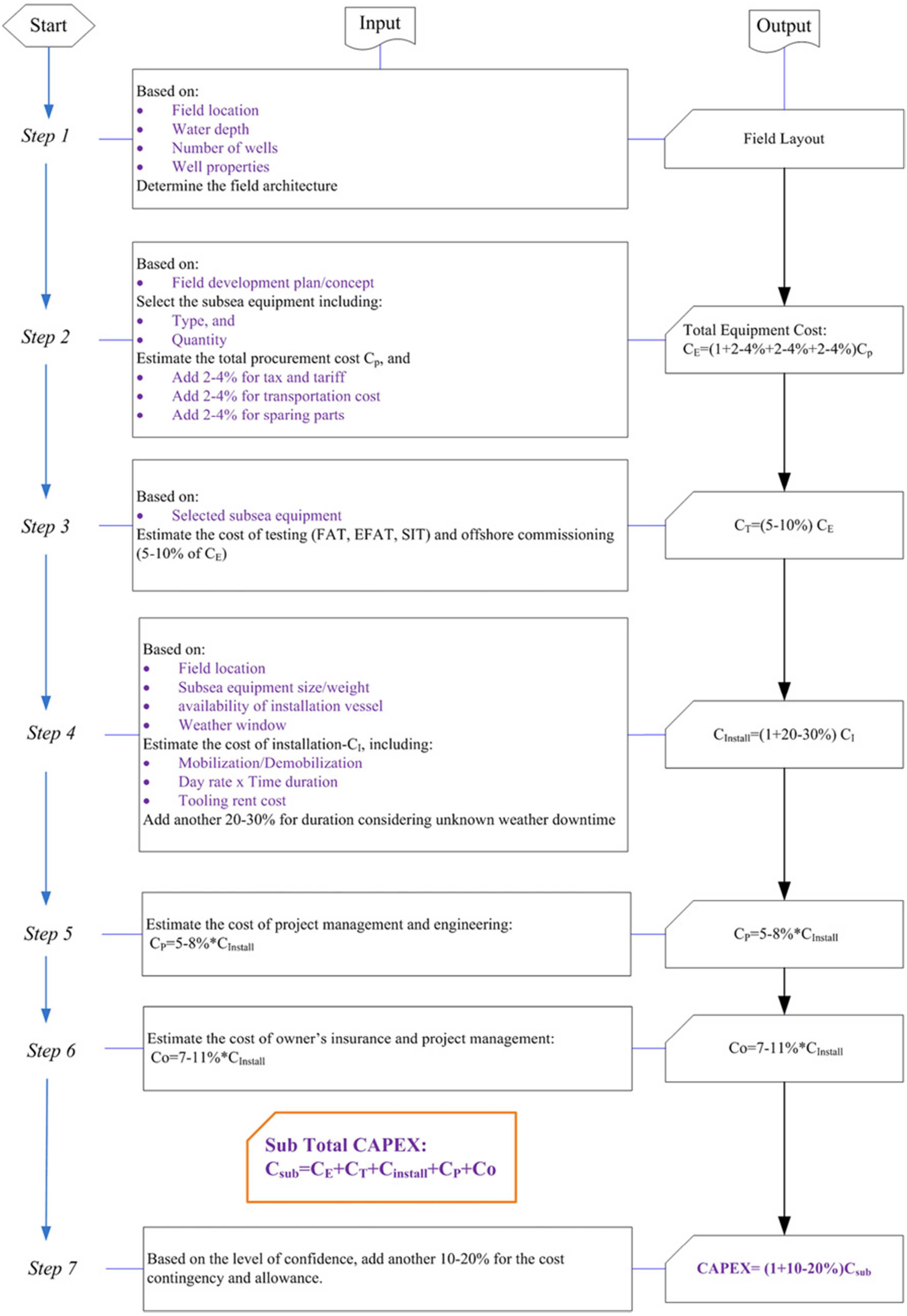
2.10 Overall Lifecycle Cost

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

$$LC = \ CAPEX + \ OPEX + RISKEX + RAMEX \tag{2.19}$$

$$LC = \ CAPEX + \ \sum_{ke(i,n)} \frac{OPEX}{(1+r)^k} + \sum_{ke(i,n)} \frac{RISKEX}{(1+r)^k} + \sum_{ke(i,n)} \frac{RAMEX}{(1+r)^k} \tag{2.20}$$

Where: $OPEX_i$ and RC_i represent the OPEX and Risk Cost in year i respectively, r is the discount rate and N is the field life in years.



Based on:
- Field location
- Water depth
- Number of wells
- Well properties

Determine the field architecture

Based on:
- Field development plan/concept

Select the subsea equipment including:
- Type, and
- Quantity

Estimate the total procurement cost C_p, and
- Add 2-4% for tax and tariff
- Add 2-4% for transportation cost
- Add 2-4% for sparing parts

Based on:
- Selected subsea equipment

Estimate the cost of testing (FAT, EFAT, SIT) and offshore commissioning (5-10% of C_E)

Based on:
- Field location
- Subsea equipment size/weight
- availability of installation vessel
- Weather window

Estimate the cost of installation-C_I, including:
- Mobilization/Demobilization
- Day rate x Time duration
- Tooling rent cost

Add another 20-30% for duration considering unknown weather downtime

Estimate the cost of project management and engineering:
$C_P=5\text{-}8\%*C_{Install}$

Estimate the cost of owner's insurance and project management:
$Co=7\text{-}11\%*C_{Install}$

Sub Total CAPEX:
$C_{sub}=C_E+C_T+C_{install}+C_P+Co$

Based on the level of confidence, add another 10-20% for the cost contingency and allowance.

Figure.2.14: CAPEX Calculation Steps [Y.Bai].

Chapter.3

3.0 Life Cycle of Satellite Cluster Subsea System

3.1 Subsea System Field Development

A 6-well satellite clustered subsea system design was developed to demonstrate the model. Figure.3.1 shows the overall layout for the base case 6-well subsea system. The subsea system includes hydraulic and electrical umbilicals and pipeline connecting the subsea system to a remote host platform. Flow-line jumpers connect the pipeline end manifolds to a 6-well manifold and well jumpers connect the manifold to individual wells that are clustered around the manifold. Hydraulic and electrical flying leads connect the hydraulic and electrical termination units to individual wells.

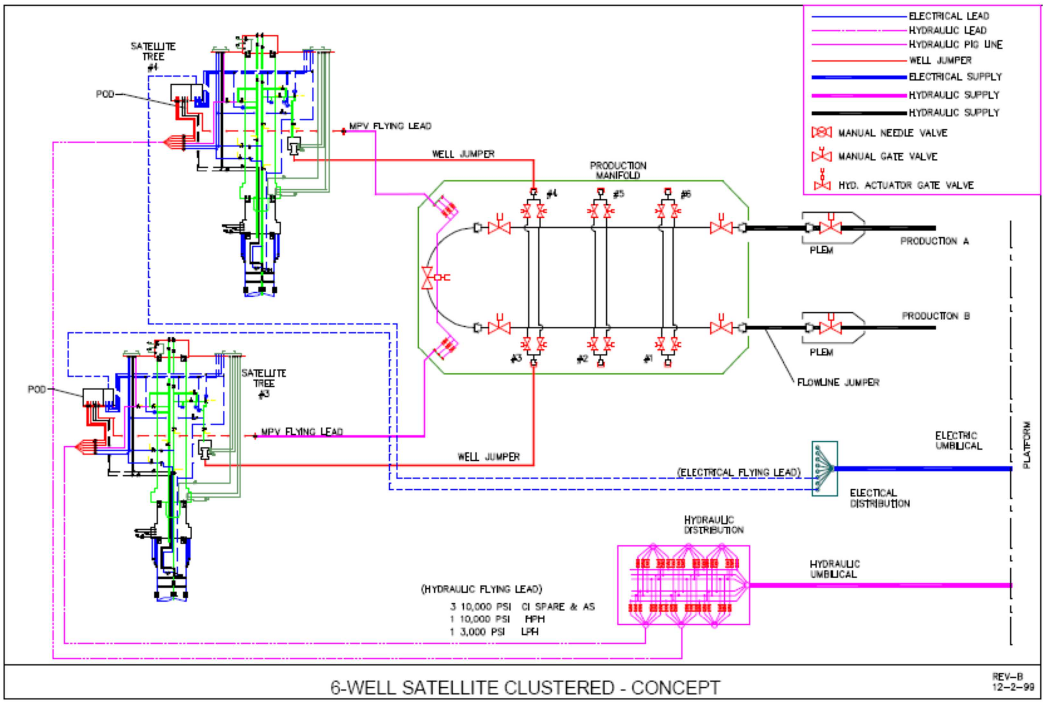


Figure.3.1: Satellite Cluster.

The methodology and spread sheet tool has been expanded to model additional subsea facilities with pipeline umbilical extensions to an additional subsea manifold with associated wells. This permits the evaluation of a variety of subsea configurations and numbers of wells.

A schematic of the conventional tree used in the base case is displayed in Figure.3.2. The tree consists of a 4-inch vertical access production bore with wire-line plug access to the tubing hanger via the tree. The annulus bore is 2-inch nominal with direct wireline access to the tubing hanger annulus.

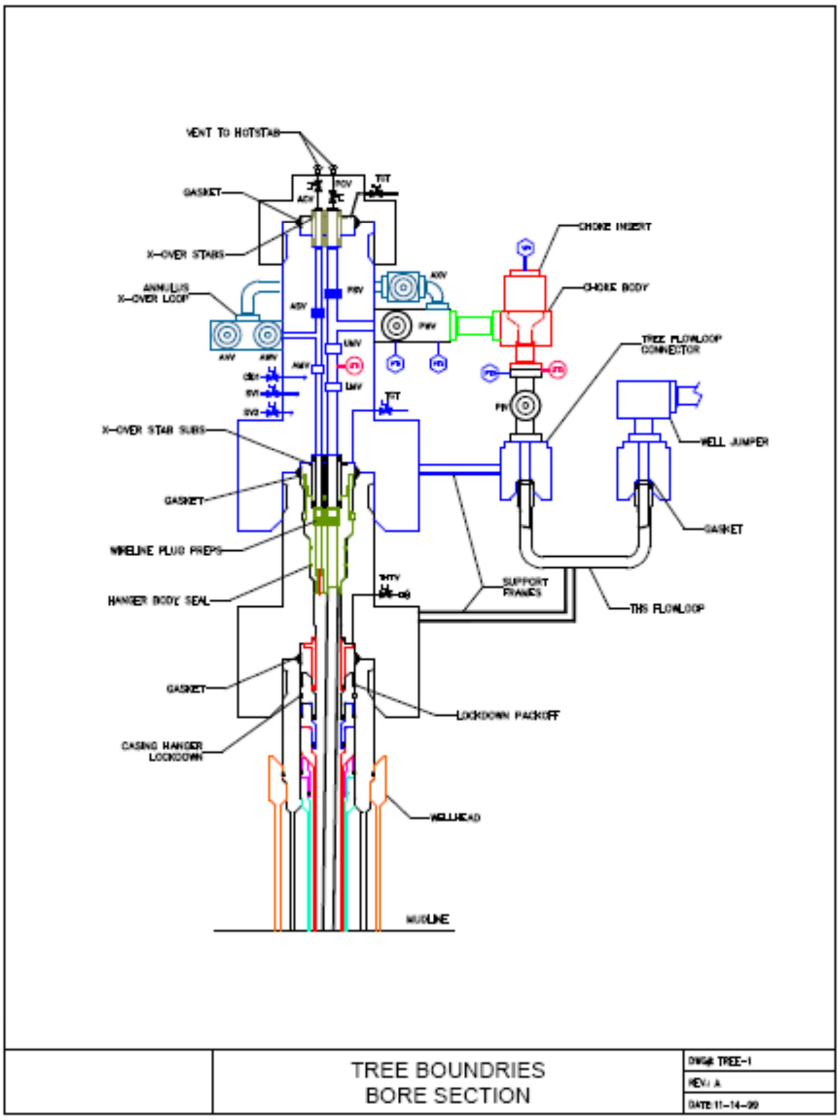


Figure.3.2: Conventional or Vertical Tree Schematic

The horizontal tree connects directly to the subsea wellhead system. The horizontal tree design eliminates a tubing head spool as presently found in the base case vertical tree system. The horizontal tree assembly will carry the flow-line hub enabling vertical well jumper connections between the tree and manifold. Figure.3.3 displays the base case horizontal tree configuration).

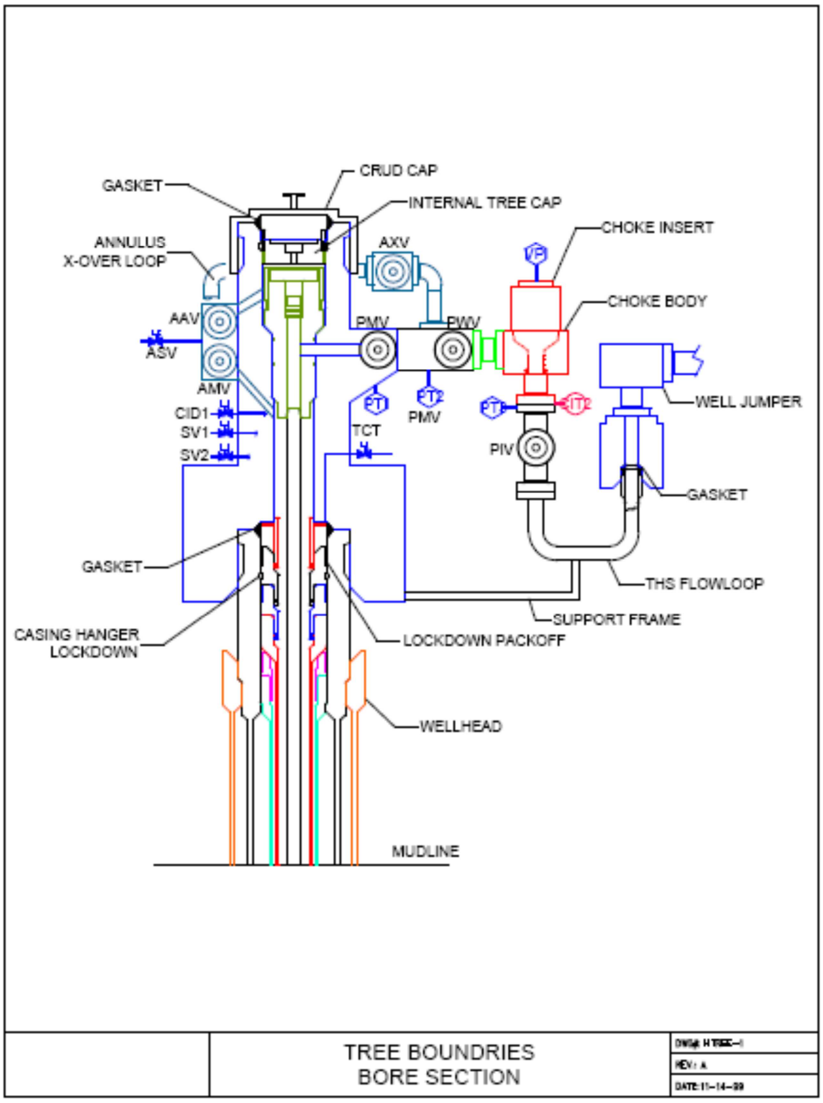


Figure.3.3: Horizontal Tree Schematic

3.2 Results and Discussion

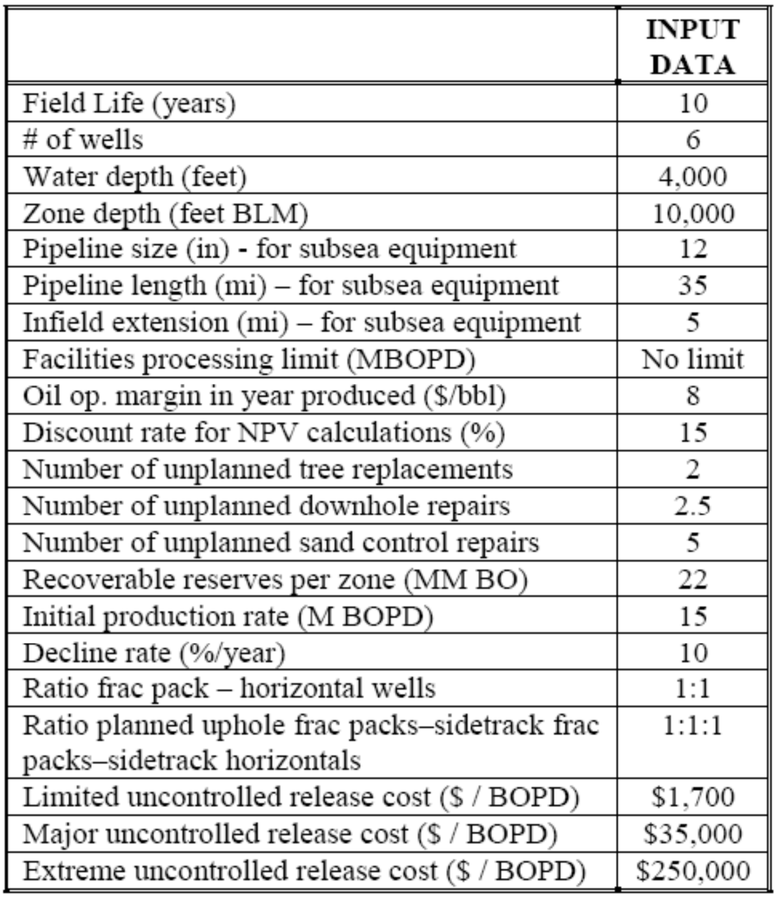
The methodology and spread sheet program developed by this JIP has been used to quantify the CAPEX, OPEX, RISKEX and RAMEX factors that determine the differences in these well systems. The following sections describe results and conclusions derived from evaluation of numerous case examples.

Dry Tree Tieback Systems.

We have compared three dry-tree well systems for a case example: dual casing riser, single casing riser and tubing riser. The base case input data are summarized in Table.3.1 and the lifecycle costs are presented in Table.3.2 and Figure.3.4. The results indicate that a dual casing riser is the most cost efficient. The single casing system is differentiated by its high RISKEX and the tubing riser system is differentiated by its high OPEX and RAMEX. Note, however, that the base case is located in deep water 1220 m and produces from a high-pressure reservoir.

Single casing risers provide an ideal solution for shallow water and moderately deep water when formation pressures are very near seawater gradient. Because well interventions are performed with a surface BOP stack through the single casing riser, a small leak in a single casing riser can cause loss of well control in deepwater when formation pressures are abnormal. RISKEX during well intervention operations is quite high in this case. RAMEX is higher than for a dual casing riser because any annular pressure requires an immediate intervention.

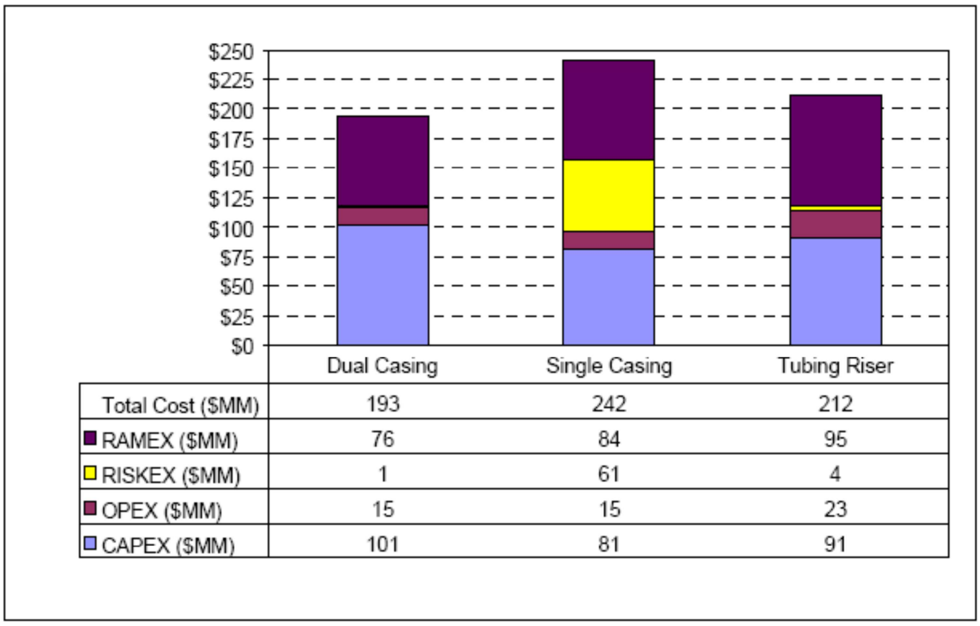
Table.3.1: Case Study Input Data



	INPUT DATA
Field Life (years)	10
# of wells	6
Water depth (feet)	4,000
Zone depth (feet BLM)	10,000
Pipeline size (in) - for subsea equipment	12
Pipeline length (mi) – for subsea equipment	35
Infield extension (mi) – for subsea equipment	5
Facilities processing limit (MBOPD)	No limit
Oil op. margin in year produced ($/bbl)	8
Discount rate for NPV calculations (%)	15
Number of unplanned tree replacements	2
Number of unplanned downhole repairs	2.5
Number of unplanned sand control repairs	5
Recoverable reserves per zone (MM BO)	22
Initial production rate (M BOPD)	15
Decline rate (%/year)	10
Ratio frac pack – horizontal wells	1:1
Ratio planned uphole frac packs–sidetrack frac packs–sidetrack horizontals	1:1:1
Limited uncontrolled release cost ($ / BOPD)	$1,700
Major uncontrolled release cost ($ / BOPD)	$35,000
Extreme uncontrolled release cost ($ / BOPD)	$250,000

Table.3.2: Dry Tree Completion Alternatives RAMEX Results, 6 wells, 1220m

	DUAL CASING	SINGLE CASING	TUBING RISER
% Uptime	98.0 %	97.8 %	97.8 %
Repair Cost ($MM)	11.4	12.0	15.7
Production Lost ($MM)	25.6	29.1	28.9
Total RAMEX ($MM)	**37.0**	**41.1**	**44.6**



	Dual Casing	Single Casing	Tubing Riser
Total Cost ($MM)	193	242	212
■ RAMEX ($MM)	76	84	95
■ RISKEX ($MM)	1	61	4
■ OPEX ($MM)	15	15	23
■ CAPEX ($MM)	101	81	91

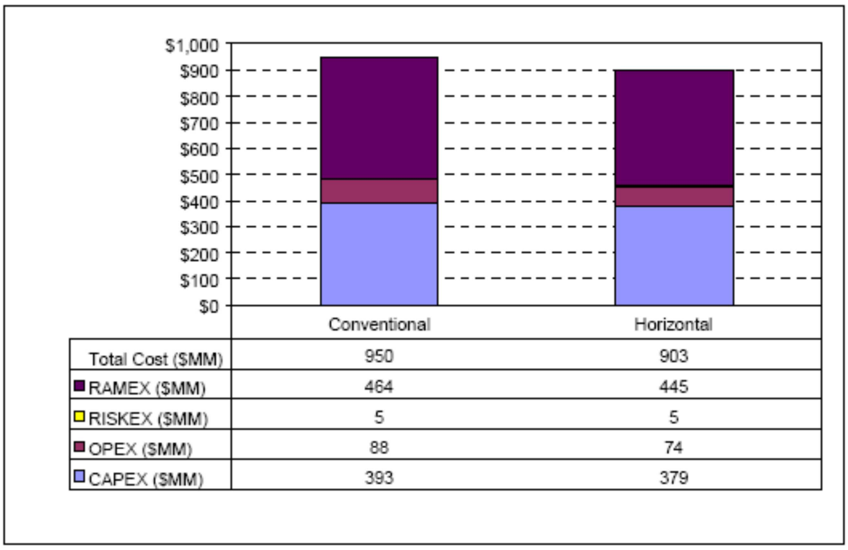
Figure.3.4: Dry Tree Completion Alternatives Lifecycle Cost ($MM NPV), 6 wells, 1220m

Subsea Production Systems

The results of a case example of subsea well systems are shown in Table 3.3 and Figure 3.5. Input data presented in Table 3-3 were used for this example. The results indicate that the horizontal tree system is the most economical for the base case and both cases are dominated by the RAMEX.

Table.3.3: Subsea Completion Alternatives RAMEX Results, 6 wells, 1220m

	CONVEN-TIONAL TREE	HORIZON-TAL TREE
% Uptime	89.6 %	89.6 %
Repair Cost ($MM)	69.4	64.1
Production Lost ($MM)	132.3	131.9
Total RAMEX ($MM)	**201.7**	**196.0**



	Conventional	Horizontal
Total Cost ($MM)	950	903
■ RAMEX ($MM)	464	445
□ RISKEX ($MM)	5	5
■ OPEX ($MM)	88	74
□ CAPEX ($MM)	393	379

Figure.3.5: Dry Tree conventional and horizontal Lifecycle Cost ($MM NPV), 6 wells, 1220m

Horizontal subsea tree system permits workover operations without removing the subsea trees. This system is most economical if numerous workovers are required for recompletions to new zones.

Conventional subsea trees can be replaced more easily than horizontal trees in the event of the failure of a tree valve or actuator. Conventional subsea trees can be replaced without pulling the completions string; horizontal subsea trees require the completion string to be pulled prior to pulling the tree. Therefore, the most economical type of tree is influenced by the reliability of the tree components such as valves, valve actuators, connectors, etc.

Subsea production systems have several unique advantages. CAPEX can be much less than for a new platform facility when an existing facility is available to accept production from a subsea production system. RISKEX is relatively low for subsea systems. Table 4 and Figure 3 show that RAMEX and OPEX can be significantly higher than dry-tree systems, depending on reservoir characteristics. The daily spread cost for a MODU is about twice that of a platform rig operation and it takes almost twice as long for most well interventions. Handling subsea BOP's and marine risers takes much longer than dry-tree intervention operations. Therefore, subsea well interventions cost three to four times as much as dry-tree interventions.

Smart completions may be useful to minimize RAMEX for subsea wells. Smart or intelligent completions have the potential to:

- Remotely and inexpensively isolate a depleted zone and initiate flow from a new productive zone, regulate the flow from adjacent zones to maximize recoveries and reservoir performance, remotely achieve other changes in downhole configurations.
- The use of a smart completion for zonal recompletion when the primary zone is depleted provides the potential to eliminate an expensive workover.

This potential saving is partially offset by several smaller costs. The alternate zone must be properly completed with an appropriate sand control system, thus, increasing the initial well cost and perhaps delaying production. Reservoir characteristics are better understood after several years of production, thus, permitting improved re-completion designs. Smart completion tools cost more to install and because of increased complexity are more likely to fail, requiring an unplanned workover.

The net present value (NPV) of a smart completion CAPEX must be compared to the NPV of a later workover and the system RISKEX and RAMEX to determine the most cost effective development plan

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Autobiographies

Jaswar Koto was born on October, 1970. He is a descendant of the Prophet Rasullullah S.A.W through Husein R.A. He is a President of Ocean and Aerospace Research Institute, Indonesia. Professor on offshore engineering and also President of International Society of Ocean, Mechanical & Aerospace for scientist and engineers.

He has been invited as a Visiting Professor more than 16 times, received several international awards and supervised PhD, Master and Bachelor Students.

He received his bachelor degree in 1994 from Institut Teknologi Sepuluh Nopember (ITS), Indonesia, Curtin University in 1996 and Notre Dame University in 1999. In 2003 he has completed PhD with receiving award in engineering form Aerospace and Marine Engineering, Osaka Prefecture University, Japan.

He has started his researches since 1994 on structure analysis of fluid flow in subsea pipelines, subsea pipeline corrosion due to Carbon Monoxide, design and hydrodynamic analysis of AUV in Australia. Then, he joined Research and Development Institute, Sumitomo Heavy Industries -Marine Engineering-, Japan. In 2005, he joined ExxonMobil projects. Since 2010, he has a contract with Department of Aeronautical, Automotive, and Ocean Engineering, Faculty of Mechanical Engineering. He is also appointed as head of High Performance Computing, CICT, Universiti Teknologi Malaysia.

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