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MASTER'S THESIS

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Abstract:

The scope of the work was to create a model that will allow the comparison of Life Cycle Costs (LCC) for subsea production systems and floating structures with dry wellheads for the Mexican territorial waters of the Gulf of Mexico.

To give validity to the model, an empirical comparison on the resulting recovery factor based on data of the US Gulf of Mexico was included. This comparison is intended to answer ¿Is there a significant difference in the recovery factor when is used the dry tree vs. the wet tree concept solutions?

The model proposed integrates a number of already published models done by academics, the industry and governments. Also, it was found that the activity in deep water offshore Mexico is having place in a region with an evident lack of preexisting infrastructure. Hence it is proposed in the model that new offshore structures shall have an added value for comparison purposes

Two hypothetical projects (three different concepts for each project) of field development, based in public information released by PEMEX, are assessed.

Conclusions and recommendations are made to increase the possibilities of feasible future field development and efficient depletion of the hydrocarbons located in Mexican deepwater.

Acknowledgement:

This thesis has represented a large amount of challenging work that finally has been completed. It also increased my knowledge and extended much more my curiosity about the oil and gas industry, which makes me understand in a much better way the complexity and scope of decisions that are taken when the field development projects are committed.

I hope that this work will contribute to the discussion and further analysis that increase the possibilities of oil and gas field development and ensure an efficient depletion of hydrocarbon resources located in Mexican deepwater. Most of all, is my best wish that these possibilities will be in the wellbeing of the Mexican population

This work might have not been possible without the valuable and encouraging participation of the advisor for this master thesis the professor Ove Tobias Gudmestad. The advice and commitment of the professor Jonas Odland as well as the feedback received from the professors Tore Markeset and Arnfinn Nergaard were very important.

An acknowledgement is needed also to an important sponsor for the writing of this thesis, the "Instituto de Financiamiento e Información para la Educación" from Guanajuato Mexico.

Big thanks to my parents Jose Jesus and Maria Esther and for all my brothers and sisters for their support and encouragement.

Finally and most important, this work is dedicated to my wife Olena and my daughter Elena Valentina whom represents my major motivation.

Table of Contents

Enclosure:

- Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf
- Annex B: Requirements, activities and products of the development planning phases
- Annex C: Field development examples
- Annex D: Marine operations
- Annex E: Extended results of the recovery factor data analysis for oil and gas fields in the U.S. Gulf of Mexico.
- Annex F: Nova Scotia Model Description, reverse modeling of the excel file.
- Annex G: Design Basis for the Case Analysis

1. Scope of the work

The scope of the work is to create a model that will allow the comparison of Life Cycle Costs (LCC) for subsea production systems and floating structures with dry wellheads for the Mexican territorial waters of the Gulf of Mexico. This model should be capable of generating a basis for economical analysis of oil and gas deepwater production systems in the early stages of the concept selection phase of a project.

The first part of this thesis (Chapters 3, 4, 5 and 6) will introduce to the theoretical background of field development in deep water. The second part (Chapters 7, 8 and 9) presents the development, conclusions and recommendations.

In Chapter 3 is shown a revision of the state of the art in production of oil and gas in deep water. The Offshore field development process before concept selection is overviewed in chapter 4. In chapter 5 is presented a deeper review of the “concept selection” and “life cycle cost”. Before to close the first part, in the chapter 6 of this thesis, a brief summary of the characteristics of production concepts for offshore field development in deepwater is made.

A discussion on comparisons of the recovery factor dry vs wet tree is done in chapter 7. This discussion is intended to answer an important question. ¿Is there a significant difference in the recovery factor when is used the dry tree vs. the wet tree concept solutions?.

Chapter 8 presents the models employed in the creation of the model proposed to calculate the cost of deep water concepts either dry or wet tree.

Most of the calculations were made using the “Oil and Gas Exploration Economic Model” of the Nova Scotia Department of Energy (Nova Scotia, 2008), see annex F, and the results obtained were adjusted where necessary by the “Empirical cost models for TLP’s and SPARS´s “ (Jablonowsky, 2008), and the “Models of Lifetime Cost of Subsea Production Systems, prepared for Subsea JIP, System Description & FMEA” (Goldsmith, 2000).

In this work is also proposed a way to calculate the added value of an offshore structure acting as a hub, see point 8.4. Tax calculations are out of the scope of this work, consequently, the results will show just values before taxes.

In chapter 9, the proposed model was used to perform LCC analysis for a ***case study*** centered in the development of the deep water regions of Mexico. The two projects of field development considered are Lakach (Lakach Field) and Holok (Noxal, Lalail, Leek and Tabscoob fields). The names of the projects are just representing proposals for the analysis in this study and it should not be understood that they are the real denominations of the projects. For each project were evaluated three different concepts.

Subsea production concepts (tieback to shore or tieback to offshore facilities) are characterized by evident savings in capital costs, but become a more questionable selection following the considerations of the Life Cycle Costs Analysis due to the cost of their intervention and work over operations as well as the typically lower recovery factor when they are compared against floating structures with dry wellheads.

Alternative concepts using floating structures (SPAR or TLP) with dry wellheads would represent an increased recovery rate with respect to subsea tieback concepts. However they are also associated with high investments costs and a huge competence challenge for the skills in the construction, installation, and operation management of these facilities.

For the case analysis it was found that the activity in deep water offshore Mexico is having place in a region with an evident lack of preexisting infrastructure. This fact makes it important to develop a network of facilities that should increase the feasibility of development in the future.

Hence it is proposed here that additional offshore structures shall have an added value for comparison purposes. This added value will be calculated by doing an evaluation of NPV for the prospects that could be developed if the facility would be in place already.

This work closes with conclusions and recommendations that in opinion of the author might increase the possibilities of development and ensure efficient depletion of hydrocarbon resources located in Mexican deepwater.

2. Expected benefits of this work

PEMEX Exploración and Producción (PEP) is developing the field Lakach in the Mexican territorial waters of the Gulf of Mexico. The Lakach field is the first offshore field to be developed in deep water by PEMEX and is a part of an extensive effort by this National Company to fulfill the exploratory works and field development in basins that before were not considered to be commercially feasible.

A subsea tieback to shore has already been revealed by PEP as the selected concept for this development. However, there are many other prospects of development in the adjacent area that are already being included in the portfolio of exploration and that in the future could be the subject of further studies.

FIRST PART: THEORETICAL BACKGROUND

3. State of the art in production of oil and gas in deep water

3.1. Sizing the global industry of construction of subsea oil and gas facilities.

The subsea technology is not the only way that can reach deep water, as we will see along this work, also the floating structures that use dry completion can be a sound solution for field development in deep water. However, subsea systems are important because in many cases they are the only option to develop fields and alone or in conjunction with floating structures represent the most extendedly used solution for deep water.

The construction of production facilities of oil and gas using subsea technology is expected to be one of the most dynamically developed industries in the next years. According to "Infield Energy Analysts" (Offshore, 02-09-2009), the forecasted total global subsea sector´s expenditure will exceed $80 billion USD over the period 2009 through to 2013.This amount almost doubles the expenditure in subsea equipment, drilling and completion that were accounted for $46 billion USD the past five years.

The biggest operators, based upon the number of subsea valve trees expected to be started up within the next five years are:

1. Petrobras 374
2. Shell 244
3. Total 237
4. Chevron 236
5. BP 229
6. ExxonMobil 215
7. Statoil 194

In total 3,222 subsea valve trees are expected to begin their operations in this period.

3.2. Subsea deep water record.

The record in drilling and completion is hold by Shell Oil Co. This company has reached 9,356 ft (2,852 m) below the water's surface in the Silvertip field at the Perdido Development project in the Gulf of Mexico (Offshore, 12-02-2008).

- Location: Gulf of Mexico, US
- Depth: ~2,380 metres
- Interests: Shell 35% (operator), Chevron 37.5%, BP 27.5%
- Fields: Great White, Tobago, Silvertip
- Peak Production: 130 kboe/d [API: 18-40]
- Key contractors: Technip, Kiewit, FMC Technologies, Heerema, Marine Contractors.

Technology:

Perdido, moored in approximately 2,380m of water, will be the world's deepest Direct Vertical Access Spar. The spar will act as a hub that will enable the development of three fields – Great White, Tobago, and Silvertip – and it will gather process and export production capability within a 48km radius. Tobago, in 2,925m of water, will be the world's deepest subsea completion.

However, Deep water is not only good news. Petroleos Mexicanos (PEMEX) is a particular case of a national oil and gas company that is planned to start the operation of projects in deep water in the first half of the 2010's. This company has identified operative challenges and risks that will be enounced next (PEMEX, 2008).

3.3. Main operative challenges.

Among many others these can be pointed to:

Marine currents and waves: strong marine current and waves induce the movement of structures and pipeline vibrations resulting in fatigue in the components of the drilling and production equipment.

The temperature changes, due to the different degrees of temperature between the surface and the drilled sub seabed formations make the pumping of the drilling fluid to become complex. Also these low temperatures alter the properties of the cement utilized to secure the casing of the well.

Critical aspects of drilling at the start up: During the drilling across shallow formations, the water flows are at high-pressure, there are also gas flows and therefore the pressures are usually abnormal.

Remote Operation of subsea installation must be made through R.O.V s, since human beings cannot reach great depths.

High costs involved: the fields need to be developed with fewer wells than the traditionally employed in the shallow waters. The conditions usually demand highly deviated and horizontal wells to ensure the flow of oil.

Subsea facilities and equipment: the application of new technologies is required to make possible the flow assurance either to the multiphase transportation systems or for fluids separation equipment on the seabed; a high degree of automation and use of robotics is required.

Salt formations: the demand for specialized technologies for formations surveying and assessment, also the drilling of these is challenging and demand the use of new and underdevelopment technologies.

Geometry of the reservoir in deep water may be different from the familiar in shallow waters.

3.4. Risks in projects in deep water.

Geological risks: exists due to the complexity of geological structures and the difficulty of identifying reservoirs, also in some cases the presence of saline subsurface formations deteriorate and diminish the likelihood of discovering deposits in these environments.

Operative risks: the operations are considerable more difficult to solve than in shallow water, for example:

•Flows of shallow waters and flows of gas might cause blow outs during drilling.

•Underwater tides and waves threaten the drilling facilities and the production infrastructure.

•Drilling equipment is expensive and sometimes unavailable

•Installation and maintenance of facilities is carried on at distant places and offer difficulties to access, which increase costs and delay operations.

Financial Risk: nevertheless, exposure of capital due the high costs of exploration, development and operation all-together with instability of oil prices.

Although the technology, equipment, and materials required for the project execution in subsea field developments, including deep water, have high cost of acquisition and operation, in the most of the cases they are already commercially available worldwide.

Nevertheless and particularly more important for the operators, is necessary acquire skills and implement systems to minimize risks for the operator company and increase the added value of the investment.

Proper business process management trough the whole lifecycle undoubtedly will diminish risks as well as will increase expected economical value added of the project.

Components for the management of the business process that can be listed are:

- Asset Management
- Documentation and management of project architecture, standards, recommended practices and procedures.
- Human resources and competence management
- Health, Safety and Environmental management.
- Implementation and management of suitable information systems
- Life Cycle Cost Management
- Process Safety Management
- Project Management
- Reliability and maintenance methodologies
- Risk Management.
- Suppliers and contractors management.

4. Offshore field development

Along the next chapters (4 and 5) some basic assumptions and facts will be reviewed on offshore field development and the concept selection in deep water. Necessarily, only an extract of all the public and available information will be mentioned due the expectancy and requisite to develop innovative content in this thesis. Wherever necessary, is suggested and encouraged to search and consult general references on this topics, a non exclusive list of suggested references is shown below:

- **Class Notes of Offshore Field Development with Compendium (Odland, 2000-2008).**
- **Deepwater development: A reference document for the deepwater environmental assessment Gulf of Mexico OCS (1998 through 2007)(Regg, 2006).**
- **Deepwater petroleum exploration & production: A nontechnical guide, (Leffler, 2003).**
- **Handbook of Offshore Technology, Volume I, (Chakrabarti, Editor, 2005).**
    - Chapter 1, Historical Development of Offshore Structures (Chakrabarti et. al, 2005).
    - Chapter 2, Novel and Marginal Offshore Structures (Capanoglu et. al., 2005).
    - Chapter 6, Fixed Offshore Platform design (Karsan et. al, 2005).
    - Chapter 7, Floating Offshore Platform design (Halkyard et. al, 2005).
- **Petroleum Engineering Handbook (Lake, Editor in chief, 2006).**
    - Volume I General Engineering (Fanchi, Editor, 2006).
        - Petroleum Economics (Wright, 2006).
    - Volume II Drilling Engineering (Mitchell, Editor, 2006).
        - Introduction to Well Planning (Adams, 2006).
        - Offshore Drilling Units (Childers, 2006).
    - Volume III Facilities and construction engineering (Arnold, Editor, 2007).
        - Oil and gas processing (Thro, 2007).
        - Gas Treating and processing (Wichert, 2007).
        - Piping and pipelines (Stevens and May, 2007).
        - Offshore and Subsea Facilities (O'Connor et. al., 2007).
        - Project Management of Surface Facilities (Kreider, 2007).
    - Volume V Reservoir engineering and petrophysics (Holstein, Editor, 2007).
        - Estimation of primary reserves of crude oil, natural gas, and condensate (Harrel and Cronquist, 2007).
        - Valuation of oil and gas reserves (Long, 2007).
- **Oil & Gas Exploration and Production Reserves, Costs, Contracts (Babusiaux, 2004).**
- **Oil and gas production handbook, an Introduction to oil and gas production (Håvard, 2006).**

4.1 Origins of oil and gas resources

The terms “Oil and gas” encompasses all the different hydrocarbon compounds (those compounds made of Hydrogen and Carbon in a chemical configuration) that are useful either for combustible or for transformation purposes and that were formed from the transformation of organic substances through geophysical and geochemical processes along plenty millions of years.

The sedimentary basins are those geological layers that were formed by successive deposition of organic and inorganic masses. Along the pass of the time, those first depositional layers were subject to increasing temperatures and pressures, down in the earth, as new layers were deposited on the surface.

In some cases, the conditions deep in the earth were propitious for the decomposition and transformation of the organic masses along many thousands and millions of years. These sedimentary layers where the organic substances are changing its properties are known usually as ***Source Rocks.***

Once the source rocks start to produce hydrocarbon compounds, those tend to climb passing trough interconnected porous in the rock and or fractures in the rock media, the path that the substances follow is refereed frequently as the ***migration path***. ***Porosity*** is the fraction of volume of the rock that is the empty space inside of a rock formation and ***permeability*** is the ability to flow or pass trough of the fluids contained in the rocks.

The hydrocarbons substances that move from the source rock are expected to flow trough a porous and permeable media until they are stopped by a geological barrier that is above a region of porous and permeable rock that is able to store the hydrocarbon substance and make possible its economical recovery. The geological barriers are know commonly as ***traps*** and the region of porous and permeable rock where the hydrocarbon is stored is named ***Reservoir Rock***. Depending on its form and origin the traps are classified as anticline, stratigraphic, unconformity and fault. The anticline traps are by most the more exploited so far due to their relative easiness to be located and dimensioned.

Summarizing, a promising area to be drilled for exploration (prospect) of oil and/or gas field must have:

1. A source rock reservoir rich of organic matter.
2. Enough heat and pressure along millions of years to make possible the transformation of the organic matter to hydrocarbon substances.
3. A migration path.
4. A reservoir rock limited by a:
5. Trap system with a impermeable seal (anticline, stratigraphic, unconformity or fault).

4.2. Hydrocarbon products

It is know that the characteristics of the reservoir are the main driver (On the decision to develop or not, on the specification of the concept and engineering, etc.) for the field develop. Those characteristics for example, will determine the type and fractional amount of the mixture of products to extract.

Hydrocarbons are not homogeneous when they are found in the subsoil. The considerable variations of the hydrocarbons in color, gravity, aroma, sulfur content and viscosity are common in petroleum from different geographical areas and even from reservoir to reservoir.

All the hydrocarbon reservoirs will differ from any others in its contents of hydrocarbons compounds and associated substances. The hydrocarbons can range in physical state from solids to gasses with water and sand as well as other impurities such as sulfur, oxygen and nitrogen.

The classification of the hydrocarbon products is based on its chemical composition. Lighter hydrocarbons (those with molecules with a small number of atoms of carbon) are usually gasses when are extracted and stay at normal atmospheric conditions.

The definitions of Odland (Odland, 2000-2008) regarding the different products that can be processed from the reservoir mixtures are reproduced below; the figure 4.1 shows the relation of the different products with the number of atoms of carbon predominant in the hydrocarbon substance:

- ***Petroleum*** *is a collective term for hydrocarbons, whether solid, liquid or gaseous. Hydrocarbons are compounds formed from elements hydrogen (H) and carbon (C). The proportion of different compounds, from methane and ethane up to the heaviest components, in a petroleum find varies from discovery to discovery. If a reservoir primarily contains light hydrocarbons, it is described as a gas field. If heavier hydrocarbons, it is called an oil field. An oil field may feature a gas cap above the oil and contain a quantity of light hydrocarbons in solution - also called associated gas.*

- ***Crude oil*** *includes condensate and natural gas liquids. Most of the water and dissolved natural gas have been removed.*

- ***Condensates*** *means the heavier natural gas components, such as pentane, hexane, iceptane and so forth, which are liquid under atmospheric pressure - also called natural gasoline or naphtha.*

- ***Natural gas*** *means petroleum that consists principally of light hydrocarbons. It can be divided into:*

    - ***lean gas****, primarily methane but often containing some ethane and smaller quantities of heavier hydrocarbons (also called sales gas) and*
    - ***wet gas****, primarily ethane. propane and butane as well as smaller amounts of heavier hydrocarbons; partially liquid under atmospheric pressure.*

- ***LNG*** *means* ***Liquefied Natural Gas*** *lean gas – i.e. primarily methane- convened to liquid form through refrigeration to -163C under atmospheric pressures.*

- ***LPG*** *means* ***Liquefied Petroleum Gas*** *and consists primarily of propane and butane, which turn Liquid under a pressure of six to seven atmospheres. LPG is shipped in special vessels.*

- ***Naphtha*** *means an inflammable oil obtained by the dry distillation of petroleum.*

- ***NGL*** *means* ***Natural Gas Liquids*** *light hydrocarbons consisting mainly of ethane, propane and butane which are liquid under pressure at normal temperature.[Odland, P.p. II "Miscellaneous term", Hard copy compendium, 2000-2008].*

Additionally there is an alternative post processed product known as ***GTL (Gas to liquids)***. Gas to liquids refers to a refinery process to convert natural gas or other gaseous hydrocarbons into longer chained hydrocarbons such as gasoline or diesel fuel.

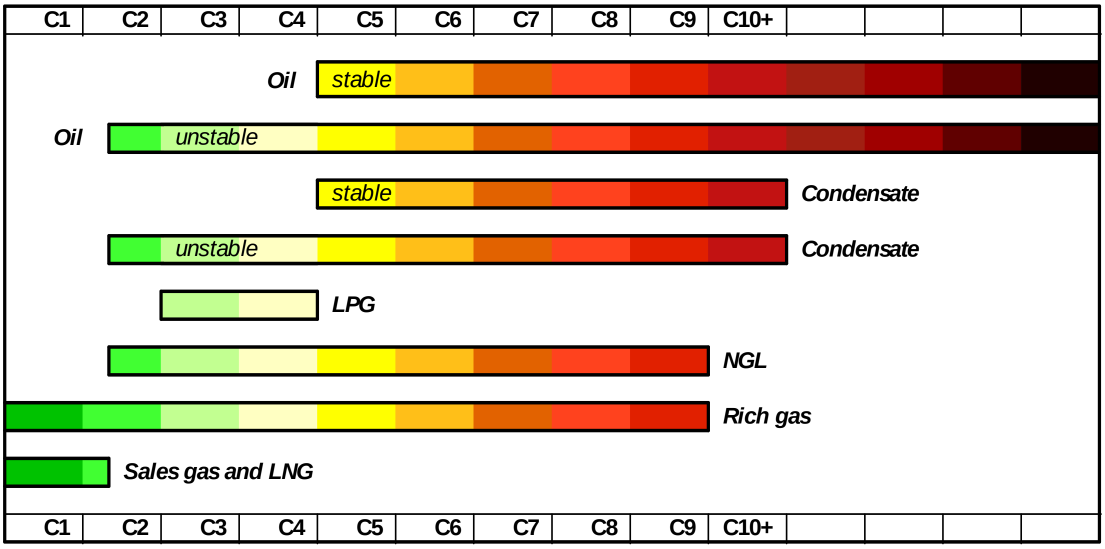

Figure 4.1: Classification chart of hydrocarbons and sales products [Odland, P.p. 12, Mod. 3 Petroleum resources and production, Class Notes...,2000-2008].

4.3 Value chain in oil and gas

The exploration and production of oil and gas has as main purpose to **"Extract (in a cost effective, efficient, safe and as environmentally friendly as reasonable) the hydrocarbons that rely in basins under the soil surface (either in land, fresh water bodies or in the seas) and transport, process and deliver the production to a market"**.

These previous facts are the basis to explain the term "value chain" that is going to be introduced in this section.

The value chain of oil and gas encompasses the chain of technological solutions that make possible to bring the hydrocarbon products from the reservoir to the final market. It is usually divided in Up-stream, Mid-stream and downstream.

Upstream in offshore, refers to the extraction and initial processing or stabilization to transportation located offshore.

Mid stream refers to the transportation and distribution networks of technologies and process that mobilize the products from offshore to onshore processing facilities or to distribution pipeline networks to market delivery.

Downstream, is mentioned to make reference to the refining and further transformation of the products received from the upstream and midstream steps.

The transportation issue is closely related to the products handled and it takes an important role determining the selection of the value chain elements that will be emplaced. The goal is to optimize the life cycle value creation along the entire value chain, from the reservoir to market

A field of oil plus an associated gas reservoir will have most of the possible products cataloged on the above list. Then, the handling options for the exploitation of these reservoirs would be as shown in the figure 4.2.

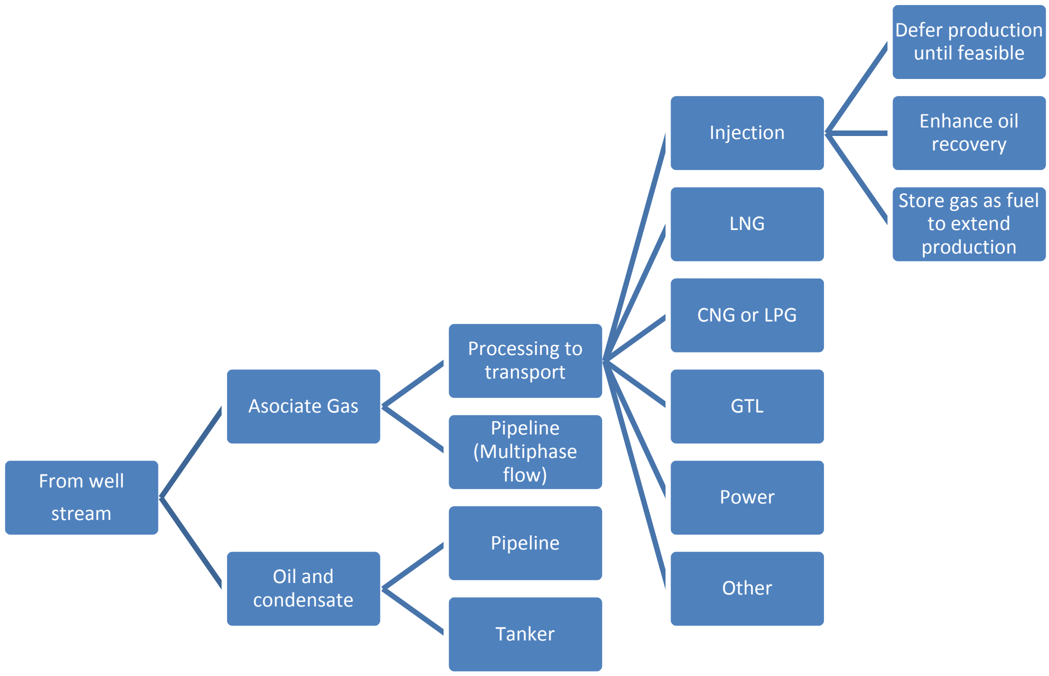

Figure 4.2: Products and handling options for a field of oil with associate gas.

The selection should in addition conciliate aspects entirely related to the production process such as type of hydrocarbons, geographic region, water depth, available existing assets and infrastructure, etc. There are also other non technical aspects, but not for that less important, that require attention.

There are many aspects not merely related to the hydrocarbon production that must be taken in consideration. One of the most important among them is the existence of different shareholders around any oil and gas project that can have many different points of view, reacting according to them instead of focusing on the value creation. In this case a careful analysis of the value chain would help to find and conciliate the shareholders interest.

4.4 Phases and decision gates planning the offshore field development

The field development is a sequential process that is carried out over several years. The figure 4.3 shows the main stages of it.

Figure 4.3: Stages of the field development.

Along each section of the field development until the start of the project execution there are several major decision gates that drive to the continuation or not of the investment. These decision gates are in place since the beginning of the pre-concession works. It is relevant for the scope of this work to extend the discussions of the first four stages:

- Pre-concession or prelease work
- Concession round
- Exploration
- Appraisal and development planning

Figure 4.4 shows the decision gates related to the pre-concession works, the concession round and the exploration of prospects.

In most of the world regions the process starts with the interest of an oil and gas company to explore a determinate region or section offshore.

Exploratory activities have as a goal to find accumulations of hydrocarbons that can be extracted in a profitable way. These activities conclude successfully after the drilling of a well that reach an accumulation of oil and gas o alternatively with a declaration of non commercial feasibility or in the worse case, failure to find hydrocarbons (a dry hole).

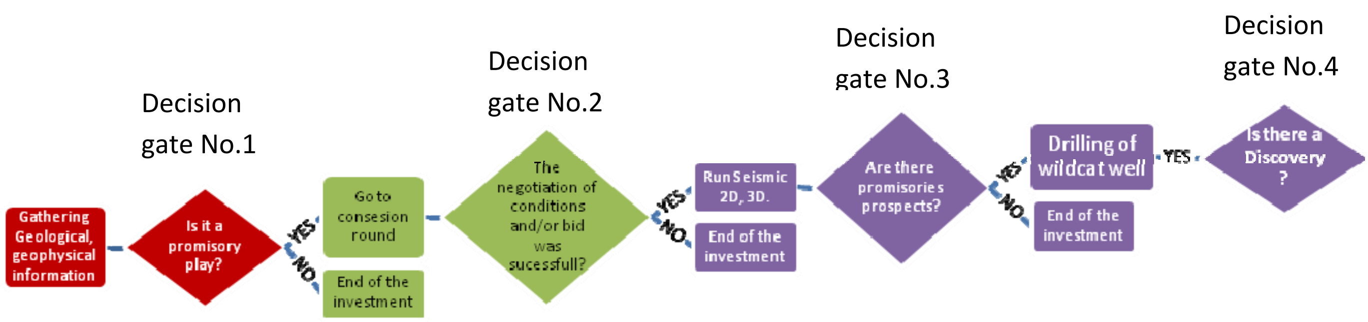

Figure 4.4: Decision gates related to the pre-concession works, the concession round and the exploration of prospects

Oil companies classify the level of maturity in the definition of areas likely to content hydrocarbon resources previous to the exploratory drilling, a set of commonly referred definitions after Magoon will be reproduced below (Magoon et al., 1999).

> ***Petroleum province**, a geographic term, is an area where petroleum occurs in commercial quantities. Basin is sometimes used geographically to mean petroleum province, such as the Williston Basin or Paris Basin. The Zagros fold belt could be a structural province or a petroleum province, not a basin.*
>
> *A map showing differential thickness of sedimentary rocks is used to determine basins (thick), uplifts (thin), and fold belts (folded). These features are properly named provinces; if they contain petroleum, they are called petroleum provinces. The use of "basin" in this context is improper; it is also inconsistent with the petroleum system concept described below, which defines "basin" as the area into which sedimentary rocks are deposited.*
>
> ***A sedimentary basin** is a depression filled with sedimentary rocks. The presence of sedimentary rocks is proof that a basin existed.*
>
> *The depression, formed by any tectonic process, is lined by basement rock, which can be igneous, metamorphic, and/or sedimentary rock. The basin fill includes the rock matter, organic matter, and water deposited in this depression. In certain cases, such as with coal and some carbonate deposits, the sedimentary material is formed in situ.*
>
> *The essential elements of a petroleum system are deposited in sedimentary basins. Frequently, one or more overlapping sedimentary basins are responsible for the essential elements of a petroleum system. Traps are formed by tectonic processes that act on sedimentary rocks. However, the moment petroleum is generated, biologically or thermally, a petroleum system is formed.*
>
> ***The petroleum system** includes the pod of active source rock, the natural distribution network, and the genetically related discovered petroleum occurrences. Presence of petroleum is proof that a system exists.*
>
> *The pod of active source rock is part of the petroleum system because it is the provenance of these related petroleum occurrences. The distribution network is the migration paths to discovered accumulations, seeps, and shows. In contrast to the play and prospect, which address undiscovered commercial accumulations, the petroleum system includes only the discovered petroleum occurrences. If an exploratory well encounters any type or amount of petroleum, that petroleum is part of a petroleum system.*
>
> *The play and prospect are used by the explorationist to present a geologic argument to justify drilling for undiscovered, commercial petroleum accumulations. **The play** consists of one or more geologically related prospects, and a **prospect** is a potential trap that must be evaluated by drilling to determine whether it contains commercial quantities of petroleum. Once drilling is complete, the term "prospect" is dropped; the site becomes either a dry hole or a producing field.*
>
> *The presence of a petroleum charge, a suitable trap, and whether the trap formed before it was charged are usually involved in this evaluation. These terms are compared in the table* 4.1. *[Magoon et al., P.p. 24-25, 1999].*

Item to be Compared	Sedimentary Basin	Petroleum System	Play	Prospect
Investigation	*Sedimentary rocks*	*Petroleum*	*Traps*	*Trap*
Economics	*None*	*None*	*Essential*	*Essential*
Geologic time	*Time of deposition*	*Critical moment*	*Present day*	*Present day*
Existence	*Absolute*	*Absolute*	*Conditional*	*Conditional*
Cost	*Very low*	*Low*	*High*	*Very high*
Analysis	*Basin*	*System*	*Play*	*Prospect*
Modeling	*Basin*	*System*	*Play*	*Prospect*

Table 4.1 Comparison of area concepts in exploration [Magoon et al., P.p. 25, 1999]

4.4.1 Pre-concession or prelease work

At the stage of the pre-concession or prelease works the oil companies should gather and evaluate geological information of the play´s area and negotiate or present an offer in a public bid considering the royalty and tax conditions that will govern the future value of the area to explore. Usually the oil companies are understood to pay the cost and assume the risk of these gathering of information.

A set of technical and economical disciplines is used for the analysis of the information gathered, it should be understood that those technical and economical disciplines are not going to be used at one single time but will be constantly updated according to the delimitation of prospects for exploration advance. Lewell shows graphically an approach of the interactions of disciplines for the Prospect de-risking that illustrate the above expressed, see figure 4.5.

The stratigraphycal analysis, structural geology and seismology correlations help to understand the geological data, including maps, cross-sections, electric logs, and seismic surveys. Furthermore, the reservoir geology deals with the relationships between paleo-environmentalg interpretations and the practical application of these interpretations to field development. All those science resources are quite sophisticated nowadays, but we must be aware of their associate's uncertainties in geological and geophysical data/interpretation.

Reservoir characterization and modeling allow advanced interpretation and recognition of the geological data which make them easier to be presented for evaluation to the integrated asset teams in charge of the development plans.

The volumetric analysis will help to understand and realistically evaluate economically the geological data and its interpretation. Analyst also should be aware of how geological data impact decisions made during production of a field (Well planning, reservoir appraisal, field development concept, uncertainty analysis).

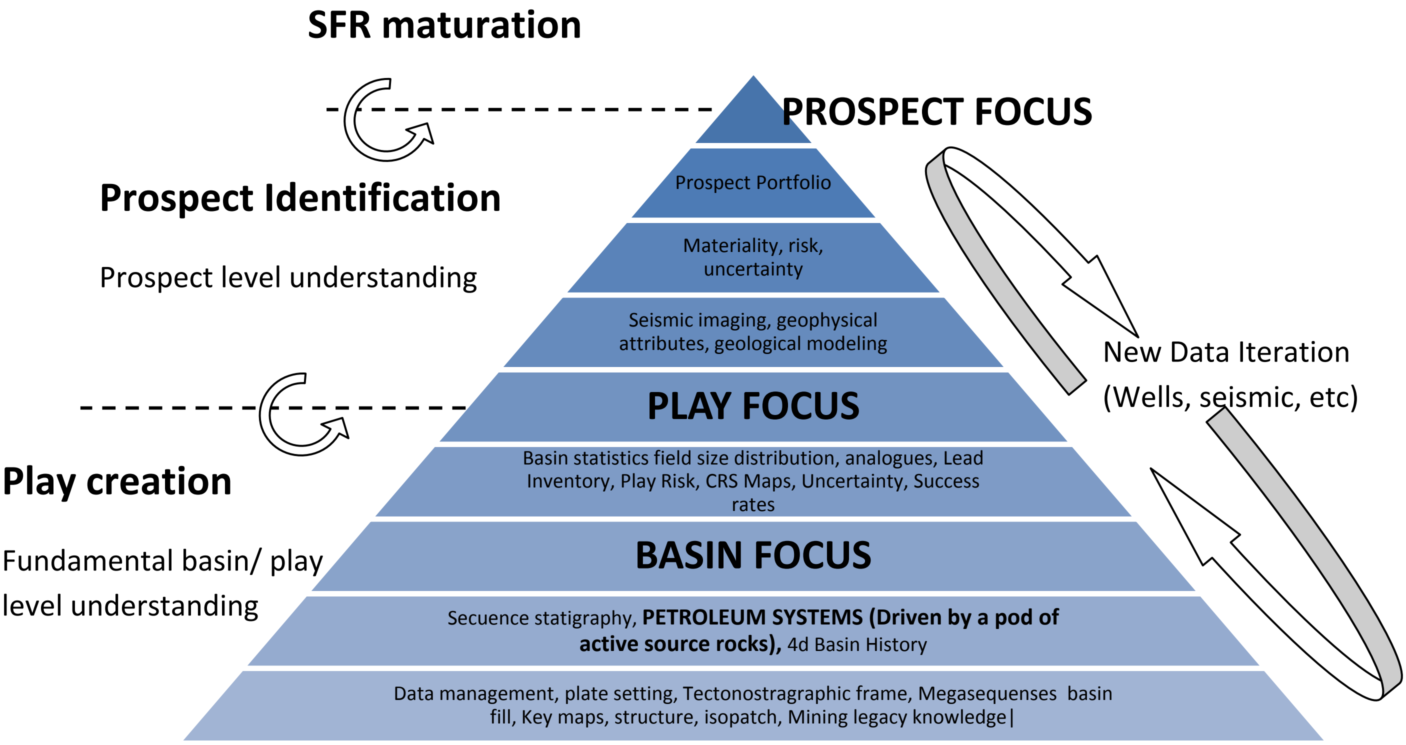

Figure 4.5 Interactions of disciplines for the Prospect de-risking *[Lewell, P.p. 11, 2009]*

After the evaluation of the prospects and the play, Oil companies should be able to identify whether or not it is interesting to engage in a exploratory commitment and even to start with a drilling exploration program and in this way to pass the first, second and third decisions gates shown in figure 4.4.

At the early stage of maturation of the projects is common that different companies get together in a coordinate association to develop a specific field. The aim of these associations is to take advantage of the particular technological, organizational, political or financial strength of the companies that will diminish the risk for the others, making possible to develop a field. Another reason can be to integrate neighbor's exploration license areas that have been proven and that where initially assigned to different companies.

In any case a conjunction of companies will be leaded operatively by one of them that will be knew as the "operator company" other companies will be then knew as the partners. The operator is not necessarily the main partner in relation to the capital invested, however is a common practice that the operator has a substantial participation to encourage the interest in good results in the project.

Another important aspect in these associations will be the decision making process that must be characterized by transparency and agreement among the parties.

4.4.2 Concession round.

The oil companies must evaluate in this stage both technical and economical aspects of the exploration ventures. Besides the geological risks the relevance of the tax systems in the profit results must be assessed because different tax systems might drive whether there is a commercially successful discovery or not.

The oil and gas resources contained in the subsoil are entitled to be property of the nation in where these accumulations of hydrocarbons rely, with some exemptions like in the USA where a particular owner of the land is also entitled to have rights over the subsoil. The exploitation of those resources however is in the hands of oil companies, either of national, private or mixed shared ownership.

Despite some countries have National Oil Companies that operate in their own countries with monopoly practices, they are more the exception than the rule. The most of the producing countries have emplaced ***Fiscal Systems*** in order to ensure the collection of cash flow from the oil and gas ventures.

A particular analysis of those systems should be emplaced for each country or even each province or state because the set of laws and codes are different according to the geographical location of the facilities and resources. Nevertheless, it can be listed four mechanisms that the States can use to get benefits from the exploitation of resources, either emplacing all of them or just partially and with or without operative participation through National oil companies (Masseron, 1990).

- **Cash Bonus:** Is a form of initial payment of the company that wants a permit to do exploration. The amount can be specified by law or can be subject to negotiation. The contracts establish an initial payment that is usually done when the concession is granted and also can include a series of further payments as the time passes. The payment is irrespective of the results of the exploration activities.
- **Annual Rental:** A yearly payment to the owner of the land and the rights of exploitation of its subsoil. This payment is also not dependant of the results of the exploration activities.
- **Royalties:** A payment in exchange of the rights of exploitation due once the first oil is extracted. It can be in cash or in petroleum products and is set according in a percentage (around 12%-15%) of the planed rate of exploitation that might be adjusted on the view of the actual production.
- **Income Tax:** The proportional taxes that all countries impose to commercial activities (around 50% in average for oil and gas activities).

The governments as a general rule might use the above elements in two main ways to tax the oil and gas extraction:

1.) Concession agreements. See figure 4.6 for a example of distribution of expenses and income along the life cycle of the field development with this tax system.

2) Production sharing agreements. See figure 4.7 for a example of distribution of expenses and income along the life cycle of the field development.

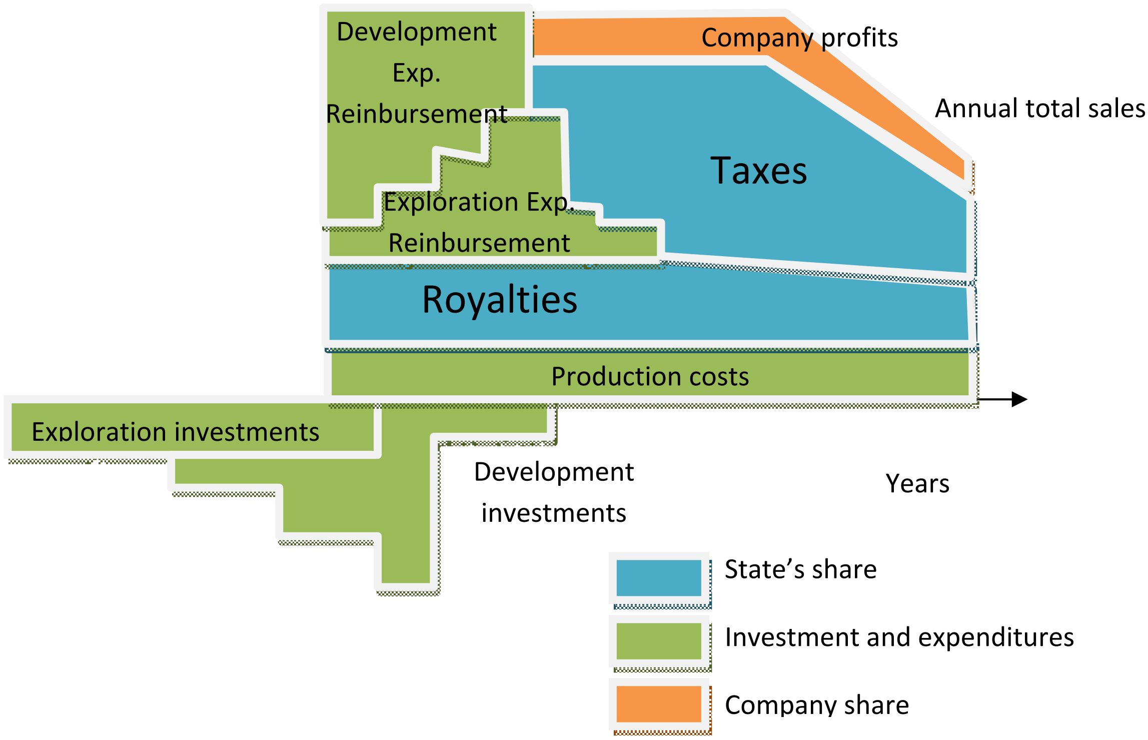

Figure 4.6 Cash flow distributions in standard concession agreements [Masseron, P.p. 137, 1990]

In this work is not intended to explore this important aspect of the economical evaluations, it is however recommended to review the following documents as a way to understand with more clarity the aspects related to tax systems for the decision making of both oil companies and governments.

- Fiscal System Analysis: Concessionary and Contractual Systems used in Offshore Petroleum Arrangements (Kaiser and Pulsipher, 2004).
- Fiscal systems for hydrocarbons : design issues (Tordo, 2007).

4.4.3 Exploration activities

The exploration activities follow an extensive process to increase the probability of success, is common that the exploration drilling is preceded of many seismic surveys and analysis previous to be approved. The most important and costly activity is drilling, which marks the success or failure of the value chain until this point, success in case that there is enough oil and gas to be commercially feasible develop, failure in case that it is found a “dry hole”, and stand by in case the finding is not commercially feasible at the moment but could be exploited in the future due to technological improvement.

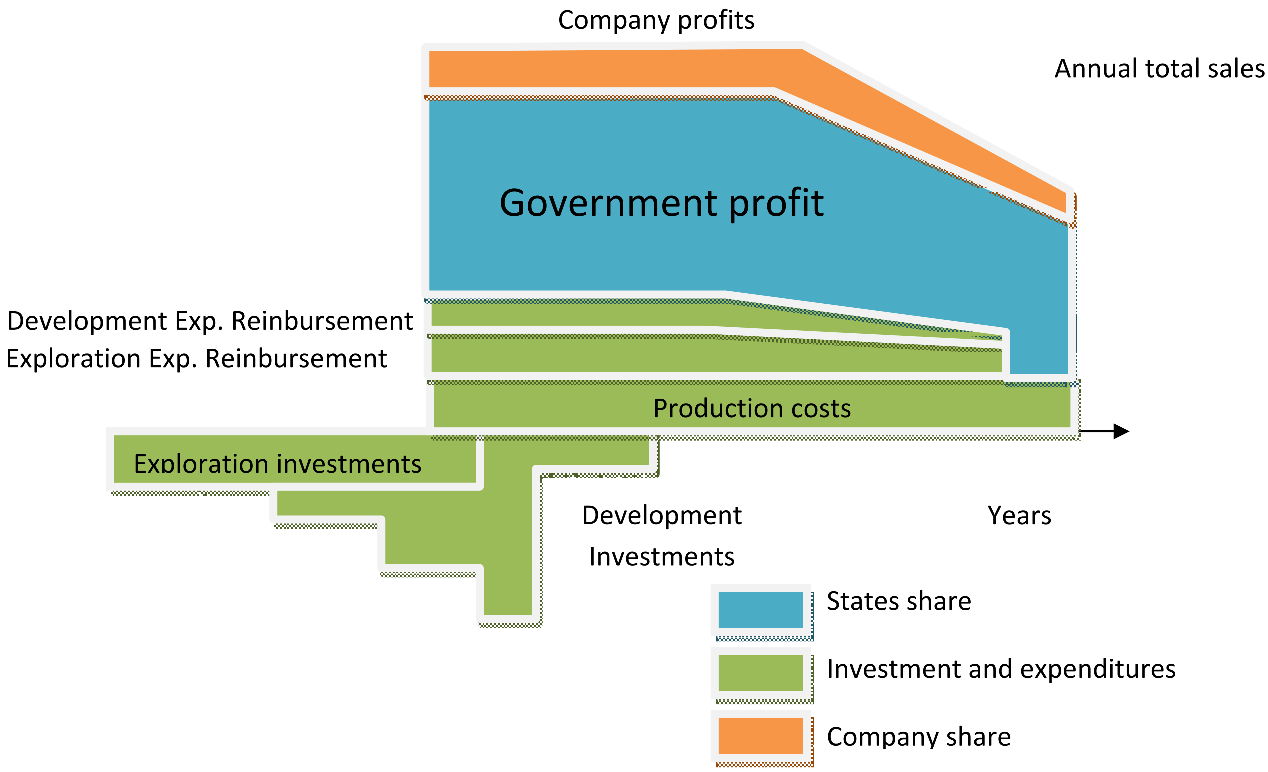

Figure 4.7 Cash flow distribution in standard production sharing agreement [Masseron, P.p. 137, 1990]

The main economical trigger of exploration drilling and consequently of the most of the investment expenditures in exploration is the price of the oil. As an example is suggested to take a look in annex D. Annex D shows an empirical study on the drivers of the investment activity in Norway.

In this annex D was intended to identify which are the factors that drive the level of petroleum investments in exploration. It was also proposed to explain how and in which magnitude those factors influence the investment decisions with basis in an econometric analysis using statistical inference on available data of the Norwegian Continental Shelf.

It was found that the exploration investments level is driven mainly by only one explanatory variable available in the originally considered data set, the oil price. It was also found the existence of a positive correlation between the level of investment in exploration and the oil price that improves as it is employed a lagged distribution of the explanatory variable.

It is inferred then that the increment in one dollar in the price of the barrel of oil induce approximately an investment of 26 Million NOK to be realized two quarters after the change in the price is effective and 11 Million NOK and 26 million NOK to be perceptible tree and four quarters after the price is adjusted.

4.4.4. Appraisal and development planning

Once it was proven a commercial discovery it is recommended to the oil company to proceed to develop an appraisal drilling program that will provide of information needed for an effective development plan. It is a bargaining situation to balance the cost-benefit of the investment in this appraisal program. Figures 4.8 and 4.9 show the decision gates related to the appraisal and early development planning for a field development.

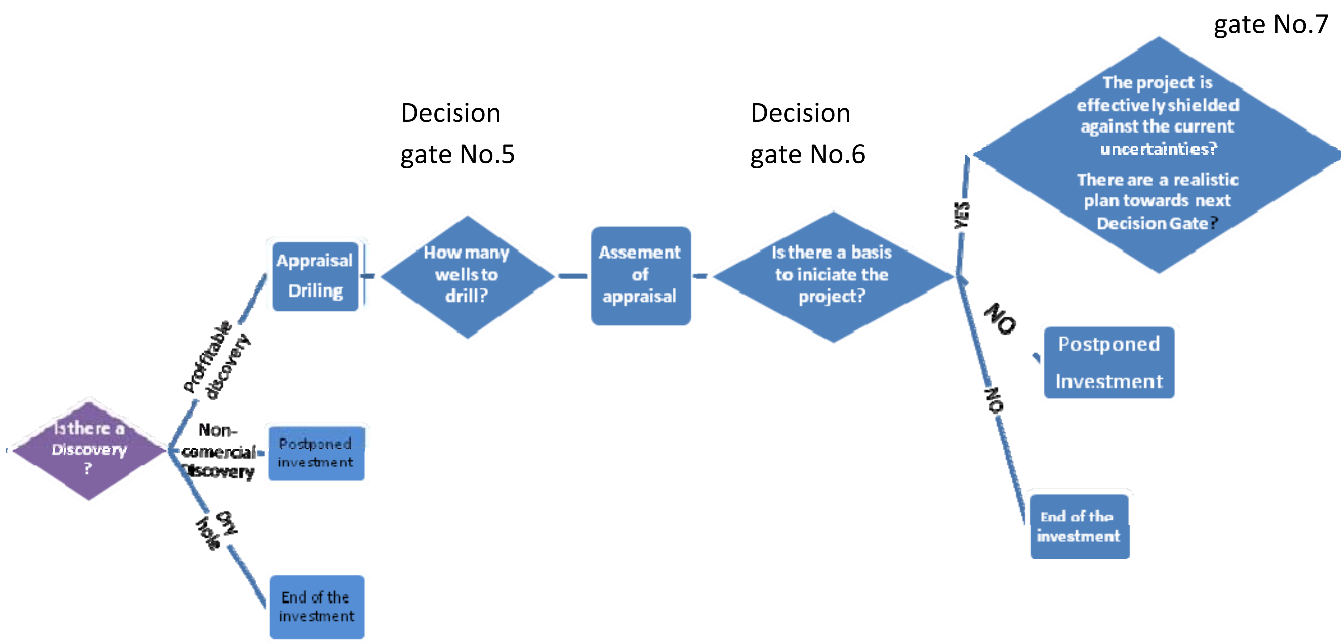

Figure 4.8: Decision gates related to appraisal and early development planning.

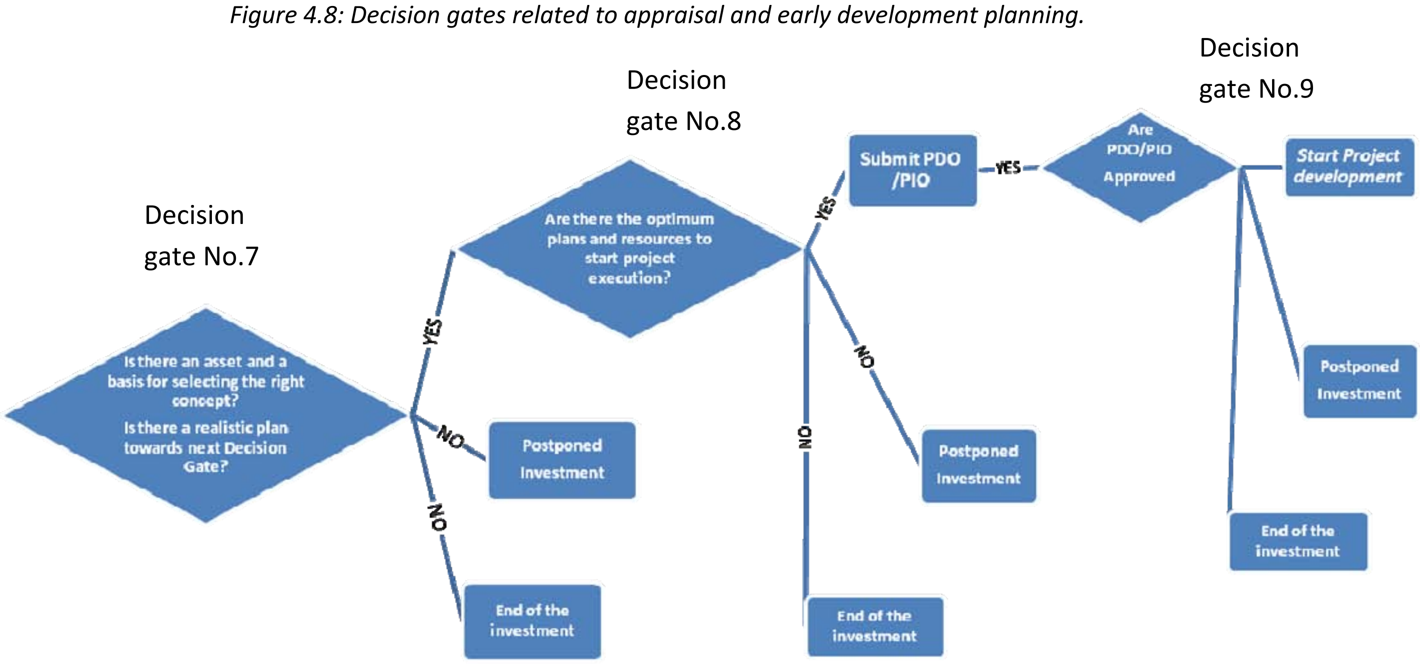

Figure 4.9: Decision gates related to early development planning.

The stage of the early development is discussed in an extraordinary clarity in the "Introduction to development of a petroleum installation" (Coker J.W.A. and Gudmestad, 2003), although it is discussed in the frame of the company Statoil and the Norwegian continental Shelf it is suitable to be reproduced below, due its high value added and correspondence whit the topic here explained. Below the excerpt from [Coker J.W.A. and Gudmestad, P.p. 11-23, 2003].

Once the exploration has proven a finding of hydrocarbons suitable for commercial exploitation the Investment projects are divided into two periods, the project planning and the project execution, see figure 4.10.

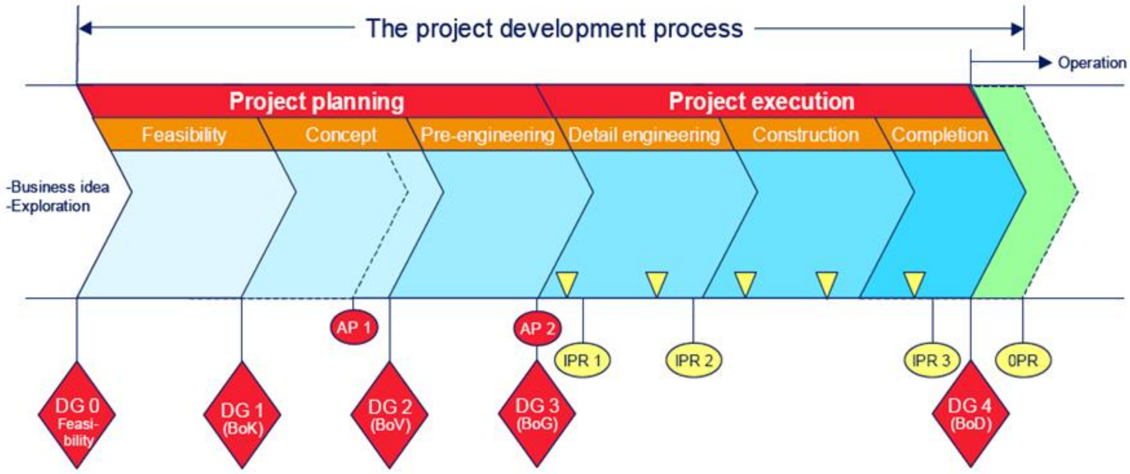

Figure 4.10. The project development model for investment projects with phases and decision gate, figure 7 in [Coker J.W.A. and Gudmestad, P.p. 12, 2003]

The outcome of the planning stage is the decision to initiate the project execution. The successful completion of the project execution conducts to the start of the production operations. Both periods are divided in phases with identifiable purpose and results.

It is proposed to define five decision gates (DG) *[for this work, it will be described only the first three of the mentioned literature]*, established at milestones to review the status of the project progress to be able either to terminate, continue the project or to implement important changes. This decision gates coincide with transition steps in the projects and also approval points (AP) are defined in order to take major decisions. The process of the project development must flow smoothly from the feasibility assessment to the start-up despite is divided in phases.

The planning period.

Is an assessment period is aimed to make clear if a business opportunity that satisfy the expectations of the oil company in profitability, HSE and technical feasibility can be development despite of the uncertainties. This assessment must be systematic and inclusive of the viable range of concepts and should deliver a selected concept to develop.

It consists of three phases:

- **Feasibility**, which conclude in DG 1 (Coker J.W.A. and Gudmestad, 2003) and in decision gate No. 6 in this work, see figure 4.9.

- **Concept,** which conclude in DG 2 (Coker J.W.A. and Gudmestad, 2003) and in decision gate No. 7 in this work, see figure 4.9.
- **Pre-engineering**, which conclude in DG 1 (Coker J.W.A. and Gudmestad, 2003) and in decision gate No. 8 in this work, see figure 4.9.

*The main purpose of the **feasibility phase** is to establish and document whether a business opportunity or a hydrocarbon find is technically feasible and has an economic potential in accordance with the corporate business plan to justify further development. The feasibility phase is initiated at DG 0 with a project agreement that defines the task, goal, framework and budget. The feasibility phase leads to decision gate DG 1, "Decision to start concept development" (BoK). [Coker J.W.A. and Gudmestad, P.p. 12, 2003].*

*The purpose of the **concept phase** is to provide a firm definition of the design (resource and product) basis and to identify all relevant and feasible technical and commercial concepts. Further to evaluate and define the selected alternative (preferably one) and confirm that the profitability and feasibility of the business opportunity will be in accordance with the corporate requirements and business plans. The concept phase leads to the selection of the concept(s) (AP1) to be further developed up to decision gate DG 2, "Provisional project sanction" (BoV). [Coker J.W.A. and Gudmestad, P.p. 15, 2003].*

*The purpose of the **pre-engineering phase** is to further develop and document the business opportunity based on the selected concept(s) to such a level that a final project sanction can be made, application to authorities can be sent and contracts can be entered into. The preengineering phase leads to approval point 2 (AP2), "Application to the authorities", and to decision gate 3 (DG 3) " Project sanction" (BoG). [Coker J.W.A. and Gudmestad, P.p. 19, 2003].*

An additional point is the submission and approval of the plan of development and the plan of installation and operations. Coker and Gudmestad (2003) explain this point as Approval point 2, here corresponding to the Decision gate No. 9. See figure 4.9.

Approval point 2 (AP 2), "Application to the authorities"

The project shall compile and prepare for submittal of the necessary application(s) for approval of the facility development in accordance with the relevant laws and regulations. It is particularly important to have undertaken an analysis to determine which requirements apply.

For projects within the jurisdiction of the Norwegian Petroleum Act, a "Plan for development and operation" (PDO) (Norwegian: PUD) or a "Plan for installation and operation" (PIO) (Norwegian: PAD) is required. The PDO / PIO shall be prepared in accordance with the document "Guidelines for PDO and PIO", issued by the Norwegian Petroleum Directorate. The PDO / PIO shall be approved by the responsible business unit, corporate management (KL), the board and the partners, before it is submitted. When the partnership submits a PDO / PIO to the authorities, this represents a commitment by the partnership to carry out the project development. For projects in this category, completion of the PDO / PIO and DG 3 (BoG) should occur at the same time. [Coker J.W.A. and Gudmestad, P.p. 21, 2003].

Annex C shows the summary of requisites, activities and products for each of the phases of the development planning.

The commitment to use specific technology and configurations, the set up of performance and cost are determined in the early stage of conceptual design, consequently as the project advance the ease of change in the concept become much more difficult and the cost incurred due change of mind increase considerably. The figure 4.11. shows the relationship with the project phases and the cost, easiness of change and technical issues for a project developed according to the model presented in figure 4.10.

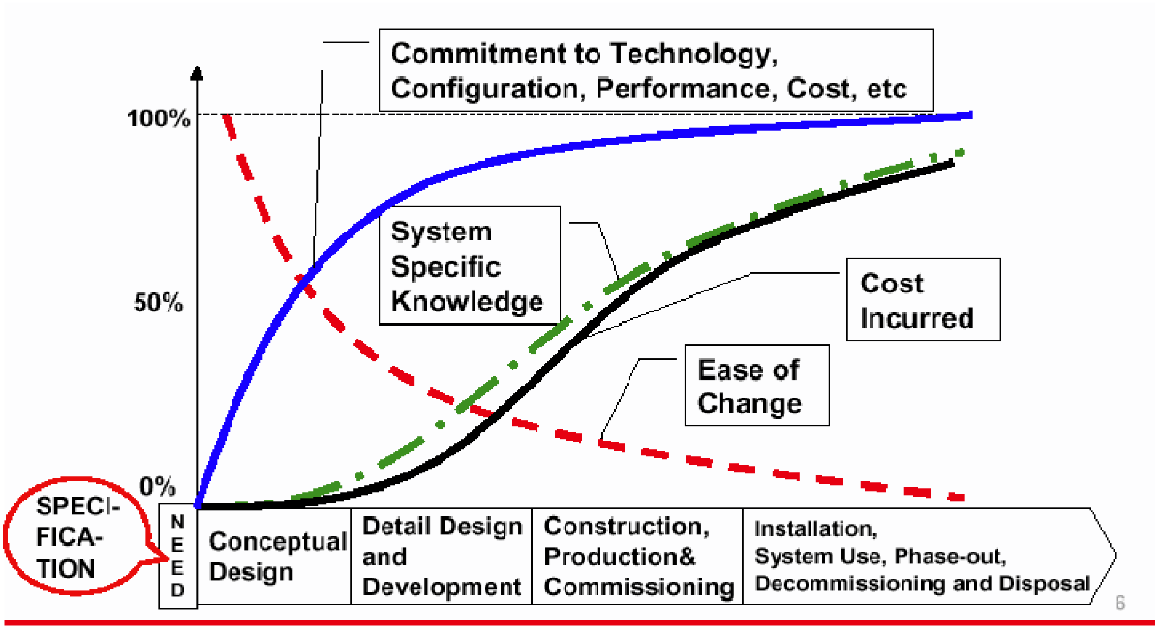

Figure 4.11 Summary of relationships between project phases and cost, change easiness and technical issues, Figure 8 in [Coker J.W.A. and Gudmestad, P.p. 23, 2003)

5. Concept Selection and Life Cycle Cost

5.1 Concept selection purpose and organization

A concept is a business case documenting an option for the development of an oil and gas field. The basis is technical information with a relatively accurate economical forecast. Odland (Odland, 2000-2008) offers the following definitions see chart 5.1.

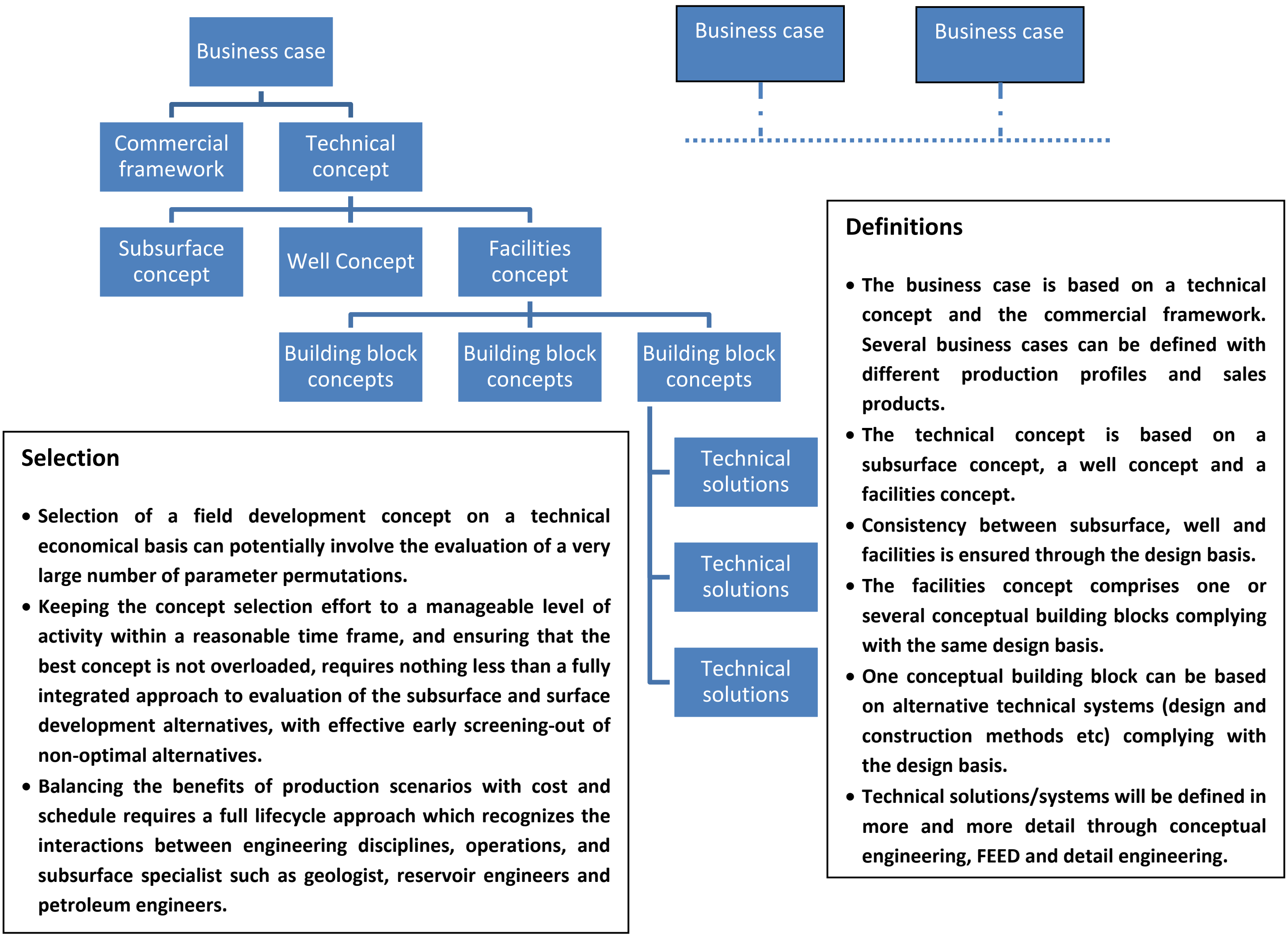

Chart 5.1. Definitions of concept selection [Odland, Chapter 7, P.p. 20, 2000-2008]

Continuing with the information shown in the Chapter 4 and Annex D, the concept stage has as purpose:

> *… provide a firm definition of the design (resource and product) basis and to identify all relevant and feasible technical and commercial concepts. Further to evaluate and define the selected alternative (preferably one) and confirm that the profitability and feasibility of the business opportunity will be in accordance with the corporate requirements and business plans. The concept phase leads to the selection of the concept(s) (AP1) to be further developed up to decision gate DG 2, "Provisional project sanction" (BoV).*

Different sources of literature, for example (Karsan, 2005) also relate the "Front End Loading (FEL)" processes, these are defined as all the activities that precede the start of the basic design phase and these should deliver:

- A well defined field development plan.
- Basis for conceptual design.
- Configuration of the field as well as conceptual drawings of major components of the development.
- Concept cost estimate +/- 40%.

Ignoring small differences it will be assumed that the ***concept stage*** is not different from the ***FEL***, along this work and hence It will not be a differentiation of both terms hereby.

The concept stage is generally by a group of multidisciplinary senior staff with expertice in both technical as well as economical issues. For the demanded flexibility and rapid response it is recommended to handle a flat and hands on organization dedicated to this task. Figure 5.1 shows a suggested organization.

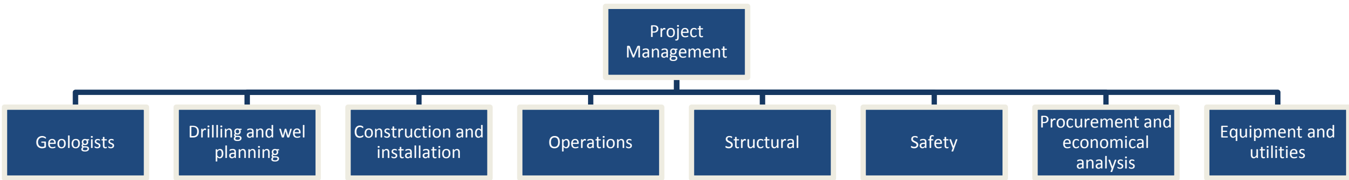

Figure 5.1. Suggested organization to develop a concept selection for a field development.

5.2 Factors influencing the concept selection.

The concept selection is developed as an spiral at the beginning with a high level of uncertainty and high requirements of flexibility that are being refined and narrowed as the process advance. Figure 5.2 and table 5.1 list some of the main issues that must be addressed when the concept of development is being chosen. (Karsan, 2005).

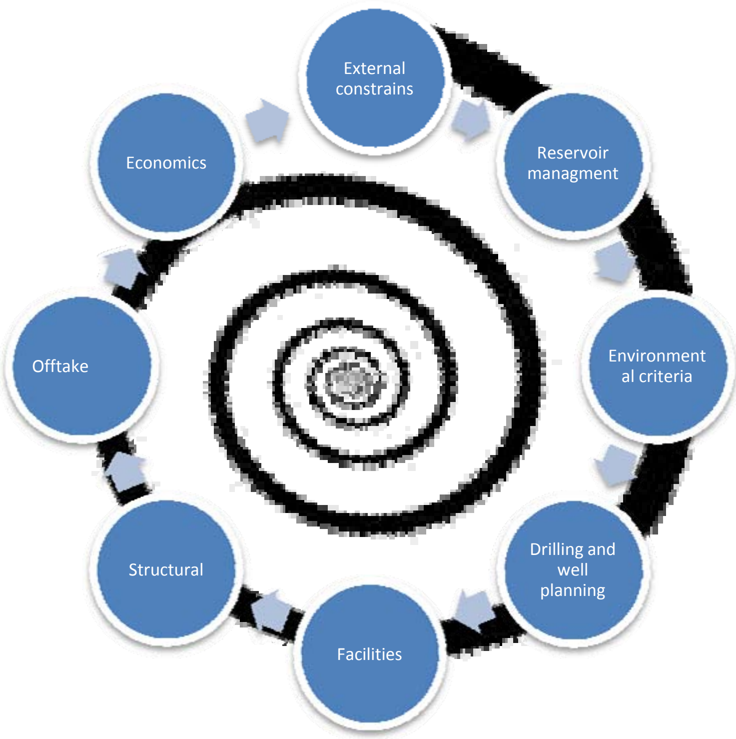

Figure 5.2. Design spiral in the offshore field development (Karsan, 2005)

External constrains	***Reservoir management***	***Environmental Criteria***	***Drilling and Wells plan***
Government regulations	*Mapping and reserves estimates*	*Meteorological*	*Casing size and sequence.*
Company and partners policies/goals	*Well tests and fluid properties*	*Oceanographic*	*Directional design*
Industrial design codes	*Modeling and development scheme*	*Geotechnical*	*Rig Selection*
	Bottom hole locations	*Biological*	*Completion and workover*
Facilities	**Structural**	**Offtake**	**Economics**
Oil/gas processing	*Floaters*	*Metering*	*Cost/Schedule*
Injection	*Subsea template*	*Pipeline*	*Risk*
Accommodation and logistics		*Tanker*	*Project strategy*
		Storage	*Operating plan*

Table 5.1 Elements of the spiral design in the offshore field development in deep water.

The elements that are in a close interaction with the production process are pointed:

1. Reservoir management (Subsurface concept).
2. Well systems features (Well concept).
3. Facilities (Facilities concept).

Cited by Karsan, Morrison (Morrison, 1997) proposes figure 5.3. That shows the drivers affecting those three elements.

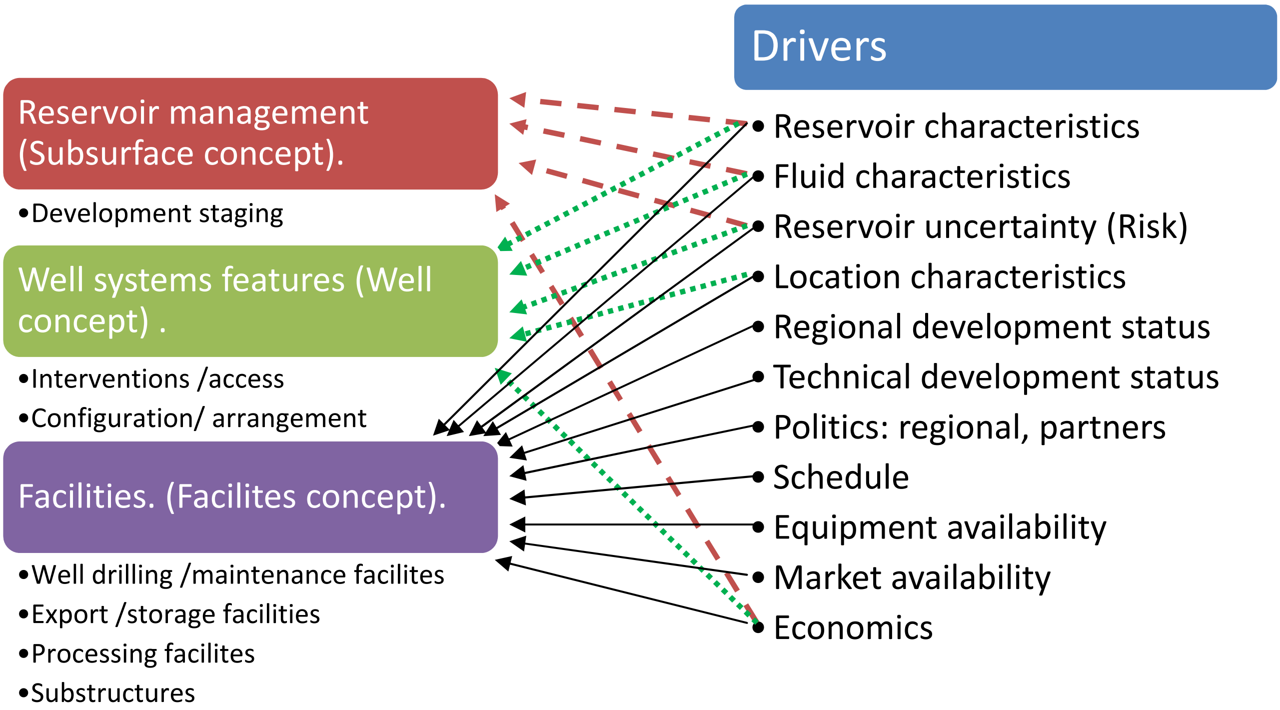

Figure 5.2. Factors that drive field development selection (Morrison, 1997)

5.2.1 Reservoir characteristics

The main driver of any field development is found down hole. Among some of the important facts that are needed it is necessary to have the most detailed picture of the following aspects:

5.2.1.1 Size of Field and complexity of the reservoir

These parameters will interact with the fluid characteristics to determine the optimal number of wells. The number of wells will increase when the reservoir becomes larger and also when is more fragmented (or complex, see also 7.2) since it will require more depletion points to keep a required recovery factor.

The drilling of those wells has a major impact on the facility selection. As more wells are required the larger the topsides should be considered. Dry tree solutions will need more load capability from the substructure than the wet tree solutions.

If the field is extremely fragmented and the depletion points are distant or have difficult access trough directional drilling, the best option becomes the subsea completion that will require straight and simpler drilling.

On the other hand, a clustered set of depletion points will be favorable for a single central structure, possibly with a rig package included, this will save the appointment of a semisubmersible rig for well maintenance and work over, particularly expensive in deep water scenarios (Stiff and Singelmann, 2004).

Odland (Odland, 2000-2008) also mentions that in case of larger fields it might be reasonable to think of the development as made up of several hub structures. More than one major structure in the field will open the possibility of increased recovery factor, more options for handling and transport of the hydrocarbons as well as risk and reliability robustness.

5.2.1.2. Expected Production Rate

As a result of a big and pressurized reservoir a high production rate can be foreseen. This will need more processing equipment leading to higher loads in the topsides. It will be necessary also larger export facilities. The concept will need consequently much more capacity for space and weight. The balance between produce at high rate or undersize the facilities must be assessed in this case. *(Stiff and Singelmann, 2004)*

5.2.1.3. Quantity of Gas and pressurization

A high pressure field with a relatively high content of gas leads to increasing need of processing equipment. Small fields might not be economical to exploit if the only solution is a large floating structure with capability to process the gas, in this case the subsea solutions become an attractive concept to study (Stiff and Singelmann, 2004).

Several options for handling of gas can be reviewed in the MMS study "Technology assessment of alternatives for handling associated gas produced from deepwater oil developments in the GOM" (Ward et. al., 2006).

5.2.1.4 Length of field life

Another aspect is the influence on the decommissioning considerations since some concepts such as SPAR's, production semisubmersibles and FPSO's can be reused when a field is exhausted. On the contrary, a TLP will represent a complex scenario for its relocation (Stiff and Singelmann, 2004).

Odland (Odland, 2000-2008) also points out that in small field developments it might be an option for the operator companies to establish leasing agreements instead of commit to the construction of the production assets.

5.2.2. Fluid characteristics

5.2.2.1 Type of Crude

The subsea concepts are the best solution when it is anticipated that the wells will have low workover / interventions requirements and a high-quality flow assurance (Dry gas reservoirs, free of parafins, etc.) The solution for complex flow assurance might involve the use of chemicals and other technologies, but they might be cost prohibitive (Stiff and Singelmann, 2004).

5.2.2.2. Need for Workover and Intervention.

All the types of wells will eventually require some kind of maintenance; they can be from a simple i***intervention*** (for example a coil tubing operation) to full ***work over*** (recompletion) procedure to hit a different pay zone.

Nergaard (Nergaard, 2009) gives a definition of the two terms and explains their purposes as:

Workover: The term is used for a full overhaul of a well. It reflects the full capacity to change production equipment (tubing etc) in the well as well as the Xmas tree itself. This implies the use of a rig with fullbore BOP and marine riser. This means the we have to apply the same capacity systems as used during initial completion of the well. Full overhaul/workover might imply a full recompletion of the well. Using a full capacity drilling/completion rig offers the full capacity for redrilling, branch drilling and recompletion. In some cases we see the full capacity WOI system referred to as Category C intervention: heavy well intervention.

Well intervention: This term is used commonly for all vertical interventions that is done during the wells production life, i.e. after initial completion. The term is most commonly used for the lighter interventions; those implying that operations take place inside and through the Xmas tree and the tubing. These are:

Category B intervention: medium well intervention, with smaller bore riser.

Category A intervention: light well intervention – LWI, through water wireline operations.

The purpose of the interventions is to increase the recovery rate and also as required:

- Survey – mapping status-data gathering.
- Change status (ex open/close zones – smart wells)
- Repair
- Measures for production stimulation.

When the facility has a drilling package on board, or the capability to install one, the cost of these well interventions become lower than in the subsea developments, where for the same operations a dedicated type of vessel must be appointed (a semisubmersible with a day rate of 500,000 USD per day for example). Light intervention vessels are available at a lower rate but with lower capabilities (Stiff and Singelmann, 2004).

5.2.3. Reservoir uncertainty (Risk)

Although oil companies invest a lot of time and resources in the de risking of their investments (See 4.4.2) there is a substantial risk that might be the result of a limited appraisal of the discovery. The best option in this case is to have a flexible concept designed to be able to adapt to possible resizing of the production rate as well as ability to accommodate more wells or supplementary process capability. These options, of course, have a cost that must be evaluated.

5.2.4. Location characteristics

5.2.4.1 Water Depth

The main driver in offshore is the water depth at the proposed site, it influences overall cost of the development and also restricts the number of possibilities. Ronalds (Ronalds, 2005) explores in the paper "Applicability ranges for offshore oil and gas production facilities" some key features and constraints of the ten common fixed, floating and subsea facility options that include, of course, water depth and some other drivers here mentioned. For an updated survey consult Wilhoit and Chan (Willhoit and Chan, 2009)

Facility	*No direct vertical well access*				*Direct vertical well access*				
	FPSO	*Subsea*	*Semi*	*Minifloater*	*Semi*	*TLP*	*Comp tower*	*Spar*	*Jacket*
First application	*1977*	*1961*	*1979*	*1998*	*1975*	*1984*	*1984*	*1997*	*1947*
Present maxima									
Water depth (m)	*1993*	*2934*	*2414*	*1425*	*576*	*1450*	*531*	*2382*	*126*
Well slots capability	*120*	*63*	*51*	*36*	*51*	*46*	*58*	*26*	*61*
Oil production capability (MBOE/d)	*317*	*412*	*352*	*317*	*283*	*366*	*277*	*154*	*253*

Table 5.2 Production facilities statistics with data of Willhoit and Chan (Willhoit and Chan, 2009).

5.2.4.2 Environmental conditions

Related to the area of interest of this work it is undeniable that hurricanes and tropical storms are commonly present in the Gulf of Mexico usually in the second semester of the year.

However, the conditions on Mexican sites are usually milder than those presented in the northern Gulf of Mexico because the paths of the hurricanes, are often directed to the north and the shield effect that produces on the side of the Yucatan peninsula weakens the strength of the hurricanes as they pass on firm soil.
Motivated by the effects of the hurricane seasons in 2004-2005, the American Petroleum Institute (API) released a document reevaluating the metocean conditions due the impact of the hurricanes. In this guidance are proposed changes due to the observed conditions that occured since the API RP2A were last updated. The document is available on the API web site with the code:

API BULL 2INT-MET
Revision / Edition: 07   Chg: Date: 05/00/07
INTERIM GUIDANCE ON HURRICANE CONDITIONS IN THE GULF OF MEXICO

It is likely to expect this kind of phenomena to be strengthened in the future years due to possible climatic changes.

5.2.4.3. Geotechnical conditions

A careful study is needed for the installation and decommissioning, a soft soil could be as risky as an extreme tropical storm and the combined effects might be catastrophic.

5.2.5 Regional development status

In a region like U.S. Gulf of Mexico an enhanced possibility to develop small fields exists, due its extensive networks of pipelines. The distance to the facilities is a major restrictive element to consider for small to medium field developments because of flow assurance issues; due to this reason a major content of gas in the production fluids has a longer reach to be exported.

The development of hub´s in any case might create the feasibility for further developments in an area. Even in the case of ownership of different companies it is possible to establish agreements to allow the transportation of crude per a transfer fee (Stiff and Singelmann, 2004).

5.2.6. Technical development status.

Sometimes the companies face options to develop fields by using new technologies. However, operator companies, either national or international usually prefer a conservative approach to the development and use of new technologies. This adversity change when the technology become proven, but still it would be necessary to implement effective programs for technology acquisition.

5.2.7 Politics

The governmental, corporative and industrial polices usually have the same weight as the technical and economical considerations. The governments may ask for the fulfillment of tariffs of local contents, restrictions on particular development options, health, safety and environment regulations, and even recovery factors like the NPD in Norway, see 7.2.

Corporate politics will be evident in the selection of specific development options because of the perception to have lower risk than others based on previous experiences of the operator. Also for the preference of contractors companies that are viewed as more reliable, even though those companies can offer just a limited pool of options where the best concept is not necessarily included (Stiff and Singelmann, 2004).

5.2.8. Schedule

The drilling strategy might have a powerful impact on the schedule to get the first oil. A company might save a lot of time running a partial or total pre-drilling program while they are constructing the floating structures and/or the subsea systems. Pre drilling in deep water means the appointment of semisubmersibles or drilling ships that will represent a considerable cost against the option of some floaters that might have the possibility to drill from the same structure. This drilling strategy of course is part of the decisions that must be analyzed in the conceptual stage.

5.2.9. Equipment availability

The heavy lift vessels are examples of scarce but unavoidable tools for some concept of field development. Hence the appointment of them become a fact of major importance when the concept is defined.

5.2.10. Market availability

The gas is the most representative example of one product that must have a mature market to make it feasible to commit a field development. In contrast to the oil that might be stabilized and transported by tankers to the market, the gas production needs to be delivered at a constant basis to a market because the storage cost of large amounts of product is extremely costly if technically feasible.

5.2.11. Economics

Practically in all the past examples the economics is part of the debate between one options or another.

5.3 Life Cycle Cost in concept selection processes

The economical analysis for field development are essentially Life cycle cost analysis, the minimum requirements are already suggested initially for the oil and gas industry by the Norwegian Standards (Norsok).

- O-CR-002 Life cycle cost for production facility (Rev. 1, April 1996)
- O-CR-001 Life cycle cost for systems and equipment (Rev. 1, April 1996)

Those standards were withdrawn in 2001 when the series ISO 15663 were published:

- ISO 15663-1:2000 Petroleum and natural gas industries -- Life cycle costing -- Part 1: Methodology.
- ISO 15663-2:2001 Petroleum and natural gas industries -- Life-cycle costing -- Part 2: Guidance on application of methodology and calculation methods.
- ISO 15663-3:2001 Petroleum and natural gas industries -- Life-cycle costing -- Part 3: Implementation guidelines.

The use of the LCC in most of the concept studies is limited to the Capital Expenditures (CAPEX) and Operational Expenditures (OPEX). Goldsmith (Goldsmith et. al., 2000) propose a much more ample spectra to calculate LCC including the risk and the reliability costs associated with the field development options. Below the methodology proposed by Goldsmith to estimate the lifecycle cost of subsea production systems [Goldsmith et. al., Sections 2.1-2.3.3, 2000].

2.1 Introduction

The economics of deepwater developments are different from shelf activities. Deepwater is characterized by high capital expenditures with relatively low operational expenditures and high sustainable production rates - hence high costs for production interruption.

Field development profitability is a function of many income and expense factors such as capital expenditures (CAPEX), operating expenditures (OPEX), production rate, product price and the frequency of completion component failures. Component failures reduce the field total production rate and increase intervention expenditures.

Until recently it was quite common for the decision making process used to evaluate deepwater ventures to focus on optimizing the balance between potential revenue, CAPEX and OPEX according to the equation:

$$Profit = Max\ (Revenue - CAPEX - OPEX) \quad (2.1)$$

The shortcoming in this equation is that it does not take into account unscheduled and unplanned events that have the potential to destroy a facility, tarnish a company's reputation, pollute the environment, and/or shut down production for a long time. Major accidents, although highly unlikely, have the potential to put a facility out of business for 3, 6, 12 months or even render it totally useless.

When moving into deeper water, the economic penalty for delayed/lost production becomes greater. The uncertainty related to whether "unforeseen" events will occur is also increased as prototype and novel technology are introduced into an operating environment not encountered in shallow water platform design. Furthermore, subsea well system repairs and interventions also become more expensive and are associated with longer delays due to reduced availability and increased mobilization times for the required repair vessels. The alternative to a subsea system, a dry tree tieback concept provides the efficiency and the convenience of direct well access, but requires the surface host to support the weight of permanently attached production/intervention risers for which the load cost penalty and the likelihood of a riser leak increases with water depth.

The implications of disasters and business interruptions should be incorporated into business decision analyses that seek to evaluate the viability of alternative designs. These analyses introduce two more components to the economic "balance", namely, risk expenditures (RISKEX[1]) and reliability/availability/maintainability expenditures (RAMEX[2]). It takes a balanced, mature appraisal of the uncertainties and risks involved when considering front-end cost savings (CAPEX) that may have detrimental consequences on initial, intermediate and long-term revenue streams.

Inclusion of an "unforeseen" RISKEX and RAMEX element into equation (2.1) modifies the economic model to:

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[1] *RISK Expenditures (RISKEX) are defined as the costs associated with the risks of a blowout. It is derived by estimating the frequency of the event and multiplying the frequency by the estimated cost (clean-up cost, outrage cost, asset damage cost and business interruption cost) for that event.*

[2] *Reliability/Availability/Maintainability Expenditures (RAMEX) are defined as the cost associated with lost revenues and interventions due to component failures.*

Profit = Max (Revenue - CAPEX - OPEX – RISKEX - RAMEX) (2.2)

The methodology is developed to permit predictions of lifetime cost for a field development based on statistical and judgmental reliability data and assumed system parameters. It might be asked "Why not simply estimate the lifetime cost for a field development rather than estimating all these input parameters?" The answers are:

• The system is broken down to a level where some experience data is available and where it is possible to evaluate failure modes and their corresponding effect on system level.

• The quality of the input data (reliability of completion string components, sand control system failures, subsea equipment, risers, individual well production profiles, rig availability time, rig spread costs, etc.) is independently evaluated to minimize bias.

• The methodology and spreadsheet tool "model" show the sensitivity to changes in specific input data that is not readily apparent otherwise.

• This model is especially useful to determine which parameters most influence field development cost. The quality of data for these parameters can then be scrutinized to achieve the maximum practical quality. Likewise, time is not wasted by attempting to improve the quality of data that are of minor importance.

• Sensitivity analyses can determine the financial incentive for improving reliabilities of components.

2.2 System Boundaries

The systems that can be analyzed by using the proposed methodology are typical highrate, deepwater well completion systems and cover both subsea well tieback and dry tree tieback concepts. A subsea well intervention has longer rig availability and mobilization time, is more sensitive to weather conditions, and is associated with higher day rates for the repair resource. However, all these parameters are part of the input data specified by the user.

The methodology includes:

Subsea: Downhole completion components, casing, wellhead equipment, subsea production trees, flowline jumpers, tie-in sleds, flowlines and risers (up to the boarding valve), subsea control module, control jumpers, subsea distribution units, umbilical termination assemblies, umbilicals, topside controls and chemical injection points.

Dry Tree: Downhole completion components, casing, wellhead equipment, risers, tensioners/air cans, surface production tree and manifold up to the 1st stage separation isolation valve.

For both concepts the well intervention equipment (risers, BOPs, controls, etc.) necessary to install and workover the completion equipment are included.

Examples of sand control systems considered by this project are frac-packs and horizontal laterals with gravel pack.

2.3 Life Cycle Cost Calculations

The CAPEX, OPEX and RISKEX occur during different times in the field-life. The net present value of future costs is used to take the time value of money into account. The lifecycle cost is calculated by:

where $OPEX_k$, $RISKEX_k$, $RAMEX_k$ represent the OPEX, RISKEX and RAMEX in year k respectively, r is the discount rate and N is the field-life in years.

The various cost elements are defined as follows:

CAPEX: Includes material cost and costs associated with installation

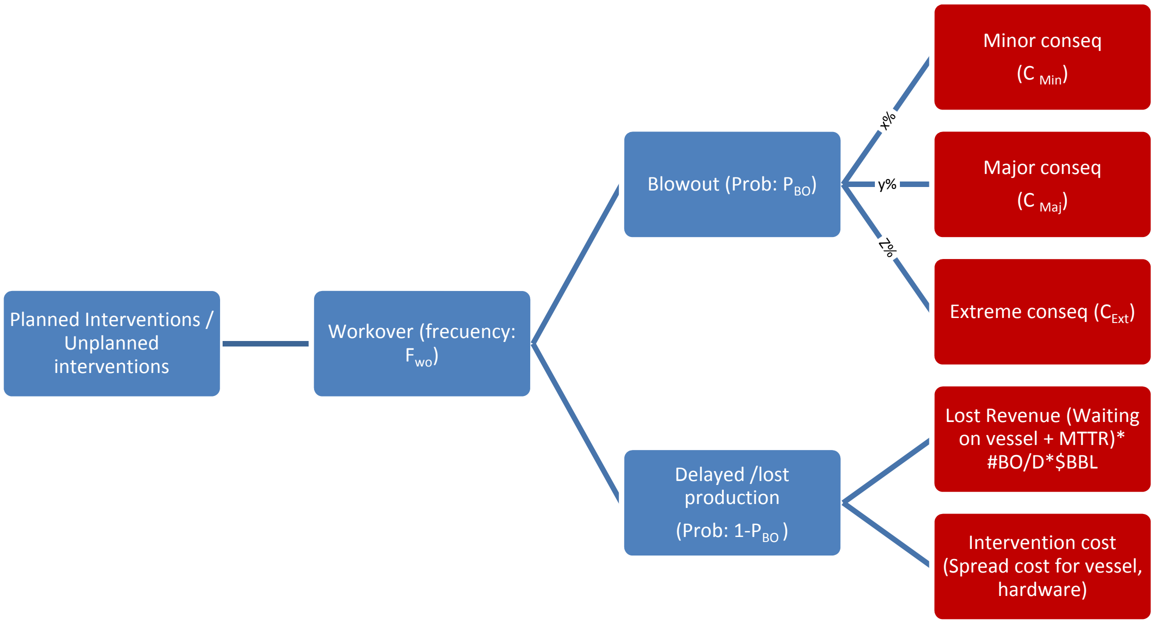
OPEX: Includes intervention costs associated with "planned" interventions, i.e. re-completions caused by depleted reservoir zones.

RISKEX: Includes risk costs associated with blowouts

RAMEX: Includes lost revenues and intervention cost associated with "unplanned" intervention, i.e. interventions caused by component failures such as sand controls system failures, tubing leaks and production tree valve failures.

The RISKEX and RAMEX element are further illustrated in figure 5.3.

The method by which these cost elements are calculated is described in the following sub-sections.



x + y+ z = 100%

Figure 5.3. RISKEX and RAMEX calculation approach adapted from figure 2.1 (Goldsmith, 2006)

2.3.1 Operating Expenditures (OPEX)

Each of the identified intervention procedures are broken into steps. The duration of each step is estimated based on a combination of historical data and expert judgment. This is further documented in Section 5. The non-discounted OPEX associated with a recompletion is estimated as:

OPEX = (Intervention Duration) x (Vessel Spread Cost)

2.3.2 Risk Expenditures (RISKEX)

The probability of failure of the well completion system is a function of the probability of failure during the various operating modes (drilling, completion, normal production, workovers and re-completions). The lifetime probability of a blowout is calculated as:

$$P(\text{BO during lifetime}) = P(\text{drilling}) + P(\text{initial compl.}) + P(\text{prod}) + \sum P(WO) + \sum P(re-compl.)$$

The cost of a blowout depends on the size of the release ("Limited, "Major" or "Extreme"). The Risk Cost (RC) associated with a certain activity (j) was calculated as:

$$RC(j) = \sum_{i\,\in\{\text{limited, major, extreme}\}} Probi\,(activity\ j) \cdot Ci)$$

where Probi(activity j) is the probability of a blowout of size i during activity j, and Ci is the cost of leak of size, i ∈{limited, major, extreme}. This is further described in Section 7.

2.3.3 Reliability, Availability and Maintainability Expenditures (RAMEX)

The RAMEX is divided into two:
- *Cost associated with lost revenues*
- *Cost associated with interventions*

For the model developed, the consequence for the production in a given year 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*
- *Mobilization time for the repair resources*
- *Active repair time*

An example is given below:

Example 1:

- *Failure: Workover (WO) required to repair the failure in year*
- *Resource: Rig*
- *Production loss: 50% while waiting on rig (90 days) + 30 days for WO.*
- *Production rate: 10,000 BOPD in year 3.*
- *Lost volume:*

The financial consequence of a well failure will in addition to the factors discussed above depend on:
- *Failure time*
- *Oil operating margin in year produced ($/BBL)*
- *Spread cost for intervention vessel ($/day)*

An example is given below:

Example 2:

- *WO required to repair the failure*
- *Resource: Rig*
- *Failure time: year 3*
- *Production loss: 50% while waiting on rig (90 days) + 30 days for WO*

- *Production rate: 10,000 BOPD in year 3*
- *Spread cost for Rig: $100,000 per day*
- *Oil operating margin in year produced: $10/BBL*
- *Discount rate: 15%*
- *Financial Consequence (FC):*

FC = Lost Revenues + Intervention Cost

$FC = 0.5* 90days\ 1* 30days)* 10{,}000BOPD*(\$10\ per\ BO/(1+0.15)^3)+ (\$100{,}000/d * 30days)/(1\ 0.15) \approx 4.9MM + 2MM = 6.9MM$

6. Production concepts for offshore field development in deepwater

Field development in deep water has a number of generic concepts associated. The production technology concepts can be divided in two branches, either if the solution employs wet or dry tree. As mentioned in the introduction the dry tree has been associated in most of cases with a low capital expenditure but a lower recovery factor per well and flexibility to use new or already emplaced offshore structures. On the other hand, the dry tree solutions are related to higher capital expenditure, more complex operation and maintenance as well as possibility to get an improved recovery factor. See figure 6.1.

Table 6.1. shows examples of fields that have employed the generic concepts as illustrated in figure 6.1. Annex C in this work give details on the particular characteristics of each one of the field development concepts listed in table 6.1.

For another reference it is recommended to review the survey of the records in deep water and its concept selection updated yearly and provided by the company Mustang Engineering, see http://www.offshore-mag.com/index/maps-posters.html and "2009 Deepwater solutions & records for concept selection" (Wilhoit and Supan, 2009).

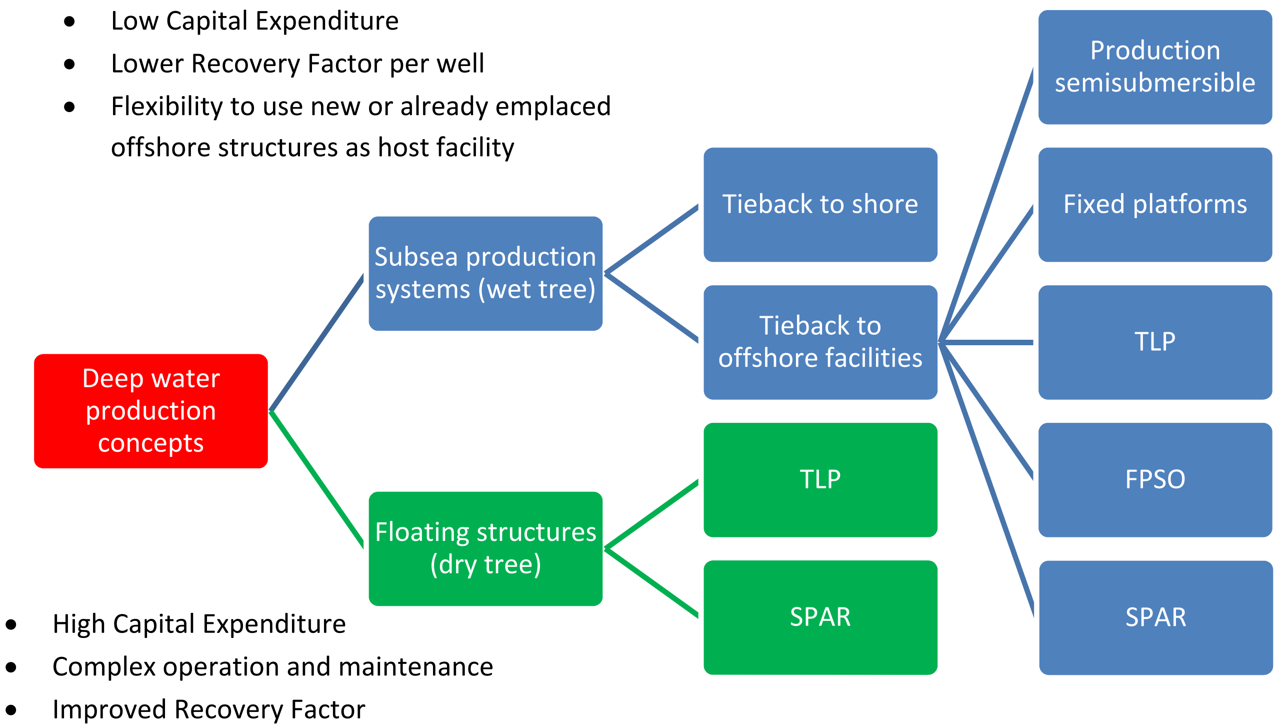


Figure 6.1 Generic classifications of technological concept solutions for deep water

Generic Concept	Field Development Example	Location
Subsea tieback to shore	*Ormen Lange*	*Norway.*
Subsea tieback to existing platform	*Canyon Express*	*Gulf of Mexico U.S.A.*
Subsea tieback to semisubmersible	*Thunder Horse*	*Gulf of Mexico U.S.A.*
Subsea tieback to FPSO	*Pazflor*	*Angola, West Africa.*
Subsea tieback to SPAR	*Boomvang*	*Gulf of Mexico, U.S.A.*
Subsea tieback to TLP	*Auger*	*Gulf of Mexico, U.S.A.*
Dry tree SPAR	*Mad Dog Field*	*Gulf of Mexico, U.S.A.*
Dry tree TLP	*Matterhorn Field*	*Gulf of Mexico, U.S.A*

Table 6.1 Examples of fields employing generic concepts of field development for deep water, see Annex C for details of the field developments.

6.1 Technological assessment of the subsea production systems (wet tree solutions)

An assessment of the Subsea Production and well systems was developed for the MMS in 2003 and lead by Scott (Scott et. al., 2004). Scott identified seven issues that are accounted as some of the most important to deal with when a subsea production system is selected:

1. *Subsea Processing*,
2. *Flow Assurance*,
3. *Well intervention*,
4. *Long term well monitoring*,
5. *Factors affecting ultimate recovery*,
6. *Safety and Environmental concerns*,
7. *Technology development and transfer.*
8. *Reliability of production and control of subsea systems.*
9. *A flexible concept. Tieback to floating or fixed offshore installations or tie back to shore.*
10. *Marine Operations.* [3]

6.1.1. Subsea Processing

The expected primary recovery factor per well, using a subsea production system are historically lower than for production systems based on a fixed or floating platforms. Subsea processing is typically mentioned to help to increase the recovery extending the productive life of the reservoir.

FMC is one of the most important suppliers of the technology and services related to this issue. FMC explains (FMC, 2009) that the subsea processing might move some of the equipment that is installed at the top of the platform to the seabed. This represents a potential cost saving instrument considering that the weight of the equipment at the top-sides is a major driver of capital costs on floating structures, see “Empirical cost models for TLP´s and Spars” (Jablanowski, 2008).

For example, the flowlines and the topsides might increase their efficiency by having subsea separation and local reinjection of produced water and/or gas to the reservoir or to any other

[3] *Points 8 and 9 and 10 were not listed by Scott but are important as previously enounced by the opinion of this author.*

disposal zone. The subsea gas/liquid separation and the liquid boosting can improve the rate of production when used in low energy reservoirs. (FMC, 2009).

Subsea processing can be configured in a outnumbered way of configurations according to the needs of the field. A classification for the configuration of subsea processing is provided by Scott in table 6.2. He signals that at the year 2004, multiphase pumping was the only commercial solution available.

For a dry gas reservoir the normal expectancy is that the reservoir pressure will drop over the life of the field and it would be necessary at some point introduce a ***Gas boosting system*** that could be either a topside system or a state of the art subsea gas compression system. Statoil is one of the operator companies with projects on development for this particular technology for its field “Ormen Lange”.

Bass (Bass, 2006) points that subsea gas compression is an alternative to consider instead of the use of onshore compression technologies when it is used for short range distances and a competitor concept for the floating compression systems for longer offsets. He predicts that the subsea compression is likely to be chosen when there is a case of a large field with a moderate long distance from the reservoir to the existing infrastructure. Also in the case of a short distance, the subsea compression might be a more effective alternative than the topside compression if there is liquid holdup in the system.

Classification	***Characteristic***	***Equipment***	***Water Disposal***	***Sand Disposal***
Type 1	*Multiphase Mixture is Handled Directly*	*Multiphase Pump*	*None...Pumped with Other Produced Fluids*	*None…Pumped with Other Produced Fluids*
Type 2	*Partial Separation of the Production Stream*	*Separator and Multiphase Pump; possible use of Wet-Gas Compressor*	*Possible Re-Injection of partial water stream, i.e. "free" water*	*None..Pumped with Liquid Stream*
Type 3	*Complete Separation of the Production Stream at Subsea Conditions*	*Separator and Scrubber Stages w/ Single or Multiphase Pump; possible use of Gas Compressor*	*Re-Injection/Disposal of Majority of Water Stream*	*Must be addressed*
Type 4	*Export Pipeline Quality Oil & Gas*	*Multi-Stage Separator and Fluid Treatment; single-phase pumps and compressors*	*Re-Injection/Disposal of Entire Water Stream*	*Must be addressed*

Table 6.2 Classification of Subsea Processing Systems after Scott (Scott et. al., 2004)

Bass (Bass, 2006) also states that the Subsea gas dewpointing/dehydration (subsea separation) may be useful in several ways related to a gas field, including:

- To reduce the flow assurance costs by eliminating or minimizing the need for continuous hydrate inhibition.
- To reduce pipeline construction costs by removing water and allowing the use of cheaper carbon steel rather than a corrosion resistant alloy.

- To process close to sales quality or even reach sales quality that also addresses flow assurance needs.

6.1.2 Flow Assurance

Scott (Scott et. al., 2004) refers that flow assurance is the term related to the study of the complex phenomena involving the transportation of produced fluids trough the producing and transportation flow lines.

The produced fluids are a combination of hydrocarbon gases, crude oil/condensate and water together with hydrocarbon solids such as, hydrates, scale, wax, paraffin, asfaltenes, and other solids and gases such as sand, CO_2, H_2S.

In order to get satisfactory recoveries rates it is necessary to identify the potential and quantify the magnitude of the produced fluid to be managed in the system. The flexibility of the system is required because different parameters of the produced fluid (pressures, temperatures, production fractions) involved in the design of the system are expected to change along the life of the project, and also that mentioned flexibility will be necessary to control during the transient periods of production (shutdown and restart).

The design of a flow assurance program for a field needs to consider the requirements for all parts of the system for the entire production life. Some of those considerations are, production profiles, chemical injection & storage, produced fluids properties, host facility (pigging, fluid storage, tubulars (tubing & flowline ID's) & handling, intervention capability, Insulation (tubing, wellhead, etc.), capital and operating costs.

Flow assurance also depends to a large extent if the development is for an oil or a gas reservoir. Flow assurance is much more challenging in oil than in gas producers, both of them will have corrosion and hydrate issues but in oil's the wax, asphaltenes, scale and emulsion expectations should also be considered in the design.

The gas systems can be managed with a flow assurance strategy driven by the injection of hydrate inhibitors chemicals such as MEG (monoethylene glycol), thermal isolation is usually not as demanding as in oil production but is an important factor in low temperature environments for example in the developments on the Norwegian continental shelf (Ball, 2006).

6.1.3. Well Intervention

The cost of well interventions in subsea production systems is considerable higher compared to fixed or floating platforms with work over systems since they require the mobilization of MODU's (Mobil offshore drilling units) or drilling ships for each well location.
This issue is the main reason to select pressure boosting at the seafloor rather than artificial lift in the wellbore and has also motivated the development of Intelligent Well Technology (IWT) to increase the operative flexibility as an alternative to well intervention (Scott et. al., 2004).

6.1.4. Long term well monitoring

Scott (Scott et. al., 2004) refers to this long term well monitoring as Intelligent Well Technology (IWT), which compresses two main concepts:

1. Monitoring of measurements of down hole flow and/or reservoir conditions. The measurement is performed by electronic devices or fiber optics, parameters currently functional today are pressure, temperature and flow rate.
2. Remotely control zones through on/off control or choking. The control is achieved by electric, hydraulic or electro-hydraulic (hybrid) actuation of a valve or sleeve. Commercially available.

Control and monitoring are being accepted slowly due to concerns about complexity, reliability and cost. It does not matter how sophisticated is the installation when the system fails and workover is required.

An additional motivation for further development of IWT in the Gulf of Mexico is that in this region there has been registered a large occurrence of Sustained Casing Pressure (SCP) in producing wells. Citing Wojtanowicz (Wojtanowicz et. al., 2001) "*The Minerals Management Service (MMS) defines SCP as a pressure measurable at the casinghead of a casing annulus that rebuilds when bled down and that is not due solely to temperature fluctuations and is not a pressure that has been deliberately applied.*"(Wojtanowicz et. al, P.p. 4, 2001).

SCP is identified as a cause of leakages that are dangerous for personnel near well heads located on topsides of platforms and for the environment in subsea facilities. Currently is not possible for a monitor to access the outer with a subsea wellhead a necessary improvement is to find a way to develop the ability to monitor and remediate SCP.

6.1.5. Factors affecting ultimate recovery

Scott (Scott et. al., 2004) also found that the multiphase flowlines that make possible the development of long subsea tiebacks reduce the ultimate recoveries. According to his work since the subsea wells operate with a continual high backpressure the energy that could be used to deplete more efficiently the reservoir is lost in the flow line and in the choke valves of the system.

6.1.6. Risk, safety and environmental concerns

Although each facility is different due its design, functions and operation conditions, the remoteness of the subsea systems location reduces the risks to the personnel but still, the environment risks remain for subsea production systems. It is recommended to be as strict as reasonably possible with the safety system requirements defined for subsea production systems. (Brandt, 2004).

6.1.7. Technology development and transfer.

As mentioned before, just some of the conceptually developed subsea production systems have been implemented commercially. Operator companies either national or international usually prefer a more conservative approach on the development of new technologies. This, however, is going to change when the technology become proven, but the implementation of effective programs of technology acquisition will still be necessary.

6.1.8. Reliability of production and control of subsea systems

To obtain cost effective and reliable production and control systems are also challenges of major importance, this aspect is managed in general by redundancy in design and applying reliability centered design and maintenance philosophies.

The reliability also implies a lot of work on the organization of the operators and contracting companies that are part of the subsea projects. The high amount of uncertainty due to restrictions in time and budgeting are a cause of increased risk in the design, construction, installation and operation of the systems.

On the knowledge of the importance of human and organizational factors, API has released recently a "Recommended Practice for Subsea Production System Reliability and Technical Risk Management" API 17 N (API, 2009) This document has as purpose that the users of that RP gain a better understanding of how to manage an appropriate level of reliability throughout the life cycle of their subsea projects.

The whole industry demand that the developers of subsea systems:

> *— recognize the trade off between up front reliability and engineering effort vs. operational maintenance effort,*
> *— provide better assurance of future performance of subsea systems,*
> *— effectively manage the risks from using novel equipment and standard equipment in novel applications,*
> *— schedule projects with sufficient time to address all the technical risks. [API, P.p. 1, 2009]*

On the other hand, Scott (Scott et. al., 2004) mention in their work that most of the designs have focused on increasing component reliability and extending the mean time to failure to address intervention concerns. Remarkably the redundant systems were not found to be in widespread use due to the increased capital costs these systems incurred.

6.1.9. A flexible concept. Tieback to floating or fixed offshore installations or tie back to shore.

The main benefit of the subsea production systems is that they are recognized to diminish the capital cost of the new developments since the construction expenditures of an entire new-brand offshore platform are avoided.

The subsea production systems might be quite different in form and size (ISO-13628-1,2005), they can be designed as:

- A single satellite well with a flowline linked to offshore platforms, floating or onshore processing facilities.
- Several wells located in one or more templates.
- Wells or set of wells in templates clustered around a manifold with or without subsea processing connected to facilities onshore or offshore.

The concept of a subsea production system to shore has been used already in several developments around the world i.e. Snøhvit, Ormen Lange, Patricia Baleen, BHPBP Minerva, and ONGC G-1.

As example of deep water tiebacks to fixed platforms just as example is possible to mention, the Devils Creek, Pompano, Bullwinkle and Canyon Express, all of them located in U.S. Gulf of Mexico and acting as a host for subsea tiebacks.

The subsea production systems are most often selection when a semisubmersible or a FPSO is employed, however there are recent developments that have used topside trees using a semisubmersible this are related to mild environment as West Africa. (Often, 2000).

Odland summarizes the characteristics of the semisubmersible production units (Odland, 2008):

- Large number of risers, these facilities can handle a large number of slots for production and injection risers what made them suitable for larges and multifield tie back field developments.
- Good motion characteristics, due its proven dynamic characteristic response it is possible to have a high pay load on its top sides.
- New built or conversion, it is possible to use drilling rig hulls that are still usable and otherwise would face decommissioning.
- Not offer storage capability.
- Have a spread mooring systems.

Lim and Ronalds (Lim and Ronalds, 2000) presented an historical and prospective review on the Semi submersible production systems and FPSO's. In their view the floating production systems were developed initially (1970's) for their advantages in deep water and reservoirs of short production life, at the beginning the semisubmersibles were common selected against FPSO's because the concept offered:

- Drilling and workover capability for wells located just below the semi.
- Good motion response (stability).
- Availability of drilling rigs for conversion to production semis.
- It was possible to use rigid risers before the technology of flexible risers appeared.

Later, at the end of 1980s and beginning of 1990 the semisubmersibles were recognized for their capabilities to operate in the deep water.

At the beginning of the 2000's the FPSO are more numerous than the semisubmersibles, some reasons for this are:

- Advantages of the shape of the hull of the FPSO's, more stability and maniobrability.
- Improvements in turret technology.
- Preferable when used for small and remote oil fields.

The production semisubmersibles are also popular in case of gas reservoirs and compete with the new designs of SPAR's and TLP's when there is a large reservoir to exploit and a suitable infrastructure of pipelines is available. Its evolution has been remarkable, through developing new types of risers, hulls forms and methods of construction.

Odland (Odland, 2008) also states that in deep water the principal challenge of the semisubmersible is related to the hydrodynamic effects that induce loss of position and slamming over the structure and the riser systems. A related issue with the deep water is its weight gain due both the mooring and the riser systems.

6.1.10 Marine operations.

Regarding marine technology and operations, although important is not considered to be a challenge for the subsea production systems. After its installation the subsea facilities are considerable less exposed to environmental loads than the fixed and floating offshore units.

However as stated in the Standard ISO ISO-13628-1:2005 *"All applicable loads that can affect the subsea production system during all relevant phases, such as fabrication, storing, testing, transportation, installation, drilling/completion, operation and removal, should be defined and form the basis for the design"* [ISO-13628-1,2005].

Since marine operations represent an important part of the costs of installation a summary of marine operations for both, subsea production systems as well as floating structures, is presented in Annex D.

6.2 Technological assessment of floating structures (dry tree solutions)

Any floating structure has as a purpose to extend the range of operation offshore by the provision of space to locate machinery and supplies for the exploitationn of oil and gas fields. The technical solutions are not so different from the ones that are installed onshore but the reduced weight and space capability is a major restriction for the equipment.

This topic is extensive and it is suggested for the reader to consider as a reference the ISO standard IS0 19904-1, Floating offshore structures Part 1: Monohulls, semi-submersibles and spars (ISO, 2006) which have been developed for this topic.

> *ISO 19904-1:2006 provides requirements and guidance for the structural design and/or assessment of floating offshore platforms used by the petroleum and natural gas industries to support production, storage and/or offloading, drilling and production, production, storage and offloading, and drilling, production, storage and offloading. [ISO, Abstract, 2006]*

Whilst the ISO standard IS0 19904-2, Floating offshore structures Part 2: Tension Leg Platform is still in discussion and development process, "API RP 2T- Recommended Practice for Planning, Designing, and Constructing Tension Leg Platforms" is the suggested reference to know more about TLP´s.

This Recommended Practice is a guide to the designer in organizing an efficient approach to the design of a *Tension Leg Platform (TLP). Emphasis is placed on participation of all engineering disciplines during each stage of planning, development, design, construction, and installation. Iteration of design through the design spiral…. [ANSI/API, Scope, 1997].*

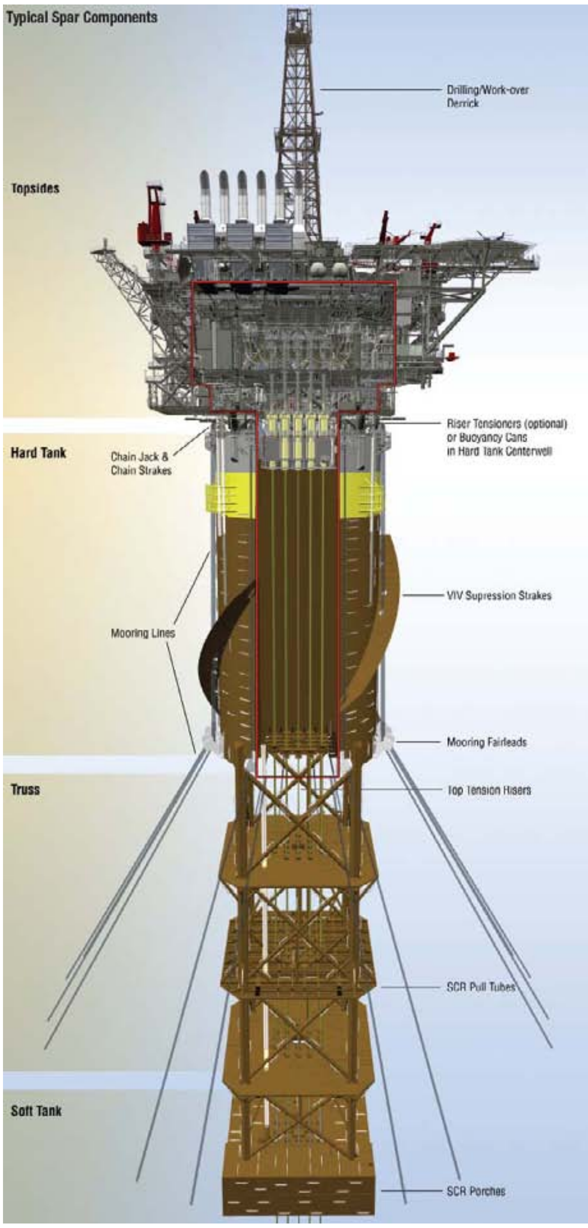


Figure 6.2. Typical Spar Components [Wilhoit, 2009]

6.2.1 State of the art of developed fields using SPAR.

The SPAR system is currently in use at seventeen locations (those developments are Neptune, Medusa, Genesis, Gunnison, Front Runner, Boomvang, Nansen, Mirage, Tahiti, Holstein, Kikeh, Mad Dog, Constitution, Red Hawk, Horn Mountain, Devils Tower and Perdido.) 16 of them in the GOM and 1 more in Malaysia. Although the design of each SPAR is different it is possible to say that there are broadly three different versions of Spar, classic version, truss version and cell version, (Sablok, 2009).

The Record in drilling and completion in deep water is held by Shell Oil Co. using the SPAR "Perdido". The SPAR is moored in ~2,380m of water and will be the world's deepest direct vertical access SPAR in operation. The SPAR will act as a hub for, and enable development of, three fields – Great White,Tobago, and Silvertip – and it will gather process and export production within a 48km radius. Tobago, in ~2,925m of water, will be the world's deepest subsea completion (Offshore Magazine, 2008).

6.2.2 Description of the SPAR floating system.

A SPAR is a floating system with deep-draft floating caisson that produces low motion response characteristics compared to other floating concepts.

For this document it is relevant to introduce the configuration of the Truss Spar (See figure 6.2). In this version the hull can be divided in three sections:

1) The cylindrical hard tank upper section provides buoyancy to support topsides, hull, mooring and risers. This section includes both variable ballast and void components.

2) The truss section has heave plates. The truss helps to reduce the overall hull weight, environmental loads and heave motion. The reduced hydrodynamic loads and motions also results in savings in the mooring system and facilitate the building and transportation of the hull.

3) The soft tank is also known as “keel” contains the fixed ballast and is divided in different compartments to control the buoyancy during transport. It also acts as a natural hang-off location for export pipelines and flow lines since the environmental influences from waves and currents and associated responses are less pronounced as we go deeper in the water.

6.2.3. Benefits and challenges of the SPAR’s concept.

The low motion characteristics make the SPAR a structure suitable to accommodate a large diversity of combinations of production systems. Sablok and Barras (2009) announce the benefits of this hull type has for the field development:

1. The SPAR is a floating structure viable and technologically mature for application in a large range of water depths and environments.

2. Provides high hydrodynamic stability which make possible to install export risers of large diameter to connect with pipelines and in this way develop gas fields easily.

3. The high stability also allows to accommodate large and flexible options for drilling and production equipment:
    - Dry trees-subsea trees
    - Subsea production systems
    - Direct vertical access
    - Drilling from the platform, MODU, tender assistance.
    - Export risers systems
    - Disconnectable moorings and risers.
    - Sour fluids treatment.

4. They also can be designed to allow major local content. Although the adjudication of these projects must follow technical and economical evaluations there is considerable options for constructors in the Region of Gulf of México (TECHNIP) and even some of them have their construction yards installed in Mexico (FLOATEC LLC).

5. Diminish dependence of lifting equipment that could result in high cost and be scarcely available using its hull as a basis to install cranes to perform the installation of the system modules over the SPAR deck.

6. In the Gulf of Mexico region there is also considerable availability of large lifting vessels that can manage the transport and installation of SPARS.

Challenges:

The main challenge to consider is the massive structure of the SPAR´s. This massive structure can be installed as one single piece after relatively complex marine operations, see Annex D.

It is also important to consider the cost of the steel; it is suggested to make careful arrangements to ensure that the project could not be jeopardized by instability in the price of the steel along the construction process.

6.2.1 State of the art of developed fields using TLP´s.

The TLP system has been employed and planned as concept in twenty five field developments up to 2010; table 6.3 summarize the list of those field developments.

Notable facts are:

- The Hutton TLP in UK, has already been retired
- The Typhoon TLP in US GOM was converted to artificial reef after the damages caused by the hurricanes Katrina and Rita.
- World's larger TLP is Heidrun in Norway
- World´s deepest installed TLP is Magnolia in US GOM at 1425 m water depth. (Willhoit and Supan, 2010)

6.2.4. Description of the concept of the TLP´s systems.

Regg (Regg et. al., 2000) did a summary of the deepwater concepts for the MMS in 2000. bBelow a part of their work is reproduced taking advantage of its clear description of the TLP. See figure 6.3 for a visualization of a generic concept.

> *A Tension Leg Platform (TLP) is a buoyant platform held in place by a mooring system…*
>
> *The TLP's are similar to conventional fixed platforms except that the platform is maintained on location through the use of moorings held in tension by the buoyancy of the hull. The mooring system is a set of tension legs or tendons attached to the platform and connected to a template or foundation on the seafloor. The template is held in place by piles driven into the seafloor. This method dampens the vertical motions of the platform, but allows for horizontal movements. The topside facilities (processing facilities, pipelines, and surface trees) of the TLP and most of the daily operations are the same as for a conventional platform…(see figure 6.4).*

	FACILITY INDUSTRY NAME	General Location	Water Depth (M)	STATUS	TLP/TLWP (Type)	Operator/ Partner 1
1	*HUTTON*	*UK*	*147*	*RETIRED*	*6 Column Conventional TLP*	*ConocoPhillips*
2	*JOLLIET*	*US - GOM*	*536*	*PRODUCING*	*4 Column Conventional TLWP*	*MC Offshore Petroleum*
3	*SNORRE A*	*NORWAY*	*335*	*PRODUCING*	*4 Column Conventional TLP*	*Statoil*
4	*AUGER*	*US - GOM*	*873*	*PRODUCING*	*4 Column Conventional TLP*	*Shell*
5	*HEIDRUN*	*NORWAY*	*345*	*PRODUCING*	*4 Column Conventional TLP*	*Statoil*
6	*MARS*	*US - GOM*	*894*	*PRODUCING*	*4 Column Conventional TLP*	*Shell*
7	*RAM/POWELL*	*US - GOM*	*980*	*PRODUCING*	*4 Column Conventional TLP*	*Shell*
8	*MORPETH*	*US - GOM*	*518*	*PRODUCING*	*1 Column New Generation TLP*	*Eni*
9	*URSA*	*US - GOM*	*1,159*	*PRODUCING*	*4 Column Conventional TLP*	*Shell*
10	*ALLEGHENY*	*US - GOM*	*1,009*	*PRODUCING*	*1 Column New Generation TLP*	*Eni*
11	*MARLIN*	*US - GOM*	*987*	*PRODUCING*	*4 Column Conventional TLP*	*BP*
12	*TYPHOON*	*US - GOM*	*639*	*Note*[4]	*1 Column New Generation TLP*	*Chevron*
13	*BRUTUS*	*US - GOM*	*910*	*PRODUCING*	*4 Column Conventional TLP*	*Shell*
14	*PRINCE*	*US - GOM*	*454*	*PRODUCING*	*4 Column New Generation TLP*	*Palm Energy Offshore*
15	*WEST SENO A*	*INDONESIA*	*1,021*	*PRODUCING*	*4 Column New Generation TLWP*	*Chevron*
16	*MATTERHORN*	*US – GOM*	*859*	*PRODUCING*	*1 Column New Generation TLP*	*Total*
17	*MARCO POLO*	*US - GOM*	*1,311*	*PRODUCING*	*4 Column New Generation TLP*	*Anadarko*
18	*KIZOMBA A*	*ANGOLA*	*1,178*	*PRODUCING*	*4 Column New Generation ETLP*	*ExxonMobil*
19	*MAGNOLIA*	*US - GOM*	*1,425*	*PRODUCING*	*4 Column New Generation ETLP*	*ConocoPhillips*
20	*KIZOMBA B*	*ANGOLA*	*1,178*	*PRODUCING*	*4 Column New Generation ETLP*	*ExxonMobil*
21	*OVENG*	*EQUATORIAL GUINEA*	*271*	*PRODUCING*	*4 Column New Generation TLWP*	*Amerada Hess*
22	*OKUME/EBANO*	*EQUATORIAL GUINEA*	*503*	*PRODUCING*	*4 Column New Generation TLWP*	*Amerada Hess*
23	*NEPTUNE*	*US - GOM*	*1,280*	*PRODUCING*	*1 Column New Generation TLP*	*BHP*
24	*SHENZI*	*US - GOM*	*1,333*	*PRODUCING*	*4 Column New Generation TLP*	*BHP*
25	*PAPA TERRA P61*	*BRAZIL - CAMPOS BASIN*	*1,180*			*Petrobras*

Table 6.3 List of the field developments using the TLP´s concept (Willhoit and Supan, 2010)

[4] *Damaged by the hurricanes RITA and Katrina currently converted into artificial reef.*

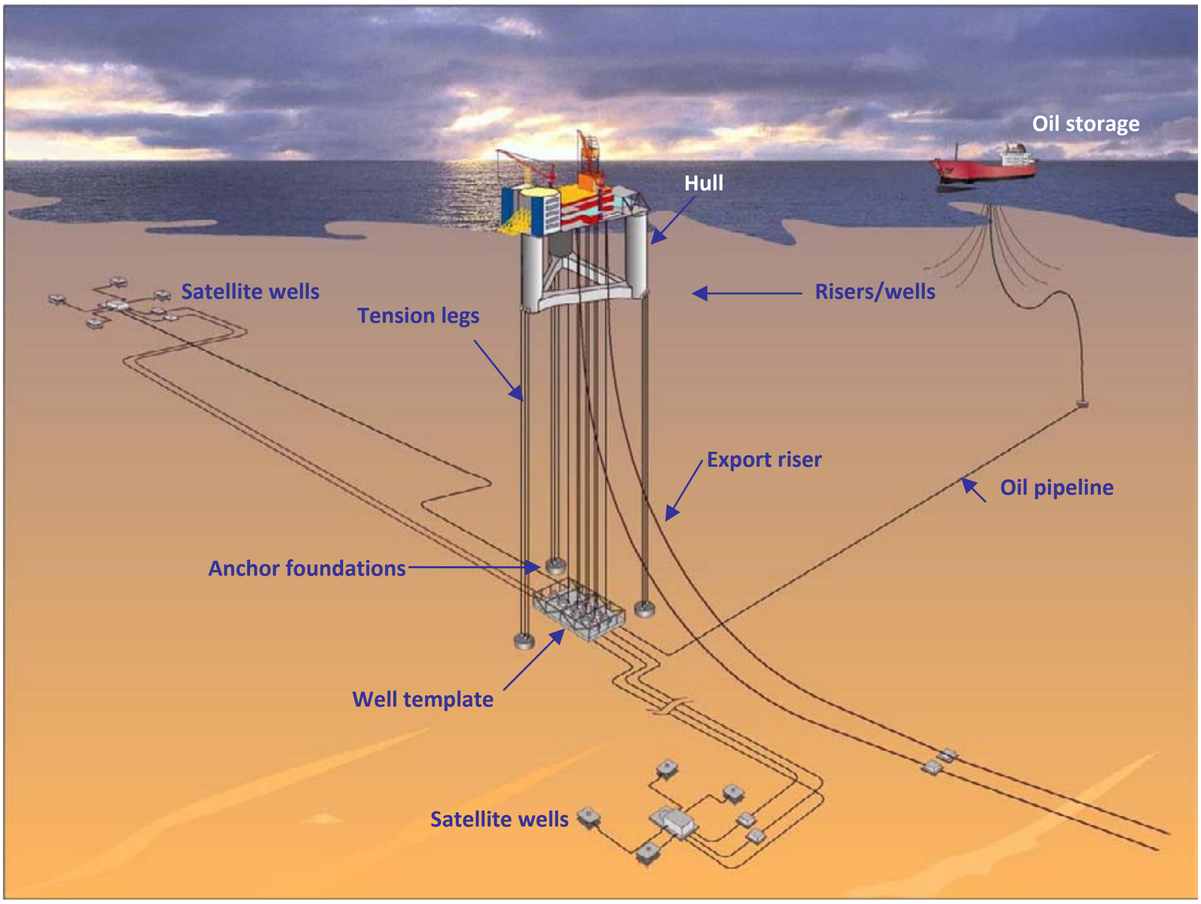


Figure 6.3. A TLP concept illustration figure from Offshore Field Development by Odland [Odland, P.p. 5 Mod. 5, 2008]

TECHNICAL DESCRIPTIONS

Foundation. *The foundation is the link between the seafloor and the TLP. Most foundations are templates laid on the seafloor, then secured by concrete or steel piles driven into the seafloor by use of a hydraulic hammer, but other designs can be used such as a gravity foundation. The foundations are built onshore and towed to the site. As many as 16 concrete piles with dimensions of 100 ft in diameter and 400 ft long are used (one for each tendon).*

Hull. *The hull is a buoyant structure that supports the deck section of the platform and its drilling and production equipment. A typical hull has four air-filled columns supported by pontoons, similar to a semisubmersible drilling vessel. The deck for the surface facilities rests on the hull. The buoyancy of the hull exceeds the weight of the platform, requiring taut moorings or "tension legs" to secure the structure to the seafloor. The columns in the hull range up to 100 ft in diameter and up to 360 ft in height; the overall hull measurements will depend on the size of the columns and the size of the platform.*

Modules. *…Modules are units that make up the surface facilities on the deck section of the platform. Early in TLP development, industry discovered that it is cost effective to build the surface facility in separate units (modules), assemble them at shallow inshore location, and then tow them to the site. The modules that are part of a typical TLP include the wellbay, power, process, quarters, and drilling; they are secured to the deck, which is attached to the hull. The typical surface facility will be 65,000 sq ft. The living quarters house up to 100 people, depending on the type and scope of activity being performed. Process capacity ranges up to*

150,000 BPD oil and 400 MMscfd gas. A typical drilling rig located on a larger TLP would have a 1.5 million-pound pull derrick, a 2,000-hp top-drive derrick, and three 2,200-hp pumps.

Template. *A template provides a frame on the seafloor in which to insert either conductors or piles. Not all TLP's use templates; if used, they are typically the first equipment installed at the site. There are several types of templates that may be used in conjunction with a TLP to support drilling foundation integrity, or the integration of the two. Drilling templates provide a guide for locating and drilling wells; they may also be a base for the tie-in of flowlines from satellite wells or for export pipelines and their risers. Foundation templates may be one single piece or separate pieces for each corner. The foundation piles are driven through the foundation template. An integrated template is a single piece that contains all drilling support, anchors the tendons, and locates and guides the foundation piles. Separate templates allow each part to be installed individually. They also use smaller pieces that weigh less and are easier to install. The drilling template can be installed and drilling can begin while the foundation template is being designed and built.*

Tension Legs (tendons). *Tension legs are tubulars that secure the hull to the foundation; this is the mooring system for the TLP. Tendons are typically steel tubes with dimensions of 2-3 ft in diameter with up to 3 inches of wall thickness, the length depending on water depth. A typical TLP would be installed with as many as 16 tendons.*

Production Risers. *A production riser conveys produced fluids from the well to the TLP surface production facilities. An example riser system for a TLP could be either a single-bore or dual-bore (concentric pipe) arrangement. The dual-bore riser would consist of a 21-inch, low pressure (e.g., 3,000 psi) marine riser that serves as an environmental barrier, and an 11 ¾-inch inner pipe (casing) that is rated for high pressures (e.g., 10,000 psi) [Regg, P.p. 28-30, 2000].*

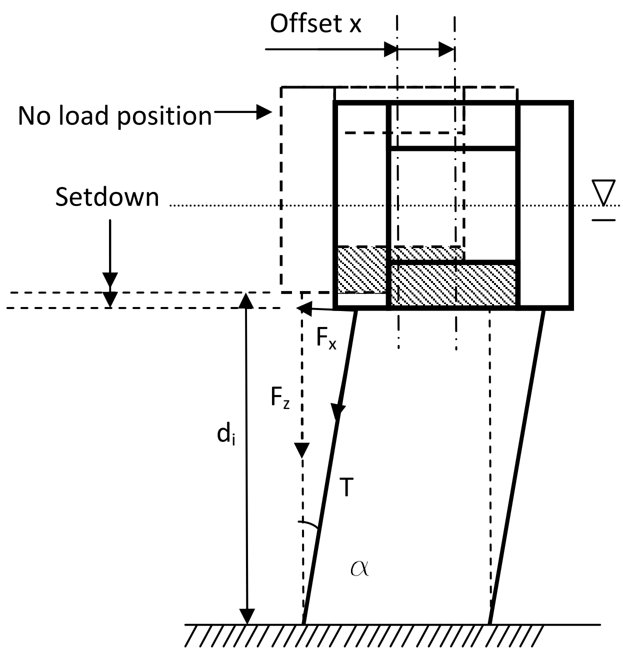


Figure 6.4. TLP in offset. When a TLP is offset by a distance x, the tendons are supposed to maintain the length d_i, and consequently the tension T. This effect will cause the TLP to keep its position.

The concept of a lighter TLP known as "mini TLP" or monocolumn is also a popular concept to develop small fields. An analysis of the concept was made by Kibbee and Snell (Kibbee and Snell, 2002), below their conclusions:

This section draws conclusions from project experience and future plans for expanding the capabilities of mono-column TLP's.

1. The successful installation and operation of SeaStar TLP's in the Morpeth, Allegheny, and Typhoon fields demonstrates that tension-leg moorings provide a reliable, cost-effective, and compact means for providing safe and stable real estate in deep water, regardless of the operator's choice of completion type (i.e., wet-tree or dry-tree). The tension-leg mooring makes it possible for smaller, less expensive hulls to be stable with favorable motion characteristics. The elimination of vertical motion not only makes dry-trees feasible, but it also expands SCR applicability, simplifies production operations, and increases personnel comfort and safety.

2. The mono-column hull has proven its versatility in all project phases:

- *Design: Mono-column hull sizes continue to increase to support increasing payloads. Between standard designs, it is possible to increase payload capacity by adding a column extension, thereby avoiding extensive hull structural redesign.*
- *Fabrication: SeaStar's modular nature allows it to be efficiently built in relatively small fabrication yards, thereby increasing competition.*
- *Installation: The monocolumn hull can be wet-towed or dry-towed. Smaller hulls, like Morpeth, Allegheny, and Typhoon can be lifted and installed much like a vertically lifted jacket. Larger hulls, like Matterhorn, can be wettowed. Major innovations are underway to reduce dependence on derrick barges.*
- *Operations: There are no holes below the waterline in a SeaStar hull, eliminating the possibility of accidental flooding due to pilot error.*

3. Like the mono-column fixed base platform, the monocolumn TLP will continue to evolve based on field experience and new requirements. The standardized nature of the monocolumn TLP product avoids the inefficiency of starting with "a blank sheet of paper" on each project, while still providing the benefit of product-focused lessons learned and execution systems. Atlantia's continuous involvement in platform performance monitoring provides a wealth of knowledge that can be used to validate design tools and improve design details. [Kibbee et. al. P.p. 4-5, 2002].

6.2.5. Benefits and challenges for the TLP concept.

Odland made a summary of the characteristics of the TLP concept during his class at the University of Stavanger [Odland, 2008]. He stated that the TLP concept is well-known, but needs a careful design of its hull and mooring configuration. It has a complex dynamic behavior but is suitable for deep water. The wells are located over the platform, which increase the capability for increased oil recovery. A challenge to manage is also the, top-tensioned (exposed) rigid risers.

Its installation and decommissioning presuppose comprehensive and complex marine operations, however, it is possible to do the installation of the topsides at shore. The concept is not suitable for oil storage. Last but not least, subject of main concern is the action of the Hurricanes in the Gulf of Mexico, the recent effects of Katrina, Lili, Ivan, etc. allowed research on the effects of the environmental loads on floating structures including the TLP.

SECOND PART: DEVELOPMENT, CONCLUSIONS AND RECOMMENDATIONS

7. Discussion on the recovery factor Dry vs. Wet Tree

One of the most important technical data when the economical evaluations are done is the ***recovery factor***. The recovery factor either of gas or oil expresses the fraction of the hydrocarbons that rely in the subsoil and that is expected or is brought to the surface, this of course will give estimates of the amount of the production and consequently of the profit that is expected to be obtained from the development.

When a volumetric analysis is performed the first step is the creation of geological maps (structure, fault contours and Isopatch maps), once they are prepared the next step is to obtain the expected amount of hydrocarbons recoverable either oil and/or gas (Roebuck, 1992).

The recoverable oil in stock tank barrels:

$$The\ recoverable\ oil\ in\ stock\ tank\ barrels = \frac{6.2898(\varphi)(1-S_w)}{B_o} \times R.F. \times Vol$$

Where:

- 6.2898 = the volume of barrels per cubic meter.
- φ = Porosity, decimal
- S_w =Connate water saturation decimal
- Bo= Oil formation volume factor, reservoir barrel/stock tank barrel
- R.F.= Recovery Factor
- Vol = The reservoir bulk volume from planimetric survey in cubic meters.

The recoverable dry gas in thousands of cubic feet (MCF):

$$The\ recoverable\ dry\ gas\ in\ MCF = 35.3146(\varphi)(1-S_w)\left(\frac{PT_{sc}}{P_{sc}TZ}\right) \times R.F. \times S.F. \times Vol$$

- 35.3146 = the volume of cubic feet per cubic meter.
- φ = Porosity, decimal
- S_w =Connate water saturation decimal
- P = Reservoir pressure
- T = Reservoir temperature in Kelvin
- P_{sc} = Pressure in standard conditions (depending on the required pressure base)
- T_{sc} = Temperature standard. *Usually a temperature of fifteen (15) Celsius degrees.*
- Z =Gas deviation factor (compressibility factor)
- R.F.= Recovery Factor
- S.F. Shrinkage factor.
- Vol = The reservoir bulk volume from planimetric survey in cubic meters.

The conventional discussions relate the recovery factor to the recovery methods which are classified in primary, secondary and tertiary and in particular for the oil fields also named IOR

(Improved oil recovery), EOR (Enhanced oil recovery for Oil). The table 7.1 shown the relation between recovery factors, technologies and their classifications.

Recovery methods	***Also referred as:***	***Technologies***	***Recovery Factor Associated by Roebuck (1992).***	***Recovery Factor Associated by Odland (2000-2008)***
Primary	Primary	Gas: Gas expansion	50-90%	
		Oil: Oil depletion		15-20%
Secondary	IOR (Improved oil recovery) For oil reservoirs	Gas: Water flodding and non miscible gas cap.	40-75%	
		Oil:		15-45% in addition
		Dissolved gas,	5-20%	
		Gas cap,	20-40%	
		Water drive	30-60%	
		Gravity drainage.	25-80%	
Tertiary	EOR (Enhanced oil recovery) for Oil reservoirs.	Oil. Thermal EOR CO2 EOR Other gases EOR Chemical/microbial EOR		2-8% in addition.

Table 7.1 Relation between recovery factors, technologies and its classifications with data from (Odland 2000-2008) and (Roebuck 1992).

A further discussion on these topics is out of the scope of this work, if is desired to complement knowledge on this topic it is suggested to take a look into the following references:

- *Design engineering aspects of waterflooding (Rose et. al, 1989).*
- *Enhanced oil recovery (Green and Willhite, 1998).*
- *Reservoir engineering aspects of waterflooding (Craig Jr., 1993).*
- *Waterflooding (Ganesh, 2003).*

The discussion in this work will be focused to know if there is evidence to differentiate the recovery factor when a development is designed by using dry tree or alternatively wet tree solutions and to find the best fitted probability distributions for different types of fields; non associated gas reservoir, undersaturated oil reservoir, saturated oil reservoir.

7.1 Empirical analysis of recovery factors in deepwater US Gulf of Mexico for dry tree vs. wet tree field development solutions.

Historically the recovery factor of the subsea production systems is perceived to be not as good as the one observed in the solutions that use dry trees. The reasons for this difference might be related to:

1. The cost of the well interventions in subsea production systems is considerable higher compared to fixed or floating platforms with work over systems since they require the mobilization of MODU's (Mobil offshore drilling units) or drilling ships for each well location.
2. The subsea wells operate with a continual high backpressure which causes that the energy that could be used to deplete more efficiently the reservoir is instead, lost in the flow line and in the choke valves of the system. (Scott, 2004).
3. Costs of subsea developments are more sensitive to the number of wells than platform developments.
4. Recoverable reserves depend on incremental costs (Odland, 2000-2008)

Hence for modeling the recovery factor there are two ways that are suggested according to data available and the level of complexity in which the modeling is intended to be performed:

- **Empirical probability distributions of the recovery factors by general analogy** for rapid tests.
- **Recovery factor by factorial model analogy** for deeper analysis.

7.1.1. Purpose

The model here proposed would consider that the recovery factor can be forecasted by analogy to historical values using the recovery factors reported to the MMS of the USA for the fields in deep water. These probability distributions will differentiate the recovery factor when a field is developed with subsea or dry trees in the case of dominant reservoir types:

- Non associate gas reservoir.
- Undersaturated oil reservoir.
- Saturated oil reservoir.

This model is intended to be used for analysis on the Mexican side of the Gulf of Mexico; hence the historical evidence that can be inferred from the statistics of the North of the Gulf of Mexico is considered to be a suitable analogy.

7.1.2 Methodology

The methodology to obtain the probability distributions will be shown next.

1. The information analyzed was taken from the data set "Atlas of Gulf of Mexico Gas and Oil Sands Data Available for Downloading" (MMS, 2006). The data used correspond to the fields of the worksheet:

    a. ***"MMS Field"*** MMS field name.
    b. ***"WDEP"*** Water depth (feet).
    c. ***"RESTYP"*** Dominant reservoir type: Nonassociated gas (N), Undersaturated oil (U), Saturated oil (S).
    d. ***"ORF"*** Oil recovery factor (decimal).
    e. ***"GRF"*** Gas recovery factor (decimal).

2. The data was filtered excluding the sands with associated water depth shallower than 1800 ft. (≈550 m).

3. The sands associated to the dry tree TLP's and SPAR's projects listed below were identified (See tables 7.2 and 7.3).

FIELD MMS DENOMINATION	FIELD DEVELOPMENT NICK NAME
GB426	Auger
GC158	Brutus
GB783	Magnolia
GC608	Marco polo
VK915	Marlin
MC807	Mars-ursa
MC243	Matterhorn
VK956	Ram-powell
GC654	Shenzi

Table 7.2 TLP's Projects located in Gulf of Mexico in water depths deeper than 1800" ft .

4. If the "ORF" or the "GRF" for each observation was found to be "0", cero, it was assumed that it was not intended to produce and hence those observations were eliminated from the data set.

5. Then the data were filtered and subsets were created according to the dominant reservoir type (Non associated gas (N), Undersaturated oil (U), Saturated oil (S), afterwards subordinate subgroups, with subsets of data related to dry tree and wet tree were also created. A list of those groups and the number of observations for each of them is shown in table 7.4. and figure 7.1.

FIELD MMS DENOMINATION	FIELD DEVELOPMENT NICK NAME
EB643	Boomvang north
GC680	Constitution
MC773	Devils tower
EB945	Diana
GC339	Front runner
GC205	Genesis
GB668	Gunnison
GC644	Holstein
AC025	Hoover
GC826	Mad dog
MC582	Medusa
EB602	Nansen
VK825	Neptune
AT063	Telemark

Table 7.3. SPAR Projects located in Gulf of Mexico in water depths deeper than 1800" ft.

6. From the previous list, subgroup "2. General oil recovery factor from non associate gas fields" (10 observations) and the subordinate groups "2.1 Dry tree oil recovery factor from non associate gas fields"(8 observations) and "2.2 Wet tree oil recovery factor from non associate gas fields"(2 observations) were found not to be statistically valid as reference due the few number of observations and consequently considered just as general reference. See figure 7.1.

7. The data sets were analyzed to find the best suitable probability distribution. The program "@Risk for Excel, Risk Analysis Add-in for Microsoft Excel Version 5.5.1 Industrial Edition" was used. From that program the tool "Distribution fitting" and the method "parameter estimation" were used. The possible probability distribution to be compared by the program were:

- Beta general
- Exponential
- Extreme value distribution
- Gamma
- Inverse Gauss
- Logistic
- Log-Logistic
- Log- Normal
- Normal
- Pareto
- Pearson 5
- Pearson 6
- Triangular
- Uniform
- Weibull

The goodness of fit was evaluated by calculation of the statistic χ2.

8. The probability distributions shown above were compared considering the goodness of fit and in case that the statistic χ2 were close for two or more distributions, the probability distribution that was comparatively more simple to model for further use was preferred.

9. A test was also done to test the hypothesis: $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} = 0$ vs. $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} \neq 0$ with μ calculated from the data sets created in this methodology.

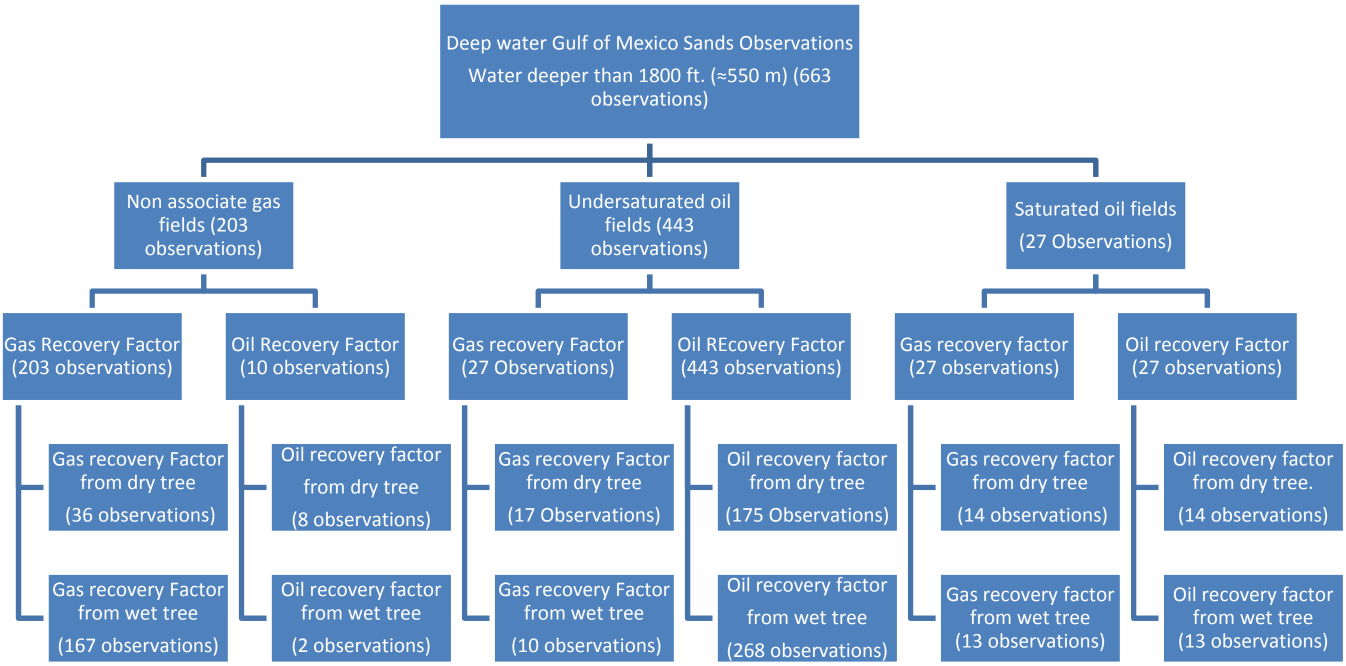


Figure 7.1 Subgroups and subordinate groups with number of observations from sands in projects located in Gulf of Mexico at water depths deeper than 1800" ft.

7.1.3 Results and inferences

The oil and gas recovery factors listed in this data set correspond to the estimated values declared by the operator companies to the MMS for each sand, and are subject to change due to different factors including technology improvements, operations management philosophy and refinement of calculations as more information from the reservoirs become available

The class of fields most exploited in deepwater in Gulf of Mexico corresponds to undersaturated oil fields (≈ 65%) followed by the non associated class (≈ 30%) and finally saturated oil fields class (≈ 4%).

The mean recovery factors for the different types of reservoir are summarized in table 7.5. According to the test of hypothesis $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} = 0$ vs. $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} \neq 0$ with μ calculated from the data sets created in this methodology, there is not statistical evidence that suggest that a field developed with dry tree has a better recovery factor than one developed with wet tree solutions.

Subgroup or subordinate group		Number of observations
1. Gas recovery factor from non associate gas fields		***203***
	1.2 Dry tree gas recovery factor from non associate gas fields	*36*
	1.3 Wet tree gas recovery factor from non associate gas fields	*166*
2. Oil recovery factor from non associate gas fields		***10***
	2.1 Dry tree oil recovery factor from non associate gas fields	*8*
	2.2 Wet tree oil recovery factor from non associate gas fields	*2*
3. Gas recovery factor from undersaturated oil fields		***27***
	3.1 Dry tree gas recovery factor from undersaturated oil fields	*17*
	3.2 Wet tree gas recovery factor from undersaturated oil fields	*10*
4. Oil recovery factor from undersaturated oil fields		***443***
	4. 1 Dry tree oil recovery factor from undersaturated oil fields	*175*
	4.2 Wet tree oil recovery factor from undersaturated oil fields	*268*
5. Gas recovery factor from saturated oil fields		***27***
	5.1 Dry tree gas recovery factor from saturated oil fields	*14*
	5.2 Wet tree gas recovery factor from saturated oil fields	*13*
6. Oil recovery factor from saturated oil fields		***27***
	6.1 Dry tree oil recovery factor from saturated oil fields	*14*
	6.2 Wet tree oil recovery factor from saturated oil fields	*13*

Table 7.4. Subgroups and subordinate groups with number of observations from sands in projects located in Gulf of Mexico at water depths deeper than 1800" ft.

With exception of the gas recovery factor from saturated oil fields, all the other test fail to reject the null hypothesis $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} = 0$. This means that the inferred mean value of recovery factor is the same either for dry tree vs wet tree solutions.

In the only exception (gas recovery factor of the saturated oil fields) is perceptibly a difference in favor of the dry tree. Despite the oil recovery factor from the same type of reservoirs is larger for dry tree than for the wet tree, the pooled variance for both samples is too large to make a differentiation on their means.

It is inferred that a criteria that prefer a dry tree with the argument of a better recovery factor must be evaluated further, extending the analysis to consider the specific characteristics of the reservoir and the exploitation concept that is part of the field to be developed.

Subgroup	***Best fitted probability distribution dry tree***	***Mean recovery factor dry tree from best fitted probability distribution***	***Best fitted probability distribution wet tree***	***Mean recovery factor wet tree from best fitted probability distribution***
Gas recovery factor from non associate gas fields	*Triangular*	*0.5340*	*Triangular*	*0.4989*
Gas recovery factor from undersaturated oil fields	*Triangular*	*0.5348*	*Logistic*	*0.5586*
Oil recovery factor from undersaturated oil fields	*Gamma*	*0.3083*	*Log Normal*	*0.3207*
Gas recovery factor from saturated oil fields	*Normal*	*0.585*	*Normal*	*0.43846*
Oil recovery factor from saturated oil fields	*Triangular*	*0.3459*	*Exponential*	*0.2510*

Oil recovery factor from non associate gas fields (Referencial)	***Best fitted probability distribution combined dry and wet tree***	*Weibull*	***Mean recovery factor combined dry and wet tree***	*0.3057*

Table 7.5. Summary of the results of the recovery factor according to the subgroups and subordinate groups from sands in projects located in Gulf of Mexico at water depths deeper than 1800" ft.

7.2 Multifactorial models for the prediction of the recovery factor.

The prediction of the recovery factor based on models that consider a number of factors is popular among operator companies and regulatory authorities. Both Operator companies and regulatory entities are interested in getting the most of the extraction of hydrocarbons, however it could be an alternative for the operator companies to select a field development solution focusing on just one fraction of the feasible recovery in order to save investment costs. For the regulatory authorities this is not tolerable since considerable volumes that could be extracted and count for tax purposes as a future income are instead abandoned in the subsoil.

An example of a regulatory authority is the Norwegian Petroleum Directorate. Extracted from its Resource Report 2005 we can have a view of what is the point of view of this institution regarding to the recovery factor.

> *The objective of the authorities is that as much as possible of the resources that are proven on the Norwegian continental shelf are recovered in a manner that creates the highest possible value for society.The Norwegian Petroleum Directorate strives to make this feasible, partly by helping the petroleum industry choose the best recovery methods, encouraging the various players to work together to gain benefit from coordination, and putting focus on the framework conditions where it considers this to be necessary. To ensure a high recovery factor, good utilization of the resources and value creation from the fields, access to appropriate technology, sufficiently qualified personnel and ability to take decisions are essential. [NPD, P.p. 30, 2005]*

7.2.1 The Reservoir Complexity Index from the Norwegian petroleum directorate.

Regarding the calculation of the recovery factor, the proposal of the NPD is to bench mark the recovery factor as a function of the Reservoir Complexity Index (RCI). This Index has fundament in the fact that the reservoirs have unique characteristics but if there is a way to assess the quality of the reservoirs, the complexity indicated by one measure (the reservoir complexity index, RCI) will have a strong correlation with the recovery factor expected from a development.

The parameters that describe the reservoir quality according to the proposal by NPD include:

- General permeability.
- Contrasts in permeability
- Vertical and horizontal communications in the reservoir (influenced, for example, by faults),
- Impervious strata,
- Density,
- Tendency for water or gas to be drawn towards the production wells (coning) and the like.

For each parameter are given a value based on objective limits and subjective assessments. The factors are pondered and the possible value result of the index is normalized to be between 1 and 0. High values of the index mean a more complex reservoir. (NPD, 2005).

Bygdevoll (Bygdevoll, 2010) did show the most important parameters found by NPD for the Norwegian fields. The scope of the study by NPD and oil companies of the Norwegian Continental Shelf considered the factors that had better correlation for its area of interest. It should not be understood that the same factors have the same relevance for all the fields around the globe. Table 7.3 reproduce the data contained in the lecture by Bygdevoll, regarding the RCI complexity attributes, its description and complexity scores.

7.2.2 Inferences about the Reservoir Complexity Index from the Norwegian petroleum directorate on the performance of dry and wet tree solutions.

From the same presentation a data set was extracted for the fields encompassed by the study differentiating the dry tree and the wet tree developments. The results of the analysis of this data set are shown graphically in figure 7.2.

What can be inferred from the figure 7.2 is that on the Norwegian Continental Shelf, depending of the complexity of the reservoir, there is:

A linear trend on the recovery factor for fields developed with dry tree to decrease as the reservoir becomes more complex.

An exponential trend on the recovery factor for fields developed with wet tree to decrease as the reservoir becomes more complex. A linear trend was also tested but is not shown because the exponential regressed function has a better R^2 (R^2 = 0.5891 in linear regression vs R^2 = 0.6672 in exponential regression).

When the reservoir has a low complexity (up to 0.4) it seems that there is not an evident difference between the performances of dry vs wet tree solutions. As the complexity increases however the dry tree solutions become a better option based on the recovery factor registered.

Many oil companies worldwide employ methodologies similar to the RCI as a common basis. Although the calculation of this index is out of the scope of this work it could be useful for the reader to take a look on the patented work of Harrison (Harrison, 2004) who propose *"A method for computing complexity, confidence and technical maturity indices for the evaluation of a reservoir."*

	Complexity attribute	***Description***	***Complexity score***				
			Low complexity				***High complexity***
			1	***2***	***3***	***4***	***5***
1	*Average permeability*	*Describes the pore volume weighted average permeability in the main flow direction of the defined reservoir. mD*	*>10*	*1000-10000*	*100-1000*	*10-100*	*<10*
2	*Permeability contrast*	*Describes the permeability contrast between geological layers/facies types, and is calculated as log 10 [Kmax/Kmin]*	*<1*	*1-2*	*2-3*	*3-4*	*>4*
4	*Structural complexity*	*Describes how fluid flow between wells is affected by fault density, fault throw, fault transmitability.*	*The fault properties does not restrict fluid flow*				*The fault properties restrict fluid flow significantly. (High density of faults with throw larger than reservoir thickness and/or zero transmissibility).*
5	*Lateral statigraphic continuity*	*Describes the statigraphic continuity of the flow units in the main flow direction within the defined reservoir.*	*High degree of continuity*				*Highly continuous. Difficult to predict/describe injector/producer connecting flow units.*
9	*Stock Tank Original Oil in Place (STOOIP) density*	*Describes the areal concentration of STOOIP and is defines as STOOIP/area (mill Sm^3/km^2)*	*<4.5*	*2-4.5*	*1-2*	*0.5-1*	*<0.5*
11	*Coning tendency*	*Describes the conning problems associated with a gas cap or aquifer support. Large complexity only in cases where the oil band is thin*	*No conning tendency*		*Some coning problems from gas cap or aquifer*		*Thin oil zone and production severely restricted by gas or water coning problems*

Table 7.3 RCI complexity attributes, their description and complexity scores [Bygdevoll, P.p. 7, 2010].

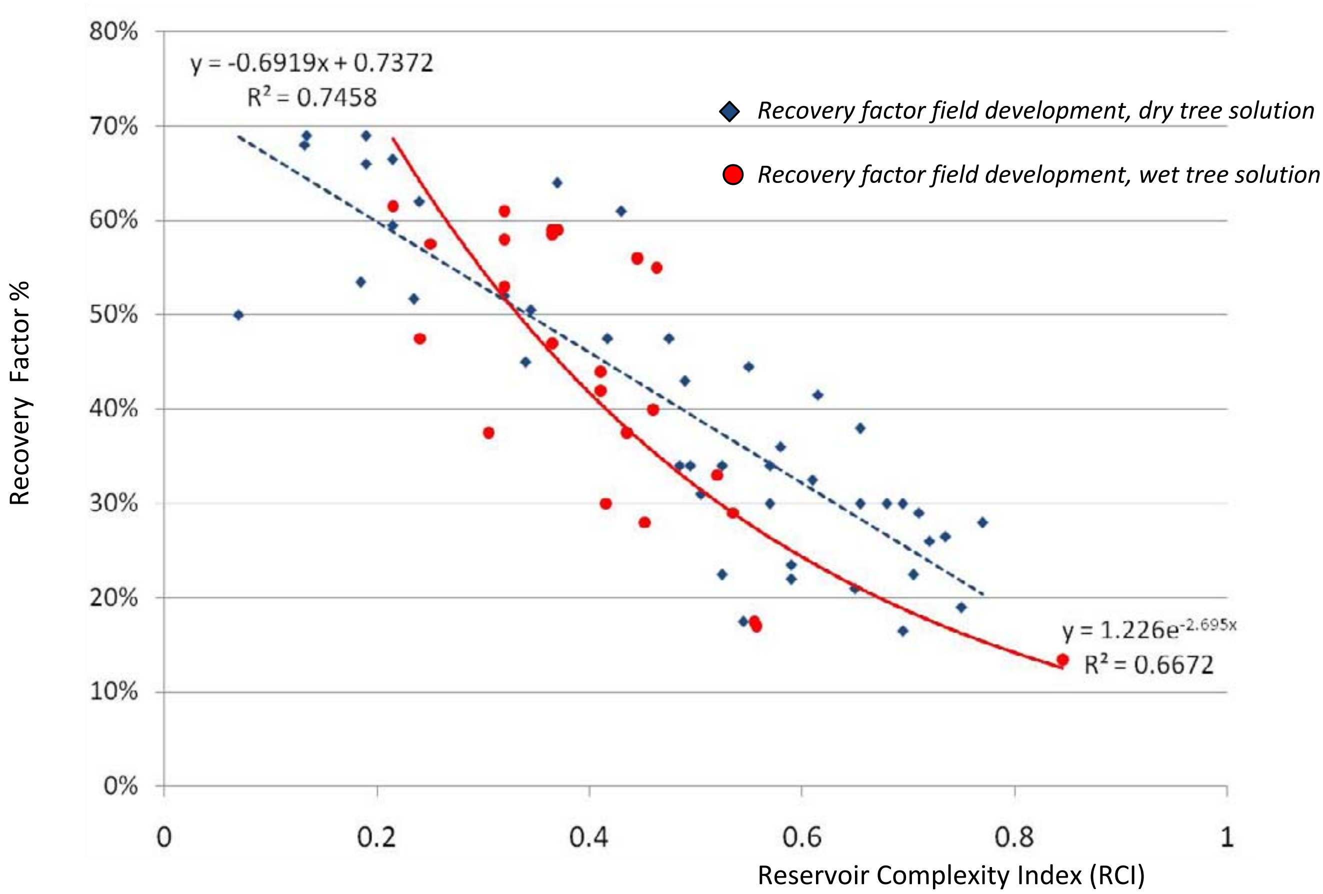


Figure 7.2 Scatter plot and a regression line showing the correlation between the recovery factors for oil from various deposits in relation to the reservoir complexity index (RCI), inferred data set from Bygdevoll, (Bygdevoll, P.p. 10, 2010]

8. Models presentation

Most of the calculations were made using the "Oil and Gas Exploration Economic Model" of the Nova Scotia Department of Energy (Nova Scotia, 2008), see annex F, and the results obtained were adjusted where necessary by the "Empirical cost models for TLP's and SPARS´s " (Jablonowsky, 2008), and the "Models of Lifetime Cost of Subsea Production Systems, prepared for Subsea JIP, System Description & FMEA" (Goldsmith, 2000).

In this work is also proposed a way to calculate the added value of an offshore structure acting as a hub, see point 8.4.

Tax calculations are out of the scope of this work, consequently, the results will show just values before taxes.

8.1 Oil and Gas Exploration Economic Model of the Nova Scotia Department of Energy

The description of the model as given on the web page is reproduced in the next two paragraphs.

> *The Oil and Gas Exploration Economic Model is an excel based model designed to provide screening economics for the evaluation of oil and gas exploration prospects and discoveries on the Nova Scotian shelf in the shallow waters around Sable Island, either as tie-ins to existing infrastructure or as stand-alone developments, and in deep water either as stand alone or with subsea tie back to existing infrastructure.*
>
> *The model provides full cycle calculations, from exploration to abandonment, and includes Nova Scotia offshore royalty and provincial and federal corporate income taxes. The government share is therefore incorporated into the cash flow and economic indicator calculations. [Nova Scotia,, P1, 2008].*

A full description of the model is shown in Annex F. Since the aim of this work is to evaluate a region that is different than this model is tailored for, a modification of the input costs was necessary. Tables 8.1, 8.2 and 8.3 show the assumptions used in the economical calculations of the investments in the field developments scenarios.

8.2 Empirical Cost Model for TLP's and SPAR's CAPEX.

Jablanowsky (Jablonowsky, 2008) presented a paper which estimates costs for SPAR's and TLP's projects using public and private data on 24 major projects. Besides, to provide an analysis of the variables that affect costs, the paper investigates the complexity of regression model specification in a decision-making setting. He also evaluates the sensitivity to modeling assumptions, sample selection bias, and other model specification issues.

When the models from point 8.2 and also 8.3 were used, a simple update in the costs was made using the "***IHS CERA Upstream Capital Costs Index (UCCI)".*** *The IHS CERA UCCI tracks the costs of equipment, facilities, materials, and personnel (both skilled and unskilled) used in the construction of a geographically diversified portfolio of twenty eight onshore, offshore, pipeline and LNG projects. It is similar to the consumer price index (CPI) in that it provides a* *clear, transparent benchmark tool for tracking and forecasting a complex and dynamic environment. The UCCI is a work product of CERA's Capital Costs Analysis Forum for Upstream (CCAF-U)."* [IHS Indexes, P1, 2010].

<u>**General Cost & Time Assumptions**</u>			
Estimate Date		1-Jan-09	
Deepwater Limit	Metres	200	
		Shallow Water	Deep Water
Seismic & Fixed Times			
Seismic Program Time	Days	90.0	90.0
Seismic Program Cost	KUSD	7,500.0	7,500.0
Seismic Processing Time	Days	180.0	180.0
Seismic Processing Cost	THOUSAND USD	3,500.0	3,500.0
Processing to Wildcat Time	Days	120.0	120.0
Wildcat Review Time	Days	90.0	90.0
Widcat Review Cost	THOUSAND USD	500.0	500.0
Wildcat to Appraisal Time	Days	120.0	120.0
Appraisal Review Time	Days	30.0	30.0
Appraisal Review Cost	THOUSAND USD	350.0	350.0
Time Between Appraisal Wells	Days	90.0	90.0
Appraisal to Preliminary Engineering	Days	180.0	180.0
Prelim Eng & Regulatory Prep	Days	300.0	300.0
Regulatory Approval	Days	180.0	180.0
Rig Rate	USD/day	250,000.0	500,000.0
Exploration / Appraisal Well Drilling			
Fixed Cost per well	THOUSAND USD	4,000.0	15,000.0
Fixed Cost per metre	USD/metre	2,300.0	3,400.0
Variable Cost per day (non-rig)	USD/day	180,000.0	250,000.0
Fixed days	Days	4.0	10.0
Average metres / day	metre/day	60.0	50.0
Development Well Drilling			
Fixed Cost per well	THOUSAND USD	3,000.0	6,000.0
Fixed Cost per metre	USD/metre	2,300.0	3,200.0
Variable Cost per day (non-rig)	USD/day	90,000.0	230,000.0
Fixed days	Days	2.0	4.0
Average metres / day	metre/day	40.0	40.0
Well Completion			
Fixed Cost per well	THOUSAND USD	700.0	700.0
Fixed Cost per metre	USD/metre	900.0	900.0
Variable Cost per day (non-rig)	USD/day	50,000.0	200,000.0
Fixed days	Days	2.0	3.0
Average metres / day	metre/day	600.0	600.0
Reenter & clean keeper	Days	4.0	4.0
Renenter predrill	Days	2.0	2.0
Preliminary Engineering			
Fixed Cost	THOUSAND USD	5,000.0	5,000.0
Variable Cost	USD/mcf	3.0	3.0

Table 8.1 Assumptions used in the economical calculation of the investments in field developments scenarios.

Gas Facilities			
Fixed Platform Fixed Cost	THOUSAND USD	7,000.0	
Fixed Platform Cost / Metre Water	THOUSAND USD/metre	320.0	
Fixed Platform Topside Fixed Cost	THOUSAND USD	25,000.0	
Fixed Platform Variable Cost	THOUSAND USD/MMSCFD	850.0	
Production Jack-up Fixed Cost	THOUSAND USD	190,000.0	
Production Jack-up Topside Fixed Cost	THOUSAND USD	5,000.0	
Jack-up Topside Variable Cost	THOUSAND USD/MMSCFD	600.0	
Tehtered Structure Fixed Cost	THOUSAND USD		300,000.0
Tethered Structure Cost /Metr e Water	THOUSAND USD/metre		5.0
Tethered Structure Topside Fixed Cost	THOUSAND USD		5,000.0
Tethered Structure Variable Cost	THOUSAND USD/MMSCFD		1,000.0
Additional Fixed Process Cost Sour Gas	THOUSAND USD	20,000.0	20,000.0
Additional Variable Process Cost Sour Gas	THOUSAND USD/MMSCFD	300.0	300.0
Subsea Well Surface Equipment	THOUSAND USD	2,000.0	10,000.0
Subsea Well Flowline Bundle	THOUSAND USD/Km	1,500.0	10,000.0
Subsea Manifold Fixed Cost	THOUSAND USD	9,000.0	25,000.0
Subsea Manifold Cost	THOUSAND USD/well	300.0	600.0
Oil Facilities			
FPSU Fixed Cost	THOUSAND USD	250,000.0	350,000.0
FPSU Platform Cost /MetreWater	THOUSAND USD/metre	5.0	5.0
FPSU Platform Topside Fixed Cost	THOUSAND USD	200,000.0	250,000.0
FPSU Platform Variable Cost	THOUSAND USD/MMBBL	1,200.0	1,200.0
Rented FPSU Fixed Cost	THOUSAND USD/day	170.0	200.0
Rented FPSU Variable Cost	THOUSAND USD/MMBBL/day	2.5	2.5
Export			
Export to Shore Pipeline Fixed Cost	THOUSAND USD	10,000.0	20,000.0
Export to Shore Pipeline Variable Cost	THOUSAND USD/km	1,000.0	1,200.0
Satellite Pipeline Fixed Cost – Sweet	THOUSAND USD	12,000.0	27,000.0
Satellite Pipeline Variable Cost – Sweet	THOUSAND USD/km	1,200.0	2,700.0
Satellite Pipeline Fixed Cost – Sour	THOUSAND USD	14,000.0	31,500.0
Satellite Pipeline Variable Cost – Sour	THOUSAND USD/km	1,400.0	3,150.0
Subsea Export Bundle Fixed Cost - Sweet	THOUSAND USD	7,000.0	15,750.0
Subsea Export Bundle Variable Cost – Sweet	THOUSAND USD/km	2,500.0	5,625.0
Subsea Export Bundle Fixed Cost – Sour	THOUSAND USD	10,000.0	22,500.0
Subsea Export Bundle Variable Cost - Sour	THOUSAND USD/km	3,500.0	7,875.0
Engineering and Project Management	%	0.1	0.1
Facilities Contingency	%	0.2	0.2

Table 8.2 Assumptions used in the economical calculation of the investments in field developments scenarios.

Abandonment Cost			
Fixed Platform Fixed	THOUSAND USD	3,000.0	
Fixed Platform per depth	THOUSAND USD/metre	30.0	
Jack-up Fixed Cost	THOUSAND USD	5,000.0	
Tethered Structure Fixed Cost	THOUSAND USD		5,000.0
FPSU Fixed Cost	THOUSAND USD		5,000.0
Subsea Manifold	THOUSAND USD	2,000.0	3,000.0
Cost per Surface Well	THOUSAND USD	2,000.0	2,000.0
Cost per Subsea Well & Flowline Bundle	THOUSAND USD	3,500.0	3,500.0
Export Pipeline variable cost	THOUSAND USD/km	100.0	100.0
Satellite Pipeline variable cost	THOUSAND USD/km	150.0	250.0
Operating Costs			
Platform & Jack-up Facilities			
Fixed Cost /Year			
Subsea	THOUSAND USD	2,000.0	2,000.0
basic process, water knock out	THOUSAND USD	7,000.0	7,000.0
full process, sweet	THOUSAND USD	19,000.0	19,000.0
full process, sour	THOUSAND USD	25,000.0	25,000.0
Fixed Cost /Year / Capacity			
Subsea	USD/MMSCFD	200.0	200.0
basic process, water knock out	USD/MMSCFD	280.0	280.0
full process, sweet	USD/MMSCFD	370.0	370.0
full process, sour	USD/MMSCFD	530.0	530.0
Variable Cost			
Subsea	USD/MCF	0.1	0.1
basic process, water knock out	USD/MCF	0.1	0.1
full process, sweet	USD/MCF	0.2	0.2
full process, sour	USD/MCF	0.2	0.2
Oil Costs			
Fixed Cost/Year	THOUSAND USD	10,000.0	12,000.0
Fixed Cost /Year / Capacity Sweet	USD/MBOPD	250.0	250.0
Fixed Cost /Year / Capacity Sour	USD/MBOPD	300.0	300.0
Variable Cost Sweet	USD/BBL	2.5	2.5
Variable Cost Sour	USD/BBL	3.2	3.2
Transport & Process Tariff			
Direct Pipeline Tie-in	USD/MCF	0.4	0.4
Satellite to Main Platform – Sweet	USD/MCF	0.6	0.6
Satellite to Main Platform – Sour	USD/MCF	0.8	0.8
Subsea Process & Transport – Sweet	USD/MCF	1.0	1.0
Subsea Process & Transport – Sour	USD/MCF	1.2	1.2
Shuttle Tankers	USD/BBL	0.7	0.7
Pipelines			
Fixed Cost /Year	THOUSAND USD	2,000.0	2,000.0
Variable Cost	THOUSAND USD / km	40.0	40.0

Table 8.3 Assumptions used in the economical calculation of the investments in field developments scenarios.

8.3 Goldsmith Models for OPEX, RAMEX and RISKEX.

Reference is made to paragraph 5.3 and "Models of Lifetime Cost of Subsea Production Systems, prepared for Subsea JIP, System Description & FMEA" (Goldsmith, 2000). The RAMEX results from this report are used to correct the calculations presented in chapter 9. The RISKEX are not included because every concept development has a particular and unique set of characteristics that cause considerably different outcome scenarios and consequently different results, too complex for a first initial screening as the scope of this work considers.

8.4 Value added of a floating structure acting as a Hub

As it is show in appendix G, the activity in deep water offshore Mexico is having place in a region with an evident lack of preexisting infrastructure. This fact makes it important to develop a network of facilities that should increase the feasibility of development in the future.

Hence it is proposed here that additional offshore structures shall have an added value for comparison purposes. This added value will be calculated by doing an evaluation of NPV for the prospects that could be developed if the facility would be in place already.

To account for this added value, a series of assumptions have been considered:

1. It will be assumed that the estimated prospective resources are the real original volume in place.
2. The net present value will also be discounted by some assigned probabilities representing discovery, appraisal and development in the way that:

Accounted added value =

NPV (Development the field X Overall Chance of success)

When apply…	*- NPV(Cost for planning development the field X Probability of pass an appraisal, given a discovery)*
When apply…	*- NPV (Cost for appraisal X Probability of a discovery)*
When apply…	*- NPV (Cost for wildcat)*

Where:

Overall Chance of Success = (Probability of discovery) X (Probability to pass to appraisal given a discovery) X (Probability of develop, given an appraisal, given a discovery)

These formulas are intended to discount the uncertainty of the discovery and also the uncertainty related to pass the different decision gates mentioned in chapter 4. It will also discount the irreversible investments that occur in the field development process.

3. The criteria to add prospects to the analysis was the distance to the proposed facility; when it was identified that there was less than 90 km in a slightly curved route, the prospect was allowed to be included in the calculations.

4. It should not be understood that all the included prospects are proposed to be tied back to the host facility since there are capability restrictions in every structure; it is just an assumption to calculate the added value of new infrastructure in the region of interest.

5. The parameters of the NPV calculation will be shown in chapter 9. As a general case, for calculation purposes, we will assume a subsea field development with a tie back to processing and a production stream induction through the offshore. In some cases an array in “daisy chain” is proposed. For many of the prospects a low probability and low forecasted resources were assumed since there was not a clear expectation related to them in the literature listed in chapter nine.

9.0 Case Analysis.

The scenarios to be studied in this thesis are included in the prospective areas of development of the National Company PEMEX Exploración y producción.

According to Morales (Morales, 2009) nine areas were defined as the most important for Mexican deep water. The most relevant characteristics to be considered were economical value, prospective resource size, hydrocarbon type, geological risk, distance to production facilities, and environmental restrictions. Figure 9.1 shows the prospective hydrocarbon fluids in Mexican offshore areas as well as the relative position of some of the exploratory wells and also US developments for reference. Figure 9.2 shows the location of the areas listed in table 9.1. Table 9.1 lists the areas with their associated geological risks and water depth.

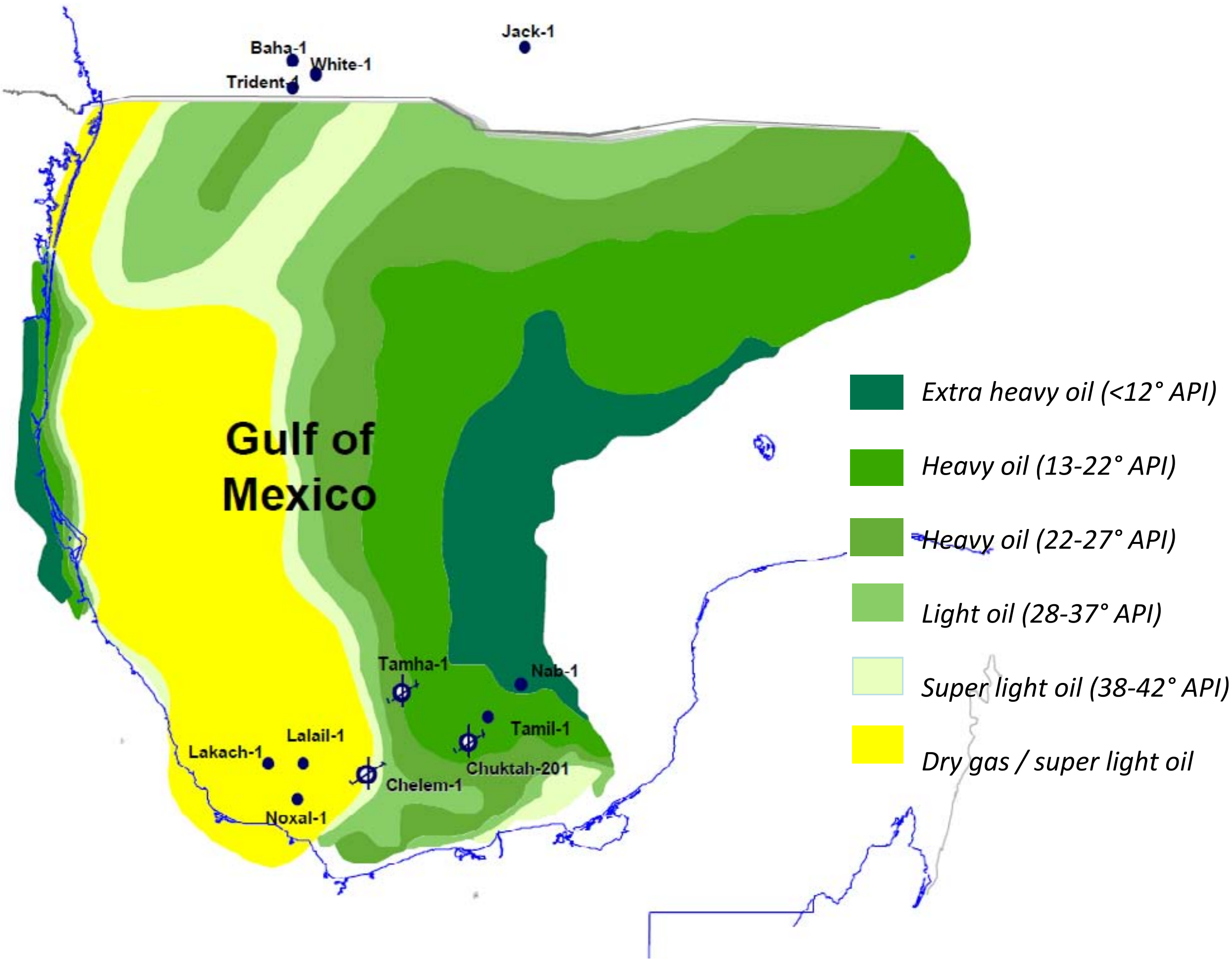


Figure 9.1 Prospective hydrocarbon fluids in Mexican offshore areas (Morales, 2009)

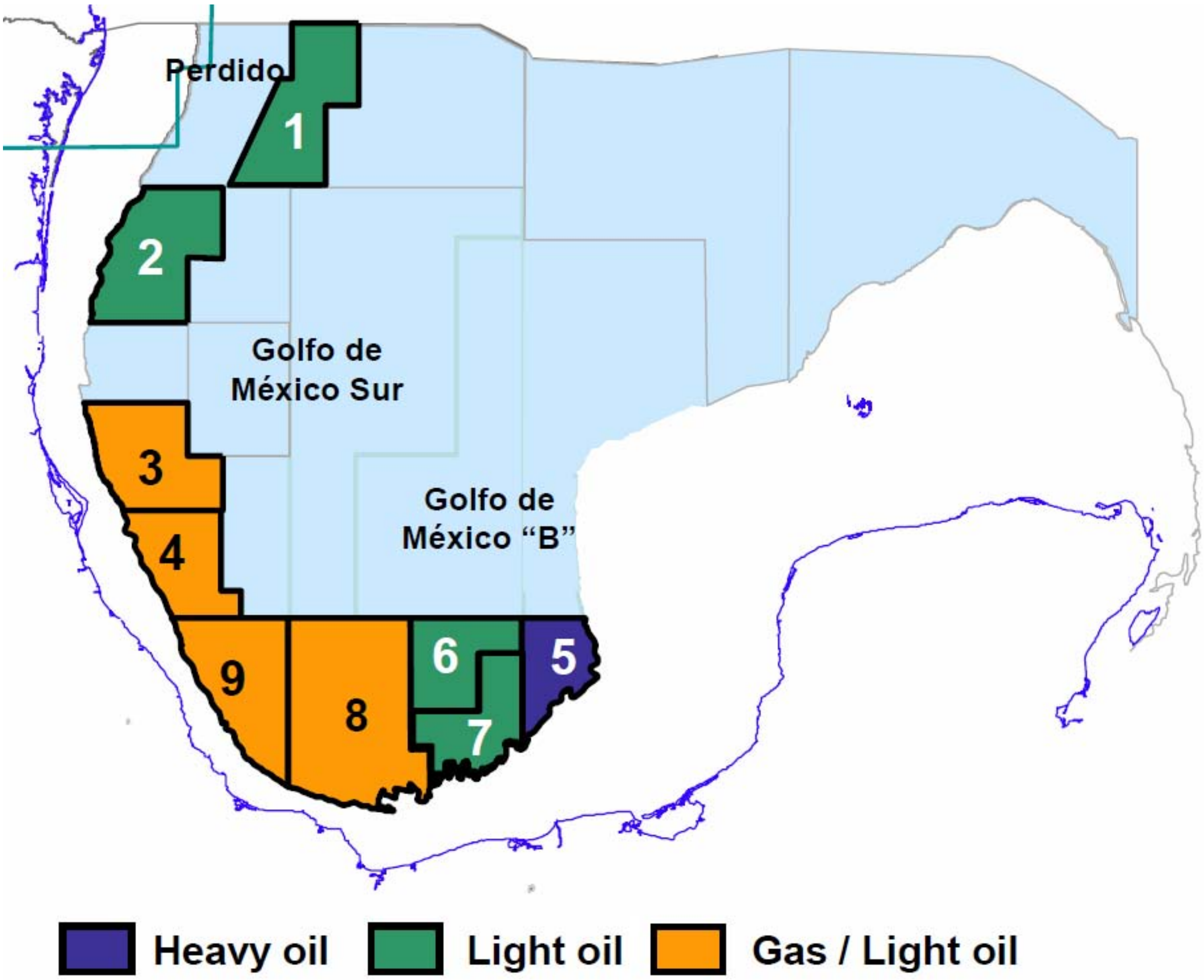


Figure 9.2 Mexican deep water areas after PEMEX (See table 9.1).(Morales, 2009)

Area	*Risk*	*Water depth (m)*
1. Perdido folded belt	*Low-Moderate*	*>2,000*
2. Oreos	*Moderate-High*	*800-2,000*
3. Nancan	*High*	*500-2,500*
4. Jaca-Patini	*Moderate-High*	*1000-1,500*
5. Nox-Hux	*Moderate*	*650-1,850*
6. Temoa	*High*	*850-1,950*
7. Han	*Moderate – High*	*450-2,250*
8. Holok	*Low-moderate (Western)*	*1,500-2,000*
	High (Eastern)	*600-1,100*
9. Lipax	*Moderate*	*950-2,000*

Table 9.1: Prospective deepwater areas defined by PEMEX in Mexican offshore. (Morales, 2009)

Table 9.2 lists the exploratory wells drilled by Pemex in deep waters (more than 500 meters water depth):

YEAR	*WELL*	*WATER DEPTH*	*TOTAL DEPTH*	*RESULT*	*Original Volume in place*	
					MMMcf	*MM B.O.E.*
2004	*Chukta-201*	*513 m*	*4901 m*	*Dry hole*	-------------	------------------
2004	*Nab-1*	*679 m*	*4050 m*	*Extra heavy oil, non commercial*		*408*
2006	*Noxal-1*	*936 m*	*3640 m*	*Gas, non comercial*	*583.60*	*85.9*
2007	*Lakach-1*	*988 m*	*3813 m*	*Gas, under development*	*1,732.70*	*255.1*
2007	*Lalail-1*	*805 m*	*3815 m*	*Gas, non comercial*	*1,181.30*	*173.9*
2008	*Chelem-1*	*810 m*	*3125 m*	*Dry hole*	-------------	------------------
2008	*Tamha-1*	*1121 m*	*4083 m*	*Dry hole*	-------------	------------------
2008	*Tamil-1*	*778 m*	*3598 m*	*Heavy oil, may be developed*		*200 (Prospective resources not incorporated as reserves)*
2009	*Leek-1*	*851 m*		*Gas, under evaluation*	*156.1*	*18*
2009	*Catamat-1*	*1230 m*	*5025 m*	*Gas, non-commercial*	-------------	------------------
2009	*Etbakel-1*	*681 m*	*4525 m*	*Oil, non-commercial*	-------------	------------------
2009	*Holok-1*	*n/a*	---------	*Non-productive, water*	-------------	------------------
2009	*Kabilil*	*n/a*	-----------	*Dry hole*	-------------	------------------

Table 9.2: Exploratory wells drilled by Pemex in deep waters (more than 500 meters water depth) from 2004-2009.

9.1 General basis for analysis.

As a result of above discussion, the set of deep water fields formed by Noxal, Lakach, Lalail, Tabscoob 201 and Leek was selected for study, incorporating also the shallow water discovery Tabscoob 101 due its close location to the deep water fields.

The analysis will not include Tamil and Nab fields, located in the Campeche bay region "Nox-Hux", however these fields will be commented on at the end of this chapter. The deep water heavy oil fields of Mexico are in a status of not commercially feasible, and it is possible that they are not technically feasible at this moment.

A summary of the initial assumptions for projects' evaluations are depicted in table 9.3. The projects of field development considered are Lakach (Lakach Field) and Holok (Noxal, Lalail, Leek and Tabscoob fields). The names of the projects are just representing proposals for the analysis in this study and it should not be understood that they are the real denominations of the projects.

The inclusion of the fields in the project Holok is also proposed in consideration of the relative proximity between the fields and the type of crude that is expected to be produced. The amount of reserves introduced for each case was the original volume in place multiplied by the mean recovery factor obtained for non associated gas reservoirs, see table 7.5 in chapter 7. Annex G provides more detailed information about each one of the fields.

One main characteristic of the area is that there is no closer facility than the compression Station Lerdo, around 50 km from Lakach development. The second closer export option for gas is located at least 130 km from Lakach in Coatzacoalcos.

Project	***Lakach***	***Holok***				

Evaluation Parameters

Discount Rate	*0.12*	*0.12*	*0.12*	*0.12*	*0.12*	*0.12*
Discount To	*Decision Date*	*Decision Date*	*Decision Date*	*Decision Date*	*Decision Date*	*Decision Date*
Economic Scenario	*Scenario 1 : NYMEX*	*Scenario 1 : NYMEX*	*Scenario 1 : NYMEX*	*Scenario 1 : NYMEX*	*Scenario 1 : NYMEX*	*Scenario 1 : NYMEX*

Project Parameters

Project Name	*Lakach*	*Noxal*	*Leek*	*Tabscoob 101*	*Tabscoob 201*	*Lalail*
Current Project Stage	*Development*	*Appraisal*	*Appraisal*	*Development*	*Wildcat*	*Appraisal*
Product Type	*Gas*	*Gas*	*Gas*	*Gas*	*Gas*	*Gas*
Original volume in place (Bcf)	*1732.7*	*583.6*	*156.1*	*140.9*	*300*	*1181.3*
Mean Reserves (Bcf) Wet tree design	*864.44*	*291.16*	*77.88*	*70.30*	*140*	*589.35*
Mean Reserves (Bcf) dry tree design	*925.26*	*311.64*	*83.36*	*75.24*	*149*	*630.81*
Water Depth (metres)	*988*	*936*	*848*	*234*	*400*	*806*
Reservoir Depth (m MSL)	*3150*	*2100*	*2200*	*1700*	*1700*	*2450*
Reservoir Complexity	*Medium*	*Medium*	*Medium*	*Medium*	*Medium*	*Medium*
Areal Extent Factor	*Medium*	*Medium*	*Medium*	*Medium*	*Medium*	*Medium*
Reservoir Pressure	*Normally Pressured*	*Normally Pressured*	*Normally Pressured*	*Normally Pressured*	*Normally Pressured*	*Normally Pressured*
Gas Calorific Value (btu/scf)	*1086*	*1086*	*1086*	*1086*	*1086*	*1086*
Liquid Yield (bbl/mmcf)	*59*	*59*	*59*	*59*	*59*	*59*
Gas Type	*Sweet*	*Sweet*	*Sweet*	*Sweet*	*Sweet*	*Sweet*
Keep Appraisal Wells ?	*No*	*No*	*No*	*No*	*No*	*No*

Risk Parameters (Chance of Proceeding to Next Phase)

Wildcat					*0.65*	
Appraisal	*N/A*	*0.75*	*0.75*		*0.75*	*0.75*
Development Planning	*1*	*1*	*1*	*1*	*1*	*1*

Table 9.3: Initial assumptions for projects' evaluations.

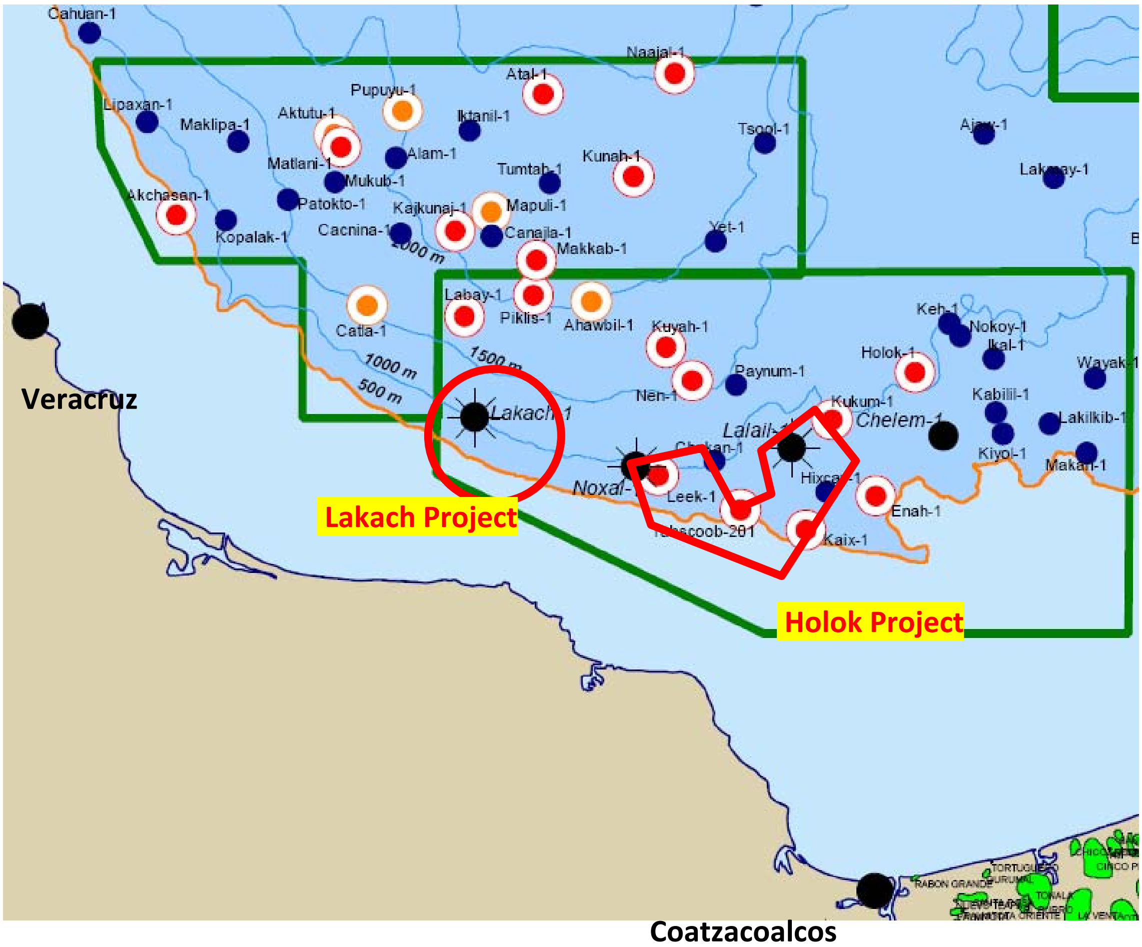


Figure 9.3: Location of deep water wild cat wells which lead to the definition of the fields listed in table 9.3. [Extracted from Hernandez, P. 15, 2009]

9.2 Scenario I: Deep water stand alone gas field

9.2.1 Basis for analysis

Refer to Annex G.

9.2.2 Alternative concepts to test

Subsea Tieback to Shore

This development scenario is a 60 km subsea tie back to shore development. The field will be connected to installations onshore for processing and the sales gas be recompressed and delivered to the network of pipelines of PEMEX onshore. It considers 8 development wells and modifications of the Compression Station Onshore, to process and induce the produced stream to the pipeline network of PEMEX. Its throughput capability should be no less than 360 MMSCFD/Day.

- ***TLP with dry tree, export pipeline for gas and off take through FSO for condensate.***

A TLP located in Lakach with a 60 km pipeline for gas export from the development to the compression Station Onshore. Offtake of oil and condensate will be possible trough an FSO. It considers 9 development dry wellhead wells with one single drilling center; the Facility also considers the inclusion of a full capability drilling package for drilling and workover.

The TLP should have the possibility to become a Hub for future possible developments of prospects (See table 9.4 and figures 9.4 and 9.5) and to have a throughput capability not minor than 360 MMSCFD/Day.

Name of the prospects	*Water Depth (m)*	*Forecasted Resources (MMMSCF Dry Gas)*	*Estimated Reserves (MMMSCF Dry Gas)*	*Distance to Lakach Field development*	*Probability of discovery*	*Probability to pass to appraisal given a discovery*	*Probability to develop, given the appraisal, given the discovery.*
KAJKUNAJ-1	*2073*	*1400*	*698*	*43 km*	*35%*	*50%*	*80%*
LABAY-1	*1700*	*1100*	*549*	*24 km*	*55%*	*50%*	*80%*
PIKLIS-1	*1,945*	*2400*	*1197*	*31 km*	*38%*	*50%*	*80%*
MAKKAB-1	*1,945*	*600*	*299*	*34 km*	*55%*	*50%*	*80%*
KUNAH-1	*2,160*	*2100*	*1048*	*65 km*	*44%*	*50%*	*80%*
ATAL-1	*2,409*	*1600*	*798*	*72 km*	*41%*	*50%*	*80%*
NAAJAL-1	*2470*	*2600*	*1297*	*88 km*	*39%*	*50%*	*80%*

Table 9.4: Identified prospects located close to the Lakach development area with assumed resources reserves and probabilities of development for calculation of added value.

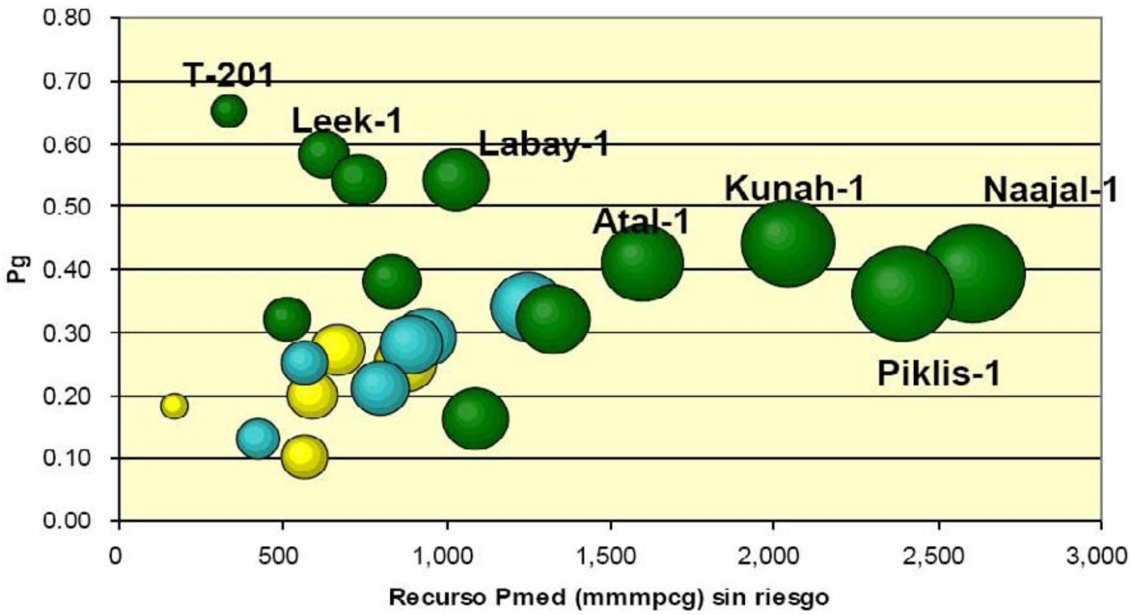


Figure 9.4: Identified prospects located close to the Lakach development area with assumed forecasted resources and geological probability of success after PEMEX [Hernandez, 2009]

- ***SPAR with dry tree, export pipeline for gas and off take through FSO for condensate.***

A SPAR located in Lakach with a 60 km pipeline for gas export from the development to the compression Station Onshore. Offtake of oil and condensate will be possible trough an FSO. It considers 9 development dry wellhead wells with one single drilling center, the Facility also considers the inclusion of a full capability drilling package for drilling and workover.

The Spar should have the possibility to become a Hub for future possible developments of prospects (See table 9.4 and figures 9.4 and 9.5) and to have a throughput capability not minor than 360 MMSCFD/Day.

Figure 9.5: Location of prospects and hypothetical paths of pipelines if Lakach would have been developed as a processing Hub for future field developments in this gas province.

9.2.3 Results

Tables 9.5 to 9.8 show the summary of calculations done for this scenario.

Project scenario	**Deep water stand alone gas field**
Concept	**Subsea Tieback to Shore**
Stage of the Project	**Development planning**
Overall Chance of Success	**100.0%**
First Production Date	**15-Dec-12**
Abandonment Date	**1-Mar-28**
Project Start Date	**1-Jul-10**

Risked Discounted Values		**Thousands USD**	**Millions USD**
Income			
Gas Revenue			3,342.5
Liquids Revenue			1,991.7
Total Revenue			5,334.1
Expenditures			
Seismic			-
Wildcat			-
Appraisal			-
Development Planning			**- 7.4**
Preliminary Engineering Cost		7,439.06	
CAPEX Facilities & Pipelines			**- 771.0**
MainStructure (Modification of Compression Station Onshore		368,800.00	
Topside Facilities		-	
Subsea Surface & Flowlines		29,800.00	
Export Pipeline / satellite bundle		353,250.00	
Engineering & Project Management		19,152.50	
CAPEX Development Drilling			**- 509.4**
8 New Subsea Wells (Driling & Completion)		509,400.76	
OPEX			**- 227.9**
Facilities		56,793.41	
Well intervention		134,220.99	
Export		36,910.77	
RAMEX			**- 540.0**
Abandonment Expenditures			**- 10.5**
		Total Costs	**- 2,066.3**
		NPV @ 12.0 % ($M)	**3,267.9**
Added value using the structure as a Hub.			**0**

Table 9.5: Calculation results for the Deep water stand alone gas field with a concept of development as Subsea Tieback to Shore.

Project scenario	**Deep water stand alone gas field**
Concept	**TLP with dry tree, export pipeline for gas and off take through FSO for condensate.**
Stage of the Project	**Development planning**
Overall Chance of Success	**100.0%**
First Production Date	**15-Dec-12**
Abandonment Date	**1-Mar-28**
Project Start Date	**1-Jul-10**

Risked Discounted Values		**Thousands USD**	**Millions USD**
Income			
Gas Revenue			3,125.9
Liquids Revenue			1,879.1
Total Revenue			5,005.0
Expenditures			
Seismic			-
Wildcat			-
Appraisal			-
Development Planning			- 7.4
Preliminary Engineering Cost		7,439.06	
CAPEX Facilities & Pipelines			**- 1,094.6**
Main structure		331,763.65	
Topside Facilities (Include a full capability Drilling Package)		612,560.30	
Subsea Surface & Flowlines		28,360.53	
Export Pipeline / satellite bundle		84,275.41	
Engineering & Project Management		37,636.36	
CAPEX Development Drilling			**- 362.9**
9 New dry wellhead Wells (Driling & Completion)		362,914.32	
OPEX			**- 344.5**
Facilities		85,841.02	
Well intervention		202,869.79	
Export		55,789.19	
RAMEX			**- 100.2**
Abandonment Expenditures			- 30.0
		Total Costs	**- 1,939.6**
		NPV @ 12.0 % ($M)	**3,065.4**
		Added value using the structure as a Hub.	**2533**

Name of the prospects	Accounted Added Value (Millions USD)
KAJKUNAJ-1	277
LABAY-1	315
PIKLIS-1	422
MAKKAB-1	152
KUNAH-1	440
ATAL-1	402
NAAJAL-1	525
Accounted added value of an offshore floating structure in Lakach location	2533

Table 9.6: Calculation results for the Deep water stand alone gas field with a concept of development as TLP with dry tree, export pipeline for gas and off take through FSO for condensate.

Project scenario	**Deep water stand alone gas field**
Concept	**SPAR with dry tree, export pipeline for gas and off take through FSO for condensate.**
Stage of the Project	**Development planning**
Overall Chance of Success	**100.0%**
First Production Date	**15-Dec-12**
Abandonment Date	**1-Mar-28**
Project Start Date	**1-Jul-10**

Risked Discounted Values		**Thousands USD**	**Millions USD**
Income			
Gas Revenue			3,125.9
Liquids Revenue			1,879.1
Total Revenue			5,005.0
Expenditures			
Seismic			-
Wildcat			-
Appraisal			-
Development Planning			- 7.4
Preliminary Engineering Cost		7,439.06	
CAPEX Facilities & Pipelines			**- 1,031.2**
Main structure		515,369.52	
Topside Facilities (Include a full capability Drilling Package)		365,602.00	
Subsea Surface & Flowlines		28,360.53	
Export Pipeline / satellite bundle		84,275.41	
Engineering & Project Management		37,636.36	
CAPEX Development Drilling			**- 362.9**
9 New dry wellhead Wells (Driling & Completion)		362,914.32	
OPEX			**- 344.5**
Facilities		85,841.02	
Well intervention		202,869.79	
Export		55,789.19	
RAMEX			**- 104.2**
Abandonment Expenditures			- 32.0
		Total Costs	**- 1,818.3**
		NPV @ 12.0 % ($M)	**3,186.7**
		Added value using the structure as a Hub.	**2533**

Name of the prospects	Accounted Added Value (Millions USD)
KAJKUNAJ-1	277
LABAY-1	315
PIKLIS-1	422
MAKKAB-1	152
KUNAH-1	440
ATAL-1	402
NAAJAL-1	525
Accounted added value of an offshore floating structure in Lakach location	2533

Table 9.7: Calculation results for the Deep water stand alone gas field with a concept of development as SPAR with dry tree, export pipeline for gas and off take through FSO for condensate.

Summary Evaluation Parameters	KAJKUNAJ	LABAY	PIKLIS	MAKKAB	KUNAH	ATAL	NAJAAL
Overall Chance of Success	14.00%	22.00%	15.20%	22.00%	17.60%	16.40%	15.60%
First Production Date	28/11/2014	17/12/2014	11/12/2016	23/06/2014	20/11/2016	12/11/2014	20/10/2016
Abandonment Date	01/03/2030	01/03/2030	01/03/2032	01/03/2024	01/03/2032	01/03/2030	01/03/2032
Discount Date	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010
Risked Discounted Values NPV @ 12.0 % ($M USD)							
Gas Revenue	319.6	392.2	493.9	236.2	503.2	430.9	557.6
Liquids Revenue	192.3	236.0	296.6	142.0	302.2	259.2	335.0
Total Revenue	512.0	628.2	790.5	378.2	805.4	690.1	892.6
Seismic	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wildcat	-48.8	-55.7	-51.2	-51.2	-47.2	-42.6	-41.5
Appraisal	-40.4	-71.3	-58.4	-46.6	-62.6	-41.3	-48.7
Development Planning	-1.0	-1.5	-1.3	-1.4	-1.5	-1.3	-1.4
Facilities & Pipelines	-35.7	-35.1	-117.2	-46.0	-120.2	-65.7	-134.8
Development Drilling	-38.6	-62.1	-60.1	-28.6	-50.9	-42.6	-50.0
Operations	-69.0	-86.7	-78.4	-50.5	-81.1	-93.2	-89.6
Abandonment	-1.0	-1.3	-1.4	-1.5	-1.6	-1.5	-1.9
Total Costs	-234.6	-313.7	-368.1	-225.8	-365.0	-288.3	-368.1
Accounted added value	277.4	314.5	422.4	152.3	440.3	401.9	524.5

Table 9.8: Summary of calculation results for the added value of the offshore floating structure in the location of Lakach.

9.3 Scenario II: Deep water array of gas and condensate fields in proximity

Table 9.3 lists the characteristics of the fields Noxal, Leek, Tabscoob and Lalail. All of them are discoveries with probable and possible reserves in place. The small size and relatively large distance to infrastructure are the main factors to postpone their development. Based in the similarity of these issues with the *Canyon Express field development* (see chapter 6 and annex C.), it is proposed in this work, to address the challenge of the development proposing the concepts:

1. Subsea development with tiebacks to a platform of separation and recompression with off take in FSO for condensate.
2. Floating structure for separation and recompression with off take through an FSO for condensate for tie back of the fields Noxal, Leek and Tabscoob based in Lalail.
3. Floating structure for separation and recompression with off take through an FSO for condensate for tie back of fields Lalail, Leek and Tabscoob based in Noxal.

A comparison between dry and wet well trees will not be developed for this scenario. The reasons are that the proposed concepts considered are only subsea developments and there were not found a significant difference in the comparison using dry vs. wet well trees for the kind of hydrocarbons that are understood to be found in the prospects (See chapter 7).

9.3.1 Basis for analysis

Refer to Annex G.

9.3.2 Alternative concepts to test

- ***Subsea developments in tieback to a platform of separation and recompression with offtake in FSO for condensate.***

The Holok compression station offshore (HCSO) is the proposed new offshore structure with separation and recompression that will serve as a Hub for the development of the Fields, Lalail, Noxal, Leek, and the Tabscoobs (101, 201). HCSO will take advantage of a shallow water location to become the structure for subsea tieback developments.

In figure 9.6 is shown the location of the structures and the fields and also a number of routes in red that might be considered for a further study (not included in this work) to give some hint about the added value of this offshore facility for the development of additional prospects.

A summary of the Technical parameters for evaluation are listed below.

- 65 km export distance from HCSO to the Compression Station Onshore.
- 100 m water depth.
- Offtake of oil and condensate trough an FSO.
- Hub for future possible developments of prospects (See table 9.9 and figure 9.6).
- Throughput capability: 430 MMSCFD/Day

Name of the prospects	Water Depth (m)	Forecasted Resources (MMMSCF Dry Gas)	Estimated Reserves (MMMSCF Dry Gas)	Distance to HCSO	Probability of discovery	Probability to pass to appraisal given a discovery	Probability to develop, given the appraisal, given the discovery.
NOXAL	936	583.6	291.16	20 km	100%	75%	100%
LEEK	848	156.1	77.88	20 km	100%	75%	100%
LALAIL	806	1181.3	589.35	46 km	100%	75%	100%
TABSCOOB 101	234	140.9	70.30	29 km	100%	100%	100%
TABSCOOB 201	400	300	140	30 km	65%	75%	100%

Table 9.9: Complementary assumptions for the calculation of the project scenario "Deep water array of gas and condensate fields in proximity"; Concept "Subsea developments in tieback to a platform of separation and recompression with offtake in FSO for condensate".

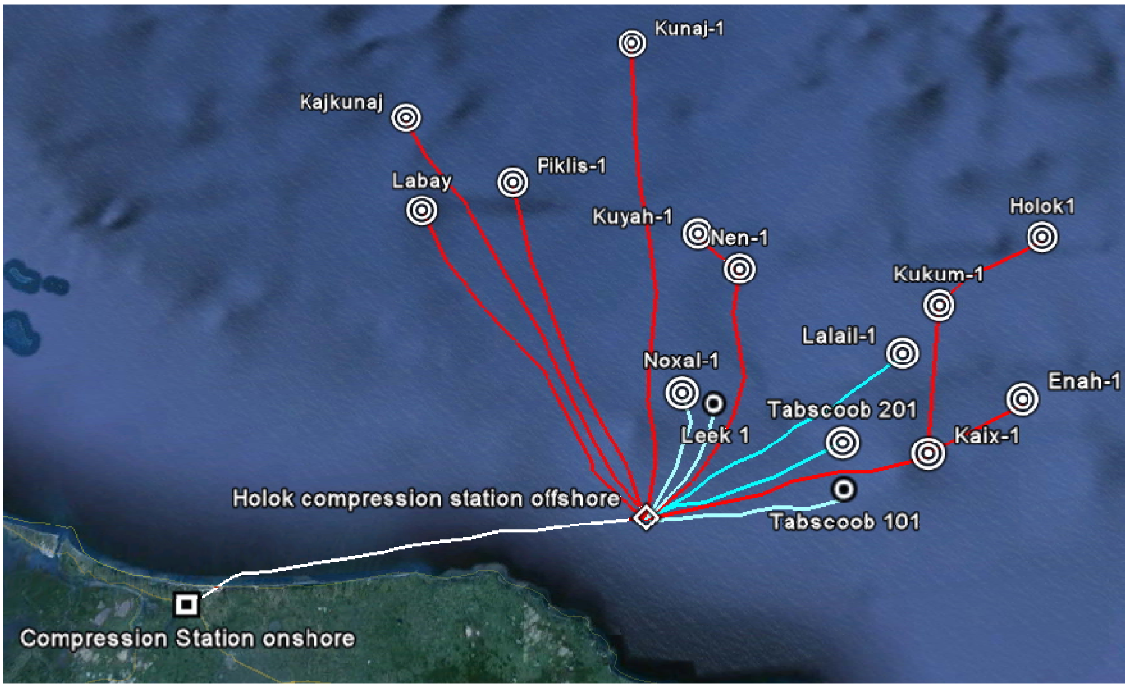


Figure 9.6: Hypothetical development for HOCS and the future field developments of this gas province.

- ***Floating structure of separation and recompression with off take on an FSO for condensate for the fields Noxal, Leek and Tabscoob based in Lalail.***

This concept proposes a semisubmersible or a floating structure with wet trees. Drilling is considered to be done with semisubmersibles and drilling vessels. The facility would be a manned new brand offshore structure with separation and recompression that will serve as a Hub for the development of the Fields, Lalail, Noxal, Leek, and also the Tabscoobs (101, 201).

The field Lalail is selected because it be the largest discovery with relation to the reserves estimated to be in place.

Figure 9.7 shows the relative location of the fields and also a number of routes in red that might be considered for a further study (not included in this work) to give more basis to estimate the added value of this offshore facility for the development of additional prospects.

A summary of the Technical parameters for evaluation are listed below.

- 110 km Export distance from the Lalail floating hub to the Compression Station Onshore.
- 806 m water depth.
- Offtake of oil and condensate trough an FSO.
- Hub for future possible developments of prospects (See table 9.10 and figure 9.7).
- Throughput capability: 430 MMSCFD/Day

Name of the prospects	***Water Depth (m)***	***Forecasted Resources (MMMSCF Dry Gas)***	***Estimated Reserves (MMMSCF Dry Gas)***	***Distance to LALAIL***	***Probability of discovery***	***Probability to pass to appraisal given a discovery***	***Probability to develop, given the appraisal, given the discovery.***
LALAIL	*806*	*1181.3*	*589.35*	*-----------*	*100%*	*75%*	*100%*
NOXAL	*936*	*583.6*	*291.16*	*5 km*	*100%*	*75%*	*100%*
LEEK	*848*	*156.1*	*77.88*	*30 km[5]*	*100%*	*75%*	*100%*
TABSCOOB 201	*400*	*300*	*140*	*17 km*	*65%*	*75%*	*100%*
TABSCOOB 101	*234*	*140.9*	*70.30*	*7 km[6]*	*100%*	*100%*	*100%*

Table 9.10: Complementary assumptions for the calculation of the project scenario "Deep water array of gas and condensate fields in proximity"; Concept " Floating structure of separation and recompression with off take in FSO for condensate for the fields Noxal, Leek and Tabscoob based in Lalail".

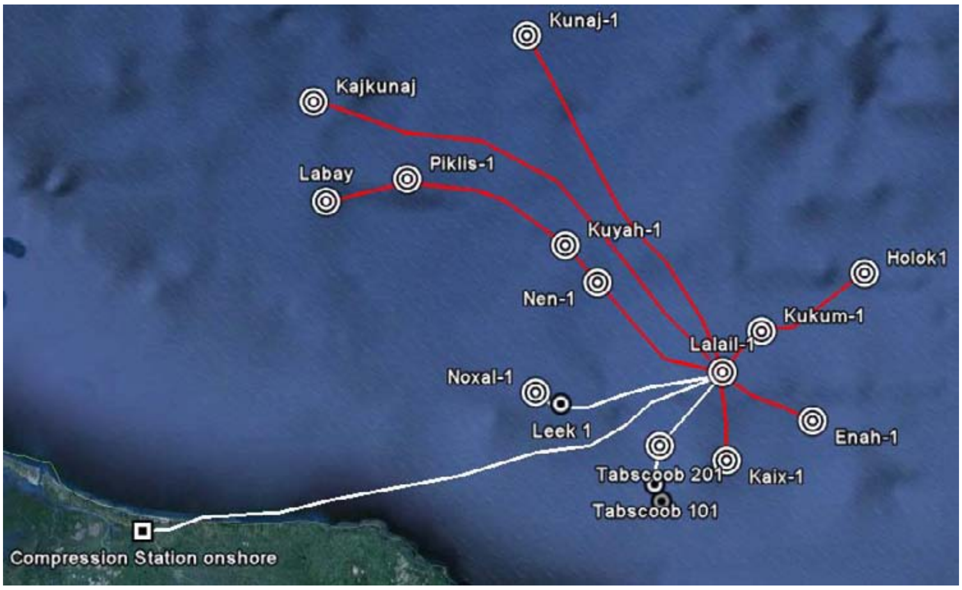


Figure 9.7: Hypothetical development for a Floating structure in Lalail also as a Hub for the future field developments of this gas province.

[5] *Note: A daisy chain Noxal-Leek_Lalailwill be evaluated*
[6] *Note: A daisy chain Lalail - Tabscoob (101) – Tabscoob (201) will be evaluated.*

- ***Floating structure of separation and recompression with off take on an FSO for condensate for the fields Lalail, Leek and Tabscoob based in Noxal***

This concept proposes a semisubmersible or a floating structure with wet trees. Drilling is considered to be done with semisubmersibles and drilling vessels. The facility would be a manned new brand offshore structure with separation and recompression that will serve as a Hub for the development of the Fields, Lalail, Noxal, Leek, and also the Tabscoobs (101, 201).

The field Noxal is selected because it be the second largest discovery with relation to the reserves estimated to be in place and the relative proximity to the Leek project, which is expected to give a better economical result than other options not mentioned so far.

Figure 9.8 shows the relative location of the fields and also a number of routes in red that might be considered for a further study (not included in this work) to give more basis to estimate the added value of this offshore facility for the development of additional prospects.

A summary of the Technical parameters for evaluation are listed below.

- 72 km Export distance from the Noxal floating hub to the Compression Station Onshore.
- 936 m water depth.
- Offtake of oil and condensate trough an FSO.
- Hub for future possible developments of prospects (See table 9.11 and figure 9.8).
- Throughput capability: 430 MMSCFD/Day

Name of the prospects	***Water Depth (m)***	***Forecasted Resources (MMMSCF Dry Gas)***	***Estimated Reserves (MMMSCF Dry Gas)***	***Distance to NOXAL***	***Probability of discovery***	***Probability to pass to appraisal given a discovery***	***Probability to develop, given the appraisal, given the discovery.***
NOXAL	*936*	*583.6*	*291.16*	*-----------*	*100%*	*75%*	*100%*
LEEK	*848*	*156.1*	*77.88*	*5 km**	*100%*	*75%*	*100%*
TABSCOOB 201	*400*	*300*	*140*	*19 km**	*65%*	*75%*	*100%*
TABSCOOB 101	*234*	*140.9*	*70.30*	*7 km*[7]*	*100%*	*100%*	*100%*
LALAIL	*806*	*1181.3*	*589.35*	*34 km*	*100%*	*75%*	*100%*

Table 9.11: Complementary assumptions for the calculation of the project scenario "Deep water array of gas and condensate fields in proximity"; Concept: " Floating structure of separation and recompression with off take in FSO for condensate for the fields Noxal, Leek and Tabscoob based in Noxal".

[7] *Note: A daisy chain Noxal-Leek-Tabscoob (101) – Tabscoob (201) will be evaluated.*

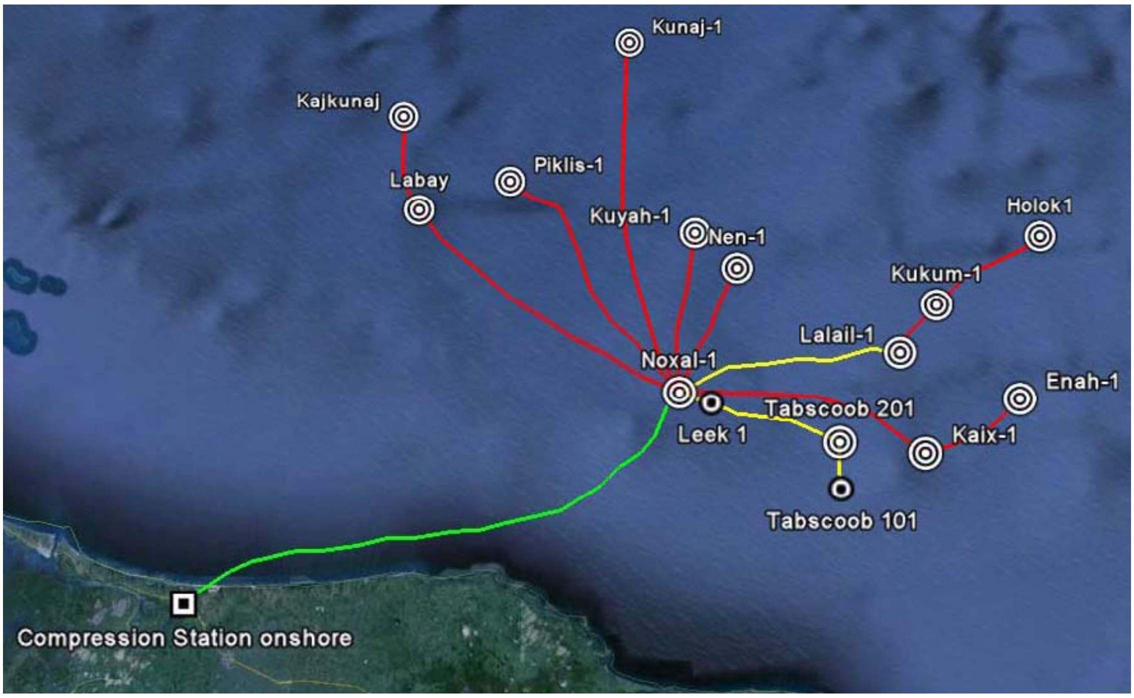


Figure 9.8: Hypothetical development for a Floating structure in Noxal also as a Hub for the future field developments of this gas province.

9.3.3 Results

Tables 9.12 to 9.14 show the summary of calculations done for this scenario.

Project scenario	Deep water array of gas and condensate fields in proximity					
Concept	**Subsea developments in tieback to a platform of separation and recompression with offtake in FSO for condensate.**					
	HOCS	LALAIL	NOXAL	LEEK	TABSCOOB 1	TABSCOOB 2
Overall Chance of Success	N/A	0.75	0.75	0.75	1	0.4875
First Production Date (Available from, for HOCS)	17/05/2012	26/03/2014	22/09/2013	25/05/2013	01/06/2013	21/01/2014
Abandonment Date	01/04/2029	01/03/2029	01/03/2024	01/03/2021	01/03/2021	01/03/2022
Discount Date	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010
Number of development wells to be drilled		6	3	1	1	2
Throughput capability: MMSCFD/Day	430.00	198.46	99.23	33.08	66.15	33.08
Risked Discounted Values NPV @ 12.0 % ($M USD)						
Gas Revenue		1540.78	842.32	240.72	289.43	263.28
Liquids Revenue		925.13	503.98	143.52	172.60	157.98
Total Revenue		2465.91	1346.31	384.24	462.03	421.27
Seismic		0.00	0.00	0.00	0.00	0.00
Wildcat		0.00	0.00	0.00	0.00	-41.90
Appraisal		-142.58	-82.43	-47.42	-49.52	-25.76
Development Planning		-4.50	-4.07	-3.72	-4.93	-2.36
Facilities & Pipelines	-591.01	-214.04	-112.44	-113.18	-200.39	-99.25
Development Drilling		-210.04	-84.66	-31.64	-44.96	-32.59
Operations	-504.07	-335.87	-177.46	-61.62	-78.71	-61.73
Abandonment	-7.69	-5.58	-4.42	-3.53	-5.63	-3.21
Total Costs	-1102.77	-691.61	-354.98	-224.28	-347.31	-151.24
NPV @ 12.0 % ($M USD)	**-1102.77**	**1774.30**	**991.33**	**159.96**	**114.71**	**270.02**
					NPV @ 12.0 % ($M USD)	**2207.55**

Table 9.12: Results for the calculation of the project scenario "Deep water array of gas and condensate fields in proximity"; Concept "Subsea developments in tieback to a platform of separation and recompression with off take in FSO for condensate.".

Project scenario	Deep water array of gas and condensate fields in proximity				
Concept	**Floating structure of separation and recompression with off take in FSO for condensate for the fields Noxal, Leek and Tabscoob based in Lalail.**				
	LALAIL	LEEK	NOXAL	TABSCOOB 201	TABSCOOB 101
Overall Chance of Success	0.75	0.75	0.75	0.4875	1
First Production Date	30/11/2015	05/06/2016	22/09/2016	23/01/2017	19/05/2016
Abandonment Date	01/03/2030	01/03/2024	01/03/2027	01/03/2025	01/03/2024
Discount Date	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010
Number of development Wells	6	3	1	2	1
Throughput capability: MMSCFD/Day	430.00	99.23	33.08	66.15	33.08
Risked Discounted Values; NPV @ 12% (USD $M)					
Gas Revenue	1317.79	170.81	599.96	187.27	205.84
Liquids Revenue	793.00	101.87	358.97	112.37	122.71
Total Revenue	2110.79	272.68	958.94	299.64	328.55
Seismic	0	0	0	0	0
Wildcat	0	0	0	-33.07	0
Appraisal	-186.23	-37.03	-58.67	-20.33	-35.39
Development Planning	-5.27	-2.65	-2.90	-1.68	-3.51
Facilities & Pipelines	-954.58	-109.78	-36.48	-46.10	-56.30
Development Drilling	-270.55	-25.76	-60.26	-27.23	-32.19
Operations	-238.54	-44.72	-124.74	-43.15	-53.21
Abandonment	-6.71	-3.06	-2.51	-1.86	-2.41
Total Costs	-1661.88	-179.92	-257.30	-144.26	-155.56
NPV @ 12.0 % ($M USD)	**448.91**	**14.17**	**425.25**	**69.01**	**78.29**
				TOTAL NPV @ 12.0 % ($M USD)	**1035.64**

Table 9.13: Results for the calculation of the project scenario "Deep water array of gas and condensate fields in proximity"; Concept "Floating structure of separation and recompression with off take in FSO for condensate for the fields Noxal, Leek and Tabscoob based in Lalail".

Project scenario	Deep water array of gas and condensate fields in proximity				
Concept	**Floating structure of separation and recompression with off take in FSO for condensate for the fields Lalail, Leek and Tabscoob based in Noxal**				
	Noxal	Leek	Tabscoob 201	Tabscoob 101	Lalail
Overall Chance of Success	0.75	0.75	0.4875	0.75	0.75
First Production Date	01/07/2015	14/05/2016	24/01/2017	19/05/2016	26/03/2017
Abandonment Date	01/03/2025	01/03/2024	01/03/2025	01/03/2024	01/03/2032
Discount Date	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010
Number of development wells	4	1	2	1	6
Throughput capability: MMSCFD/Day	430.00	30.71	61.43	30.71	184.29
Risked Discounted Values; NPV @ 12% ($M USD)					
Gas Revenue	712.07	171.85	187.21	155.04	1096.70
Liquids Revenue	428.80	102.43	112.34	92.43	658.49
Total Revenue	1140.87	274.28	299.56	247.47	1755.19
Seismic	0.00	0.00	0.00	0.00	0.00
Wildcat	0.00	0.00	-33.07	0.00	0.00
Appraisal	-82.43	-32.60	-20.33	-35.25	-101.49
Development Planning	-4.07	-2.65	-1.68	-2.63	-3.20
Facilities & Pipelines	-779.95	-36.40	-49.87	-42.22	-118.00
Development Drilling	-71.60	-21.38	-27.21	-24.00	-149.50
Operations	-119.85	-42.51	-43.26	-40.01	-237.45
Abandonment	-5.65	-1.69	-1.93	-1.80	-3.64
Total Costs	-1063.55	-137.23	-144.27	-145.92	-613.27
NPV @ 12.0 % ($M USD)	22.68	137.04	155.29	101.55	1141.91
				Total NPV @ 12.0 % ($M USD)	**1613.12**

9.4. Deep water heavy and extra heavy oil fields.

Table 9.2 lists a large discovery (NAB-1) mentioned as an extra heavy oil field and accounting for 400 MM B.O.E. The original volume of 3P oil reserves is 408.0 million barrels, while the original 3P oil equivalent reserves are estimated at 32.6 million barrels.

The payzone is estimated to be at a total profundity of 2800 m at 679 m water depth. The API grade for the oil is estimated to be between 8 an 10 degrees.

These characteristics make the field, one of the most challenging fields in the world, in case that in some moment it would be indented to be developed. No historical reference exists for a commercial development for this depth and fluid properties.

> *Heavy oil, extra-heavy oil, and bitumen projects are large undertakings and very capital intensive. In addition to the production infrastructure, additional upgrading, refining, and transportation facilities are needed. Pipelines for heavy oil and possibly for CO2 sequestration would be needed. Another issue is obtaining a sufficient supply of diluent for pipelining heavy oil. These projects also have long operating and payback periods, so unstable oil prices can deter long-term investments.[NPC, P.p. 2,2007]*

Additional information on this respect might be consulted in "Topic paper #22, heavy oil" (NPC, 2007).

9.5. Conclusions

In the first scenario, it was found that the best Net Present Value assessment result for the development of the Lakach field is the concept of subsea tieback to shore. This is true when an additional value for the development of infrastructure in the region is not considered. Although the concept has higher economical penalties in the RAMEX because of the higher costs for it maintenance, the savings in the CAPEX are notorious.

On the other hand, the potential of the Region of Holok-Temoa, related to the prospects listed in table 9.4, might increase considerably the strategic value of the investments in infrastructure. This infrastructure would be available when offshore structures and a network of pipelines will be developed in the region.

Lakach development has an ample positive Net Present Value before taxes even when a floating structure was selected. Also the calculated added value that could be obtained by using the floating structure as a hub as shown in table 9.8. Lakach has also a geographical advantage since it is located at less than 1000 meters of water depth; much easier to develop when is compared to other identified prospects of development that go from 1700 m up to 2500 m water depth.

Figure 9.5 shows a hypothetical development that could have Lakach as a processing Hub for the future field developments of this gas province.

The Lakach Field development has already been committed to be developed as a subsea tieback to shore. Consequently for future concept selection, it is strongly recommended to keep in mind the fact that the development of infrastructure increases the feasibility of future developments and increase the overall recoveries rates from the oil and gas fields.

On the second scenario, It was found that a series of medium-small size fields might be economically developed when they are planned as a group of fields.

The best NPV concept assessed for this scenario was a "Subsea development with tiebacks to a platform of separation and recompression with off take on an FSO for condensate", meanwhile the higher investment costs for floating structures either in Lalail or Noxal make them not a sounded option for efficient investment of resources.

A platform for separation and recompression, here named as "The Holok compression station offshore (HCSO)" is a proposed new brand offshore structure with separation and recompression that will serve as a Hub for the development of the Fields, Lalail, Noxal, Leek, and the Tabscoobs (101, 201). HCSO will take advantage of a shallow water location to become the structure for subsea tieback developments.

This proposed structure will reduce the costs of the development and at the same time become a high added value for future developments since its reach is comparatively equivalent with floating structures located in the Lalal and Noxal sites.

An additional advantage for the Mexican Industry as a whole is that these kind of shallow water facilities are in the scope of the capability of national contractors. This is a high potential argument on behalf of the national content that PEMEX can encourage through its corporate decisions.

Regarding the heavy and extra heavy oil discoveries, the opinion of this author is that the Exploration activities in deep water should be focused on prospects potentially commercial instead of looking for resources that can barely be produced (API-15 or less). Although the diversification of opportunities for exploration should be encouraged, is the opinion of this author that it should be focused on the Region of Holok Temoa or others that could have a similar potential of development in the short term.

There is no doubt that additional discoveries in the Holok Temoa Integral Asset and in general in the deep water in Mexico will be made in the future, but there are some few recommendations that could be issued after the development of this study.

1. It is suggested to design, coordinate and follow a strategic plan for field development in all the regions in the domain of PEMEX, looking for maximizing the possibilities of development and ensure efficient depletion of the natural resources located in Mexican territorial waters.
2. Encourage the investments in infrastructure since it makes feasible future field development and increase the capability of efficient depletion.
3. Encourage solutions that will make possible a gradual assimilation of technology for both the National Oil Company and for the national contractors. The economically feasible solutions that open the participation of national suppliers alone or in association with international contractors should have extra points in the formal assessment of concepts.
4. Exploration and appraisal should focus on prospects that are commercial in the short run. The drilling in deep water is not only expensive but it could be notoriously ineffective if it is not linked to the value chain of potential field developments.

10. General Conclusions

10.1 On the discussion on the recovery factor Dry vs. Wet Tree

In order to give validity to the model of LCC analysis here proposed, an empirical comparison on the resulting recovery factor based on data of the US Gulf of Mexico was included in the scope of this work. This comparison was intended to answer ¿Is there a significant difference in the recovery factor when is used the dry tree vs. the wet tree concept solutions?

The oil and gas recovery factors listed in this data set analyzed correspond to the estimated values declared by the operator companies to the MMS for sands located in the US Gulf of Mexico. The values are subject to change due to different factors including technology improvements, operations management philosophy and refinement of calculations as more information from the reservoirs become available

The class of fields most exploited in deepwater in Gulf of Mexico corresponds to undersaturated oil fields (≈ 65%) followed by the non associated class (≈ 30%) and finally saturated oil fields class (≈ 4%).

The mean recovery factors for the different types of reservoir are summarized in table 7.5. According to the test of hypothesis $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} = 0$ vs. $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} \neq 0$ with μ calculated from the data sets created in this methodology, there is not statistical evidence that suggest that a field developed with dry tree has a better recovery factor than one developed with wet tree solutions.

With exception of the gas recovery factor from saturated oil fields, all the other test fail to reject the null hypothesis $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} = 0$. This means that the inferred mean value of recovery factor is the same either for dry tree vs wet tree solutions.

In the only exception (gas recovery factor of the saturated oil fields) is perceptibly a difference in favor of the dry tree. Despite the oil recovery factor from the same type of reservoirs is larger for dry tree than for the wet tree, the pooled variance for both samples is too large to make a differentiation on their means.

It is inferred that a criteria that prefer a dry tree with the argument of a better recovery factor must be evaluated further, extending the analysis to consider the specific characteristics of the reservoir and the exploitation concept that is part of the field to be developed.

Consecuently a model that include a reservoir complexity index was presented and analized. The Reservoir Complexity Index from the Norwegian petroleum directorate on the performance of dry and wet tree solutions was discussed.

From a presentation provided by the NPD a data set was extracted for fields encompassed by an study differentiating the dry tree and the wet tree developments. The results of the analysis of this data set are shown graphically in figure 7.2.

What can be inferred from the figure 7.2 is that on the Norwegian Continental Shelf, depending of the complexity of the reservoir, there is:

A linear trend on the recovery factor for fields developed with dry tree to decrease as the reservoir becomes more complex.

An exponential trend on the recovery factor for fields developed with wet tree to decrease as the reservoir becomes more complex. A linear trend was also tested but is not shown because the exponential regressed function has a better R^2 ($R^2 = 0.5891$ in linear regression vs $R^2 = 0.6672$ in exponential regression).

When the reservoir has a low complexity (up to 0.4) it seems that there is not an evident difference between the performances of dry vs wet tree solutions. As the complexity increases however the dry tree solutions become a better option based on the recovery factor registered.

Many oil companies worldwide employ methodologies similar to the RCI as a common basis. Although the calculation of this index is out of the scope of this work it could be useful for the reader to take a look on the patented work of Harrison (Harrison, 2004) who propose *"A method for computing complexity, confidence and technical maturity indices for the evaluation of a reservoir."*

10.2 On the Case Analysis

Two hypothetical projects (three different concepts for each project) of field development, based in public information released by PEMEX, are assessed.

Scenario I: Deep water stand alone gas field

- Concepts: Subsea Tieback to Shore; TLP with dry tree, export pipeline for gas and off take through FSO for condensate; SPAR with dry tree, export pipeline for gas and off take through FSO for condensate.

Scenario II: Deep water array of gas and condensate fields in proximity

- Concepts: Subsea development with tiebacks to a platform of separation and recompression with off take in FSO for condensate; Floating structure for separation and recompression with off take through an FSO for condensate for tie back of the fields Noxal, Leek and Tabscoob based in Lalail; Floating structure for separation and recompression with off take through an FSO for condensate for tie back of fields Lalail, Leek and Tabscoob based in Noxal.

In the first scenario, it was found that the best Net Present Value assessment result for the development of the Lakach field is the concept of subsea tieback to shore. This is true when an additional value for the development of infrastructure in the region is not considered. Although the concept has higher economical penalties in the RAMEX because of the higher costs for it maintenance, the savings in the CAPEX are notorious.

On the other hand, the potential of the Region of Holok-Temoa, related to the prospects listed in table 9.4, might increase considerably the strategic value of the investments in infrastructure. This infrastructure would be available when offshore structures and a network of pipelines will be developed in the region.

Lakach development has an ample positive Net Present Value before taxes even when a floating structure was selected. Also the calculated added value that could be obtained by using the floating structure as a hub as shown in table 9.8. Lakach has also a geographical advantage since it is located at less than 1000 meters of water depth; much easier to develop when is compared to other identified prospects of development that go from 1700 m up to 2500 m water depth.

Figure 9.5 shows a hypothetical development that could have Lakach as a processing Hub for the future field developments of this gas province.

The Lakach Field development has already been committed to be developed as a subsea tieback to shore. Consequently for future concept selection, it is strongly recommended to keep in mind the fact that the development of infrastructure increases the feasibility of future developments and increase the overall recoveries rates from the oil and gas fields.

On the second scenario, It was found that a series of medium-small size fields might be economically developed when they are planned as a group of fields.

The best NPV concept assessed for this scenario was a “Subsea development with tiebacks to a platform of separation and recompression with off take on an FSO for condensate”, meanwhile the higher investment costs for floating structures either in Lalail or Noxal make them not a sounded option for efficient investment of resources.

A platform for separation and recompression, here named as “The Holok compression station offshore (HCSO)” is a proposed new brand offshore structure with separation and recompression that will serve as a Hub for the development of the Fields, Lalail, Noxal, Leek, and the Tabscoobs (101, 201). HCSO will take advantage of a shallow water location to become the structure for subsea tieback developments.

This proposed structure will reduce the costs of the development and at the same time become a high added value for future developments since its reach is comparatively equivalent with floating structures located in the Lalal and Noxal sites.

An additional advantage for the Mexican Industry as a whole is that these kind of shallow water facilities are in the scope of the capability of national contractors. This is a high potential argument on behalf of the national content that PEMEX can encourage through its corporate decisions.

Regarding the heavy and extra heavy oil discoveries, the opinion of this author is that the Exploration activities in deep water should be focused on prospects potentially commercial instead of looking for resources that can barely be produced (API-15 or less). Although the diversification of opportunities for exploration should be encouraged, is the opinion of this author that it should be focused on the Region of Holok Temoa or others that could have a similar potential of development in the short term.

10.3 Recommendations

There is no doubt that additional discoveries in the Holok Temoa Integral Asset and in general in the deep water in Mexico will be made in the future, but there are some few recommendations that could be issued after the development of this study.

1. It is suggested to design, coordinate and follow a strategic plan for field development in all the regions in the domain of PEMEX, looking for maximizing the possibilities of development and ensure efficient depletion of the natural resources located in Mexican territorial waters.
2. Encourage the investments in infrastructure since it makes feasible future field development and increase the capability of efficient depletion.
3. Encourage solutions that will make possible a gradual assimilation of technology for both the National Oil Company and for the national contractors. The economically feasible solutions that open the participation of national suppliers alone or in association with international contractors should have extra points in the formal assessment of concepts.
4. Exploration and appraisal should focus on prospects that are commercial in the short run. The drilling in deep water is not only expensive but it could be notoriously ineffective if it is not linked to the value chain of potential field developments.

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Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

Abstract: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

This paper documents an empirical study on the drivers of the investment activity in Norway. It was intended to identify which are the factors that drive the level of petroleum investments in exploration. It was also proposed to explain how and to which magnitude those factors influence the investment decisions with basis in an econometric analysis using statistical inference on available data from the Norwegian Continental Shelf.

It was found that the exploration investments level is driven mainly by only one explanatory variable available in the originally considered data set, the oil price. It was also found the existence of a positive correlation between the level of investment in exploration and the oil price that improves as it is employed a lagged distribution of the terms of the explanatory variable.

There is also an adjustment mechanism to moderate the reaction toward the oil and gas commodities markets. In that way it seems that the investments have a positive correlation in the same quarter against the change in the oil price, a negative correlation adjust in the first quarter after the level of investment, positive correlation affects the investment in the second quarter, negative correlation is perceptible but weak again in the third quarter and a positive correlation also is noticeable in the fourth quarter after a change in the oil and gas prices.

Despite the adjustment mechanisms, at the end, the oil price has a positive net correlation with the level of investment increasing or decreasing approximately 16 millions of NOK four quarters after the price is adjusted in 1 USD.

The proposed model also suggests that the depletion of the reservoirs is an element that the oil companies consider as a long term trend. As the amount of oil and gas produced is increased there is an inclination to diminish the level of investment in exploration, presumably since it is considered that the probability of commercial success become smaller.

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

Summary

This paper is intended to identify the factors that drive the level of petroleum investments in exploration for oil and gas in the Norwegian Continental Shelf (NCS) and explain how and in which magnitude those factors influence the investment level with basis in an econometric analysis using data of the NCS.

Initially, it is proposed that the investment level is driven by only one explanatory variable, ***the oil price*** including lagged terms. Further refinement of the model uses as explanatory variable a transformed version of the ***Total Petroleum Production*** using a reciprocal logarithmic function.

I. Motivation for the research on investments in the Norwegian oil and gas industry.

The Norwegian employees work in three types of industries, primary industries (i.e. agriculture, forestry, fish and aquaculture), secondary industries (i.e. industry, oil extraction and mining, building and construction, electricity and water supplies) and tertiary industries (i.e. retail trade, hotels and restaurants, transport and communication, public and private services, etc.). The distribution of the total population of employees has changed considerably along the last 50 years. The most of the population´s distribution has moved from primary and secondary sectors to tertiary industries.

Currently the tertiary industries represent the source of employment for almost 76% of the population, meanwhile 21% have a job related to the secondary industries and only 3 % are related to the so called primary industries.

However, the tertiary industries contribute to 56% to the gross domestic product (GDP), the secondary industries contribute 43%, and primary industries with a little bit less than 1%. ***The Oil and Gas industry represents by far the most of the income attributed to the secondary industries***.

It is also noticeable that the balance of imports and exports is greatly influenced by the Oil and Gas which are the most representative of the goods of exportation with revenues totaled NOK 560 billion in 2008 (Statistics Norway, 2009).

The oil and gas industry is consequently a major source of income for the Norwegian State, it contributed with a 33.5% of its net income in 2008. According to data presented by the Norwegian Petroleum Directorate (NPD), the Government received from direct taxes 239.6 BNOK., environmental taxes and area fee 5.5 BNOK, State Direct Financial Interest 153.8 BNOK, and from the Statoil Dividend of 2007 paid in 2008 16.9 BNOK for a total of 415.6 BNOK.

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

The sector is not only of major importance in the present time, it is expected that it will play a critical role at least for several years to come. As it is shown in the figure 1[1], the production of oil and gas products is expected to be almost without change along the next 12 years and being in an important level until 2030 (The Ministry of Petroleum and Energy…, 2009).

The importance of this industry as discussed by Mohn (Mohn, 2008) is not only at the national level. In the international perspective it is also of strategic relevance for the growth issues of the emerging economies (China, India, etc.), energy security policies (European Union and United States of America), and income distribution as well as social and environmental concerns of the producer countries.

Besides its important role in macroeconomics and international strategic aspects, the industry has a number of particular issues. It is enough to point to the required large amounts of investment in capital and the risks associated to the hydrocarbons exploitation (risks that go far from only technical and financial aspects, see as example "Nordal, 2001") in order to get an idea of how important is to enhance the understanding of the microeconomics relationships that drive the direct investments in oil and gas.

II. Scope of this research document

This paper is intended to identify which are the factors that drive the level of petroleum investments in exploration. It is also intended to explain how and in which magnitude those factors influence the investment decisions with basis in an econometric analysis using statistical inference on available data of the Norwegian Continental Shelf.

III. Theoretical and empirical basis for specifying econometric model.

Initially, it is proposed that the exploration investments level is driven mainly by one explanatory variable, ***the oil price***. It is anticipated the existence of a positive correlation with the oil price represented here by the variable "***Brent blend oil price".*** A better correlation of this variable is expected in case that it will be employed the variable terms with a lagged distribution.

Further refinement of the model includes as explanatory variable a transformed version of the **Total Petroleum Production** using a reciprocal logarithmic function.

Oil prices are almost immediately related as explanatory variables of investment in exploration. An outnumbered of authors can be cited, from the work of Mohn and Osmundsen (Mohn and Osmundsen, 2008) it can be shown just a brief example.

[1] See figures and tables attached at the end of this document.

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

Fisher(1964) estimated equations for the drilling rate, success rate and the discovery rate for different US Petroleum Administration Defence Districts (PADD) over the period 1946-1955. Explanatory variables included ***oil prices****, seismic crews and proxy variables for drilling costs. These early Fischer models had a simple structure that largely could be justified based on economic fundamental principles. However, the theoretical foundation was gradually improved, as dynamics and uncertainty were introduced explicitly in the producer's optimisation problem…*

…Since the mid 1970s (Bouhabib (1975)), accumulated measures of reserves, drilling efforts and discoveries have typically been included in the econometric exploration models. The role of these variables has been to account for the dampening depletion effects on exploration success and consequent reserve additions. Moroney & Berg (1999) illustrate that model diagnostics and forecasting performance of simple Hubbert models improve when economic and policy variables are included...

…A survey of empirical exploration models for the US oil and gas industry is offered by Dahl & Duggan (1998).Into the 1990s, some studies also emerged for the exploration and production of oil and natural gas on the United Kingdom Continental Shelf (e.g. Pesaran (1990), Favero & Pesaran (1994)). These models typically departed from an integrated, dynamic optimisation problem, and produce plausible, estimated equations for exploration, development and production. However, they fail to produce robust estimates in support of intertemporal maximization…[Mohn and Osmundsen, P.p 53 and 54, 2008]

Mohn and Osmundsen (Mohn and Osmundsen, 2008) in their own work adopted the microeconomic theory of producer behavior as starting point for their modeling approach. They express that based on a theoretical model of oil and gas production, they apply duality principles to derive exploration efforts as a part of the input/output system. Their empirical model is based on the translog profit function approach; they develop a drilling function where the drilling efforts are explained by oil prices, unit costs, tax pressure, accumulated discoveries and open exploration acreage.

Referring to the expected improvement in the correlation by using a lagged distributed variable, Pindyck (Pindyck, 1990) stated that there are two important characteristics in the most of the major investment expenditures that in conjunction can change dramatically the empathy towards an investment.

1. The expenditures are mostly irreversible; the companies cannot just disinvest and they need to assume the expenditures as a lost cost.

2. The investments can be postponed to provide to the companies the chance to wait for more information about prices, costs and market conditions before the resources' commitment is done.

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

Pindyck also explains in its model that the exploratory activity is the mean to accumulate or maintain a level of reserves. He assumed that the exploratory activity expected outcome (the reserve additions discoveries") fall as cumulative discoveries increase. The level of the reserves chosen by the producers will depend on the behavior of the production cost. If the production cost would be independent of the reserves the producers would postpone much of their exploratory activity and maintain no reserves level.

Pindyck assumed that the production cost rise as the level of reserves decline, for the particular case of oil and gas, he pointed out that at the level of individual reservoirs and fields, a lower amount of reserves means higher extraction costs as the rate of physical output per unit of capital declines. He concludes that the producers must determine an optimal reserve level- balancing revenues with exploration, production and "user cost" of the depletion, (Pindyck, 1977).

IV. Presentation of the econometric model.

The data set used for this study is comprised of time series of the variables listed in table 1. The data set shows the quarterly records from the first quarter of 1985 until the second quarter of 2008. It is assumed that the 1000 SCM of natural gas = 1 SCM of NGL = 1 SCM condensate = 1 SCM oil = 1 ESCM Oil. Table 2 shows the original data set.

After a brief analysis of the data and the valuable literature listed in section III, it was considered that an econometric model suitable to explain the level of investment in exploration could be a general distributed lag model.

An unrestricted finite distributed lag model is specified as

$$y_t = \alpha + \sum_{i=0}^{p} \beta_i x_{t-i} + \epsilon_t \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

Where b_i is the multiplier of the effect of the variable x_{t-i}. Consecuently y_t would be explained by a finite number of the variable x and the effect of its lagged values *t-1* (Greene, 2003)

Remembering the proposed model explained in point No. 3, the exploration investments level is expected to be driven by the existence of a positive correlation with the Oil price represented here by the variable "Brent blend oil price". A better correlation of this variable is expected in case is employed a lagged distribution of the variable effects.

Hence, using the model of polynomial distributed lag in a particular form for this analysis the model would be.

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

$IE_t = \alpha + \sum_{i=0}^{p} \beta_i BBOP_{t-i} + \epsilon_t$ …..……………………………………………………..……….(2)

Where:

- IE = Investment in exploration, expressed in Millions of NOK, real value.
- BBOP = Brend blend oil price, expressed in USD per barrel, real value.
- ϵ_t=error.

In this case the number of lags for the explanatory variable BBOP was determined by comparing individually the multiple coefficient of determination, R^2, and adjusted R^2, preferring the higher adjusted R^2, that exists between the variable *IE* and a generated model lag variable t-i, (k =1,2,3,4,5,6,7,8). [2]

The creation of the lag data sets implied the loss of k observations in each set; consequently the missed data was omitted in the calculation of the correlation between the variables. Table 3 shows the results of the multiple regression models for investments in exploration explained by the Brent blend oil Price and its lagged values until 8 quarterly lags.

As shown in table 3, the peak of correlation Adjusted R^2, and one of the minimum standard error of the estimate is found in the model with lag 4. Consequently it was chosen that the most appropriate number of lagged terms to be considered was 4.

If we assume that the model satisfies the normal properties of the regression by least squares estimators.

- Linearity of the relationship between dependent and independent variables.
- Independence of the errors (there are no serial correlations).
- Homoscedasticity or constant variance of the errors.
    - 3.1) versus time.
    - 3.2) versus the predictions (or versus any independent variable).
    - 3.3) normality of the error distribution.

And that the lag length p is known, the model can be solved as a classical regression model.

This model; however have many weaknesses as it will be discussed in the next section when the results are shown, just to mention the most important is that ϵ_t is expected to be serially correlated and the multi-

[2] To do the calculations and the figures shown in this document it was used the Microsoft Excel Software (2007) and the StatTools Add-in for Microsoft Excel by Palisade Corporation (2010).

collinearity of the model is expected to be severe. To solve this problem it is suggested to employ a more refined way to calculate the weight b_i (the multiplier of the effect of the variable x_{t-i}), the polynomial lag model.

The invention of this model is attributed to Almon (Almon, 1965).

> *The polynomial model assumes that the true distribution of lag coefficients can be well approximate by a low-order polynomial.*
>
> *2)* $\beta_i = \alpha_0 + \alpha_i i + \alpha_2 i^2 + \cdots + \alpha_p i^q, i = 0,1 \ldots, p > q$
>
> *Substituting 2 in 1 an collecting terms it is obtained*

$$y_t = \gamma + \alpha_0\left(\sum_{i=0}^{p} i^0 x_{t-i}\right) + \alpha_1\left(\sum_{i=0}^{p} i^1 x_{t-i}\right) + \cdots + \alpha_q\left(\sum_{i=0}^{p} i^q x_{t-i}\right) + \epsilon_t \ldots\ldots\ldots\ldots\ldots\ldots\ldots(3)$$

$$= \gamma + \alpha_0 z_{0t} + \alpha_1 z_{1t} + \cdots + \alpha_q z_{qt} + \epsilon_t \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(4)$$

> *Each z_{jt} ia a linear combination of the current and the p lagged values of x_t. With the assumption of strict exogenety of x_t, γ and $(a_0,a_1,\ldots,a_q)$ can be estimated by ordinary or generalized least squares…*
>
> *(Greene, P.p. 565-566, 2003)*

The difficulties of using Almon's technique in the estimation of distributed lags have been extensively investigated. Thomas made a discussion of the Almon’s model resulting in a critical analysis of the *“conventional criteria for choosing the “best” model (such as goodness of fit, the statistical significance of the individual parameter estimate or their sums, and an analysis of autocorrelation) demonstrates the problems of choosing the appropriate combination of lag length and degree of polynomial” [Thomas, P.P. 175, 1977]*.

V. Presentation of econometric results for the original model.

Table 4 shows the estimated parameters of the model. Figure 2 shows a plot comparison between the actual records of investment level and the model results. It is inferred that the investment in exploration is positively affected by the increase of the price of oil, being more noticeable between the second and fourth month of the increase in the oil price.

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

V.1 Commentaries on the reliability of the model. As commented before, when it is used the econometric modeling of time series by distributed lag models is common to have violations of independence between the variables. This fact is evidenced by serial correlation between the residuals; a typical tool to detect these phenomena is by the calculation of the autocorrelation or trough a Durbin Watson test.

In this case it is shown the correlation coefficients for the residuals (table 4), and the autocorrelation plot of the residuals (figure 3), it is evident that exists an autocorrelation in the residuals. This enounced observation open an ample space to search for a model correction, either by consider transformations, the application of techniques like Almon's, identification and correction for seasonality's or the search for additional explanatory variables, just to mention some.

VI. Model Correction

To correct the model is proposed the use of an additional explanatory variable based in the theory of Pindyck (Pindyck, 1997) previously referred at the end of section III. It will be transformed the variable **Total Petroleum Production** using a reciprocal logarithmic function for its cumulative value to be related linearly to the corrected model.

It means:

NEV = New Explanatory variable

NEV_t = 1/log ($\sum_{Q=1}^{t} TPP_t$

Where:

TPP_t = Total Petroleum production in time t.

Q = Consecutive posterior quarter with "1985Q1" as Q=1, !985Q2 as Q=2…

The transformed values of the NEV are shown in table 6.

Then the corrected model is formulated as following:

$$IE_t = \alpha + \sum_{i=0}^{p} \beta_i BBOP_{t-i} + NEV_t + \epsilon_t \text{………………………………………………………………….}(5)$$

Where:

- IE = Investment in exploration, expressed in Millions of NOK, real value.
- BBOP = Brend blend oil price, expressed in USD per barrel, real value.
- NEV = New Explanatory variable, as defined above.
- ϵ_t=error.

VII. Presentation of the econometric results and conclusions using the corrected model.

Table 7 shows the estimated parameters of the corrected model. Figure 4 shows a plot comparison between the actual records of investment level and the results of the corrected model.

There is a noticeable improvement in the coefficients of correlation multiple, R^2, and adjusted R^2 with perceptible changes in the coefficients. It is then inferred that the change in price of oil is positively correlated to the increase of investment in the same period. However there is also an adjustment mechanism to moderate the reaction toward the oil and gas commodities markets.

In that way it seems that the investments have a positive correlation in the same quarter against the change in the oil price, a negative correlation adjust in the first quarter after the level of investment, positive correlation affects the investment in the second quarter, negative correlation is perceptible again in the third quarter and a positive correlation also is noticeable in the fourth quarter after a change in the oil and gas prices.

Despite the adjustment mechanisms the oil price has a positive correlation with the level of investment increasing or decreasing approximately 16 millions of NOK four quarters after the price is adjusted in 1 USD.

The new explanatory variable also suggests that the depletion of the reservoirs is an element that the oil companies consider as a long term trend. As the amount of oil and gas produced is increased there is an inclination to diminish the level of investment in exploration, presumably since it is considered that the probability of commercial success become smaller.

VII.1 Commentaries on the reliability of the model. Correlation coefficients for the residuals (table 8), and the autocorrelation plot of the residuals (figure 5), Show a considerable improvement regarding the presence of evidence of autocorrelation in the residuals. Although it may be judged still to be too high, the relatively small error in the model make to think that is a reliable to predict the behavior of investment levels in exploration in the Norwegian Continental Shelf.

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Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

IX Figures and tables

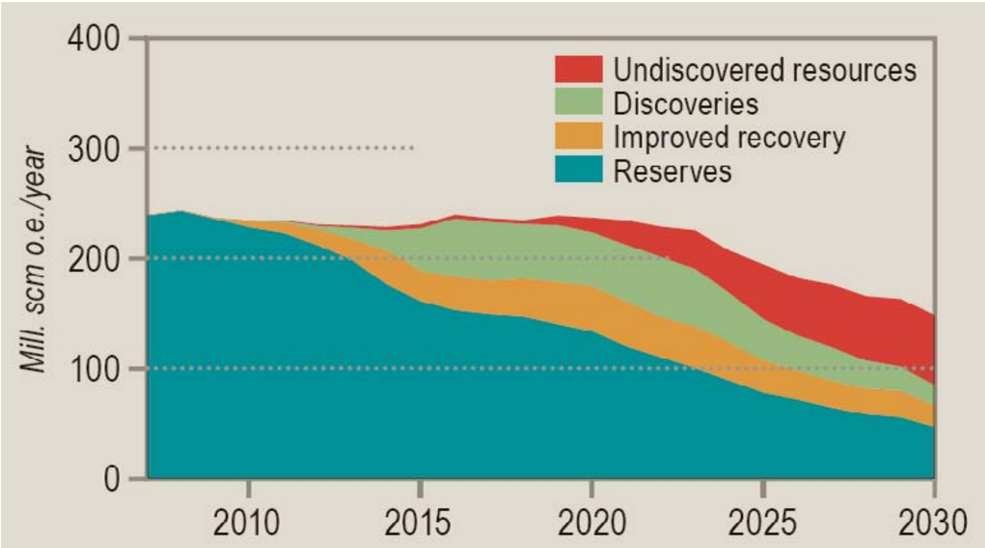


Figure 1. Production Forecast (Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy). Figure 1.4 from [The Ministry of Petroleum and Energy…, P.p. 15, 2009]

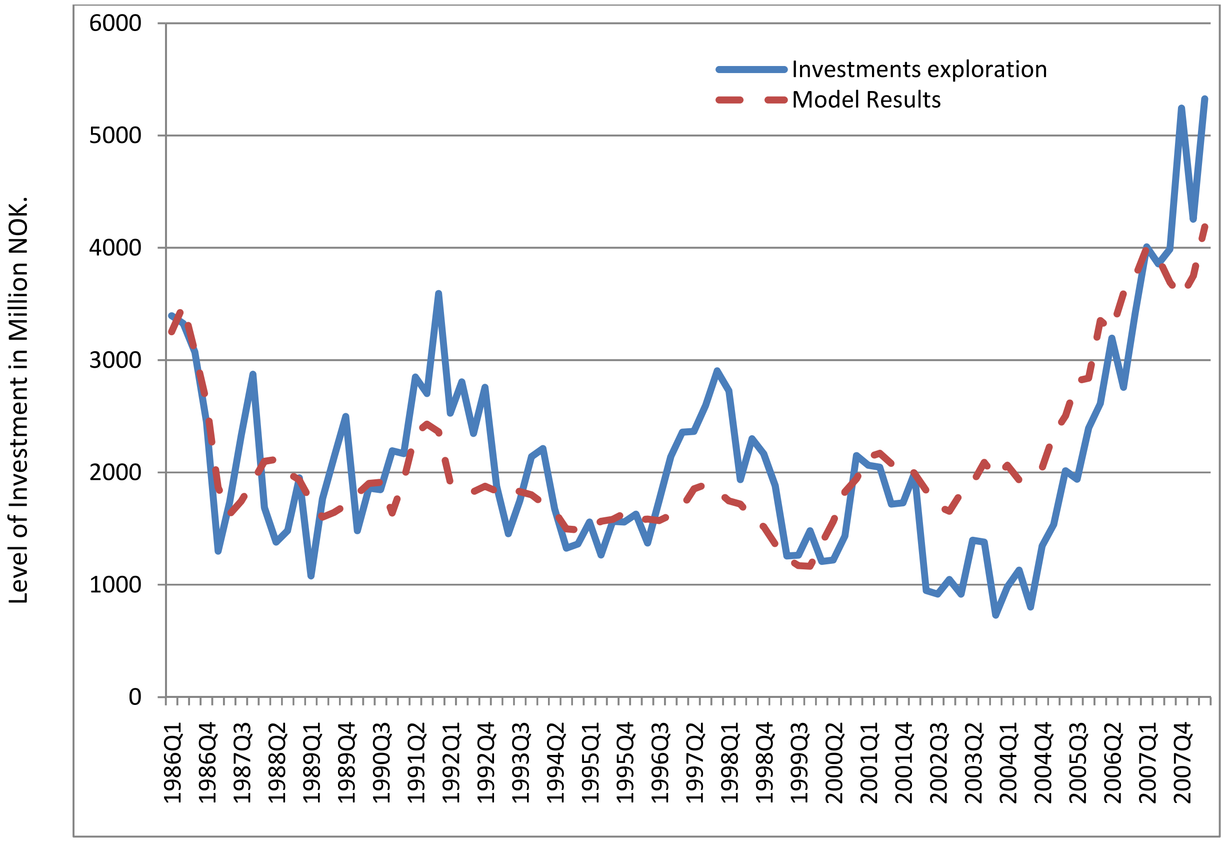


Figure 2. Plot comparison between the actual records of investment level and the model results.

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

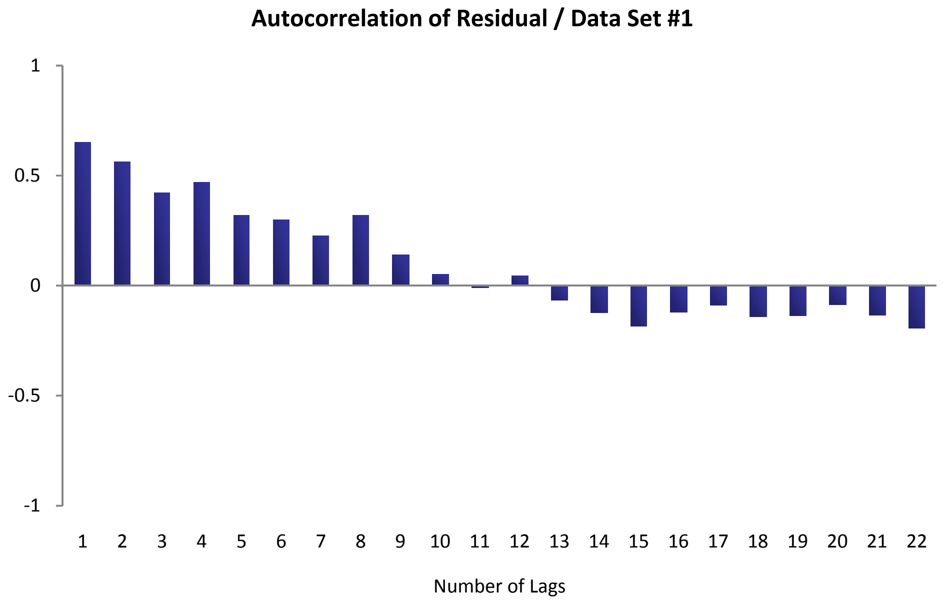


Figure 3. Autocorrelation plot of the residuals original model

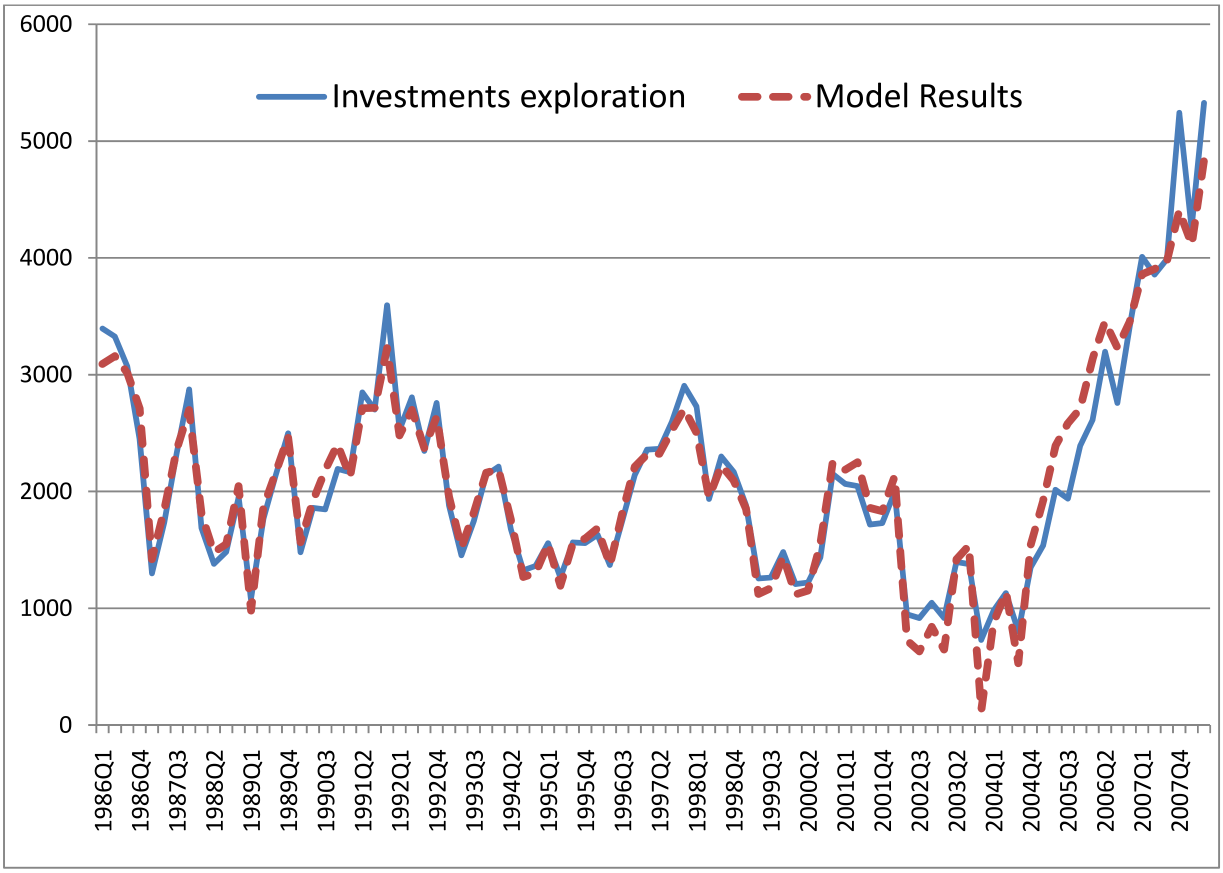


Figure 4. Plot comparison between the actual records of investment level and the corrected model results.

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

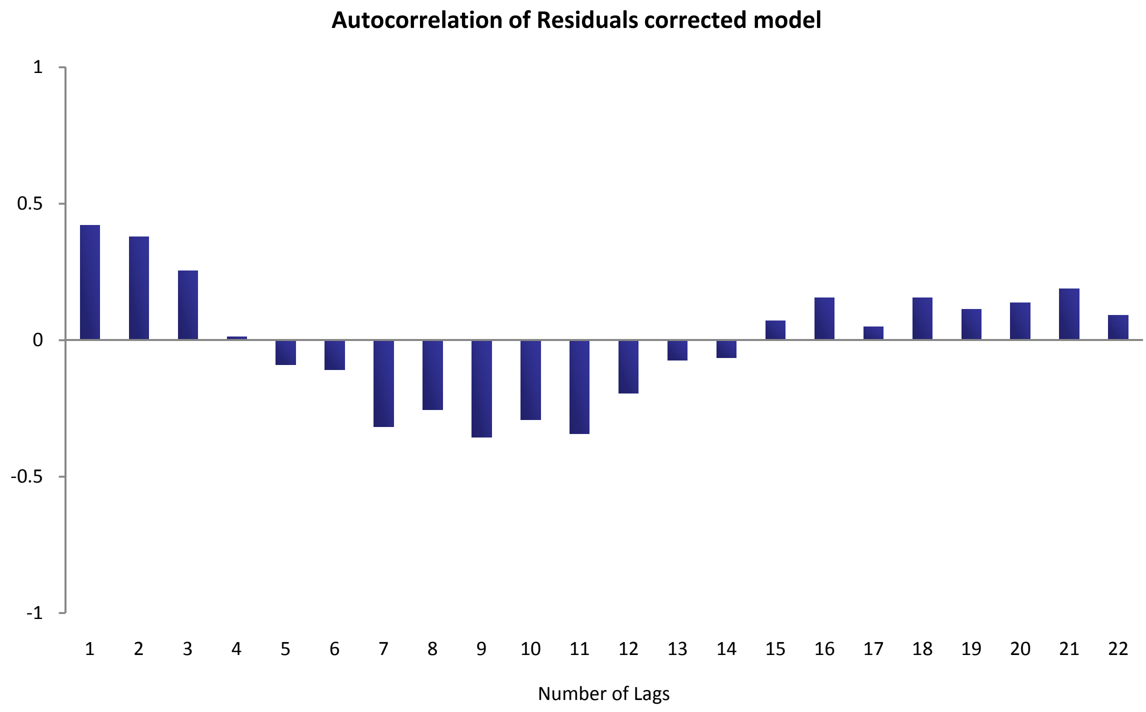


Figure 5. Autocorrelation plot of the residuals corrected model

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

Variable name in the model	Variable name	Units.
YYYYQ	Year-quarter	Label.
TI	Total investments	Millions of NOK, real value.
IE	Investments exploration	Millions of NOK, real value.
IFD	Investments field development	Millions of NOK, real value.
IFO	Investments fields in operation	Millions of NOK, real value.
TPP	Total petroleum production	Millions of oil equivalent standard cubic meter (MMESCM).
PO	Production oil	Millions of oil standard cubic meter (MMSCM).
PNG	Production natural gas	Thousands of millions of standard cubic meter MMMSCM.
PNGL	Production NGL	Millions of oil equivalent standard cubic meter MMESCM.
PC	Production condensate	Millions of oil equivalent standard cubic meter MMESCM.
FCEF	Fixed capital in existing fields	Millions of NOK, real value.
BBOP	Brent blend oil price	USD per barrel, real value.
CTPP	Cumulative total petroleum production	Millions of oil equivalent standard cubic meter

Table 1. List of variables of the data set for analysis.

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

Table 2. Original data set. *(1/4)*

YYYYQ	TI	IE	IFD	IFO	TPP	PO	PNG	PNGL	PC	FCEF	BBOP
1985Q1	10389.39461	2934.576225	7027.066593	427.7517887	18.993263	10.311565	7.99741	0.658716	0.025572	263928.4243	55.26951018
1985Q2	14553.8961	3661.948052	10127.08604	764.862013	17.57607	10.192638	6.688295	0.673999	0.021138	264950.5487	52.87524351
1985Q3	13842.66328	3907.218951	8654.325482	1281.118844	17.24193	11.704195	4.851149	0.67627	0.010316	267504.9684	52.81228587
1985Q4	16403.30159	4714.801587	11436.02381	252.4761905	20.175463	12.549476	6.6488	0.958707	0.01848	269719.5492	54.225
1986Q1	12692.91732	3395.054602	8530.873635	766.9890796	20.696209	12.160223	7.563724	0.949975	0.022287	279452.0952	33.42418097
1986Q2	14631.52806	3327.27551	10166.26531	1137.987245	15.369334	9.396451	5.145347	0.816133	0.011403	283128.6444	23.62660714
1986Q3	13886.75917	3070.421209	10022.75768	793.5802775	19.847369	12.905469	5.94325	0.990433	0.008217	283685.7815	22.24890981
1986Q4	14829.23638	2452.784533	10899.50632	1476.945525	22.854386	14.308971	7.437382	1.088817	0.019216	286976.4937	25.88171206
1987Q1	10739.02837	1299.007092	7202.652482	2237.368794	23.337415	14.333752	7.979075	1.007685	0.016903	295172.356	30.61212766
1987Q2	11805.5235	1734.325268	6859.920893	3211.277338	21.871603	13.879525	6.907717	1.06831	0.016051	298282.7506	31.4230805
1987Q3	13437.57576	2331.990358	8612.596419	2492.988981	19.714405	13.669368	5.216602	0.821843	0.006592	301987.938	31.70179063
1987Q4	16453.24129	2873.671344	11911.98959	1667.580353	24.357687	15.076476	8.047492	1.21872	0.014999	305319.0706	29.55495699
1988Q1	8252.3597	1686.893504	5439.273089	1126.193106	25.297402	16.063174	8.040875	1.178458	0.014895	317463.4534	25.28742819
1988Q2	10860.69692	1379.75901	7922.234043	1558.703865	23.000827	14.928392	6.93165	1.126458	0.014327	323781.878	25.44470256
1988Q3	10732.85868	1482.757432	7455.840155	1794.261094	23.285764	16.213141	5.891983	1.174541	0.006099	333011.4326	22.47498923
1988Q4	13262.20325	1952.593937	9946.652434	1362.956874	26.361441	17.518306	7.465062	1.366218	0.011855	341660.7195	20.72991033
1989Q1	8030.453395	1079.468579	5987.391396	963.5934205	29.325089	20.160785	7.949311	1.200856	0.014137	354147.7212	26.62079291
1989Q2	10363.5	1767	7215	1381.5	29.451535	21.46251	6.83144	1.143624	0.013961	353505.9	27.945
1989Q3	11193.68508	2139.793899	7773.889118	1280.002061	29.54703	22.076592	6.214489	1.248842	0.007107	356230.087	26.1364798
1989Q4	15584.04138	2498.363376	11820.94633	1264.731667	31.347993	22.283347	7.742491	1.30459	0.017565	359065.6137	28.67120033
1990Q1	9794.399757	1480.191997	7187.625303	1126.582458	31.427748	22.698752	7.529928	1.184794	0.014274	362431.0744	29.00474939
1990Q2	10346.72793	1860.215741	7063.909309	1422.602877	30.165643	23.590826	5.356293	1.209891	0.008633	361392.2577	23.0504994
1990Q3	9653.399523	1846.262907	6510.732724	1296.403892	28.46381	21.675829	5.617256	1.160157	0.010568	362380.923	38.04507546
1990Q4	11363.65543	2193.657389	7320.693846	1849.304194	35.024217	26.576806	6.975974	1.4566	0.014837	360794.0051	46.1121521
1991Q1	10443.95874	2167.029973	6843.030362	1433.898404	34.915173	26.654093	7.013826	1.233311	0.013943	366805.8462	29.19861814

Table 2. Original data set. *(2/4)*

YYYYQ	TI	IE	IFD	IFO	TPP	PO	PNG	PNGL	PC	FCEF	BBOP
1991Q2	11234.90755	2849.110169	6426.511941	1959.285439	34.755992	26.96565	6.505075	1.271062	0.014205	368394.6795	26.16558166
1991Q3	12541.52533	2702.233308	8004.04835	1835.243668	31.542384	26.100068	4.522432	0.907896	0.011988	372364.1431	27.57720645
1991Q4	15336.48912	3594.295533	9682.789233	2059.404353	37.278051	28.790108	6.985679	1.485173	0.017091	375872.2131	28.30990836
1992Q1	13220.64994	2528.164196	8836.208666	1856.277081	38.909837	30.681669	7.014135	1.195834	0.018199	386372.4641	25.02058153
1992Q2	12976.74878	2806.077473	8391.041745	1779.62956	37.54694	30.033859	6.253388	1.250451	0.009242	389114.032	27.35381722
1992Q3	14636.20922	2347.649044	10683.70079	1604.859393	37.721256	30.411773	6.121829	1.176762	0.010892	394736.5838	27.29887514
1992Q4	15750.97497	2757.500934	11313.5861	1679.887934	40.667672	32.871733	6.444307	1.336185	0.015447	400026.4202	25.9140269
1993Q1	14277.84365	1879.157095	10771.33383	1627.352723	38.776668	30.974351	6.554169	1.238442	0.009706	411186.628	24.36341237
1993Q2	15149.83486	1453.959633	11435.33945	2260.53578	38.705549	31.994155	5.508979	1.193622	0.008793	414901.4433	24.1972844
1993Q3	15921.12885	1747.780837	12198.63436	1974.713656	39.751671	33.066005	5.296814	1.34552	0.043332	422694.6244	21.88375551
1993Q4	17048.38769	2140.652254	12392.2041	2515.53133	45.485618	35.808951	7.443886	1.740356	0.492425	429547.0432	19.96264199
1994Q1	13413.3437	2212.401171	9005.743045	2195.199488	44.913902	35.496902	7.151609	1.70799	0.557401	441937.1903	18.45872987
1994Q2	15715.79215	1676.140988	11462.38735	2577.263808	45.470048	36.538416	6.571701	1.734115	0.625816	443930.6697	21.08312137
1994Q3	11862.73943	1326.066137	8644.906035	1891.767257	41.986315	34.47788	5.386773	1.501746	0.619916	446701.1211	21.90948681
1994Q4	11930.28078	1362.456803	8375.140389	2192.683585	50.705229	39.769062	7.731525	2.178213	1.026429	450088.8413	21.52343413
1995Q1	11540.93583	1558.122995	7572.812834	2410	47.655285	37.136843	7.507828	2.06648	0.944134	455281.9925	21.7802139
1995Q2	12091.37522	1264.290265	8473.815929	2353.269027	47.205666	37.523423	6.70588	2.021269	0.955094	452058.7572	23.21277876
1995Q3	11732.46909	1564.244083	8153.223243	2015.001766	47.473008	38.671915	6.197711	1.786937	0.816445	459856.8587	20.68632992
1995Q4	13967.04545	1559.112051	10289.63002	2118.303383	53.922971	43.44372	7.402181	2.066972	1.010098	463089.907	21.64159619
1996Q1	10939.55992	1629.241782	7131.606575	2178.711559	55.098868	43.262035	8.65408	2.139677	1.043076	474130.8261	23.80609756
1996Q2	12607.5184	1370.988433	8502.155626	2734.374343	54.613458	43.82204	8.01323	1.928438	0.84975	475285.1977	24.68286015
1996Q3	12917.0122	1749.559233	7772.879791	3394.573171	56.594327	44.243332	9.272141	1.998771	1.080083	477582.3105	25.87181185
1996Q4	13839.14127	2140.460526	8613.163089	3085.517659	59.196169	44.094739	11.467594	2.165206	1.46863	479686.2164	28.99009695
1997Q1	14616.09664	2358.793694	9594.988005	2662.314942	58.539404	43.576074	11.422224	1.969322	1.571784	488051.0161	26.2267135
1997Q2	18387.14846	2365.172355	12956.01195	3065.964164	57.457357	44.523246	9.215334	2.037328	1.681449	494286.4761	22.26988055

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

Table 2. Original data set. *(3/4)*

YYYYQ	TI	IE	IFD	IFO	TPP	PO	PNG	PNGL	PC	FCEF	BBOP
1997Q3	15493.38501	2596.39523	10291.97274	2605.017036	55.468093	42.48839	9.6109	1.911772	1.457031	501664.6968	22.81083475
1997Q4	16593.24187	2904.735772	10636.81911	3051.686992	61.873148	45.326088	12.70111	2.155172	1.690778	506948.6433	22.92439024
1998Q1	17159.11913	2727.020134	10952.96477	3479.134228	60.012232	44.339455	11.886633	2.165477	1.620667	524367.8809	17.08026846
1998Q2	20153.98698	1935.400534	14509.47096	3709.115487	56.372018	42.683892	10.01702	2.01933	1.651776	535578.6599	16.03583111
1998Q3	20418.01099	2299.688748	14314.38915	3803.933089	51.499029	39.498569	9.275805	1.476264	1.248391	548126.1801	15.71233356
1998Q4	20763.81331	2167.085402	14595.21847	4001.509434	58.438828	42.22183	13.01065	1.728619	1.477729	558936.9166	13.21471367
1999Q1	18188.89564	1881.650804	11100.07877	5207.166065	57.62707	41.227703	13.014136	1.769634	1.615597	575355.6646	14.72733837
1999Q2	19254.08602	1255.650049	10951.01173	7047.424242	54.396697	39.960229	11.207973	1.736598	1.491897	578589.6432	19.19597589
1999Q3	17355.06856	1262.830558	10115.62684	5976.611166	55.016809	41.441415	10.227302	1.728161	1.619931	587095.8276	24.9615573
1999Q4	15993.63636	1481.194391	9284.559961	5227.882012	63.616952	46.060369	14.029604	1.757664	1.769315	586994.6567	27.10278852
2000Q1	13887.87492	1207.691449	6856.273133	5823.910338	64.097671	45.946175	14.71653	1.700608	1.734358	592765.1841	30.99779834
2000Q2	14990.97816	1219.876543	6864.952517	6906.149098	56.857865	42.931451	10.481249	1.792298	1.652867	592596.3419	32.04559987
2000Q3	14169.11171	1433.908173	5927.276743	6807.926791	57.177225	45.237826	9.303478	1.498409	1.137512	595234.3329	33.76205428
2000Q4	15883.16604	2150.009381	6400.290807	7332.865854	66.298135	47.065115	15.246399	2.234054	1.752567	594303.7392	31.86580675
2001Q1	13465.48521	2064.759704	4940.277264	6460.448244	62.64597	44.970059	13.179208	2.725307	1.771396	596760.3244	27.99416205
2001Q2	14571.17996	2046.371803	5557.897381	6966.91078	59.370844	43.728617	11.489224	2.639166	1.513837	596619.644	30.40753654
2001Q3	15131.83385	1717.403077	5911.915385	7502.515385	62.519614	45.145248	13.078729	2.57536	1.720277	609696.5566	27.12547692
2001Q4	16913.58982	1728.816677	5950.01073	9234.762416	67.727248	47.040529	16.147475	2.984114	1.55513	614263.8587	21.62498467
2002Q1	13774.47256	1993.760671	4309.344512	7471.367378	64.181336	42.931945	16.574905	2.910304	1.764182	617249.7878	23.9310061
2002Q2	13407.72589	948.1428138	5065.165252	7394.417829	65.105304	43.975524	16.104573	3.016239	2.008968	613467.2538	27.83411158
2002Q3	13122.32939	916.633303	4848.507734	7357.188353	60.535563	42.777729	13.393326	2.605761	1.758747	613239.5214	30.15241128
2002Q4	13702.31334	1047.103448	5348.248876	7306.961019	69.146039	43.96392	19.427892	3.265874	2.488353	605842.9988	29.42584708
2003Q1	12781.64479	916.1373578	4811.566054	7053.941382	69.197032	42.779752	20.537902	3.059194	2.820184	592890.5731	32.76939341
2003Q2	13484.42171	1395.827402	5180.213523	6908.380783	61.010387	40.100241	15.226209	3.103581	2.580356	607034.831	28.28462337
2003Q3	14142.61161	1379.294643	4190.602679	8572.714286	61.598437	40.125615	15.900744	2.998723	2.573355	613339.6205	31.10047619

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

Table 2. Original data set. *(4/4)*

YYYYQ	TI	IE	IFD	IFO	TPP	PO	PNG	PNGL	PC	FCEF	BBOP
2003Q4	13758.63004	729.2106043	3727.433353	9301.986078	70.731465	42.469558	21.459551	3.716561	3.085795	614550	31.10299171
2004Q1	11892.82609	981.5350488	3135.993789	7775.297249	71.201567	42.37896	22.557282	3.5937	2.671625	620127.6424	33.968811
2004Q2	12718.93267	1129.886798	3363.087327	8225.958542	65.431491	41.520432	18.287528	3.192738	2.430793	618842.2943	37.39361952
2004Q3	13010.81029	801.6794118	3752.157353	8456.973529	58.731599	39.199483	15.139962	2.719914	1.67224	621386.3903	45.60570588
2004Q4	14432.50146	1349.543593	4326.789058	8756.168812	68.641343	39.678296	22.480266	4.115032	2.367749	620463.6662	47.00134582
2005Q1	13542.22401	1538.095168	4499.960469	7504.168375	66.874717	37.856711	22.750418	4.08569	2.181898	633964.9318	52.007306
2005Q2	15721.53345	2014.265856	5240.860122	8466.407472	62.514224	36.680529	20.00964	3.629888	2.194167	637475.9887	53.60208514
2005Q3	15528.82803	1939.144509	5386.976879	8202.706647	61.984658	37.170685	19.06361	3.820212	1.930151	646652.8717	65.38343931
2005Q4	19515.18109	2394.067261	5306.641276	11814.47255	65.88354	36.428816	23.139722	4.199353	2.115649	653530.6936	58.8195171
2006Q1	15557.6511	2613.652249	4055.095961	8888.902893	65.635272	35.139372	23.707734	4.31438	2.473786	673845.941	64.97887425
2006Q2	17913.42433	3195.721358	5248.141443	9469.561528	59.247435	32.927093	20.185482	3.791927	2.342933	677494.9731	72.60678925
2006Q3	19595.81425	2757.49788	6707.731128	10130.58524	60.095204	33.433052	20.189341	4.098996	2.373815	689141.4419	69.52001696
2006Q4	20612.39344	3417.320527	5784.405496	11410.66741	63.874011	35.077938	23.529962	4.467183	0.798928	695468.825	61.18602075
2007Q1	18281.01503	4008.580947	4420.611001	9851.823079	62.048571	33.868767	23.063427	4.296304	0.820073	727589.5228	63.65283527
2007Q2	22799.87736	3857.562729	8049.413589	10892.90104	56.44848	30.696821	20.890099	4.064585	0.796975	735784.075	70.75085988
2007Q3	25822.30313	3988.437765	8920.673158	12913.19221	55.800317	31.632419	19.598258	3.755419	0.814221	748925.7638	77.9967965
2007Q4	27359	5243	9071	13045	63.693028	32.07903	26.110574	4.460453	1.042971	746075.2	89.86
2008Q1	25242.63828	4255.444962	9041.459474	11945.73384	64.248446	30.891708	27.947462	4.350905	1.058371	759503.5811	95.95455915
2008Q2	27616.58563	5326.225075	8509.715925	13780.64463	57.838423	29.511705	23.207904	4.117481	1.001333	779926.82	119.871333

Table 2. Original data set.

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

Table of results: Multiple regression models of investments in exploration explained by:	Multiple coefficient of determination	R^2	Adjusted R^2	Standard Error of estimate
Model with Brent blend oil Price	0.6292	0.3959	0.3894	758.2211874
Model with Lag1(Brent blend oil price)	0.6747	0.4552	0.4430	725.6134657
Model with Lag2(Brent blend oil price)	0.7331	0.5375	0.5217	667.240017
Model with Lag3(Brent blend oil price)	0.7569	0.5728	0.5530	636.6005117
Model with Lag4(Brent blend oil price)	***0.7634***	***0.5828***	***0.5580***	***609.6302003***
Model with Lag5(Brent blend oil price)	0.7621	0.5808	0.5501	611.5306888
Model with Lag6(Brent blend oil price)	0.7593	0.5766	0.5396	615.5415525
Model with Lag7(Brent blend oil price)	0.7693	0.5918	0.5499	607.7793722
Model with Lag8(Brent blend oil price)	0.7733	0.5980	0.5504	610.3718112

Table 3. Results of multiple regression models of investments in exploration explained by *Brent blend oil price until 8 lags.*

Summary	***Multiple R***	***R-Square***	***Adjusted R-Square***	***Standard Error of Estimate***
	0.7634	***0.5828***	***0.5580***	***609.6302003***
ANOVA Table	Degrees of Freedom	Sum of Squares	Mean of Squares	F-Ratio
Explained	5	43618668.19	8723733.638	23.4730
Unexplained	84	31218514.42	371648.9812	
Regression Table	***Coefficient***	***Standard Error***	***t-Value***	***p-Value***
α	505.9086819	162.6430416	3.1105	0.0026
BBOP	-2.987890109	11.93016038	-0.2504	0.8029
$BBOP_{t-1}$	-11.14539955	19.70757337	-0.5655	0.5732
$BBOP_{t-2}$	25.89794607	20.37409558	1.2711	0.2072
$BBOP_{t-3}$	11.16982713	20.42610092	0.5468	0.5859
$BBOP_{t-4}$	27.00858502	14.03918386	1.9238	0.0578

Table 4. Estimated parameters of the model.

Autocorrelation Table	Residual Data Set #1
Number of Values	90
Standard Error	0.1054
	Autocorrelation coefficient
Lag #1	0.6515
Lag #2	0.5629
Lag #3	0.4215
Lag #4	0.4696
Lag #5	0.3196
Lag #6	0.3001
Lag #7	0.2265
Lag #8	0.3195
Lag #9	0.1408
Lag #10	0.0519

Table 5. Calculated correlation coefficients for the residuals.

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

YYYYQ	Q	TPP	CTPP	NEV =1/log (CTPP)	YYYYQ	Q	TPP	CTPP	NEV=1/log (CTPP)
1985Q1	1	18.9933	18.9933	**0.7821**	1997Q1	49	58.5394	1704.1651	**0.3095**
1985Q2	2	17.5761	36.5693	**0.6397**	1997Q2	50	57.4574	1761.6225	**0.3081**
1985Q3	3	17.2419	53.8113	**0.5777**	1997Q3	51	55.4681	1817.0905	**0.3068**
1985Q4	4	20.1755	73.9867	**0.5350**	1997Q4	52	61.8731	1878.9637	**0.3054**
1986Q1	5	20.6962	94.6829	**0.5060**	1998Q1	53	60.0122	1938.9759	**0.3042**
1986Q2	6	15.3693	110.0523	**0.4898**	1998Q2	54	56.3720	1995.3479	**0.3030**
1986Q3	7	19.8474	129.8996	**0.4731**	1998Q3	55	51.4990	2046.8470	**0.3020**
1986Q4	8	22.8544	152.7540	**0.4579**	1998Q4	56	58.4388	2105.2858	**0.3009**
1987Q1	9	23.3374	176.0914	**0.4453**	1999Q1	57	57.6271	2162.9129	**0.2998**
1987Q2	10	21.8716	197.9630	**0.4354**	1999Q2	58	54.3967	2217.3096	**0.2989**
1987Q3	11	19.7144	217.6774	**0.4278**	1999Q3	59	55.0168	2272.3264	**0.2979**
1987Q4	12	24.3577	242.0351	**0.4195**	1999Q4	60	63.6170	2335.9433	**0.2969**
1988Q1	13	25.2974	267.3325	**0.4120**	2000Q1	61	64.0977	2400.0410	**0.2958**
1988Q2	14	23.0008	290.3334	**0.4060**	2000Q2	62	56.8579	2456.8989	**0.2950**
1988Q3	15	23.2858	313.6191	**0.4006**	2000Q3	63	57.1772	2514.0761	**0.2941**
1988Q4	16	26.3614	339.9806	**0.3950**	2000Q4	64	66.2981	2580.3742	**0.2931**
1989Q1	17	29.3251	369.3057	**0.3895**	2001Q1	65	62.6460	2643.0202	**0.2922**
1989Q2	18	29.4515	398.7572	**0.3845**	2001Q2	66	59.3708	2702.3910	**0.2914**
1989Q3	19	29.5470	428.3042	**0.3800**	2001Q3	67	62.5196	2764.9107	**0.2906**
1989Q4	20	31.3480	459.6522	**0.3756**	2001Q4	68	67.7272	2832.6379	**0.2897**
1990Q1	21	31.4277	491.0800	**0.3716**	2002Q1	69	64.1813	2896.8192	**0.2889**
1990Q2	22	30.1656	521.2456	**0.3680**	2002Q2	70	65.1053	2961.9245	**0.2881**
1990Q3	23	28.4638	549.7094	**0.3649**	2002Q3	71	60.5356	3022.4601	**0.2873**
1990Q4	24	35.0242	584.7336	**0.3614**	2002Q4	72	69.1460	3091.6061	**0.2865**
1991Q1	25	34.9152	619.6488	**0.3581**	2003Q1	73	69.1970	3160.8032	**0.2857**
1991Q2	26	34.7560	654.4048	**0.3551**	2003Q2	74	61.0104	3221.8136	**0.2851**
1991Q3	27	31.5424	685.9472	**0.3526**	2003Q3	75	61.5984	3283.4120	**0.2844**
1991Q4	28	37.2781	723.2252	**0.3497**	2003Q4	76	70.7315	3354.1435	**0.2836**
1992Q1	29	38.9098	762.1351	**0.3470**	2004Q1	77	71.2016	3425.3450	**0.2829**
1992Q2	30	37.5469	799.6820	**0.3445**	2004Q2	78	65.4315	3490.7765	**0.2823**
1992Q3	31	37.7213	837.4033	**0.3421**	2004Q3	79	58.7316	3549.5081	**0.2817**
1992Q4	32	40.6677	878.0709	**0.3397**	2004Q4	80	68.6413	3618.1495	**0.2810**
1993Q1	33	38.7767	916.8476	**0.3376**	2005Q1	81	66.8747	3685.0242	**0.2804**
1993Q2	34	38.7055	955.5532	**0.3355**	2005Q2	82	62.5142	3747.5384	**0.2798**
1993Q3	35	39.7517	995.3048	**0.3336**	2005Q3	83	61.9847	3809.5231	**0.2793**
1993Q4	36	45.4856	1040.7904	**0.3314**	2005Q4	84	65.8835	3875.4066	**0.2787**
1994Q1	37	44.9139	1085.7043	**0.3294**	2006Q1	85	65.6353	3941.0419	**0.2781**
1994Q2	38	45.4700	1131.1744	**0.3275**	2006Q2	86	59.2474	4000.2893	**0.2776**
1994Q3	39	41.9863	1173.1607	**0.3258**	2006Q3	87	60.0952	4060.3845	**0.2771**
1994Q4	40	50.7052	1223.8659	**0.3239**	2006Q4	88	63.8740	4124.2585	**0.2766**
1995Q1	41	47.6553	1271.5212	**0.3221**	2007Q1	89	62.0486	4186.3071	**0.2761**
1995Q2	42	47.2057	1318.7269	**0.3205**	2007Q2	90	56.4485	4242.7556	**0.2757**
1995Q3	43	47.4730	1366.1999	**0.3189**	2007Q3	91	55.8003	4298.5559	**0.2752**
1995Q4	44	53.9230	1420.1229	**0.3172**	2007Q4	92	63.6930	4362.2489	**0.2747**
1996Q1	45	55.0989	1475.2217	**0.3156**	2008Q1	93	64.2484	4426.4974	**0.2743**
1996Q2	46	54.6135	1529.8352	**0.3140**	2008Q2	94	57.8384	4484.3358	**0.2738**
1996Q3	47	56.5943	1586.4295	**0.3125**					
1996Q4	48	59.1962	1645.6257	**0.3109**					

Table 6. New Explanatory Variable, reciprocal value of the logarithm of the cumulative Total Petroleum Production.

Annex A: Empirical research on the behavior of the investment in exploration for oil and gas in the Norwegian Continental Shelf

Summary	*Multiple R*	*R-Square*	*Adjusted R-Square*	*Standard Error of Estimate*
	0.9722	***0.9451***	***0.9411***	***222.47860***
ANOVA Table	Degrees of Freedom	Sum of Squares	Mean of Squares	F-Ratio
Explained	6	70728954.13	11788159.02	238.1604
Unexplained	83	4108228.474	49496.7286	
Regression Table	***Coefficient***	***Standard Error***	***t-Value***	***p-Value***
α	14837.33354	615.2351341	24.1165	< 0.0001
NEV_t	-43440.48469	1856.161931	-23.4034	< 0.0001
BBOP	14.9515074	4.42075852	3.3821	0.0011
$BBOP_{t-1}$	-12.42818989	7.192295773	-1.7280	0.0877
$BBOP_{t-2}$	5.692158504	7.485285952	0.7604	0.4491
$BBOP_{t-3}$	-1.281528028	7.473268635	-0.1715	0.8643
$BBOP_{t-4}$	9.014604636	5.18083255	1.7400	0.0856

Table 7. Estimated parameters of the corrected model.

	Residual
Autocorrelation Table	Data Set #1
Number of Values	90
Standard Error	0.1054
Lag #1	0.4211
Lag #2	0.3785
Lag #3	0.2537
Lag #4	0.0133
Lag #5	-0.0900
Lag #6	-0.1088
Lag #7	-0.3180
Lag #8	-0.2557
Lag #9	-0.3552
Lag #10	-0.2921

Table 8. Calculated correlation coefficients for the residuals using the corrected model

Annex B. Requirements, activities and products of the development planning phases

Requirements	Activities	Products
B.I. Feasibility phase (DG 0 – DG 1)		
The main purpose of the feasibility phase is to establish and document whether a business opportunity or a hydrocarbon find is technically feasible and has an economic potential in accordance with the corporate business plan to justify further development. *The feasibility phase is initiated at DG 0 with a project agreement that defines the task, goal, framework and budget.* *The feasibility phase leads to decision gate DG 1, "Decision to start concept development" (BoK).*	***Project management*** *• A project responsible shall be appointed and an organization (dedicated or matrix) established with documented responsibility and tasks (ref. chap. 7.6)* *• The project agreement shall be updated* *• Goals for the concept phase shall be established* *• A benchmarking of key parameters (ref. chap 7.21) against comparable projects shall be carried out* *• A self-assessment shall be carried out to measure project status against DG 1 (BoK) requirements.* ***Project framing*** *• The idea or resource basis for the business opportunity shall be reviewed, evaluated and documented. For upstream projects, reference is made to AR01: "Exploration and reservoir exploitation requirements".* *• For a production facility, a product description shall be established, including an evaluation of potential markets* ***Project control*** *•A cost estimate corresponding to estimate class B (+ / - 40%) shall be established.* *• A complete review of the project's uncertainty shall be made. The review should cover resource basis, market, technical solutions, HSE, project execution, vendor market, cost estimate and profitability (as relevant). An mitigation plan to reduce the uncertainties shall be established (risks and opportunities)*	*The products from the feasibility phase constitute the documented decision basis for passing DG 1 (BoK) and form the basis for the concept phase.* ***Decision gate 1 (DG 1), "Decision to start concept development" (BoK)*** *The DG 1 approval is an authorization by the operator and the partners to continue developing the project through the concept phase towards DG 2 (BoV) in accordance with the approved project plans and budgets.* ***Timing*** *DG 1 (BoK) may be passed when the business concept has been developed to a level where it is likely that it is profitable, technically feasible and in accordance with the corporate business plans (ref. documentation requirements in appendix A).*

Requirements	***Activities***	***Products***
Feasibility phase (DG 0 – DG 1) Continued		
	Project control (continues) *• A work program, plan, budget, organization and reporting system for the concept phase activities after DG 1 (BoK) shall be established/updated.* ***HSE*** *• HSE challenges, hazards and relevant authorities' requirements shall be identified, risks shall be evaluated and risk reducing measures shall be identified* ***Technical*** *• The preliminary design basis document shall be reviewed and updated.* *• A feasible facility concept (reference case) shall be outlined, and other possible viable concepts and potential upsides by application of new technology shall be identified on the basis of a coarse assessment. The project can only proceed into the concept phase if at least one solution that is technically feasible has been documented. In the downstream area it may be necessary to carry out a screening of possible technologies and to recommend a preferred technology supplier.* *• A coarse assessment of local technical and operational requirements shall be made* *• A technology assessment shall be performed* *• A technology qualification program shall be developed (if relevant).* *• For upstream facilities, special attention shall be given to requirements for drilling activities.* *• A regularity management program (RMP) shall be established*	***Documentation*** *The DG 1 decision basis is a memorandum / document that reviews the business opportunity and the development of the project up to DG 1, refers to the project documentation and concludes that the DG 1 requirements are met. Any deviations from governing documents shall be described. For modification projects, a recommendation on whether to use this procedure as the basis for further development of the project shall be included.* *Projects overseas* *For projects overseas, the DG 1 documentation shall describe uncertainty relating to:* *• geographical location, community, social and cultural conditions* *• political, trade financial and tax conditions* *• authority requirements and approval practice* *• industrial conditions and infrastructure* *• international reputation* *• security related to personnel, activities and facility* *• personnel / industry* *• QC process* *The documented results of the project external quality control process required at DG 1 shall be part of the DG 1 documentation.*

Requirements	*Activities*	*Products*
Feasibility phase (DG 0 – DG 1) Continued		
	Commercial / economy *• The profitability of the business opportunity shall be evaluated, documented and reviewed in relation to corporate requirements* *• Requirements for commercial agreements or arrangements shall be evaluated in relation to each of the possible technical solutions* *• Agreements with partners required for the feasibility phase shall be established. A list of agreements required for further development of the project shall be established.*	***Recommendation and approval*** *The DG 1 proposal shall be evaluated and recommended by the exploration arena (when relevant) and the project development arena.* *The DG 1 approval process shall be in accordance with the delegation of authority within the responsible business area.* *The partners / co-owners shall also approve DG 1 (BoK).*

Requirements	***Activities***	***Products***
B.II. Concept phase (DG 1 – DG 2)		
The purpose of the concept phase is to provide a firm definition of the design (resource and product) basis and to identify all relevant and feasible technical and commercial concepts. *Further to evaluate and define the selected alternative (preferably one) and confirm that the profitability and feasibility of the business opportunity will be in accordance with the corporate requirements and business plans. The concept phase leads to the selection of the concept(s) (AP1) to be further developed up to decision gate DG 2, "Provisional project sanction" (BoV).*	***Project management*** *• A documented management system shall be established, adjusted to suit the project scope and size.* *• The project organization shall be continued from the previous phase, but adjusted to suit the concept phase* *• Goals and targets for the project which include profitability, regularity, project execution, HSE and quality shall be established.* *• The project agreement shall be updated* *• The project execution strategy shall be developed and documented by the core team / project management team.* *• Based on the project agreement, the project execution strategy and the overall procurement strategy, a project execution plan (PEP), which describes the project and the management system, shall be produced. The PEP shall be developed and updated continuously during the project planning period.* *• To serve as a basis for the development of strategies, a stakeholder analysis shall be carried out, appropriate to the project's scope, complexity and other requirement.* *• Based on the project execution strategy, strategies shall be developed for* *- commercial agreements* *- information technology* *- operation and maintenance* *A summary of these shall be included in the PEP (including references to the actual documents)* *• With reference to an established basis, a change control system shall be established* *• Goals for the pre-engineering phase shall be established* *•Benchmarking shall be carried out to measure the project against comparable projects* *•A self-assessment shall be carried out to measure project status against DG 2 (BoV) requirements.*	*The products from the concept phase constitute the documented decision basis for passing DG 2 (BoV) and form the basis for the pre-engineering phase. These products are listed in the table in appendix A.* ***Approval point 1 (AP 1), "Concept selection"*** *The approval point "concept selection", AP1, marks that one (or, where necessary, a limited number of) concept(s) or licensed process(es) has(have) been chosen for further detailing towards DG 2 (BoV).* *AP1 shall be the result of a screening process including all relevant and feasible alternative concepts identified for a further development of the business opportunity. Circumstances may dictate that more than one concept is selected for further development at AP1 or that a concept is selected at another point in time in the planning period. The relevant process owners shall recommend the selected concept(s).* *• The selection of the base case concept(s) shall be supported by documentation describing the concept screening process, focusing on:* *• design basis* *• concept alternatives and variants* *• screening parameters and weighting* *• description of and justification for both the selected concept(s) and the rejected option(s).* *• technology qualification program (final, when relevant)*

Requirements	Activities	Products
Concept phase (DG 1 – DG 2) Continued		
	Project Management (Continued) *• Project framing* *• The idea or resource basis for the project shall be reviewed, updated, evaluated and described for use in the concept development.* *•The product description and market analysis shall be updated and further developed Project control* *• A planning system shall be established with a main plan showing the main project activities, main milestones, important activities with regard to authorities and partners, and main supervision activities* *• Cost estimates shall be developed to an accuracy corresponding to estimate class C (+ / - 30 %)* *• A comprehensive uncertainty analysis shall be carried out covering all relevant technical and commercial aspects (resource basis, market, technical solutions, HSE, project execution, supplier market, cost estimate and profitability). A mitigation plan for reduction of uncertainties shall be established (risks and opportunities)* *•A proposal for a plan, budget and organization for the pre-engineering phase after DG 2 (BoV) shall be established HSE* *• Challenges and hazards with regard to health, working environment, safety, security and environment shall be identified, risks shall be assessed and risk-reducing measures identified. The requirements of relevant authorities shall be identified.* *•A plan shall be established for the preparation of the environmental impact assessment (EIA), which ensures that the EIA process can be completed within the framework of the project main schedule* *•A total risk analysis shall be performed* *• HSE program and plan shall be established*	***Decision gate 2 (DG 2), "Provisional project sanction" (BoV)*** *The DG 2 approval is an authorization by Statoil and the partners to continue developing the project through the pre-engineering phase towards DG 3 (BoG) in accordance with the approved project plans and budgets.* *The approval includes a decision to develop the necessary applications to the authorities. (For projects within the jurisdiction of the Norwegian Petroleum Act, this concerns PDO / PIO (PUD / PAD), including the EIA (KU)).* ***Timing*** *DG 2 (BoV) may be passed when the business concept has been developed to a level where it has been documented that it is profitable, technically feasible and in accordance with the corporate business plans (ref. documentation requirements in appendix A).* ***Documentation*** *The DG 2 decision basis is a memorandum / document that reviews the business opportunity and the development of the project up to DG 2, refers to the project documentation (ref. App. A) and concludes that the DG 2 requirements are met. Any deviations from governing documents shall be described.*

Requirements	*Activities*	*Products*
	Concept phase (DG 1 – DG 2) Continued	
	Technical *• The design basis document shall be reviewed and updated. Where relevant, infrastructure evaluations shall be included.* *• Reports from reviews and verifications shall be assessed* *• For upstream field developments, special attention shall be given to requirements for drilling activities and –equipment* *•For upstream field development, a production strategy for the field shall be developed* *• The regularity management program (RMP) shall be updated and the required activities carried out (ref. NORSOK Z-016)* *• A regularity analysis shall be carried out for the total production / value chain* *• For concepts that require ship transportation, a shipping simulation study shall be carried out* *• An operation verification of design shall be carried out* *• All relevant concept alternatives and concept variants shall be identified and evaluated* *• The best concept solution(s) shall be proposed and selected* *• Value improving activities (ref. app. D) shall be performed* *• The selected concept(s) shall be defined as per requirements to cost estimate class C* *• A technology qualification program shall be established (if relevant).* *• The project technical and operational requirements and guidelines shall be established (preliminary)* *• A system for handling of technical information shall be selected*	***Projects overseas*** *For projects overseas, the DG 2 documentation shall describe uncertainty relating to:* *• geographical location, community, social and cultural conditions* *• political, trade, financial and tax conditions* *• authority requirements and approval practice* *• industrial conditions and infrastructure* *• international reputation* *• security related to personnel, activities and facility* *• personnel / industry* *The DG 2 documentation shall include an evaluation of the availability of qualified personnel resources in Statoil and of the capacity in the relevant supplier industry.* ***QC process*** *The documented results of the project external quality control process required at DG 2 shall be part of the DG 2 documentation.*

Requirements	*Activities*	*Products*
Concept phase (DG 1 – DG 2) Continued		
	Procurement *• Strategy shall be developed and contracts awarded for the concept phase* *• The overall procurement strategy shall be developed based on guidelines from, in parallel with and in interaction with the project execution strategy process. The strategy shall include descriptions of supplier market, contract packages, purchasing strategy, identification of long lead items and use of Statoil's frame agreements / contracts.* *• Specific strategy shall be developed and invitation to tender for pre-engineering contracts shall be prepared* ***Commercial / economy*** *• Profitability analyses shall be carried out to demonstrate that the business opportunity meets corporate requirements for profitability. The analyses shall include portfolio and value chain analyses through to the end customer* *•All financial and commercial agreements and arrangements that are relevant to the project development process shall be identified and described. A strategy and a plan for entering into agreements shall be established*	***Recommendation and approval*** *The DG 2 proposal shall be evaluated and recommended by the project development arena. The DG 2 approval process shall be in accordance with the delegation of authority within the responsible business area. Unless otherwise stated by the business area delegation of authority, final Statoil approval shall be by the corporate management (KL).* *The partners / co-owners shall also approve DG 2 (BoV).*

Requirements	***Activities***	***Products***
B.III. Pre-engineering phase (DG 2 – DG 3)		
The purpose of the pre-engineering phase is to further develop and document the business opportunity based on the selected concept(s) to such a level that a final project sanction can be made, application to authorities can be sent and contracts can be entered into. The preengineering phase leads to approval point 2 (AP2), "Application to the authorities", and to decision gate 3 (DG 3) " Project sanction" (BoG).	***Project management*** *• The project organization shall be continued from the previous phase, but adjusted to suit the pre-engineering phase. The documented management system shall be adjusted accordingly* *• The project goals (profitability, regularity, project execution, HSE and quality) shall be updated* *• The project agreement shall be updated and approved* *• The project execution strategy shall be updated as necessary* *• The following strategies shall be updated or developed (as relevant)* *- commercial agreements* *- information technology* *- commissioning strategy that shall be used as input to contracts, engineering and* *construction planning* *• The project execution plan (PEP) shall be updated* *• The change control system for the execution period shall be implemented* *• The stakeholder analysis for the project shall be confirmed or, updated* *• Necessary applications to the authorities shall be prepared* *• Benchmarking shall be carried out to measure the project against comparable projects* *• A self-assessment shall be carried out to measure project status against DG 3 (BoG) requirements* ***Project framing*** *• The business idea or resource basis and the market analyses for the project shall be reviewed and confirmed or, as necessary, updated*	*The products from the pre-engineering phase constitute the documented decision basis for passing DG 3 (BoG) and form the basis for the project execution period.* ***Approval point 2 (AP 2), "Application to the authorities"*** *The project shall compile and prepare for submittal of the necessary application(s) for approval of the facility development in accordance with the relevant laws and regulations. It is particularly important to have undertaken an analysis to determine which requirements apply.* *For projects within the jurisdiction of the Norwegian Petroleum Act, a "Plan for development and operation" (PDO) (Norwegian: PUD) or a "Plan for installation and operation" (PIO) (Norwegian: PAD) is required. The PDO / PIO shall be prepared in accordance with the document "Guidelines for PDO and PIO", issued by the Norwegian Petroleum Directorate.*

Requirements	*Activities*	*Products*
	Pre-enginnering phase (DG 2 – DG 3) Continued	
	Project control *• The planning system for the project with a main plan that shows the project's main activities, main milestones, important products, activities towards the authorities and partners and main inspection activities shall be further developed and a main plan established.* *• A resource / manpower plan for the execution period shall be developed* *• A supervision plan shall be established* *• Cost estimates at estimate class D (+ / - 20%) level and corresponding budget proposals shall be established.* *• A project control basis shall be established* *• The uncertainty analysis that covers the resource basis, market, technical solution, HSE, project execution, supplier market, cost estimate and profitability, shall be further developed and updated. The mitigation plan shall be updated accordingly* ***HSE*** *• The environmental impact assessment (EIA) program shall be established, approved and the necessary study work carried out* *• The total risk analysis shall be updated as necessary* *• The HSE program for the execution period shall be completed* ***Technical*** *• The design basis document shall be reviewed, confirmed, updated as necessary and "frozen"* *• Reports from reviews and verifications shall be assessed* *• Concept optimization shall be performed for the selected concept option(s)* *• The facility concept(s) shall be defined as per requirements to support a class D estimate* *• The technology qualification program shall be updated (if required)* *• Project technical and operational requirements and guidelines shall be completed and approved.*	*The PDO / PIO shall be approved by the responsible business unit, corporate management (KL), the board and the partners, before it is submitted. When the partnership submits a PDO/ PIO to the authorities, this represents a commitment by the partnership to carry out the project development. For projects in this category, completion of the PDO / PIO and DG 3 (BoG) should occur at the same time.* ***Decision gate 3 (DG 3), "Project sanction" (BoG) DG 3 (BoG)*** *The DG 3 approval is an authorization by Statoil and the partners to continue developing the project through the execution period in accordance with the approved project plans and budgets* ***Timing*** *DG 3 (BoG) may be passed when the business concept has been developed to a level where it has been documented that it meets the established requirements with regard to profitability, HSE, technical definition, cost estimate accuracy and project execution uncertainty*

Requirements	*Activities*	*Products*
Pre-enginnering phase (DG 2 – DG 3) Continued		
	• For downstream facilities, the responsible business unit shall enter into license agreements for the selected technology and processes (licensed technology) *• For upstream facilities, drilling plans and drilling equipment requirements shall be completed (ref. AR03, "Drilling, well & production activities")* *• For upstream facilities the production strategy for the field shall be updated* *• The regularity management program (RMP) shall be updated and the required activities carried out (ref. NORSOK Z-016)* *• The regularity study for the total production / value chain shall be updated* *• For concepts that require ship transportation, the shipping simulation study shall be updated* *• An operation verification of design shall be carried out* *• The operation and maintenance strategy for the facility shall be further developed* *• Statoil's frame agreement suppliers shall be involved in accordance with overall procurement strategy* ***Procurement*** *• Pre-engineering contract(s) shall be awarded* *• The overall procurement strategy shall be updated as necessary* *• Purchase orders for long lead items shall be placed as required by the contract plan* *• Specific procurement strategies for the execution phase shall be developed* *• Invitation to tender documents shall be prepared as required* *• Contract plan and basis for entering into contracts and purchase orders shall be developed* *• Contracts and purchase orders shall be entered into in accordance with the approved* *contract plan* *Commercial / economy*	***Documentation*** *The DG 3 decision basis is a memorandum / document that reviews the business opportunity and the development of the project up to DG 3, refers to the project documentation (ref. App. A) and concludes that the DG 3 requirements are met. Any deviations from governing documents shall be described.* ***Projects outside Norway*** *For projects outside Norway, the DG 3 documentation shall describe uncertainty relating to:* *• geographical location, community, social and cultural conditions* *• political, trade financial and conditions* *• authority requirements and approval practice* *• industrial conditions and infrastructure* *• international reputation* *• security related to personnel, activities and facility* ***Personnel / industry*** *The DG 3 documentation shall include an evaluation of the availability of qualified personnel resources in Statoil and of the capacity in the relevant supplier industry.*

Requirements	***Activities***	***Products***
	Pre-enginnering phase (DG 2 – DG 3) Continued	
	• Economic analyses and profitability calculations which demonstrate that the concept meets Statoil's requirements for profitability shall be confirmed or updated as necessary (ref. WR0324, "Investeringshåndbok") *• The strategy and plan for entering into all financial and commercial agreements and arrangements shall be reviewed and updated as necessary. All necessary agreements shall be established and approved before DG 3.* *A more detailed description of the pre-engineering phase and deliverables is given in the document WD0977, "Prosjektering". The use of standards and company specific requirements is described in WR0096.*	***QC proces*** *The documented results of the project external quality control process required at DG 3 shall be part of the DG 3 documentation.* ***Recommendation and approval*** *The DG 3 proposal shall be evaluated and recommended by the project development arena. The DG 3 approval process shall be in accordance with the delegation of authority within the responsible business area. Final Statoil approval shall be by the corporate management (KL) and the Board.* *The partners / co-owners shall also approve DG 3 (BoG).* ***Experience transfer*** *After DG 3 (BoG), the core team- / project manager is responsible for arranging a core team experience transfer workshop, focusing on the planning period. If needed, experience transfer workshops can also be arranged at sub-project levels. TEK PE PL is responsible for publishing the results on the intranet and may also facilitate the workshop.*

Annex C: Field Development Examples

C.I. Subsea tieback to shore: Ormen Lange, Norway.

Name of the project: Ormen Lange
Operator: Shell
Water Depth: 850 m / 2,805 ft
Region: Europe - North Sea
Country: Norway

Project Description

Discovered in 1997, Ormen Lange is Europe's third-largest gas field with estimated recoverable reserves of 14 Tcf (397 Bcm) of natural gas. Located on the Norwegian Continental Shelf, 75 miles (120 kilometers) northwest of Kristiansund, Norway, in the Norwegian Sea, Ormen Lange reaches 25 miles (40 kilometers) by up to 6 miles (10 kilometers). Water depths for the field range from 2,625 to 3,609 feet (800 to 1,100 meters), and hydrocarbons are located another 9,843 feet (3,000 meters) below the surface.

Partners in the field include Petoro with 36.48%, StatoilHydro with 28.91%, Shell with 17.04%, Dong with 10.34% and ExxonMobil with 7.23%. Like its development, Ormen Lange boasts a multiphase operatorship. StatoilHydro served as the field's operator during the first phase of development from 1999 through production start-up in 2007. Shell took over operatorship for the production phase of the field, including the second phase of development.

Overcoming Challenges

There were a number of challenges that had to be overcome to bring natural gas from Ormen Lange to market. First of all, the field is in environmentally unfriendly waters. Both temperatures and strong currents sought to stop field development in its tracks. Water temperatures on the seafloor stay below freezing, and especially strong currents in the area threaten field facilities. Additionally, a mountainously uneven sea floor made for difficult subsea development.

Despite these difficulties, designers devised a multiphase completely subsea field development plan, including the world's longest subsea pipeline. Submitted to Norwegian authorities on Dec. 4, 2003, the field development plan was approved on April 2, 2004.

Field Development: Phase I

At an estimated cost of US $8 billion (NOK 50 billion), the first phase of development included two 1,268-ton (1,150-tonne) subsea templates, as well as pipelines to shore and an onshore gas processing plant.

Each subsea template holds slots for eight wells, which are hooked up to the templates via a subsea manifold. FMC was awarded the US $160 million (NOK 1 billion) contract to engineer, procure, fabricate and test the subsea production system, which consisted of the two subsea templates with manifolds, eight xmas trees, control systems, an intervention system, tie-in tools, end terminations and Tee's for the pipelines. The contract also included options for additional xmas trees and control systems.

Measuring 144 feet (44 meters) long by 108 feet (33 meters) wide and 49 feet (15 meters) wide, the subsea templates were installed by Hreema's Thialf crane barge using sound signals produced by subsea acoustic *transmitters. Positioned 2.2 miles (3.6 kilometers) away from each other, the subsea templates are in waters measuring 2,789 feet (850 meters).*

Additionally, a 386-ton (350-tonne) pipeline connection box was installed 164 feet (50 meters) away from the templates. Gas, condensate and water produced from the templates are transported through two 75-mile (120-kilometer), 30-inch-diameter multiphase flowlines up the Eggkanten embankment to the gas plant Nyhamna onshore the western coast of Norway. Saipem was awarded the US $105 million (NOK 660 million) pipeline installation contract, which included tie-in operations.

After installation of the subsea equipment, development drilling for the first phase of development was performed by the West Navigator drillship. The largest deepwater wells in the world at the time, Smedvig completed the US $167 million (NOK 1.17 billion) drilling contract over a two-year period.

Innovative Solutions

To overcome icy water temperatures on the seafloor, Vetco Aibel was awarded the US $96 million (NOK 600 million) contract to engineer, procure and build a Monoethylen-Glycol (MEG) regeneration system, which included a tank farm. MEG is used as anti-freeze to prevent ice formations and plugs in the subsea production facility and pipelines.

To counteract the strong currents in the deepwater of the Norwegian Sea, Van Oord ACZ was contracted to install 3 million tons (2.8 million tonnes) of rock on the seabed to protect and support pipelines and umbilicals from Ormen Lange to Nyhamna for a consideration of US $112 million (NOK 700 million).

Production

Production from Ormen Lange commenced on October 1, 2007. With daily rates expected to increase over the first couple of years, production rates for the first phase of development is 2.5 Bcf/d (70 MMcm/d) of natural gas and 50,000 barrels of condensate a day. Peak production is predicted for 2010.

Natural gas is transported to market via the Gassco-operated Langeled pipeline, the world's longest subsea transport pipeline, traversing 746 miles (1,200 kilometers to connect Nyhamna in Norway to Easingtown in the UK.

Ensuring Long-Term Production: Phase II

The second phase of development on Ormen Lange includes the fabrication and installation of another two subsea templates. The first of them is under construction, and the fourth will be commissioned when necessary. In total, the four wellhead complexes on Ormen Lange will accommodate up to 24 wells.

Both the Leiv Eiriksson semisub and the West Navigator drillship are employed on Ormen Lange for the second phase of development drilling. West Navigator was used through the summer of 2008 for development wells and to complete and make ready new wells for production. Leiv Eiriksson is drilling the planned monitoring well and several production wells through October 2009.

Total costs for the second phase of development have not been released. Ormen Lange is expected to have a field life of 40 years.

Offshore Compression

Inevitably, as production decreases from Ormen Lange, so too will pressure. Once pressure can no longer drive produced gas to shore for processing, offshore compression will be required. There are two options for supplying offshore compression: a floating deepwater platform or a subsea compressor station.

While an offshore platform is more conventional, it is also more expensive than a subsea compressor.

Two subsea compression pilot programs are being designed for use on the field. Aker Solutions was tapped to engineer, procure and fabricate a full-size subsea compression station pilot, and Vetco Aibel was chosen to engineer, procure and construct a long step-out power supply pilot.

The subsea compressor will be located between the two original subsea templates in 2,789 feet (850 meters) of water. If chosen, the subsea compressor will be an industry first. At a cost of about US $ 401 million (NOK 2.5 billion), the subsea option is about half the cost of the offshore platform option.

Testing of the two subsea compression pilots is expected to commence in 2009, and the best system will be chosen by 2011 with installation slated for 2015. Much of the decision will be based on reservoir properties.[Subsea IQ, 2010]

C.II. Subsea tieback to existing platform: Canyon Express, Gulf of Mexico U.S.A.

Name of the project: Canyon Express
Operator: Williams
Water Depth: 2,346 m / 7,742 ft
Region: N. America - US GOM
Country: US

Project Description

An innovative development project for its time, the Canyon Express allowed three different operators to bring three marginal gas fields into production through a subsea gas gathering system. Located in deepwater Gulf of Mexico, the Canyon Express traverses a number of blocks transporting gas from the Aconcagua, Camden Hills and King's Peak in the Mississippi Canyon.

Although combined, the fields' boast a reserves reaching 900 Bcf (25 Bcm), none of them were commercially viable to be developed separately. Solving that problem, the Canyon Express project commingles gas from the three deepwater fields all located about 120 miles (193 kilometers) south of New Orleans, before transferring them to a third-party shallow-water production platform called the Canyon Station.

Although the fields used to be operated by three different companies, all three fields, as well as the Canyon Express subsea development are now operated by ATP Oil & Gas.

The Fields

Located on Mississippi Canyon Block 348 in waters measuring 7,200 feet (2,195 meters) deep, Camden Hills was discovered in August 1999. Drilled by the Ocean Clipper semisub, the discovery well reached a total depth of 15,080 feet (4,596 meters) and encountered more than 200 feet (61 meters) of natural gas.

Also discovered in 1999, the Aconcagua field is located on Mississippi Canyon Block 305 in approximately 7,000 feet (2,134 meters) of water. Drilled in March 2000, an appraisal well confirmed the discovery by intersecting more than 250 net feet (76 net meters) of gas.

Situated in waters ranging in depth from 6,200 to 6,400 feet (1,890 to 1,951 meters), the King's Peak gas field spans Mississippi Canyon Blocks 217 and 173, as well as Desoto Canyon Blocks 133 and 177.

Canyon Express

A subsea gas gathering system, Canyon Express was the longest and deepest subsea tie-back at the time of its development. The $600 million project encompasses two 12-inch-diameter, 55-mile-long (88-kilometer-long) flowlines that transfer gas from the fields to a shallow-water production platform 55 miles (88 kilometers) away.

Ten subsea development wells are scattered across the fields and daisy-chained together. Aconcagua has four wells, Camden Hills has two wells, and King's Peak has four wells. In order to monitor production at all times, each well is equipped with a wet gas flow meter. Additionally, each well is completed with two gravel-packed intervals and an intelligent well completion system, allowing the wells to be produced independently or in a commingled state.

Each of the wells delivers gas into one of the two flowlines that tie the wells back to the Canyon Station production platform. Canyon Express contains 32 individual pipeline segments, including all flowlines, supply lines, jumpers and umbilicals. Well tie-in sleds installed as a part of the flowlines eliminated the need to install multiple well manifolds and infield flowlines. Wells are connected to the tie-in sleds through an inverted U-shaped jumpers.

Measuring more than 62 miles (100 kilometers) long, the production control, electrohydraulic steel tube umbilical system includes electrical cables and fiber optics. At the time of development the umbilical was the deepest steal-tube umbilical ever.

In 2000, Saipem was chosen as the main subsea provider on the Canyon Express project. Designing a daisy-chain concept, subsea multi-phase flow meters and round-trip pigging, Intec Engineering performed the FEED and project management on the Canyon Express project. Aker Solutions (then Kvaerner) was subcontracted to manufacture the umbilicals, and Clough was tapped to install the umbilicals.

With a capacity of 500 MMcf/d (14 MMcm/d), Canyon Express was the world's deepest producing gas field at commissioning.

Canyon Station

Situated in 300 feet (91 meters) of water, the Canyon Station production platform is located in Mississippi Pass 261, approximately 55 miles (88kilometers) north of the Camden Hills field and 60 miles (97 miles) south of Mobile Bay, Alabama. Owned and operated by Williams, Canyon Station is a fixed-leg platform built to treat, process and handle natural gas and condensate from Aconcagua, Camden Hills and King's Peak.

A four-pile, four-leg platform, the topsides alone weigh in at 3,500 tons (3,127 tonnes), which includes compression and separation facilities, water treatment, and instrumentation and utilities. The jacket was installed in October 2001, and the topsides were installed in May 2002.

Production reaching the Canyon Station shallow-water production platform consists of mainly methane gas, as well as produced water and condensate. Williams personnel located on the platform performs all subsea well monitoring, flow control and chemical injection.

In February 2001, AMEC Paragon was tapped to provide project management, engineering, design/drafting, procurement and fabrication inspection for the platform.

Commencing operations in July 2002, Canyon Station's daily capacity is 500 MMcf/d (14 MMcm/d) and 1,500 bpd of condensate. From Canyon Station, production transported to shore via multiple export pipelines.

Production

In September 2002, Canyon Express/Canyon Station production commenced, first from a well on Anconcagua and another on King's Peak. Over the next two months, the rest of the wells were brought on stream, and the development eventually reached its production plateau of 500 MMcf/d (14 MMcm/d).

Future Development

Further development work is planned for Canyon Express in 2009. The project partner plans to re-develop King's Peak and Aconcagua in the second quarter of 2009. A contracted rig is scheduled to drill four to six wells in the area to net undeveloped reserves, which will be produced through the Canyon Express system.

Additionally, ATP has acquired a number of blocks in the near vicinity of Canyon Express, with expectations of tying any production found into the system.

C.III. Subsea tieback to semisubmersible: Thunder Horse, Gulf of Mexico U.S.A.

Thunder Horse Thunder
Operator: BP
Water Depth: 1,841 m / 6,075 ft
Region: N. America - US GOM
Country: US

Project Description

Situated in a water depth of 6,050 feet (1,844 meters), the Thunder Horse oil and gas field is located on Mississippi Canyon Blocks 776, 777 and 778, about 150 miles (241 kilometers) southeast of New Orleans, La. Considered to be the deepest and largest oil and gas field ever discovered in the Gulf of Mexico, Thunder Horse produces from two areas, north and south, which are tied-back to one of the largest moored semisubmersible platforms in the world, the Thunder Horse Production, Drilling and Quarters (PDQ) platform.

Originally called Crazy Horse, Thunder Horse is operated by BP, which holds 75% interest; ExxonMobil holds the remaining 25% interest in the field.

Exploration

Discovered in 1999 by the drillship Discoverer Enterprise, the Thunder Horse discovery well was drilled to a total depth of 25,770 feet (7,855 meters). The discovery found 520 feet (158 meters) of net pay in three intervals on the south side of the field. A year later, the appraisal well, Thunder Horse 2, was drilled and reached a total depth of 29,060 feet (8,857 meters). The appraisal well, located in 6,300 feet (1,920 meters) of water, 1.5 miles (2.41 kilometers) southeast of the discovery well, confirmed the previous findings.

In February 2001, additional drilling commenced on the north side of the field in order to determine the size of Thunder Horse. The exploration drilling encountered 581 feet (177 meters) of accumulated hydrocarbons in three intervals. The well was drilled in 5,640 feet (1,719 meters) of water by the drillship Discoverer 534 and reached a total depth of 26,046 feet (7,939 meters). Because a prolific amount of hydrocarbons were discovered, BP named this section of the field Thunder Horse North.

The Thunder Horse reservoir consists of upper Miocene turbidite sandstones and lies 14,000 to 19,000 feet (4,267 to 5,791 meters) below the seabed. With extreme pressures of 13,000 to 18,000 psi and temperatures ranging from 88 to 132ºC, the conditions of Thunder Horse presented challenges that weren't yet tackled in *the offshore world. However new capabilities, systems and equipment were created in order to develop the field under extreme conditions.*

Field Development

The challenges encountered on Thunder Horse made it necessary to develop the field in two stages. The Thunder Horse North and Thunder Horse South were developed simultaneously with initial development focusing on drilling and producing six wells. Over an eight-year span, Thunder Horse will have a total of 25 wells tied-back to the Thunder Horse platform.

Phase 1

The first phase of development focused on the southern portion of the field. Two production wells were drilled and tied-back to the platform. Shortly after, two additional wells were drilled, and production commenced from these two wells.

The second part of Part 1 focused on the northern portion of the field, so while production began on the southern portion of Thunder Horse, development drilling continued on the north side of the field. Located on Block 776 in a water depth of 5,640 feet (1,719 meters), an additional two production wells were drilled on Thunder Horse North, which are also tied-back to the platform. This portion of the field commenced production.

The initial six subsea wells, as well as the remaining 19 wells, are and will be connected to production manifolds, which are connected to the platform via riser flowlines. FMC Technologies fabricated the subsea trees, controls, manifolds and well connection systems in water depths of 5,700 to 6,300 feet (1,713 to 1,920 meters). In 2002, Subsea 7 received a $30 million contract for the installation of subsea structures, and controls including umbilicals, totaling more than 37 miles (60 kilometers) in length.

Heerema Marine Contractors received a contract for the installation of two steel catenary risers, a 20-inch-diameter riser and a 24-inch-diameter riser, in a water depth of 6,037 feet (1,840 meters). The 24-inch-diameter SCR is the deepest installation of its kind and a first for Heerema Marine Contractors.

Situated in a water depth of 6,037 feet (1,841 meters), the Thunder Horse semisubmersible platform is located on Mississippi Canyon Blocks 820 and 821. The 50,000-ton (45,359-tonne) Thunder Horse PDQ has the ability to process and export up to 280,000 bopd and 200 MMcf/d (6 MMcm/d). With a displacement of 143,300 tons (130,000 tonnes), and a deck load capacity of 44,092 tons (40,000 tonnes), the platform's topsides consist of three modules: production, generator and compression.

J. Ray McDermott built the process topsides modules; GVA Consultants of Sweden designed the 120,000-deadweight-ton (108,862-deadweight-tonne) hull; and Daewoo's Shipbuilding and Marine Engineering division built the hull and drilling rig for the platform. Kiewit Contractors was responsible for the deck and hull integration.

Production

The Thunder Horse field was initially scheduled to start producing in the second half in 2005, but hurricane damage and equipment problems interfered with startup plans. During that same year, Hurricane Dennis caused damage to Thunder Horse's production platform; and a leaky internal ballast valve went undetected, which caused the structure to list 20 to 30 degrees.

Despite this, production commenced from the first two Thunder Horse wells in June 2008. Another two wells commenced production on Dec. 18, 2008. The final two wells of the first phase of development started producing from Thunder Horse North on March 3, 2009. Since the sixth well came online, production has *increased to 260,000 bopd. Production rates will continue to increase once development drilling is completed on the remaining 19 wells, which should be finished in 2016.*

Thunder Horse oil and gas is transported to onshore pipelines via the Proteus and Endymion oil pipeline systems and the Okeanos gas pipeline system. Both systems are connected to the Mardi Gras Transportation System.

Phase 2

Development drilling of the remaining 19 wells will continue until all 25-production wells commence; the field is expected to operate for 25 years.

C.IV. Subsea tieback to FPSO: Pazflor, Angola, West Africa .

Pazflor Pazflor
Operator: Total
Water Depth: 762 m / 2,515 ft
Region: Africa - West
Country: Angola
Last Updated: Oct 21, 2009 (view update history)

Project Description

Angola's Block 17 has proven prolific for partners in the offshore license, with Girassol and Dalia already producing, Pazflor in development, and the CLOV project in consideration. Located approximately 90 miles (150 kilometers) offshore Angola in ultra-deep waters, the Pazflor project incorporates four fields -- Perpetua, Zinia, Acacia and Hortensia -- spanning 148,263 acres (600 square kilometers) on the eastern edge of Block 17.

Total's Angolan subsidiary, Total E&P Angola, is the operator of Angolan Block 17 with a 40% interest. Partners in the license include Statoil with 23.33% interest, Esso Exploration Angola with 20% interest and BP Exploration Angola with 16.67% interest.

Fields

First of the Pazflor cluster to be discovered, and the 10th field discovered on Block 17, Perpetua is located about 124 miles (200 kilometers) northwest of Luanda in 2,608-foot-deep (795-meter-deep) water. The Perpetua-1 exploration well discovered the field in August 2000, showing a daily flow rate of 8,740 bopd of 20-degree API in production tests.

Discovered in December 2002, the Zinia field was the 13th field encountered on Block 17 and the second of the Pazflor project. Located 90 miles (150 kilometers) from the Angolan coast, Zinia is situated in a water depth of 2,356 feet (718 meters). Also on the eastern portion of the license, the Zinia-1 well tested a flow rate of 3,650 bopd.

The discovery of the next two fields made the Pazflor project a commercial viability. The Acacia discovery followed in the spring of 2003 in water measuring 3,379 feet (1,030 meters). The Acacia-1 discovery well tested a combined 13,712 bopd from two separate zones, including Oligocene. The last to be discovered of the four eastern Block 17 fields, Hortensia is located 6 miles (10 kilometers) north of the Acacia field in waters measuring 2,723 feet (830 meters) deep. Tested at 5,092 bopd, the Hortensia-1 well was also discovered in the spring of 2003.

Field Development

Gathering oil from all four fields and water depths ranging from 2,000 feet (600 meters) to 4,000 feet (1,200 meters), the Pazflor integrated field development will link subsea wells through subsea production lines, injection lines and risers to an FPSO.

Approved by authorities in late 2007, field development calls for drilling to commence in 2009 and facility installations to commence in 2010. Pazflor production will begin in 2011, bringing production rates for Block 17 to 700,000 bopd.

With slots for 49 subsea wells, the FPSO will boast a daily processing capacity of 200,000 barrels of oil and 150 MMcf/d of gas and a storage capacity of 1.9 million barrels of oil. Additionally, the vessel will be able to process two very different types of oil: Miocene, which is found at Perpetua, Hortensia and Zinia; and Oliocene, which is located at Acacia. The topside will be able to accommodate an additional 21 wells and house a separation unit. Spread-moored in 2,500 feet (762 meters) of water, the FPSO will have a 20-year design life and be able to house up to 220 personnel.

Pazflor partners tapped Daewood Shipbuilding to provide the engineering, procurement and fabrication for the FPSO moorings, hull and topsides; and Daewoo awarded a number of subcontracts on the massive project. KBR was chosen to provide topsides engineering, procurement and interface design for the Pazflor FPSO. Dresser-Rand was awarded the $44 million contract to provide the turbomachinery for the FPSO, including four gas compression packages.

Aker Solutions was awarded the contract from Daewoo for the design and supply of the on-vessel mooring system made of eccentric fairlead chain stoppers. BW won the $100 million contract to engineer, procure, construct and install the buoy turret loading system and associated mooring equipment.

The subsea development includes 25 production wells, 22 water injecting wells and two gas injecting wells, as well as the West Africa's first-ever subsea gas/liquid separation system. Targeting two different reservoirs, the field development will recover heavier oil from Miocene reservoirs at a water depth of 1,969 to 2,953 feet (600 to 900 meters) and a lighter oil from Oligocene reservoirs at a water depth of 3,281 to 3,937 feet (1,000 to 1,200 meters).

In January 2008, FMC was awarded the $980 million contract to supply the subsea processing and production systems for Pazflor. The supply scope includes three gas-liquid separation systems, 49 subsea trees and wellhead systems, three four-slot production manifolds, production control and umbilical distribution systems, and gas export and flowline connection systems.

FMC Technologies subcontracted to Tracerco in August 2008, awarding the company the contract for the subsea separation boosting and injection systems. FMC also tapped Oceaneering to supply and install 7.3 miles (11,800 meters) of umbilicals to provide electrical power to the subsea pumps and separation systems. In October, FMC subcontracted to Grenland Group to deliver subsea structures, including 12 utility distribution modules and the materials for the three production manifolds and foundation structures.

Additionally, Pazflor partners awarded a Technip/Acergy consortium the $1.86 billion subsea development contract in January 2008. Under the agreement, for $1.16 billion, Technip will provide engineering, procurement, fabrication and installation of more than 50 miles (80 kilometers) of production and water injection rigid flowlines, conventional flexible risers and integration production bundle risers, as well as the engineering, procurement and construction of more than 37 miles (60 kilometers) of umbilicals. For $700 million, Acergy will engineer, procure, fabricate and install 34 miles (55 kilometers) of water and gas injection lines, gas export lines, and umbilicals, as well as more than 20 rigid jumpers. Acergy will also install the subsea manifolds, separation units and associated umbilicals, and the FPSO mooring lines.

In December 2007, while still under construction, Saipem's 12000 ultra-deepwater drillship was contracted for five years of drilling on Pazflor with an option for an additional two years.

C.V. Subsea tieback to SPAR: Boomvang, Gulf of Mexico, U.S.A.

Boomvang Boomvang
Operator: Anadarko
Water Depth: 1,052 m / 3,472 ft
Region: N. America - US GOM
Country: US
Last Updated: Nov 6, 2009 (view update history)

Project Description

Boomvang is a deepwater oil and gas field located in the Gulf of Mexico, south of Galveston, Texas in East Breaks Blocks 642, 643 and 688. The play is located in Lower Pleistocene/Upper Pliocene in age. The water depth of the field is 3,450 feet (1,052 meters) and it is currently producing 160 MMcf/d (4.5 MMcm/d) and 32,000 bopd.

Boomvang is 30% owned by Anadarko, formerly Kerr-McGee, 50% owned by Enterprise Oil Gulf of Mexico, Inc. and 20% owned by Ocean Energy, Inc.

The discovery well at Boomvang was drilled by Shell in 1988. In early 1999, Kerr-McGee bought s 50% interest and acquired operatorship. Production of the field didn't begin until January 2002, but development completion, final design and engineering was completed in February 2000. Although initial discovery was in 1988, additional hydrocarbons needed to proceed weren't discovered until the latter part of 1999.

Field Development

Development on the Boomvang field included Global Producer VI, the world's first of two production truss spars. Boomvang, along with its sister field, Nansen represents two significant deepwater field development projects successfully implemented simultaneously by a major independent E&P company.

Spars International Inc. was contracted to provide the hull, monitoring system, topside fabrication, spar installation, topside installation and overall project management. Spars International at the time was co-owned by CSO Aker Maritime and J. Ray McDermott. Mustang Engineering performed the topside and equipment procurement; Intec Engineering performed the subsea design. CSO Aker Rauma Offshore provided the hull project management; and PI Rauma Engineering performed the spar design.

Boomvang consists of a truss spar moored near the center of the field and two subsea systems tied to the spar. Each spar has a center wall of 40 feet (12 meters) by 40 feet (12 meters) where slots for nine dry tree risers are located in a three by three pattern. Each platform consists of a processing and shipping facility designed to handle 40,000 bopd and 200 MMcf/d (5.6 MMcm/d) of natural gas and 40,000 bwpd.

Satellite Fields

Balboa

The Balboa field, situated roughly 6 miles (10 kilometers) from the Boomvang field, is located on East Breaks Block 597 in 3,352 feet (1,022 meters) of water in the Gulf of Mexico. Discovered in July 2001, the field is *etimated to contain 7 to 8 million barrels of oil equivalent. Balboa is operated by Mariner, which holds a 50% interest; Marubeni holds the remaining 50% interest.*

In November 2009, it was reported the field's discovery well was completed and the designing of the subsea tie-back to the Boomvang facility was nearing completion. The operator is anticipating for the commencement date to occur in the fourth quarter of 2010.

C.VI. Subsea tieback to TLP: Auger, Gulf of Mexico, U.S.A.

Auger Auger
Operator: Shell
Water Depth: 872 m / 2,878 ft
Region: N. America - US GOM
Country: US
Last Updated: Oct 21, 2009 (view update history)

Project Description

Located 255 miles (410 kilometers) southeast of Houston and 214 miles (344 kilometers) southwest of New Orleans, the Auger field spans Garden Banks Blocks 426, 427, 470 and 471. Acquired through two mid-1980s OCS Lease Sales, the field is wholly owned and operated by Shell.
Drilled in 1987 by the Zane Barnes semisub (now the Jack Bates semisub), the discovery well on Garden Banks Block 426 was followed up by an appraisal well and three sidetracks across the fields' four blocks. These successful wells, in addition to 3D seismic, were used to determine field development.

Field Development: Auger TLP

Announced in December 1989, the field development plan for Auger included the installation of a tension leg platform with both drilling and production facilities.

Located on Garden Banks Block 426, the Auger TLP is a fixed platform installed in waters measuring 2,860 feet (872 meters). Seventeen Auger wells are connected to the facility; ten of which were drilled by the George Richardson semisub, and the other seven were drilled by the TLP post production start-up.

Measuring 3,280 feet (1,000 meters) from seabed to flare tower, the massive Auger TLP weighs in at 39,000 tons (35,380 tonnes). Designed and engineered by Shell, the Auger TLP was constructed and installed by a number of different companies.

The facility is comprised of a steel hull and a production and drilling topsides deck. At 20,000 tons (18,144 tonnes), the hull includes four circular steel columns connected by four rectangular steel pontoons, fabricated by Bellelli. With a production capacity of 100,000 bopd and 300 MMcf/d (8.5 MMcm/d), the topsides are an open truss box girder design measuring 290 by 330 by 70 feet (88 by 101 by 21 meters) and weighing 10,500 tons (9,525 tonnes). J. Ray McDermott tacked the topsides construction, hull and deck mating, TLP installation and mooring, and pipeline installation for the facility.

Built for drilling, completion and workover operations in addition to processing, the facility also contains a five-story accommodation unit. With 32 well slots, the Auger TLP gathers well production around a rectangular well bay.

Consisting of templates held in place by four piles, four foundations were constructed by Aker-Gulf Marine and installed at the facility's corners by Herremac. Additionally, the Auger TLP is moored through a lateral eight-line mooring system. Each line consists of 8,650 feet (2,637 meters) of five-inch-diameter wire rope and 1,800 feet (549 meters) of 5-inch-diameter chain.

Production Hub

With installation, hook-up and commissioning completed in November 1993, the Auger TLP commenced first production on April 15, 1994. Oil and gas from the development is piped to platforms in shallower waters before final export.

Since first production, the Auger TLP has been designated a processing hub for nearby fields. Now, Cardamom, Habanero, Serrano, Llano, Oregano and Macaroni also produce through the Auger TLP development.

In 1997, the pipelines exporting oil and gas from the Auger TLP were expanded. The existing oil pipeline was converted to a gas system, and a new oil pipeline was built between the Auger TLP and Shell's Enchilada platform on Garden Banks 128. The new system better delivers produced hydrocarbons from Auger to the Garden Banks Gathering System.

Satellite Fields

Cardamom

Located on Garden Banks 427 and 471, Cardamom is situated in 2,860 feet (872 meters) of water approximately 2 miles (3 kilometers) east of the Auger TLP. Discovered in 1995, the field was further delineated by a second well, drilled in November 1995.

Cardamom is developed directly to the Auger TLP, with production commencing in October 1997.

Macaroni

Located on Garden Banks 602 in 3,700 feet (1,128 meters) of water, Macaroni is situated 12 miles (19 kilometers) away from the Auger TLP. Discovered in 1995 by the Transocean Rather, the field underwent appraisal drilling in 1996 and 1997.

Acquired in the August 1989 OCS Lease Sale, Macaroni is operated by Shell, which holds 51% interest in the lease. Project partners include Eni with 34% and Devon with the remaining 15% interest.

Field development for Macaroni ties the field to the Auger TLP. Three subsea wells are clustered around a four-slot subsea template on Garden Banks 602, and then oil and gas is transported via two flowlines to the Auger TLP. The Transocean Richardson and Noble Paul Romano semisubs performed development drilling on the satellite field, and major contractors on the subsea development included FMC Technologies, J. Ray McDermott, Intec, Kongsberg Offshore and Alcatel. Production commenced on the Macaroni subsea development on Aug. 23, 1999.

Serrano

Located on Garden Banks Blocks 516 and 472 in 3,400 feet (1,036 meters) of water, the Serrano gas field is wholly owned and operated by Shell. Discovered in 1996 by the Ocean Worker, the field was further extended in 1999 by the Transocean Marianas.

Development for the satellite field included a subsea system tied-back to the Auger TLP 6 miles (10 kilometers) away. Consisting of two subsea wells, the development utilizes a subsea flowline sled to transport gas and condensate to the Auger TLP.

With estimated recoverable reserves of 50 MMboe, Serrano commenced production on Dec. 1, 2001, peaking at 160 MMcf/d (4.5 MMcm/d) of natural gas in 2002.

Oregano

Situated on Garden Banks Blocks 558 and 559, Oregano is in waters measuring 3,400 feet (1,036 meters) deep and is located 8 miles (13 kilometers) from the Auger TLP. Wholly owned and operated by Shell, the oil field was discovered in 1999 by the Noble Paul Romano.

Mirroring each other, Oregano was developed in conjunction with Serrano at a combined cost of $250 million. Oregano was also developed through a two-wells linked to a subsea manifold and tied to the Auger TLP through a subsea flowline sled.

Diamond Offshore performed the drilling and completion work on both Oregano and Serrano. A major contractor on both developments, FMC supplied the wellhead and completion equipment, including six vertical trees.

Pulling from an estimated recovery of 50 MMboe, production commenced on Oregano on Oct. 17, 2001, four months ahead of schedule. The field peaked at 20,000 bopd at the close of 2001.

Habanero

Located on Garden Banks Block 341 in 2,015 feet (614 meters) of water, the Habanero oil and gas field is located 11.5 miles (19 kilometers) away from the Auger TLP. Discovered in January 1999 by the Ocean Concord, Habanero consists of two pay zones. Situated in the H52 and H55 sands, a 225-foot (69-meter) column of oil is located in an upper zone, and a 70-foot (21-meter) column of gas condensate is located in the lower zone.

Shell serves as the operator of the satellite field with 55% interest in the block. Project partners include Murphy Oil with 33.75% and Callon with 11.25%.

Developed as a satellite field to the Auger TLP for a total investment of $190 million, Habanero field development includes two subsea wells connected to a dual pipe-in-pipe flowline system, which is then tied to the Auger TLP. Major contractors on the project include Transocean, which performed drilling and completions; and FMC with provided the subsea hardware.

With a daily peak rate of 22,000 bopd and 75 Mmcf/d (2.1 MMcm/d) of natural gas, production commenced from Habanero on Nov. 29, 2003.

Llano

Located in 2,600 feet (792 meters) of water on Garden Banks Blocks 385 and 386, the Llano oil and gas field is situated 11.5 miles (19 kilometers) from the Auger TLP.

The operator, Shell owns 27.5% interest in Llano. Lease partners on the blocks include Hess with 50% and ExxonMobil with 22.5%.

Discovered in 1998 by the Transocean Voyager & Omega, the field was delineated by two sidetrack wells. Reserves are located in the Pliocene and Miocene formations at a thickness of 150 feet (46 meters) and 95 feet (29 meters), respectively.

Developed as a subsea tie-back to the Auger TLP, Llano field development includes two wells tied through a pipe-in-pipe looped flowline. FMC also served as a major contractor on this development.

With a peak rate of 25,000 bopd and 75 MMcf/d (2.1 MMcm/d) of gas, production commenced from Llano on April 29, 2004.

Ozona

The Ozona oil and gas field is located in approxiamtely 3,280 feet (1,000 meters) of water on Garden Banks Block 515, about 175 miles southeast of Sabine, Texas. Marathon serves as the operator and holds a 68% interest; Marubeni holds the remaining 35% interest.

At a development cost of $300 million, Ozona will consist of one well subsea tied-back to the Auger platform, which is located six miles from the field.

Ozona is expected to commence production in 2011 and reach a peak production of 6,000 bopd and 13 MMcf/d.

C.VII. Dry tree SPAR: Mad Dog Field, Gulf of Mexico, U.S.A.

Mad Dog Field, Gulf of Mexico, USA
Name: Mad Dog
Location: Gulf of Mexico
Operator: BP
Distance from shore: 190 miles south of New Orleans
Water depth: 4,500ft
Equity: BP 60.5%, BHPBilliton 23.9%, Unocal 15.6%
Drilling unit range: 5,000ft to 7,000ft of water

The Mad Dog field is located in Western Atwater Foldbelt, Gulf of Mexico, approx. 190 miles south of New Orleans. The nominal water depth is 4,500ft and the field runs along the Sigsbee Escarpment. The field is operated by BP 60.5% on behalf of BHPBilliton 23.9% and Unocal 15.6%.

The drilling unit is located in 5,000ft to 7,000ft of water in Green Canyon blocks 825, 826 and 782, about 150 miles southwest of Venice, Louisiana. The gross estimated reserves are in the range of 200 to 450 million barrels of oil equivalent. The development has cost $1.54 billion to bring onstream.

The discovery well, in water depths of approx. 6,600ft, was spudded in May 1998 in Green Canyon 826 and was drilled to a measured depth of 22,410ft. The discovery was followed by a 1999 well drilled to a total depth of 22,410ft and a further successful appraisal well in February 2000. The project was sanctioned in 2001.

Mad dog's pre-drilled wells were drilled by the Ocean Confidence.

The Mississippi fan fold belt is characterised by basinward-verging anticlines and associated thrust faults. Mad Dog is one of a number of discoveries occurring in the western portion of the fold belt, where shallow salt tongues have flown over some of the folds, making seismic imaging difficult.

Development

The field is being developed by 12 wells produced with a single-piece truss spar permanently moored in 4,500ft water depths in Green Canyon Block 782, 306km south of New Orleans.

The fabrication of the spar hull commenced in Finland in July 2002, and the topsides in Morgan City, Louisiana, one month later.

Topsides

The deck measures 220ft by 163ft by 50ft (67m x 50m x 15m) and was designed around the heaviest hook load available (around 8,000t). The host facility includes production facilities with 16 slots in a 4 x 4 pattern (13 production slots, a drilling riser slot and two service slots), and quarters for 126 personnel, although the temporary quarters can accommodate an additional 60 persons. The spar also has a BP-owned drilling rig with an operating weight of 5,500t.
HULL

The 20,800t hull measures 128ft in diameter and is 555ft long. The facility is designed to process approximately 100,000 barrels of oil and 60mscf of gas per day. The spar has a maximum operating payload capacity of around 18,500t excluding hull storage. The topside and integrated decks total 10,500t

The trus spar took three weeks to travel from Finland to Passagoula, Mississippi, on the Mighty Servant 1, where it was floated off and pre-assembly preparations were completed. The Thialf was then used to lift the topsides into place.

Mooring

The spar is moored by an 11-line taut mooring configuration. There are three mooring line groups - two with four lines and one with three. The polyester mooring lines are attached to suction piles, resulting in a saving of around 1,000t of buoyancy over rope and chain systems. It is the first such use of synthetic moorings approved by the US Coast Guard or MMS.

Oil from Mad Dog will be transported via the Caesar pipeline to Ship Shoal 332B, where it will interconnect with the Cameron Highway Oil Pipeline System (CHOPS). Mad Dog gas will be exported via the Cleopatra pipeline to Ship Shoal 332A, where it will interconnect with the Manta Ray Gathering System, and from there to the Nautilus Gas Transportation System into Louisiana. Both Caesar and Cleopatra pipelines are part of the BP-operated Mardi Gras Transportation System.

C.VIII. Dry tree TLP: Matterhorn Field, Gulf of Mexico, U.S.A.

Matterhorn Field, Gulf of Mexico, USA
Operator: TotalFinaElf E&P USA
Location: Mississippi Canyon Block 243, 170km southeast of New Orleans
Water: 850m of water
Production rate: 40,000 barrels of oil equivalent per day
Production system: Mini tension leg platform
Hull fabrication: Keppel Fels
Main column diameter: 84ft

The Matterhorn field is located in Mississippi Canyon Block 243 in the deepwater Gulf of Mexico, approx. 170km southeast of New Orleans. It lies in 850m of water. The field came onstream in November 2003 and has a production capacity of 33,000 barrels of oil equivalent per day.

"The field came onstream in November 2003 and has a production capacity of 33,000 barrels of oil equivalent per day."

The Matterhrorn field is wholly owned and operated by TotalFinaElf E&P USA. After examining a number of development options, the designers settled on the use of a mini tension leg platform. The company opted for an Atlantia SeaStar design of the type previously installed on such deepwater projects as Chevron's Typhoon and British-Borneo's (Agip) Morpeth and Allegheny fields. Because of the field however, a larger version than the existing designs was deemed necessary.

The Matterhorn platform, at 4,500t, stands as the biggest of its type - double the size of the previous units and the first unit of this design to incorporate supporting vertical access production flowlines running through the central moonpool and controlled by surface (dry) trees. The contract for the hull was won by Keppel Fels in Singapore, making Matterhorn also the first one built outside of the Gulf of Mexico.

MATTERHORN SEASTAR HULL

The fabrication of the Matterhorn SeaStar hull structure began on 28 January 2002 and was completed by the end of the year. The construction is based on a relatively large central main column with a diameter of 84ft. It has a design draft of 104ft.

At the base of the column are three pontoons which project out to give the structure an effective radius of 179ft. At the point where they are attached to the main column the pontoon heights are 42 ft, however these taper down to just 27ft at the tip. "In early 2003, the structure was sailed out of Keppel Fels yard across to Pascaguola, Mississippi."

This hull structure is designed to support a payload 16,850kips (thousand pounds). The hull itself will weigh approximately 12,280kips, of which the primary hull structure will account for 10,420kips. Altogether, the platform has a displacement of 52,800kips.

In early 2003, the structure was sailed out of Keppel Fels yard across to Pascaguola, Mississippi, to await mating with the topsides.

MATTERHORN TOPSIDES

The Matterhorn topsides design is distributed over three decks. This deck arrangement was constructed at the Gulf Marine Fabricators in Ingleside, Texas. Paragon Engineering was responsible for the design of the topside facilities, employing the 3D PDMS (Plant Design Management System). The company expended over 60,000 man-hours on the design.

The deck free board is designated at 69ft and the decks have an area of 140ft^2. The operating weight of the decks and facilities is 13,350kips.

In order to process the Matterhorn hydrocarbons the platform design has process capacities of 35,000b/d of oil, 55 million scf/d of gas, 20,000b/d of water treated and 30,000b/d of water injected.

The wellbay design is centred on nine well slots although production currently flows through risers in only seven of them. Located at the top of the platform is a SuperSundowner XVI1,000hp drilling rig. Total also has one subsea injector well on the seafloor, leaving capacity for future tiebacks.

The design includes quarters for 22 men.

The Matterhorn TLP is connected to the seabed by six 32in neutrally buoyant steel tubular tendons. These were fabricated by Kiewit Offshore Service, also in Ingleside. Each tendon is secured by means of an independent, 96in-diameter, 415ft pile at the seabed, fabricated by Gulf Marine Fabricators. At 400t, the piles are among the heaviest ever installed.

The offshore installation was carried out by Heerema's Balder crane vessel.

References:

1. Offshore Technology, "Mad Dog Field, Gulf of Mexico, USA" *Industry Projects. Available in Internet at http://www.offshore-technology.com/projects/mad_dog last visited May 1st, 2010.*
2. Offshore Technology, "Matterhorn Field, Gulf of Mexico, USA" *Industry Projects. Available in Internet at http://www.offshore-technology.com/projects/matterhorn last visited May 1st, 2010.*
3. Subsea IQ, "Auger" *Offshore Field Development Projects. Available in Internet at http://www.subseaiq.com/data/Project.aspx?project_id=139 last visited May 1st, 2010.*
4. Subsea IQ, "Boomvang" *Offshore Field Development Projects. Available in Internet at http://www.subseaiq.com/data/Project.aspx?project_id=118 last visited May 1st, 2010.*
5. Subsea IQ, "Canyon Express" *Offshore Field Development Projects. Available in Internet at http://www.subseaiq.com/data/Project.aspx?project_id=115 last visited May 1st, 2010.*
6. Subsea IQ, "Ormen Lange" *Offshore Field Development Projects. Available in Internet at http://www.subseaiq.com/data/Project.aspx?project_id=222 last visited May 1st, 2010.*
7. Subsea IQ, "Pazflor" *Offshore Field Development Projects. Available in Internet at http://www.subseaiq.com/data/Project.aspx?project_id=326 last visited May 1st, 2010.*
8. Subsea IQ, "Tunder Horse" *Offshore Field Development Projects. Available in Internet at http://www.subseaiq.com/data/Project.aspx?project_id=129 last visited May 1st, 2010.*

Annex D: Marine Operations

The Marine operations may have quite different purposes. However, there are commonly referenced documents that are followed by the most of the marine contractors, one of those is the “DNV Rules for Planning and Execution of Marine Operations” (DNV, 2008).

The Rules for Planning and Execution of Marine Operations lay down technical and procedural requirements related to proper planning and execution of marine operations such as:

- Load Transfer Operations (issued 1996).
- Towing (issued 1996).
- Special Sea Transports (issued 1996).
- Offshore Installation (issued 1996).
- Lifting (issued 1996).
- Sub Sea Operations (issued 1996).
- Transit and Positioning of Mobile Offshore Units (issued 2000).

Noble Denton is also a company that proposes guidelines commonly cited on marine operations planning and execution. Some of those guidelines are listed below.

- 0009/ND operations.
- 0013/ND Rev 4 - 19 Jan 2009 Guidelines for loadouts.
- 0015/ND Rev 1 - 16 Dec 2008 Concrete offshore gravity structures/constr., tow. & install.
- 0016/ND Rev 4 - 16 Dec 2008 Seabed and sub-seabed data for approvals of mobile offshore units/MOU.
- 0021/ND Rev 7 - 17 Nov 2008 Guidelines for the approval of towing vessels.
- 0027/ND Rev 8 - 23 June 2009 Guidelines for marine lifting operations.
- 0028/ND Rev 3 - 19 Jan 2009 Guidelines for the transportation and installation of steel jackets.
- 0030/NDI Rev 3 - 15 April 2009 Guidelines for marine transportations.

One of the most important factors for marine operations are the weather conditions that prevail during operations, each operation has its limits in terms of wave and tidal height and speed of currents and winds for its various operating scenarios, whether they are survival, transfer, installation and normal operation. See the previously cited guidelines for more information and the document "Uncertainties in weatherforecasting, a risk to offshore operations (Gudmestad, 1999), for more information.

On this matter, Gudmestad (Gudmestad, 2001) proposed risk assessment tools for use in projects and offshore marine operations. His proposal emphasizes the vulnerability to climatic conditions, such as in deepwater projects during the installation period. He said, it is particularly important consider that vulnerability since some project management philosophies are more focused on implementing cost effective operations.

This leads to a high probability that complex operations are carried out in the “winter” season here the ranges with appropriate climate grow shorter and the changes in weather conditions are more frequent and more rapid than the "summer season".

Based on their findings he suggests as a starting point an identification and risk analysis in the maritime operations. These studies can be done with the implementation of a qualitative risk analysis order to compare the risk to acceptable criteria established for the project.

From qualitative analysis to quantitative risk analysis of construction and marine operations for plants in deep water can be used as a valuable tool to ensure that the technology, costs and timelines set out in the early stages of a project are realists.

The choice of realistic climatic criteria for marine operations ensures a secure facility, thus avoiding loss of assets and /or production delays.

D.I. Marine operations for a subsea production system.

Nergaard (Nergaard, 2009) proposed a matrix of activities for the life cycle of a offshore oil and gas field that is reproduced below, see table 1.a, it lists also the representative types of marine operations and the related vessels involved for a subsea production system. These activities vary in complexity with the design of the field.

Nergaard also provide an example list of the vessel size for some selected marine operations, see table 1.b

System\Activity		***Field Development***			***Production Phase***		***Abandonment***
		Design	***Construct***	***Installation***	***Production***	***Intervention***	
Well		*Oil Company*	*D. Contr.*	*DR*	*Drilling*		*Reverse Installation*
SSP	*Xmt*	*SS Supply*	*SS Supply*	*DR/WIS*	*Monitor*	*DR/MPSV*	
	Struct			*MPSV/HLV*		*MPSV*	
	Control			*MPSV*		*MPSV*	
Lines	*Flowl*	*Engineering*	*Special*	*CAP*	*Monitor*	*MPSV/CAP*	
	Umb		*Special*	*CAP*		*MPSV/CAP*	
	Risers		*Special*	*MPSV/CAP*			
FPSO/mooring			*Shipyard*	*AHTS/MPSV*	*Operation*		

- *AHTS:Anchor Handling Tug Supply,*
- *CAP: Construction and pipelay*
- *DR: Drillrig,*
- *HLV: Heavy Lift Vessel.*
- *LWI: Light Well Intervention*
- *MPSV: Multi Purpose Service Vessel(Construction)*
- *WIS: Well Intervention Semi*
- *SSP: Subsea Production,*
- *XMT: X-mas tree,*
- *STR: Subsea Template.*

Table 1.a Deepwater field macro activity matrix [Nergaard, 2009]

	Type of vessel	***Length***	***Displacement***	***Example***
DR	*Semisubmersible* *Drillships*	*Typical 100 m* *150 – 260 m*	*30 – 50,000 tons* *50 – 10,000 tons*	*West Venture* *West Navigator*
WIS	*Semisubmersible*	*Typical 60 m*	*~ 20,000 tons*	*Regalia*
LWI	*Monohull*	*90 – 125 m*	*8 – 15,000 tons*	*Island Frontier*
AHTS	*Monohull*	*70 – 100 m*	*< 10,000 tons*	*Norman Atlantic*
MPSV	*Monohull*	*90 – 125 m*	*8 – 15,000 tons*	*BOA Deep C*
CAP	*Monohull*	*100 – 150 m*	*10 – 20,000 tons*	*Skandi Navica*
HLV	*Semisubmersible*	*Up to 180 m*	*50 – 100,000 tons*	*Thialf*

Table 1.b Types and sizes of vessels (Nergaard, 2009).

Figure 1.a. shows the architecture that is going to be used to describe the marine operations of the installation of a subsea production system. It is assumed that the field architecture will include:

- 6 Xmas trees, assumed weight 40 ton each (Figure 1.b)
- A central manifold, assumed weight 50 ton each (Figure 1.c)
- Flexible flowlines and umbilicals.
- 2 Pipeline End Terminations (assumed weight 70 ton each) from where 2 rigid pipelines to shore will be installed. (Figure 1.d)

The main marine operations to consider will be:

1. Seabed preparation – rock-dumping and dredging
2. Installation of templates
3. Drilling and completion of wells
4. Central manifold installation.
5. Flowlines and umbilical's installation.
6. PLETs and Pipelines installation 2 x 8".
7. Workover and well intervention
8. Abandonment

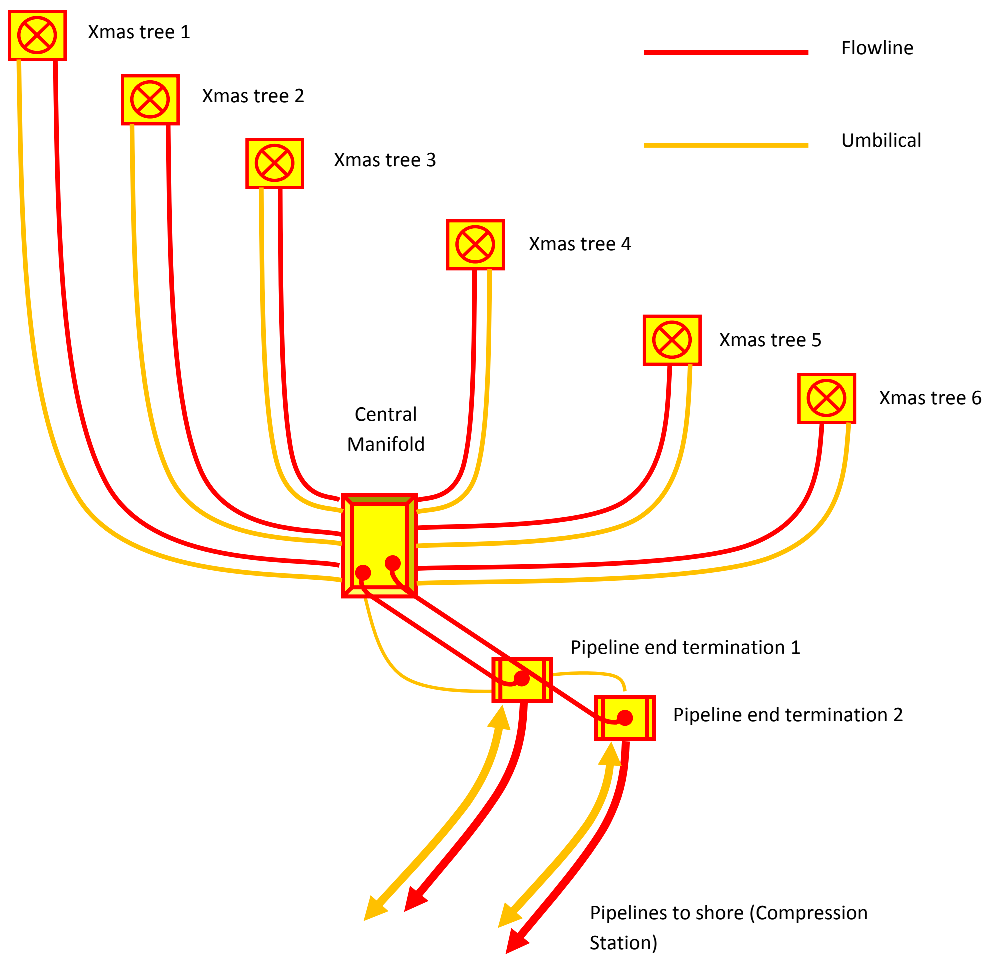


Figure 1.a A speculative field architecture to the description of the needed marine operations for the installation of the subsea production system.

Figure 1.b 15K Enhanced Horizontal Tree (EHXT)[FMC,2009]

Figure 1.c A Manifold of Norne project, Norway, [Grenland, 2009]

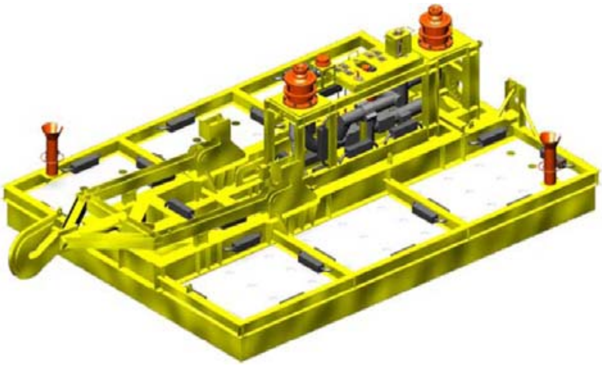


Figure 1.c A Pipeline end termination of the Cottonwood Field Development Project [Petrobras, 2007]

D.I.1 Sea bed preparation – rock-dumping, dredging, pre-trenching

These operations are commonly related to the installation of pipelines; however these operations can also be required for all the subsea installations. The purpose of this operations are ensure on bottom stability, create safe foundations for the pipeline and the subsea equipment and protect against the external interference of the eventual loads.

The irregularities of the subsea bed sometimes made necessary the rock dumping operation that consists in deposit rocks to eliminate spans where the pipelines and subsea equipment are going to be installed.

Dredging is an operation consisting on suction sand and gravel from the seabed through specialized vessels (See figure 2). The sand and gravel are present on the seabed with uneven distributions and may vary in thickness from thin layers over the bedrock or clays to many tens of meters.

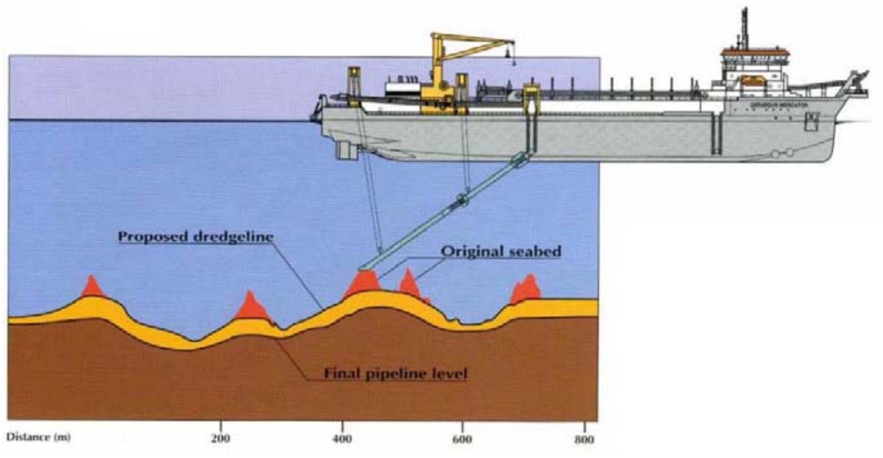


Figure 2 A dredging operation illustration (Jan de Nul, 1997)

Marine sand and gravel is also used for flood and coastal defense purposes. It can match closely the material naturally found on beaches and is therefore generally considered to be more suitable from an environmental, nature conservation, amenity and technical point of view than land-won sand and gravel or other materials. Hence they are potentially marketable resources. (DCLG, 2002).

Trenching is referred to the permanent installation of pipelines under the natural sea bed this is aimed to reduce the effects of the currents and waves on the installed pipelines.

D.I.2 Installation of templates.

The purpose of the templates is to bring support and stability for other equipment such as manifolds, risers, drilling and completion equipment, pipeline pull-in and connection equipment and protective framing (template and protective framing is often built as one integrated structure. For the offshore drilling from a floating rig is necessary the use of the predrilling templates that guide the drilling operations, allow the landing and latching of the conductor and conductor housing as well as provide sufficient space for running and landing of the BOP stack. When subsea trees are installed, the templates provide mechanical positioning and alignment for the trees and enough space for the running operations (ISO, 2005).

The marine operations are performed from a floating rig, either a semisubmersible or a drill ship.

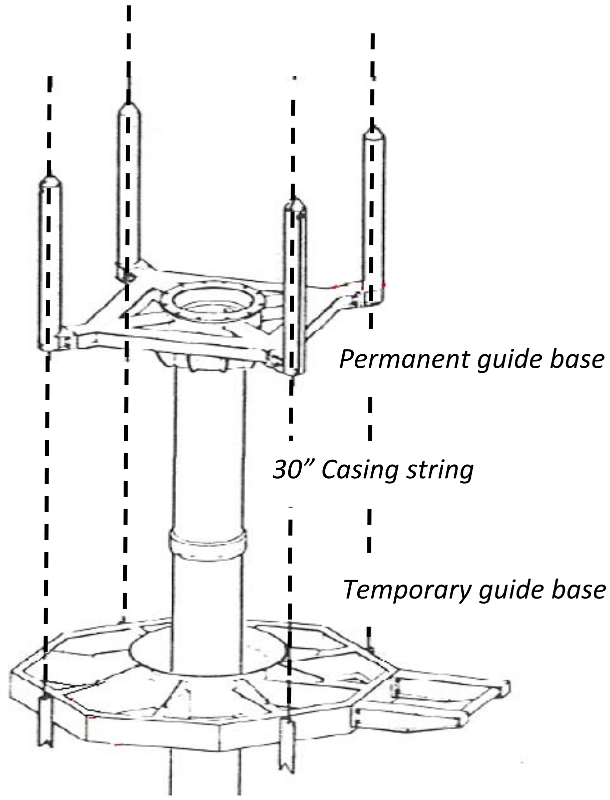


Figure 3 Pre-drilling subsea template assembly set for a single well

An example of the sequence for these installations is described with detail in the Unit 6 Subsea completions of the Petroleum Open Learning Series of Oilwell Production Technologies (POL, 2, 2002) below is shown a summary of that example, see figure 3:

1. Lower a temporary guide base (TGB) to the sea bed.
2. Release running tool from TGB and retrieve.
3. Lower 36” drilling assembly into TGB using guide frame and guide lines.
4. Retrieve guide frame.
5. Drill 36” hole.
6. Lower 30” casing through the permanent guide base (PGB).
7. Attach 30” housing to top joint of 30” casing.
8. Connect PGB to 30” housing.
9. Lower 30” casing into hole and land PGB on to TGB.
10. Cement 30” casing.

Besides a single well template, it is also common to have a multiwell template that accommodate several places for drilling wells and also another that can bring support for other kind of equipment, such as a manifold or a subsea processing system.
As an example of an integrate template structure we can take a look at the Kristin Project in Norway. The Kristin Project is a gas-condensate field considered high temperature (176°C) - high pressure (911 bar), at a water depth of 360-380 meters produces from 3 different reservoirs and is located around 190 km offshore Norway.

The concept used in this development is a set of four similar templates (See figure 4.a and 4.b) that have the following characteristics.

•4 slot drilling template & manifold system
•Suction anchor foundation
•Overtrawlable structures
•Dual manifold headers with internal pig loop
•Piping flexibility between X-mas tree and manifold taken in the manifold branch piping
•Full flow direction flexibility – remotely controlled branch valves
•Scale squeeze system
•HPHT –High Pressure High Temperature
•HIPPS –High Integrity Pressure Protection System

The estimate weight of the structure is 270 Tons what made its installation particularly challenging due the extreme weather conditions of the North Sea.

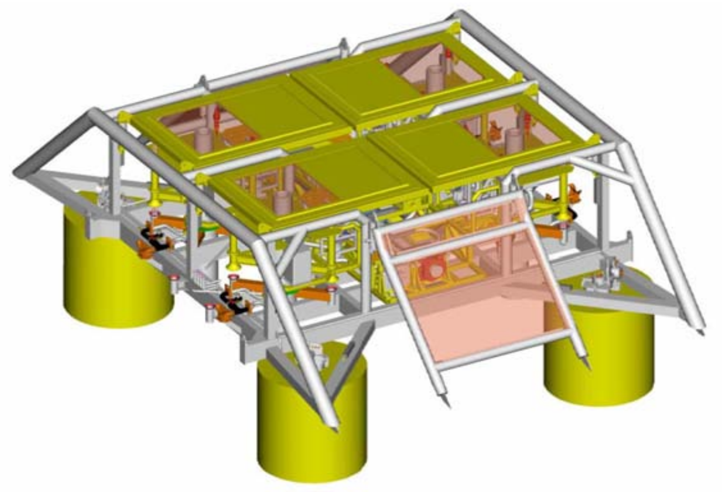


Figure 4.a A visualization of the systems integrated in the templates used at the Kristin fields. (Nergaard, 2008)

Figure 4.4.b. Subsea template at Kristin Field. (Nergaard, 2008)

A description of the activities of installation of templates was made in 1987 by Komaromy et al. below is excerpted the table of the activities and options of operations to be performed (table 2). An illustration of the installation of a subsea template from by a crane vessel is shown in figures 5.a to 5.d.

Options available for template installation	
Activity	**Options**
Loadout	Lift, roll or skid
Transportation	Barge, crane vessel, drillship or semisubmersible
Lift and lower	Conventional four-point lift, spreader beam or frame, auto or manual release of rigging Hard or soft slings, buoyancy assistance
Positioning	Tugs, tuggers with sea-bed anchors, tuggers from installation vessel, thrusters
Level measurement	Acoustics, splint level, bulls eye
Level adjustment	Jacking from mudmats or piles
Support-pile installation	Driven or drilled Preinstallation of plies in template or lowered with hammer Pile followers or underwater hammer Pile cutting
Support-pile attachment	Swaged, grouted or mechanical
Docking-pile installation	Hammer requirement and mode piles may be lowered alone, with hammer or in template
Removal of docking-pile guide	Diver or ROV Quick release or cut connection

Table 2 Activities of installation of templates (Komaromy et. al, 1987).

The planning and calculations of the activities of installation have to consider carefully three different phases of the installation.

1. Lifting in the air of the dry weight of the template from the transport barge.
2. Lowering the template into the water through the splash zone.
3. Lowering the template into the water to the sea bed.

D.I.3. Drilling and completion of wells.

Before to deal on drilling and completion is going to be mentioned some details on the equipment used to perform this activities. These operations in the case of the subsea systems are performed from mobile offshore drilling units. In the case of shallow waters these operations can be performed by jack up drilling rigs (see figure 4.6.a) and in deep water is necessary the use of semisubmersibles rigs (See figure 4.6.b) or drilling ships (4.6.c).

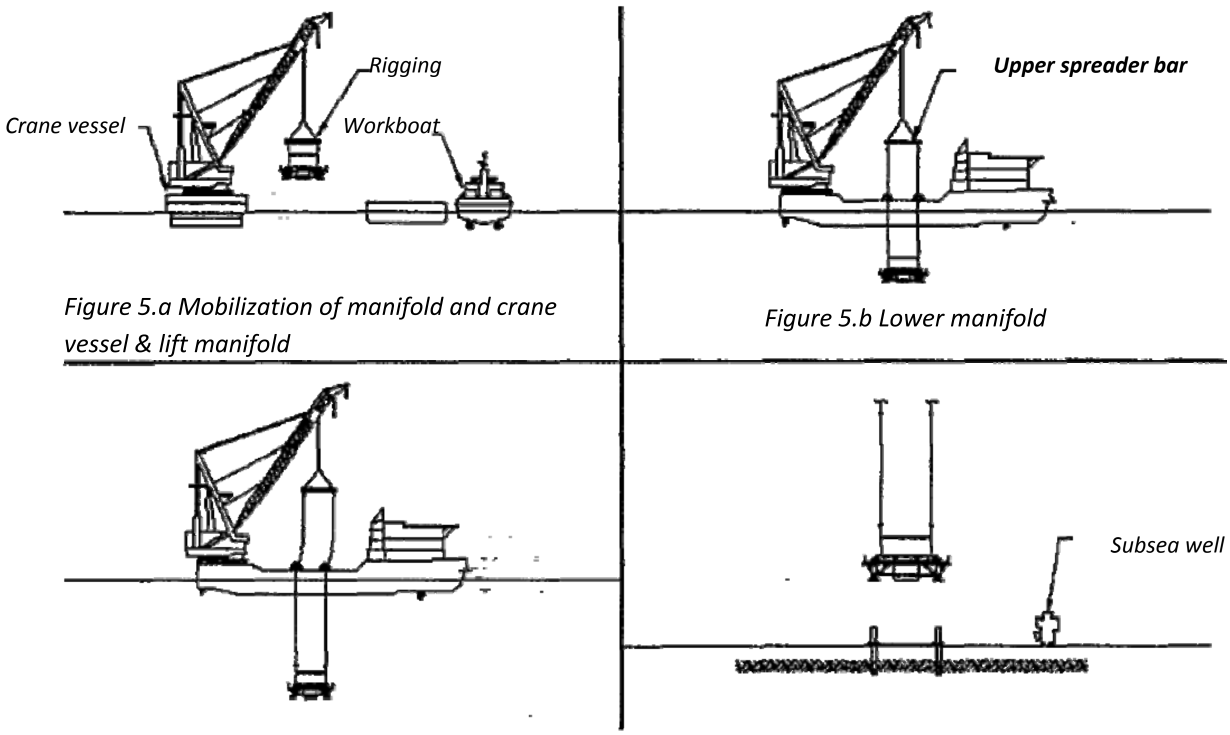


Figure 5.a Mobilization of manifold and crane vessel & lift manifold

Figure 5.b Lower manifold

Figure 5.c Add Rigging extensions

Figure 5.d Set manifold on piles

Figure 5. Installation of a subsea template from by a crane vessel [Homer, 1993]

Petromena ASA a drilling rig constructor issued a memorandum (Petromena, 2007) about the acquisition of one of their Semi submersibles from where it is excerpted the following information in the consideration of being a good descriptive summary of the main characteristics of each unit.

Jack-up rigs

Jack-up rigs are mobile bottom-supported self-elevating drilling platforms that stand on three legs on the seabed.

When the rig is to move from one location to another, it will jack itself down on the water until it floats, and will be towed by a supply vessel or similar, or carried by a heavy lift and transportation vessel, to its next location. A modern jack-up will normally have the ability to move its drill floor aft of its own hull (cantilever), so that multiple wells can be drilled at open water locations or over wellhead platforms without re-positioning the rig. Ultra premium jack-up rigs have enhanced operational capabilities and can work in water depths >300ft.

Semi submersible rigs

Semi submersible rigs are floating platforms that feature a ballasting system that can vary the draft of the partially submerged hull from a shallow transit draft, to a predetermined operational and/or survival draft (50 - 80 feet) when drilling operations are underway at a well location. This reduces the rig's exposure to ocean conditions (waves, winds, and currents) and increases stability. Semi submersible rigs maintain their position above the wellhead either by means of a conventional mooring system, consisting of anchors and chains and/or cables, or by a computerized dynamic positioning system, combining thrusters and propulsion systems with a satellite navigation system. Propulsion capabilities of semi submersible rigs range from having no propulsion capability or propulsion assistance (and thereby requiring the use of supply vessel or similar for transits between locations) to self-propelled units that have the ability to relocate independently of a towing vessel.

Drillships

Drillships are ships with on-board propulsion machinery, often constructed for drilling in deep water. They are based on conventional ship hulls, but have certain modifications. Drilling operations are conducted through openings in the hull (''moon pools"). Drillships normally have a higher load capacity than semi submersible rigs and are well suited to offshore drilling in remote areas due to their mobility and high load capacity. Like semi submersible rigs, drillships can be equipped with conventional mooring systems or DP systems… [Petromena, P.p. 25-26, 2007]

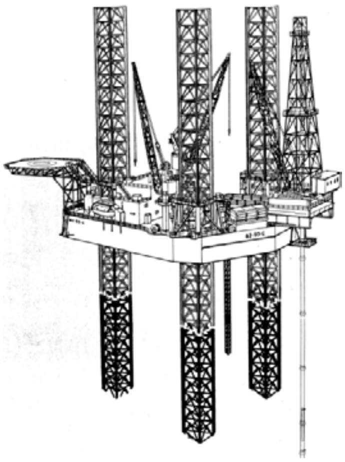


Figure 6.a A Jack up Rig in Cantilever [Drilling Kingdom, 2009]

Figure 6.b The semisubmersible rig "Petrorig I" [Petromena, 2007]

Figure 6.c A Drill ship [Visual dictionary online, 2009]

The semisubmersible rigs are classified in generations according to its year of construction or modification and its capacity to drill in depth waters (see figure 7).

- First generation: Before 1971
- Second generation: 1971-1980
- Third generation 1981-1984
- Fourth generation: 1984-1998
- Fifth generation: 1998-2006
- Sixth generation from 2006

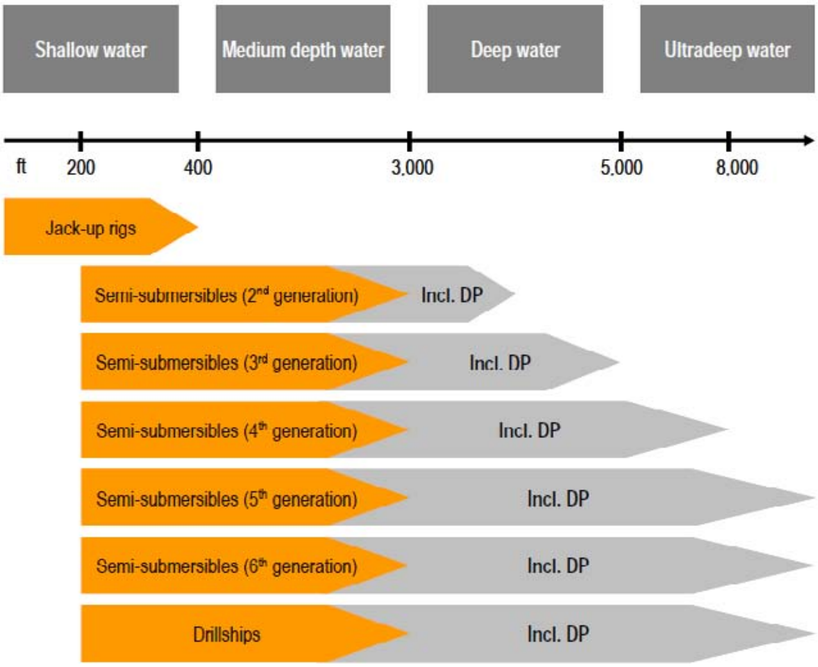


Figure 7: Main offshore rig categories by drilling depth (Petromena, 2007)

The marine operations related to drilling start with the positioning of the rigs, both semisubmersible and drilling ships use dynamic positioning as well as mooring systems.

The Wikipedia describe in a good sense the main characteristics of the Dynamic positioning (DP), (Wikipedia, 2009), figures 8 and 9 illustrate the concepts.

> ***Dynamic positioning (DP)*** *is a computer controlled system to automatically maintain a vessel's position and heading by using her own propellers and thrusters. Position reference sensors, combined with wind sensors, motion sensors and gyro compasses, provide information to the computer pertaining to the vessel's position and the magnitude and direction of environmental forces affecting its position.*
>
> *The computer program contains a mathematical model of the vessel that includes information pertaining to the wind and current drag of the vessel and the location of the thrusters. This knowledge, combined with the sensor information, allows the computer to calculate the required steering angle and thruster output for each thruster. This allows operations at sea where mooring or anchoring is not feasible due to deep water, congestion on the sea bottom (pipelines, templates) or other problems...*
>
> ***Control systems***
>
> *In the beginning proportional–integral–derivative controllers were used and today are still used in the simpler DP systems. But modern controllers use a mathematical*

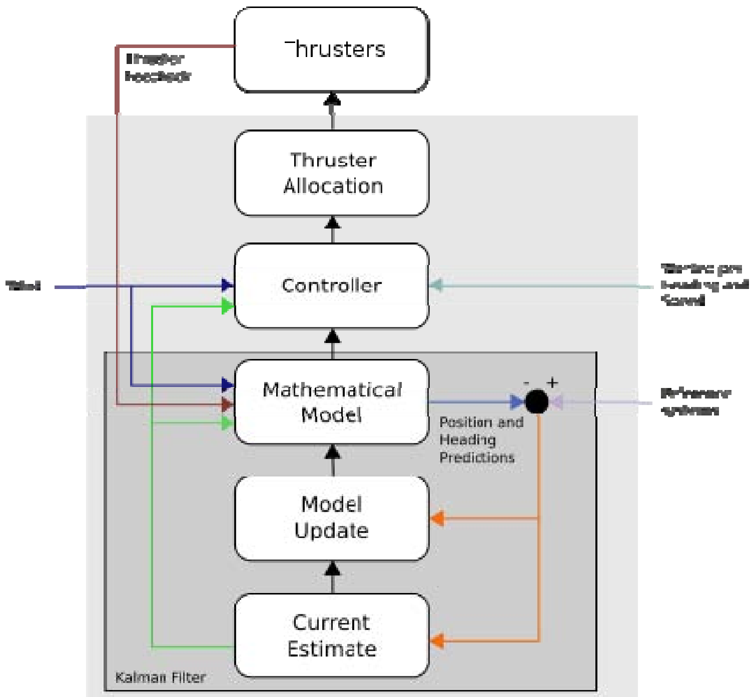


Figure 8: Simplified diagram flow of the control system for Dynamic positioning (Wikipedia, 2009)

model of the ship that is based on a hydrodynamic and aerodynamic description concerning some of the ship's characteristics such as mass and drag. Of course, this model is not entirely correct. The ship's position and heading are fed into the system and compared with the prediction made by the model. This difference is used to update the model by using Kalman filtering technique. For this reason, the model also has input from the wind sensors and feedback from the thrusters. This method even allows not having input from any position relative system (PRS) for some time, depending on the quality of the model and the weather.

The accuracy and precision of the different PRS's is not the same. While a Differential Global Positioning System has a high accuracy and precision, a Ultra- or Super- Short Base Line can have a much lower precision. For this reason, the PRS's are weighed. Based on variance a PRS receives a weight between 0 and 1.

Power and propulsion systems

To maintain position azimuth thrusters (L-drive or Z-drive), azipods, bow thrusters, stern thrusters, water jets, rudders and propellors are used. DP ships are usually at least partially diesel-electric, as this allows a more flexible set-up and is better able to handle the large changes in power demand, typical for DP operations.

The set-up depends on the DP class of the ship. A Class 1 can be relatively simple, whereas the system of a Class 3 ship is quite complex.

On Class 2 and 3 ships, all computers and reference systems should be powered through a UPS.

Class Requirements

Based on IMO (International Maritime Organization) publication 645[6] the Classification Societies have issued rules for Dynamic Positioned Ships described as Class 1, Class 2 and Class 3.

Equipment Class 1 has no redundancy: Loss of position may occur in the event of a single fault.

Equipment Class 2 has redundancy so that no single fault in an active system will cause the system to fail: Loss of position should not occur from a single fault of an active component or system such as generators, thruster, switchboards, remote controlled valves etc. But may occur after failure of a static component such as cables, pipes, manual valves etc.

Equipment Class 3 which also has to withstand fire or flood in any one compartment without the system failing: Loss of position should not occur from any single failure including a completely burnt fire sub division or flooded watertight compartment.

Mooring systems are used extensively not only in drilling but also in production, installation and service vessels.

A number of anchors are fixed in the sea bed, those anchors are attached to mooring lines either of steel chain, wire or rope or a combination of them that are connected to mooring winched in the offshore unit.

There are different standards related to this aspect of the marine operations below it is a list of the offered by DNV.

o DNV-OS-E301 Position Mooring (issued October 2008), update of previous revision
o DNV-OS-E302 Offshore Mooring Chain (issued October 2008), new standard
o DNV-OS-E303 Offshore Mooring Fibre Ropes (issued April 2008), new standard
o DNV-OS-E304 Offshore Mooring Steel Wire Rope (to be issued April 2009), new standard

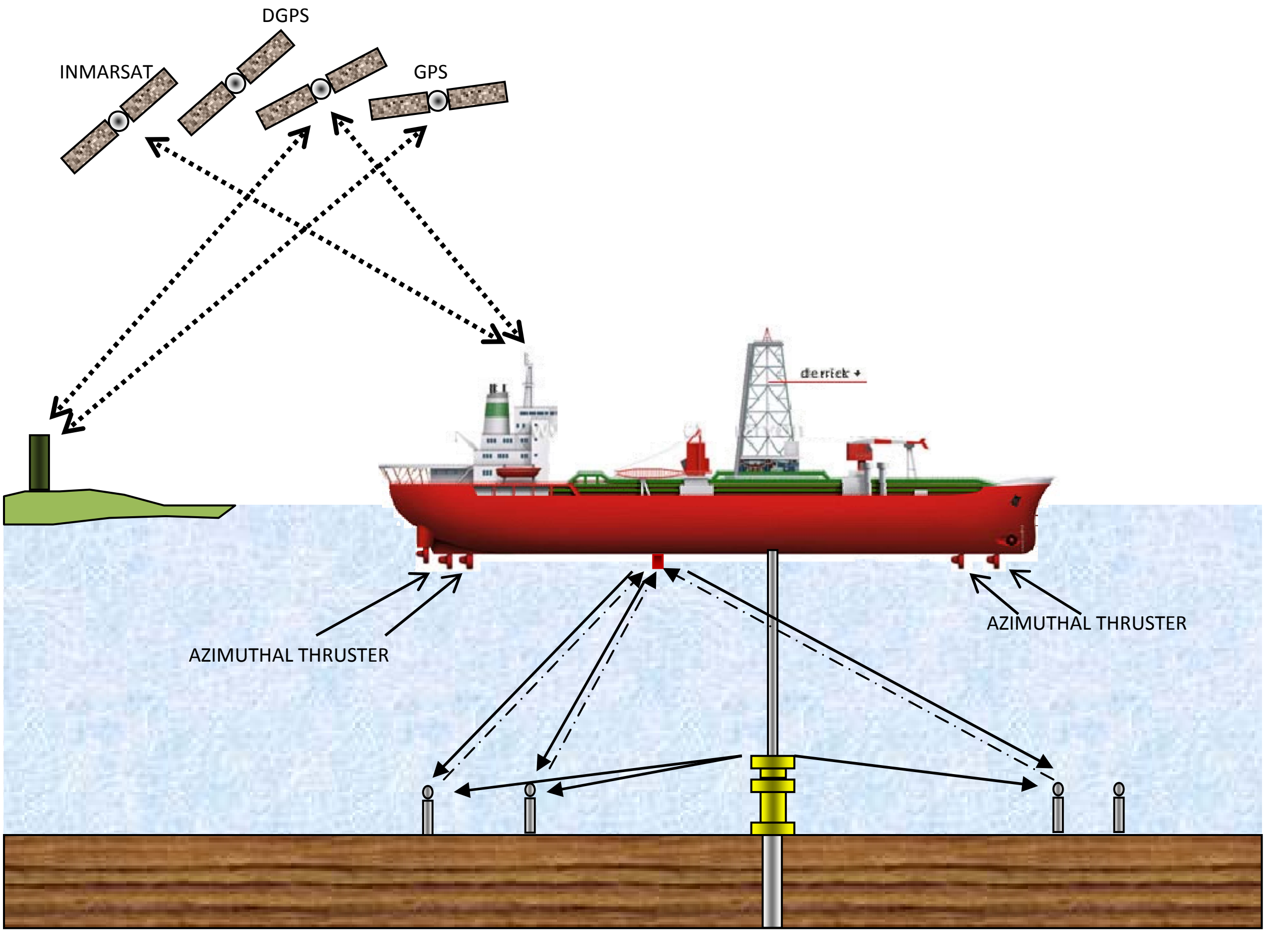


Figure 9: Dynamic positioning principles based on the illustration of Drilling Kingdom, 2009.

The principle of installation of these anchors is more or less the same for bigger offshore units. Petroleum Open Learning Series of Oilwell Drilling Technologies describes in its unit 6 Floating Drilling Installations [POL, 1, P.p. 6.5.-6.7, 2002]

> *Anchor handling work boats use a roller at their stern and two winches capable of holding the required length of pendant line.*
>
> *1. The rig crane passes the anchor to the work boat, there is attached a pendant line,* see figure 10 a.
> *2. With the anchor suspended over the stern roller, the work boat moves out to the drop point. During this time, the mooring line which is attached to the anchor is payed out from the mooring winches on the drilling rig,* as shown in figure 10 b.
> *3. At the required distance from the rig, the anchor is lowered to the sea bed on the pendant line.* Figure 10 c.
> *4. With the rig holding in tension on the mooring line the anchor digs in to the sea bed. The work boat then attached a marker buoy to the pendant line and leaves it floating on the sea surface.* Figure 10 d

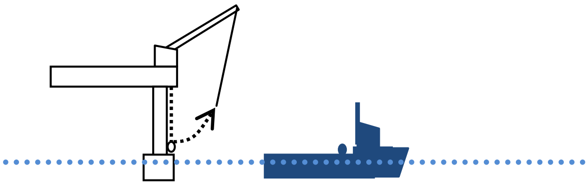


Figure 10 a.

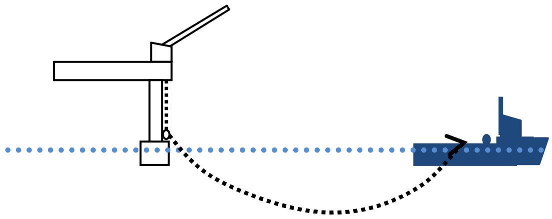


Figure 10 b.

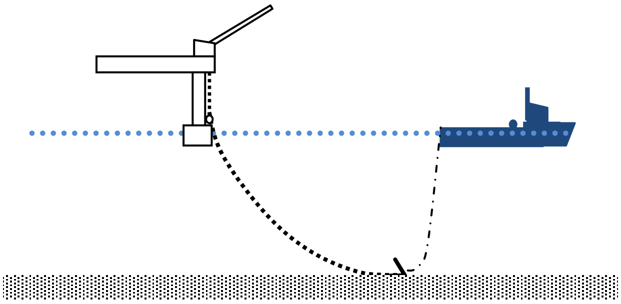


Figure 10 c.

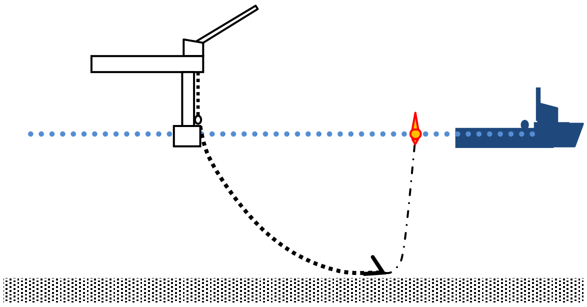


Figure 10 d.

The configurations of patters can be classified in different types according to its shape. In deep water up to up to 1000 m the catenary mooring system is made of lines of chain and/or wire rope (Figure 11.a). For exploration and production beyond 1000 m, the weight of the mooring line is a limiting factor in the design of the floater. To overcome this problem new solutions have been devised consisting of synthetic ropes in the mooring line (less weight) and/or a taut leg mooring system (Figure 11.b) (Ruinen, 2003).

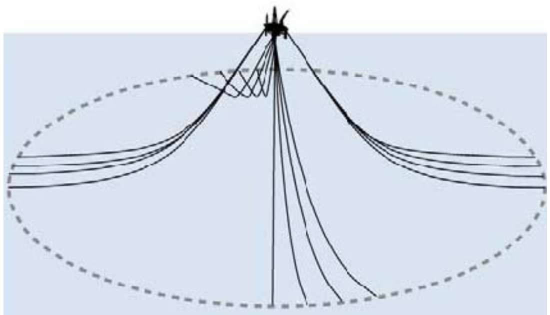


Figure 11.a Catenary mooring system

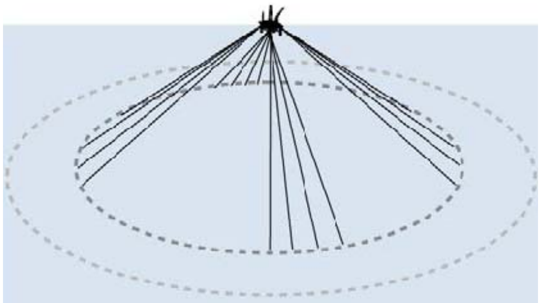


Figure 11.b. Taut leg mooring system.

Once the drilling rig is properly positioned and fixed over the well location a series of drilling operations are performed, below is a list of an example for a deep water field with a multiwell template by Nergaard in the class subsea production system (Nergaard, 2009). These operations require the Running and set of BOP and Xmas trees over the template; due the weight in skid of these components (approximately 250 ton and 40 ton) these positioning and setting are considered to be important marine operations.

1. Drill 30 - 36” pilot hole to approx. 120 m below seabed, figure 12.a.
2. Run land and cement conductor casing (30”), figure 12.b.
3. Drill 24” surface hole to approx. 500 m and run 20” surface casing, figure 12.c.
4. Run land and cement 20” casing, figure 12.d.

5. Run BOP, figure 12.e.
6. Land BOP, drill and complete well no. 1 and spud well no.2, figure 12.f.
7. Move BOP to well no 2 and run Xmas tree to well no 1. Figure 12.g.

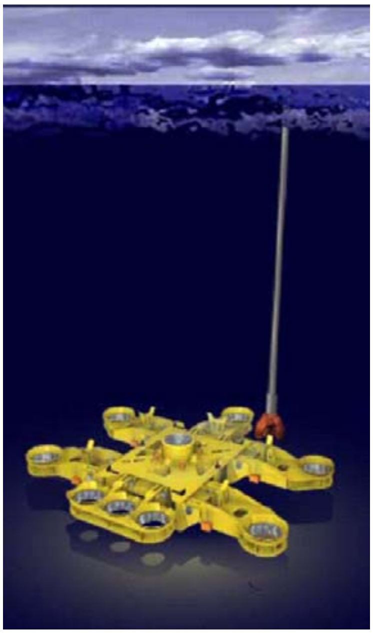


Figure 12.a

Figure 12.b

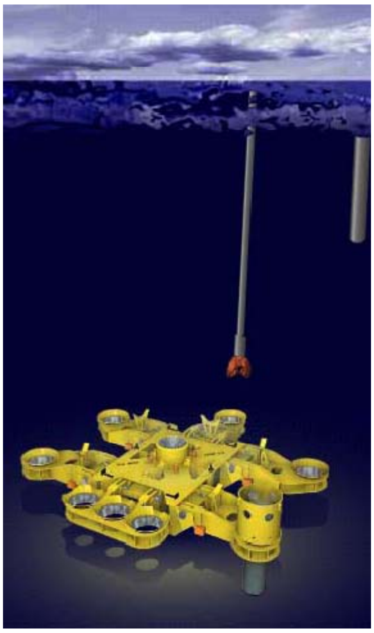


Figure 12.c

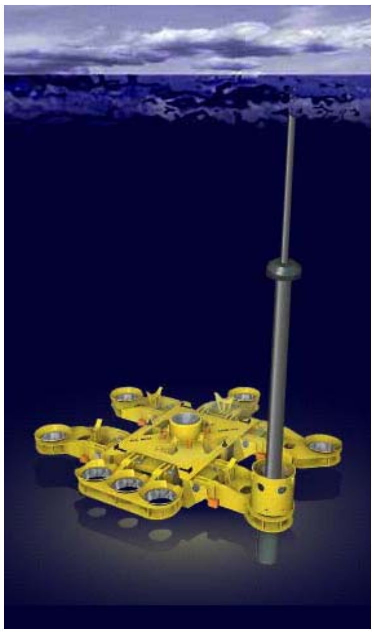


Figure 12.d

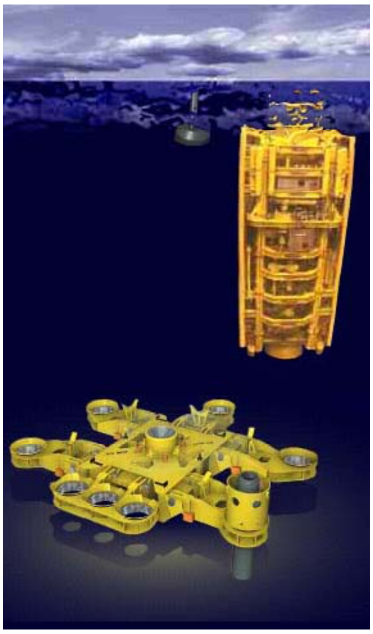


Figure 12.e

Figure 12.f

Figure 12.g

D.I.4 Central manifold installation.

Similar marine operations to install templates.

D.I.5 Flowlines and umbilical's installation.

A good summary on how to install and connect flowlines and umbilicals is available in the appendix A, Sections A.9.2 and A.9.3 of the International Standard ISO 13628-1 Design and operation of subsea production systems.

A.9.2 Flowline and umbilical configurations and installation techniques

A.9.2.1 General

Many factors need to be taken into account in the design of the flowlines and umbilicals for a subsea production system. The combination of through-life design requirements, installation options and life-cyclecosts will result in the selection of a preferred configuration and installation technique, the basic ones of which are outlined below.

A.9.2.2 Individual flowlines

Individual flowlines can be installed using S-lay, J-lay, reel (including pipe-in-pipe) and/or tow techniques as follows:

- S-lay;

The flowline is made up in a horizontal or near horizontal position on the lay vessel and lowered to the seafloor in an elongated "S" shape as the vessel moves forward.

- J-lay;

The flowline is made up in a vertical or near-vertical position on the lay vessel and lowered to the seafloor in a near-vertical orientation. This approach eliminates the overbend region of the S-lay pipe catenary.

- Reel;

The flowline is made up onshore and spooled onto a reel. The line is then transported to the desired location and unreeled onto the seafloor. The axis of the reel may be vertical or horizontal.

- tow.

The flowline is made up onshore or in a mild offshore environment and then towed to its final location, where the buoyancy is adjusted to lower the line to the seafloor and provide adequate on-bottom stability. There are several versions of the tow method, including the near-surface tow, controlled-depth tow, nearbottom tow and bottom tow. The tow methods differ primarily in the requirements for buoyancy control and in their sensitivity to environmental loadings during the towout. All of these techniques have limits with respect to the largest diameter lines that can be fabricated and installed. Reeling and towing also have some restrictions with respect to the length of line that can be fabricated and installed in a single run/unit.

Whereas the host end of a reeled flowline can be pulled up a J-or I-tube, most of the other techniques rely on the use of spools/jumpers at the host end. In the case of a tieback to an FPS, the tail end of an individual rigid pipe or flexible pipe may be suspended from the FPS to form a riser, as described in A.10.3.

The various connection options for the ends of individually installed flowlines are described in detail in A.9.9.

A.9.2.3 Bundles

Small numbers of flowlines and/or umbilicals can be strapped together during reeling operations to form a strapped bundle on the seabed. While this configuration can have some advantages in terms of on-bottom stability of the lines, etc., the benefits are somewhat limited as each line shall be at least partially designed on a stand-alone basis...[ISO-13628-1, P.p. 131-132, 2005].

A.9.3 Flowline and umbilical end connections

A.9.3.1 General

In order for a flowline or umbilical to fulfil its intended function, it is necessary to connect it to the associated subsea/surface facility equipment. A wide variety of techniques are available to complete this task, ranging from installation of flexible jumpers by divers at the subsea end of a flowline, through to pulling a multicore umbilical up through a J-tube preinstalled on a production platform. For connection of flowlines and umbilicals to subsea/surface equipment, the basic steps involved in the process are the following:

- pull-in of the two halves of the connector so that the faces are aligned and in close proximity (alternatively, the gap between the two halves of the connection may be spanned by an additional short length of sealine known as a jumper or spool);

- connection of the two halves of the connector;

- testing of the completed connection, to confirm that it has been successfully made up. ...[ISO-13628-1, P.p. 133-134, 2005].

D.I.6 PLETs and Pipelines installation 2 x 8”.

Pipelines are installed in at least 4 different methods, J-Lay, S-lay, Reel-Lay and Normal-lay (towed pipelines), of them the most suitable for the depth of the Lakach field would be a J-lay with flexibility to use a S-lay system also. A description of the advantages and disadvantages of the J lay given by Nogeira is reproduced in the table 3 (Nogeira, P.p. 931, 2005).

A PLET (Pipeline End termination) is a structural-transportation element in the subsea pipelines, as indicated in its name it is located at the end of the pipeline and is usually installed in the installation vessel and then lowered and positioned in the sea floor. Antani et. al. documented the installation of PLETS in the Neptune project in 2008, below it is a excerpt of their work that explain the procedure of installation of a PLET.

Advantages	***Disadvantages***
Best suited for ultra deep water pipeline installation.	*Some vessels require the use of j lay collars to hold the pipe.*
Suited for all the diameters.	*If shallower water pipeline installation is required in the same route, the J-lay tower must be lowered to a less steep angle. Even then, depending on the water depth, it may not be feasible to J-lay the shallow end with a particular vessel and a dual (J-lay/S-lay) installation may be required. Such as the case of the Canyon Express project.*
Smallest bottom tension of all methods, which leads to the smallest route radius, and allows more flexibility for route layout. This may be important in congested areas.	
Can tipically handle in-line appurtenances with relative ease, with respect to landing on the seafloor but within the constrains of the J-lay tower.	

Table 3 Advantages and disadvantages of the J lay construction method for pipelines (Nogeira, P.p. 931, 2005).

PLET Installation

…Although PLET installation in S-mode is well feasible, the PLETs for the Neptune project were designed to be installed using a J-mode installation method. The following section describes the standard J-mode PLET installation procedure for Solitaire before discussing the project-specific challenges and the solutions that led to the successful installation of the Neptune export PLETs.

Standard J-mode PLET installation

Starting point of this operation is that both flowlines have been laid down on the seabed (in S mode) with a (temporary) laydown head (see Figure 4.13).

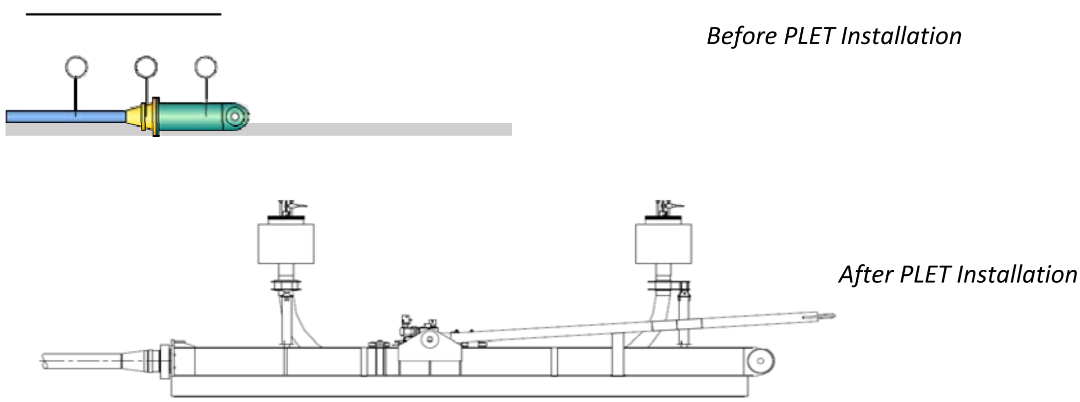


Figure 13: Schematic lay out of before and after PLET installation on seabed.

In general, for a J-mode PLET installation the following steps can be distinguished:

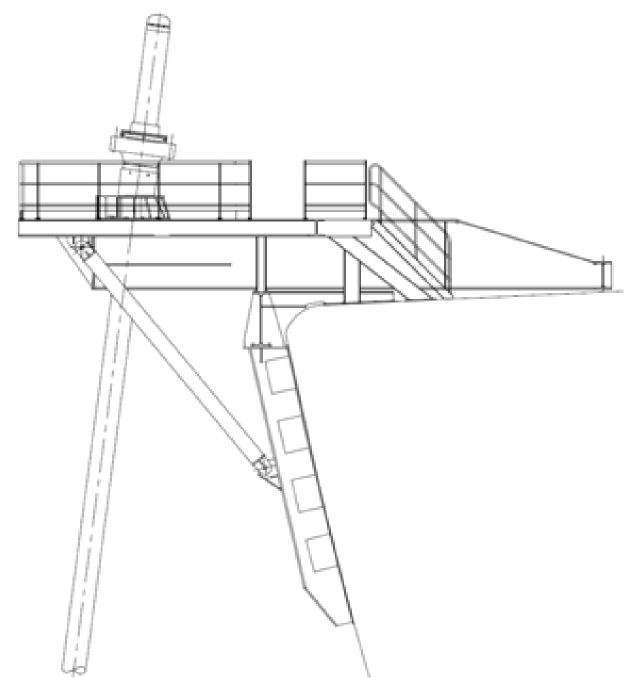
1. J-mode pipeline recovery

Before the start of the operation, the PLET has been transported and offloaded to Solitaire where it is stored on the main deck in the vicinity of the 300 mT special purpose crane (SPC). The abandonment & recovery (A&R) cable, routed over a sheave in the A-frame, is lowered to the pipeline recovery sling on the seabed and hooked in, assisted by a remotely operated vehicle (ROV). Solitaire then moves to stand-off position, the pipeline is recovered to the surface and hung off in the hang-off frame using Solitaire's SPC (Figure 14).

2. PLET Installation

Upon removal of the temporary laydown head, the pipeline end is prepared for the installation of the PLET. The SPC is used to upend the PLET using a two-point lift with the SPC main hoist and the SPC whip hoist. The PLET is then upended by lowering the whip hoist whilst the PLET load is gradually taken over by the main hoist. The rigging configuration is chosen such that the PLET angle after upending is equal to the pipeline hang-off angle. Figure 15 illustrates the up-end scheme.

After stabbing of the PLET onto the pipeline, the swivel flange on the transition forging is bolted to the PLET bulkhead ensuring the structural connection between the pipeline and the PLET. Thereafter, the PLET piping is welded to the pipeline and the weld is inspected before field joint coating is applied.



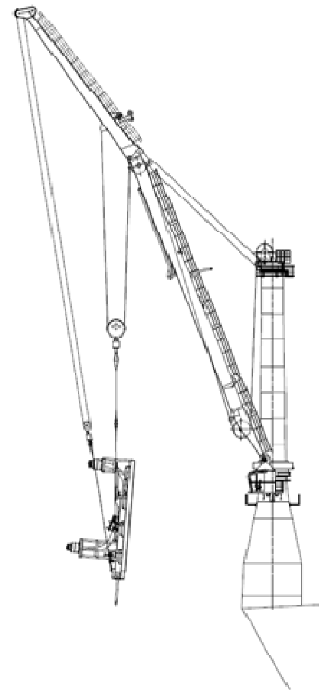


Figure 14: The pipeline hung off in aft frame.

Figure 15: Upending PLET with SPC

3. PLET Lowering

The PLET will be lifted off the hang-off frame and positioned in line with the sheave of the A-frame. Once in line, the SPC will lower the PLET pipeline assembly until the tension is transferred from SPC to A&R cable, as illustrated in Figure 16. From this point onwards, the A&R winch will lower the PLET onto the seabed.

The yoke stabilizes the PLET during lowering and ensures that the PLET is positioned on the seabed in an upright position within the installation tolerances. Once position and location have been confirmed to be within specifications, the A&R cable is disconnected and recovered onboard. [Antani, P.p. 5-6, 2008].

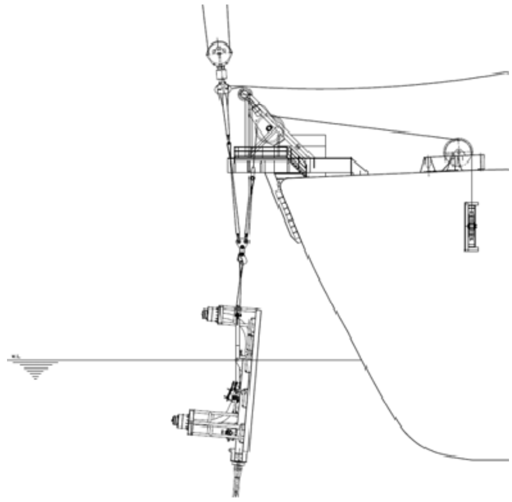


Figure 4.16: Hand over PLET pipeline assembly from SPC to A-frame

D.I.7 Workover and well intervention

Nergaard (Nergaard, 2009) give a definition of the two terms and explains its purposes as:

Workover: The term is used for a full overhaul of a well. It reflects the full capacity to change production equipment (tubing etc) in the well as well as the Xmas tree itself. This implies the use of a rig with fullbore BOP and marine riser. This means the we have to apply the same capacity systems as used during initial completion of the well. Full overhaul/workover might imply a full recompletion of the well. Using a full capacity drilling/completion rig offers the full capacity for redrilling, branch drilling and recompletion. In some cases we see the full capacity WOI system referred to as Category C intervention: heavy well intervention.

Well intervention: This term is used commonly for all vertical interventions that is done during the wells production life, ie after initial completion. The term is most commonly used for the lighter interventions; those implying that operations take place inside and through the Xmas tree and the tubing.

These are:

Category B intervention: medium well intervention, with smaller bore riser

Category A intervention: light well intervention – LWI, through water wireline operations..

The purpose of the interventions is increase the recovery rate and also as required:

- Survey – mapping status-data gathering.
- Change status (ex open/close zones – smart wells)
- Repair
- Measures for production stimulation.

D.I.8 Abandonment

At the end of the production life of the oilfield, the facilities must be decommissioned and abandoned according to the environmental and health requirements of the home country and any other applicable laws. The site must be restored to a condition that minimizes residual environmental impact and permits reinstatement of alternative industries in the area and unimpeded navigation through it.

• Floating production facilities will be removed from the field.
• Subsea infrastructure must be removed or abandoned and the wells will be plugged and abandoned.
• Buried flow lines must be abandoned at the place of the installation after be flushed.

D.II. Marine operations for a SPAR.

The SPAR is a floating structure that typically involves complex marine operations; Reeg (Reeg et. al., 2000) provides a review of the installation process of the hull of the SPAR that is reproduced next:

Installation is performed in stages similar to those of other deepwater production systems, where one component is installed while another is being fabricated. Installation schedules heavily depend upon the completion status of the hull and topsides.

Listed below are the order of events for a typical spar installation:

- *Well predrilling (drilling vessel)*
- *Export pipelines laying*
- *Presite survey; transponder array deployment; anchor pile target buoys set*
- *Anchor pile and mooring line settings*
- *Hull delivery and upending*
- *Temporary work deck setting*
- *Mooring and pipeline attachment*
- *Mooring lines pretensioning*
- *Hull ballasting and removal of temporary work deck*
- *Topsides delivery, installation, hookup, and integration*
- *Buoyancy can installation*

Prior to the delivery of the hull to location, a drilling rig might predrill one or more wells. (See figure 17)

During this time, export pipelines are laid that will carry production either to another platform (host) or to shore after processing.

A presite survey is performed and includes the following: onbottom acoustic array installed for the mooring system, identified obstructions removed, anchor pile target buoys preset, and a final survey of the mooring lay down area performed.

Once on location, a derrick barge installs the anchor piles and mooring system. The installation of the anchor piles is performed using a deck-mounted lowering system designed for deepwater installations and an underwater free-riding hydraulic hammer with power pack. Remotely operated vehicles (ROV's) observe the hammer and umbilical as the pile is lowered and stabbed into the seafloor.

In conjunction with pile installation, the mooring system is laid out and temporarily abandoned. A wire deployment winch with reels specifically designed for this type of work handles each wire. An ROV monitors the wire lay-down path as the derrick barge follows a predetermined route until it reaches the wire end on the deployment reel. The end of the mooring wire is then connected to an abandonment/recovery line and marked for later use in attaching the mooring system to the hull.

To date, all GOM spar hulls have been built in Finland. Upon completion of the hull, it is shipped to the Gulf of Mexico on a heavy-lift vessel such as the Mighty Servant III. See figure 18.

Because of its size and length it is necessary to divide the spar hull into two sections. (NANSEN/BOMVANG were delivered in only one section) *Upon arrival at an onshore facility, the sections are connected together using a wet mating technique, which allows for lower cost and ease of handling and positioning, and eliminates the need for special equipment. The hull is then ready for delivery to location.*

Depending on the proximity of the onshore assembly location to the open sea, smaller tugs (2,000 to 4,000 hp) may be used first to maneuver the hull into deeper water, and then larger oceangoing tugs (7,000 hp) tow the spar to its final destination. See figure 19.

A derrick barge and a pump boat await arrival of the hull on site. The barge and boat up-end the hull. While the hull is being held loosely in place, the pump boat fills the hull's lower ballast tank and floods the centerwell.

The hull self-up-ends in less than two minutes once it is flooded. Next, the derrick barge lifts into place a temporary work deck brought to the site on a material barge. Tasks performed using the temporary work deck are basic utility hook up, mooring line attachment, and riser installation. (Figure 20).

The hull is positioned on location by a tug and positioning system assistance. Then the mooring system is connected to the hull. After the mooring system is connected, the lines are pretensioned. (Figure 21)

Then the hull is ballasted to prepare for the topsides installation and removal of the temporary work deck.

Topsides are transported offshore on a material barge and lifted into place by the derrick barge. An important characteristic is that the derrick barge can perform the lift in dynamic positioning mode.

The topsides consist of production facilities, drilling/workover rigs, crew living quarters, and utility decks. Installation of miscellaneous structures such as walkways, stairways, and landings are also set in place by the derrick barge. The last pieces of equipment to be installed are buoyancy cans and the associated stems. The cans are simply lifted off the material barge and placed into slots inside the centerwell bay. (Figure 22)

Next, the stems are stabbed onto the cans. To prepare for riser installation, the cans are ballasted until the stem is at production deck level (figure 23) [Reeg et. al., P.p. 26-27, 2000].

A schedule of the installation of the Nansen SPAR is reproduced in the Chart 1.

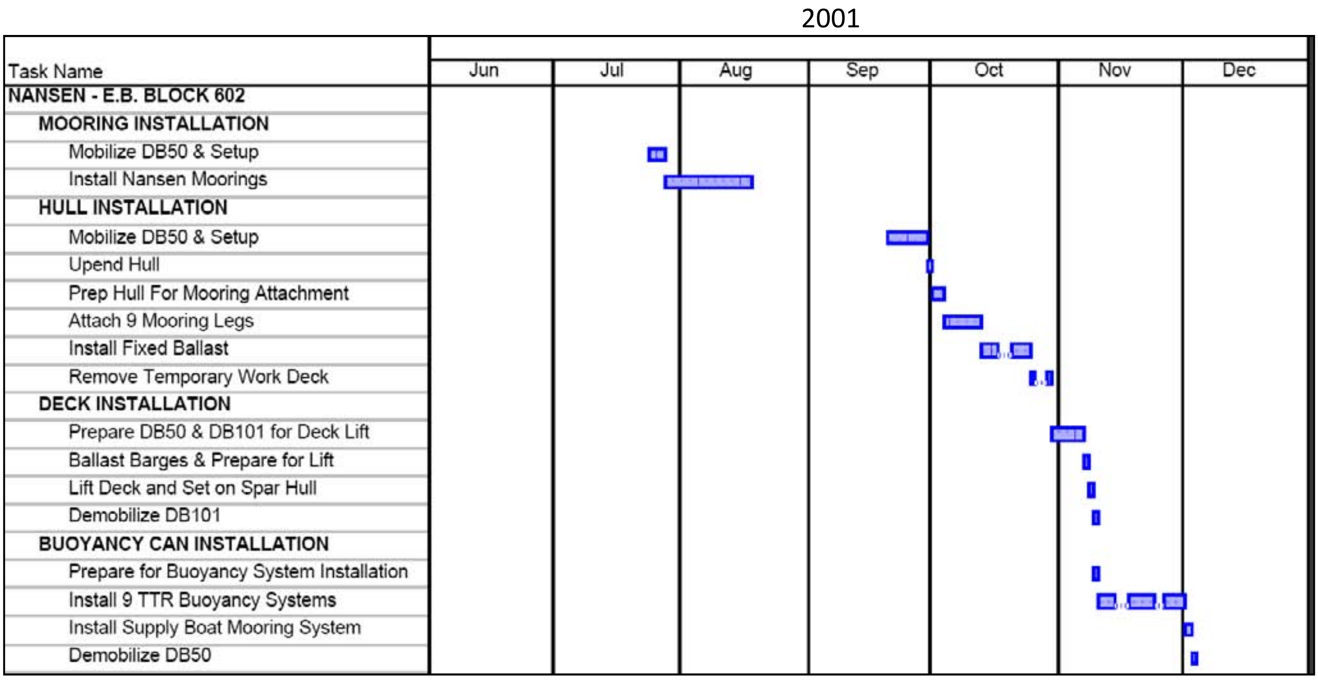


Chart 1: Project Installation time line [Beattie, P.p. 10, 2002]

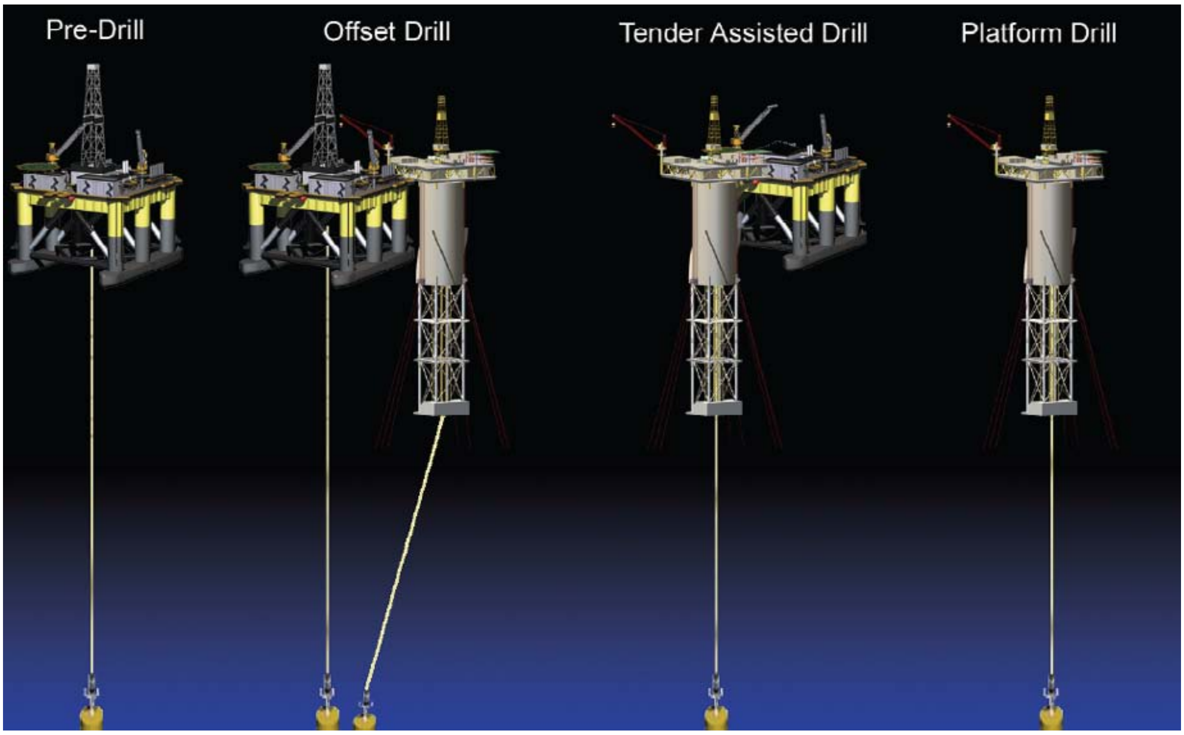


*Figure 17: SPAR drilling options (*Wilhoit*, 2009)*

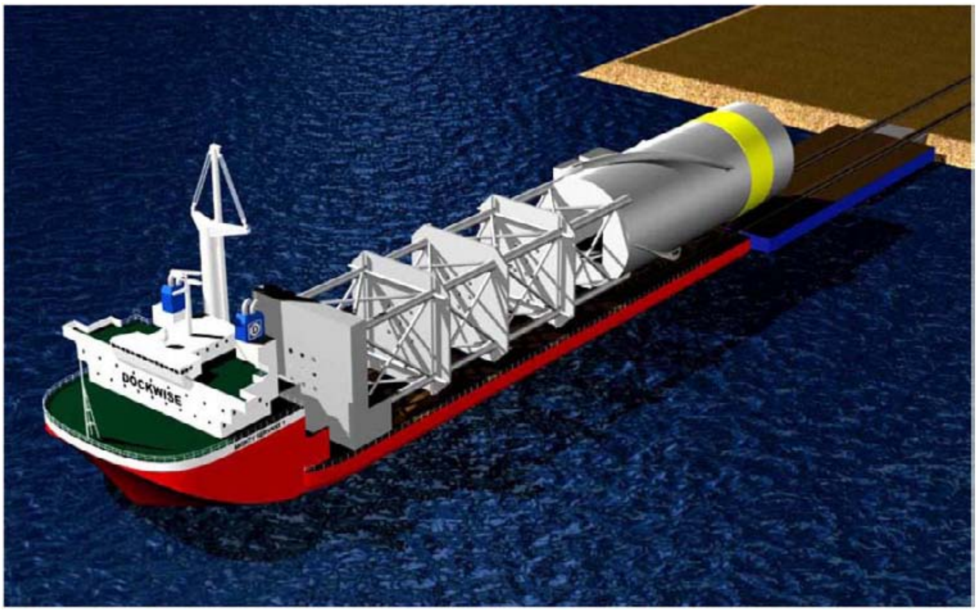


Figure 18: SPAR hull loadout [Beattie, P.p. 11, 2002]

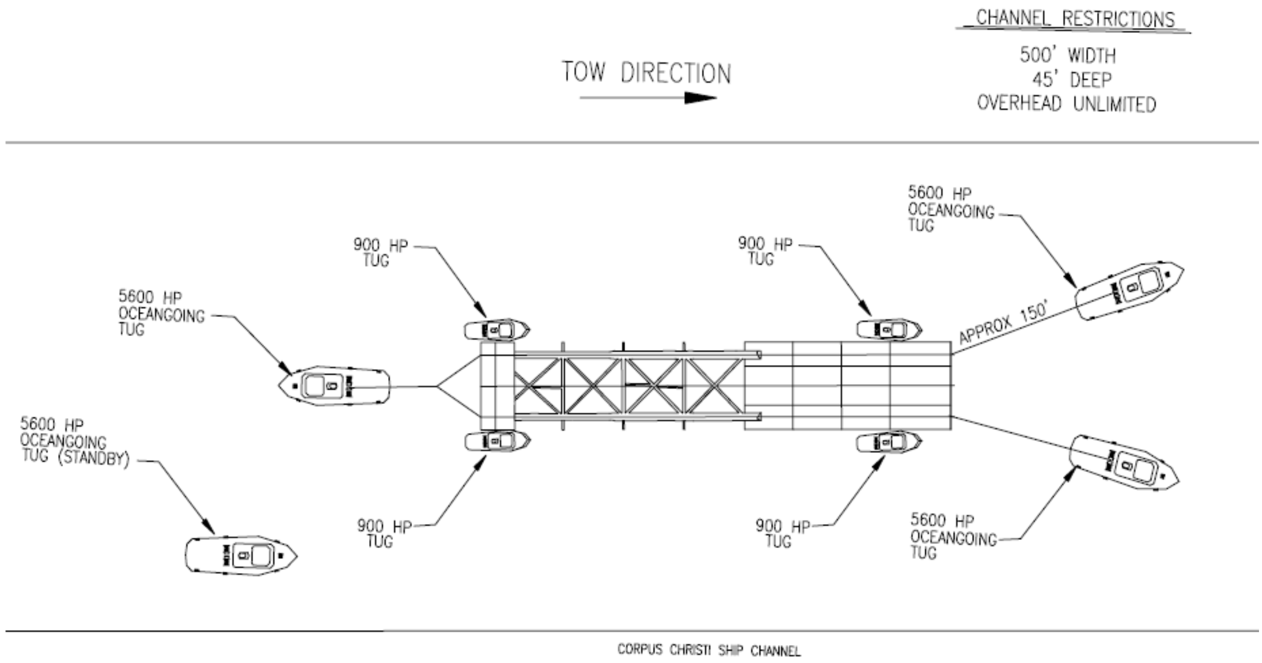


Figure 19: SPAR hull wet tow configuration [Beattie, P.p. 13, 2002]

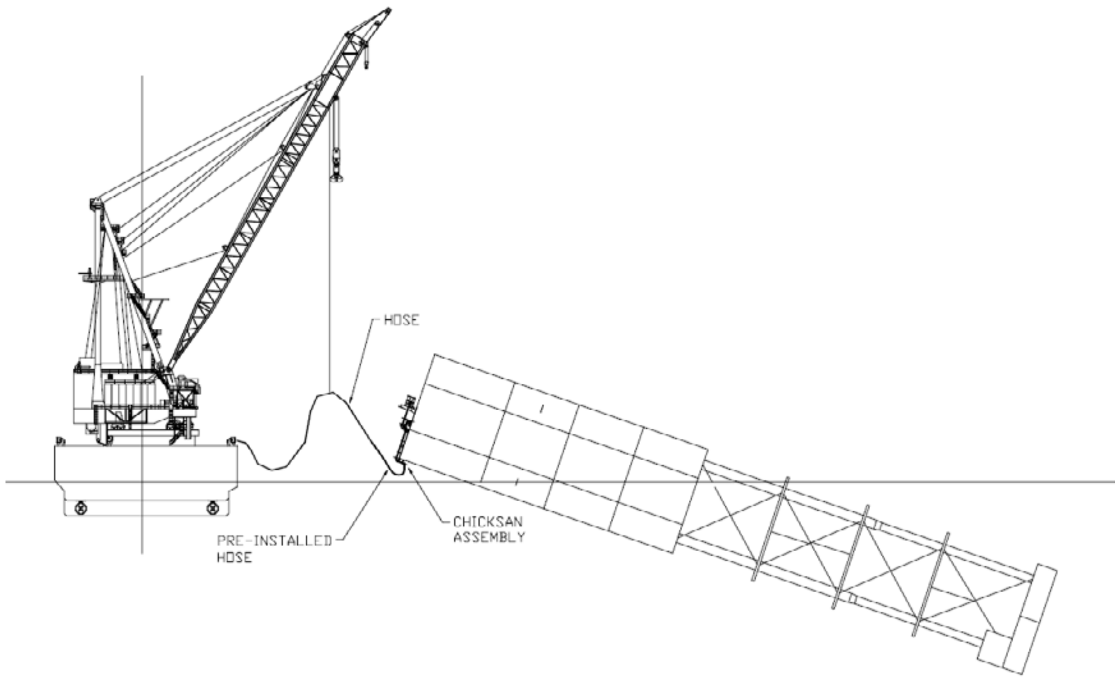


Figure 20: SPAR hard tank flooding operations [Beattie, P.p. 13, 2002]

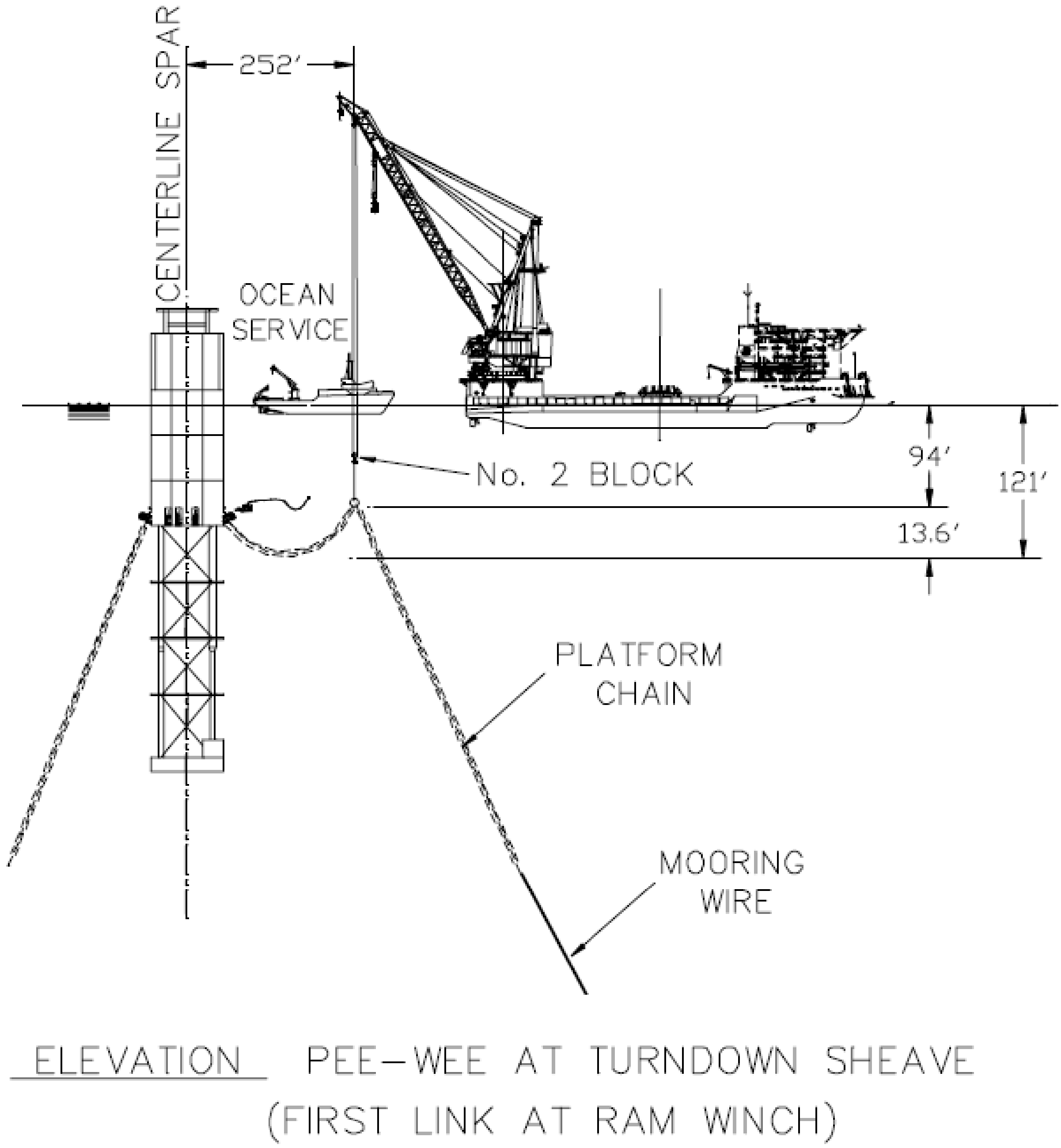


Figure 21: SPAR mooring line installation [Beattie, P.p. 14, 2002]

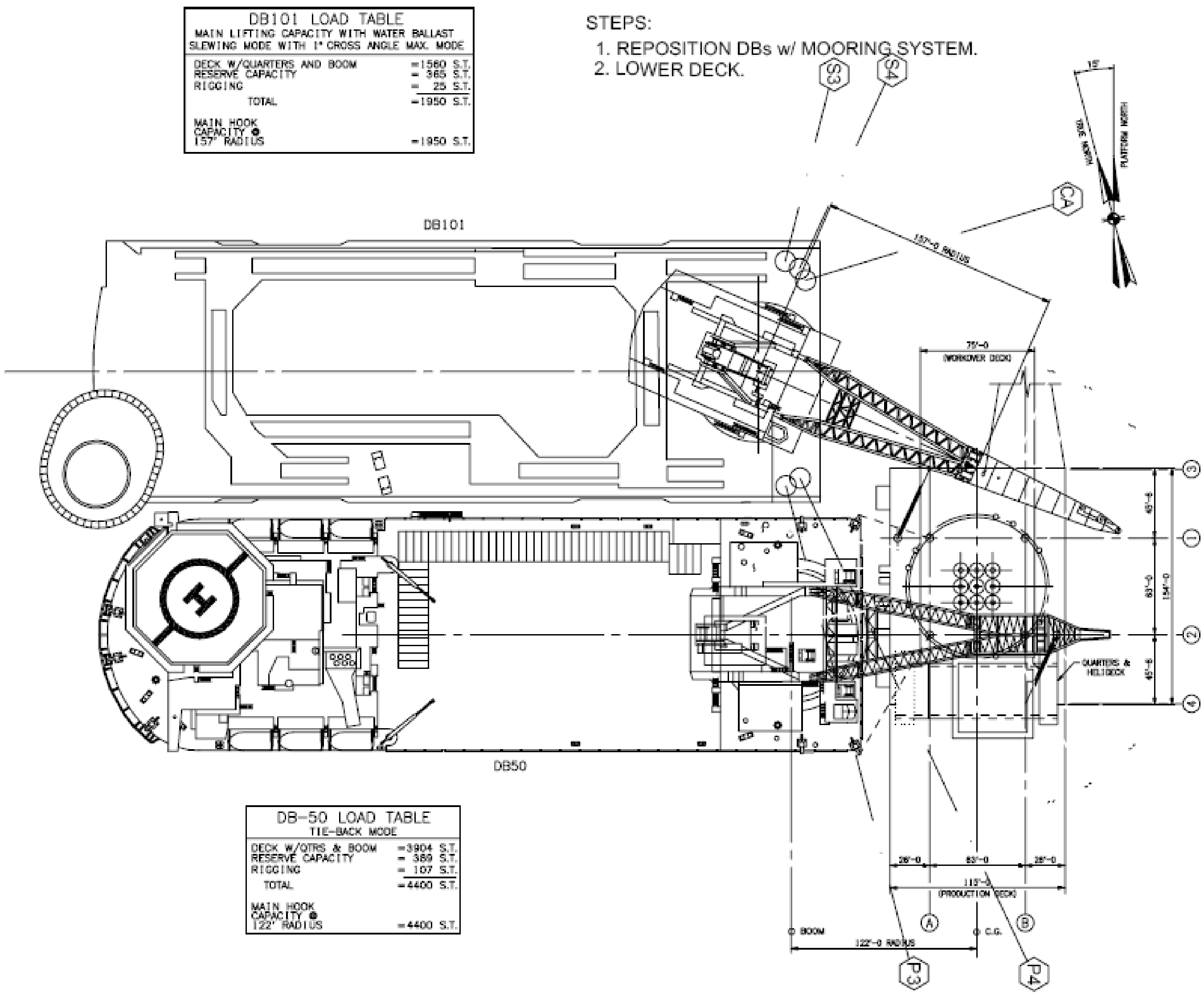


Figure 22. Deck installation arrangement [Beattie, P.p. 15, 2002]

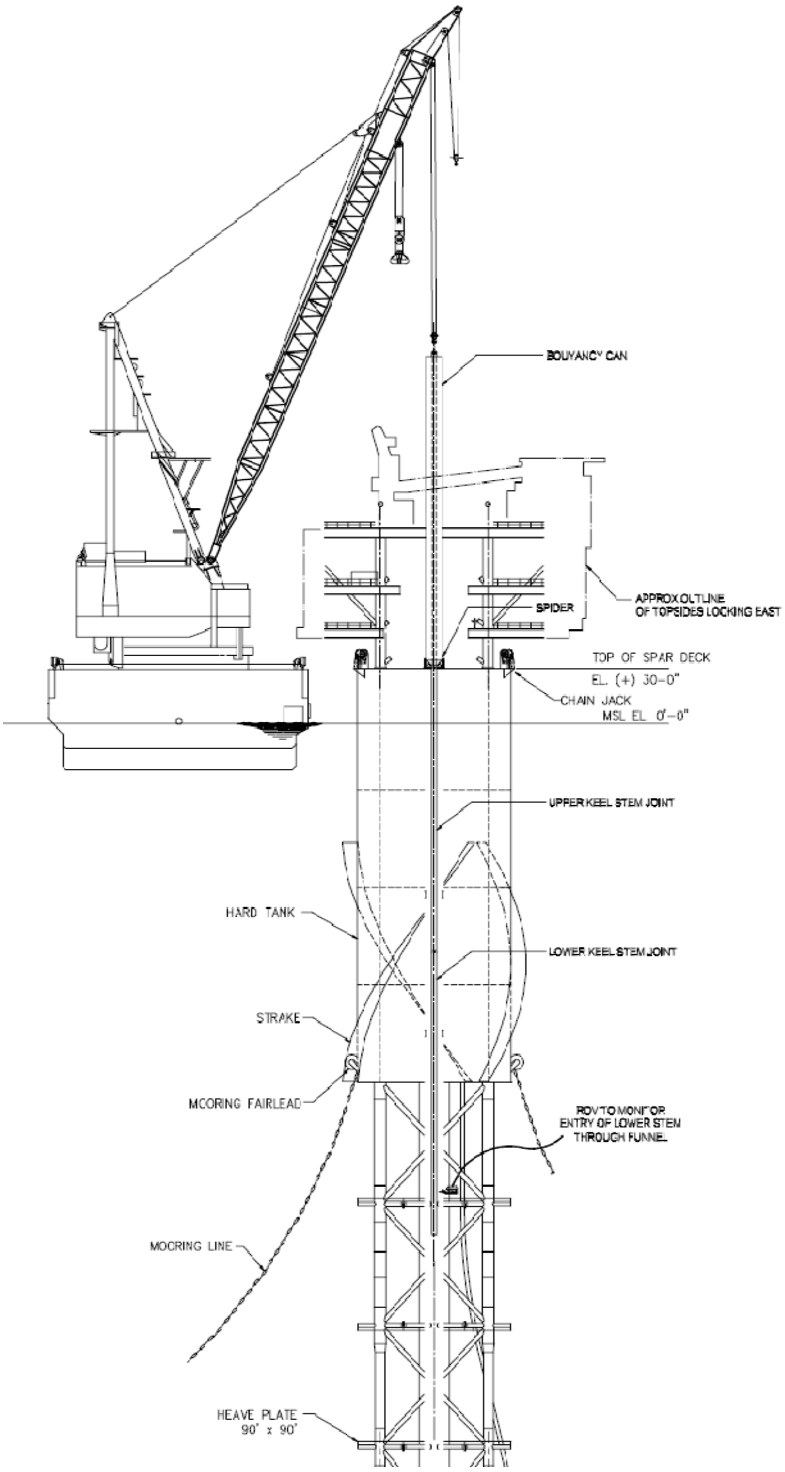


Figure 23: Buoyancy can installation [Beattie, P.p. 15, 2002]

D.III MARINE OPERATIONS FOR A TLP.

Reeg et. al. resume the installation process of the TLP concepts that is reproduced next:

INSTALLATION OVERVIEW.

Installation of a TLP is done in stages; often the design work on one section of the TLP is being done while another part is being installed. For example, the wells will often be predrilled while the TLP is being designed and constructed.

Installation of a typical TLP is done in the following order:

1. Template for wells or foundation for TLP
2. Export pipelines
3. Flexible risers and mooring lines
4. Platform/Tendons
5. Hull and Surface Facility

Template and Foundations

Templates. *Templates provide the layout for well locations and/or for the foundation, if needed. The wells may be drilled to their total depth, or partially drilled and the conductor casing set. Additional well drilling and completion operations can be done from the TLP. Template installation for drilling and foundation templates is similar, except some of the equipment used may be different. The template is built onshore and towed to location for installation.*

A drilling rig (mobile offshore drilling unit [MODU]) is preferred for installation because it eliminates the need for additional vessels. However, drilling rigs cannot lift large payloads and have limited lowering capacity. Large templates may need a crane for installation; they will also require costly handling systems and rigging.

Foundations. *Foundations secure the TLP to the seafloor by use of buried piles, which can be concrete or steel. Tendons are attached to the foundation and the platform is attached to the tendons. The piles can either be driven or drilled and grouted. Driven piles are expensive to install, but the holding power of drilled and grouted piles may not be as strong because of changes to the sole-pile interface during the jetting and drilling operations. A typical vessel used for foundation installation would be one of the several available semisubmersible construction/crane vessels. A hydraulic hammer is used to drive the piles into the seafloor.*

Export Pipelines. *Pipelines for the TLP are the same as pipelines used for conventional platforms. A steel catenary riser may be used to connect the subsea pipeline to the TLP. Various methods of installation can be used. The most common method used for installing pipelines is the J-lay method. Pipelines for TLP's range in size up to 18 inches in diameter for oil and approximately 14 inches for gas. Often the pipeline will join another system for transport to shore. Oil can be transported by tanker as an alternative to pipelines.*

Platform/Tendons. *The TLP's use tendons to secure the platform to the foundations. There is no set order for installation of the platform and tendons. In some cases the tendons will be connected to the foundations, and then the platform will be moved into place and the tendons secured to the platform. Other operations will move the platform in place first, secure the tendons to the platform, and then attach the tendons to the foundation. Another option is to secure some of the tendons to the foundations, move the platform in place, attach the secured tendons, and attach the remaining tendons to the TLP and then to the foundation.*

Hull and Surface Facility. *The upper section of a TLP consists of the hull, the deck, and the surface facilities. The surface facility modules are built onshore and typically assembled at a* *shallow-water location near shore, then towed to the site. The modules may be attached to the hull either inshore or at the site. Economics are the determining factor for where the modules and hull are assembled.*

The hull provides the buoyancy for the TLP to float in the water and supports the platform. The hull contains several of the mechanical systems needed for platform operation. Topsides-related equipment includes firewater, seawater, diesel storage, low toxic oil storage, and completion fluid storage systems. Hull-related equipment includes ballasting and trim, drain and bilge 12 hours.

• The platform was then transported to the site using four ocean-going tugboats, traveling at three miles per hour, taking seven days for the 400-mile transport.
• Because the installation took place inshore there was no need for extra helicopters, supply boats, and marine equipment, and offshore operations, quartering, and weather delays were greatly reduced. Peak manpower used during installation was 350 people.

Drilling Information. *Well drilling for the TLP often begins after well template installation. A TLP can have 50 well slots with provisions for satellite subsea well tiebacks.*

Predrilling involves using a mobile offshore drilling unit (drillship or semisubmersible) to batch drill and case the wells to a convenient depth, normally through the shallow water flow zone or other potential hazard. Predrilling may also be suspended just above the production zone. Some wells may be drilled to total depth and completed. The Sonat George Richardson semisubmersible drilling vessel is an example of the type of vessel used to predrill.

The Typhoon project was extensively documented in various OTC papers and other publication, chart 2 shows the project Schedule, pay particular attention to the points 47 to 57 in that chart.

Figure 24 shows the concept of the Typhoon field, note that this field is entirely a subsea development, while the most of the operations will not be so different as the one applied for the subsea tiebacks to shore, the availability of facilities close to the wells in this way increase the capability of processing and distribution of oil and gas which increase at the end the recovery factor.

D.IV. Marine operations for a semisubmersible.

From the tree concepts of floating structures shown in this report, the semisubmersible is the less demanding on complexity and number of marine operations since the topsides can be preinstalled before the final emplacement. The onshore operation to place the topsides over the hull is called “superlift”.

The mooring of the hull and the installation of risers and umbilicals to the main host are however operations that need to be carefully planned and is not less complex the translation from the construction yards to the field.

The Na kika project was documented in those aspects in several papers:

- OTC 16701 Na Kika – Host Construction for Record Water Depth Platform.
- OTC 16702 Na Kika – Deepwater Mooring and Host Installation.
- OTC 16704 Na Kika Umbilical Transport & Installation Challenges.
- OTC 16703 Design and Installation of the Na Kika Export Pipelines, Flowlines and Risers.

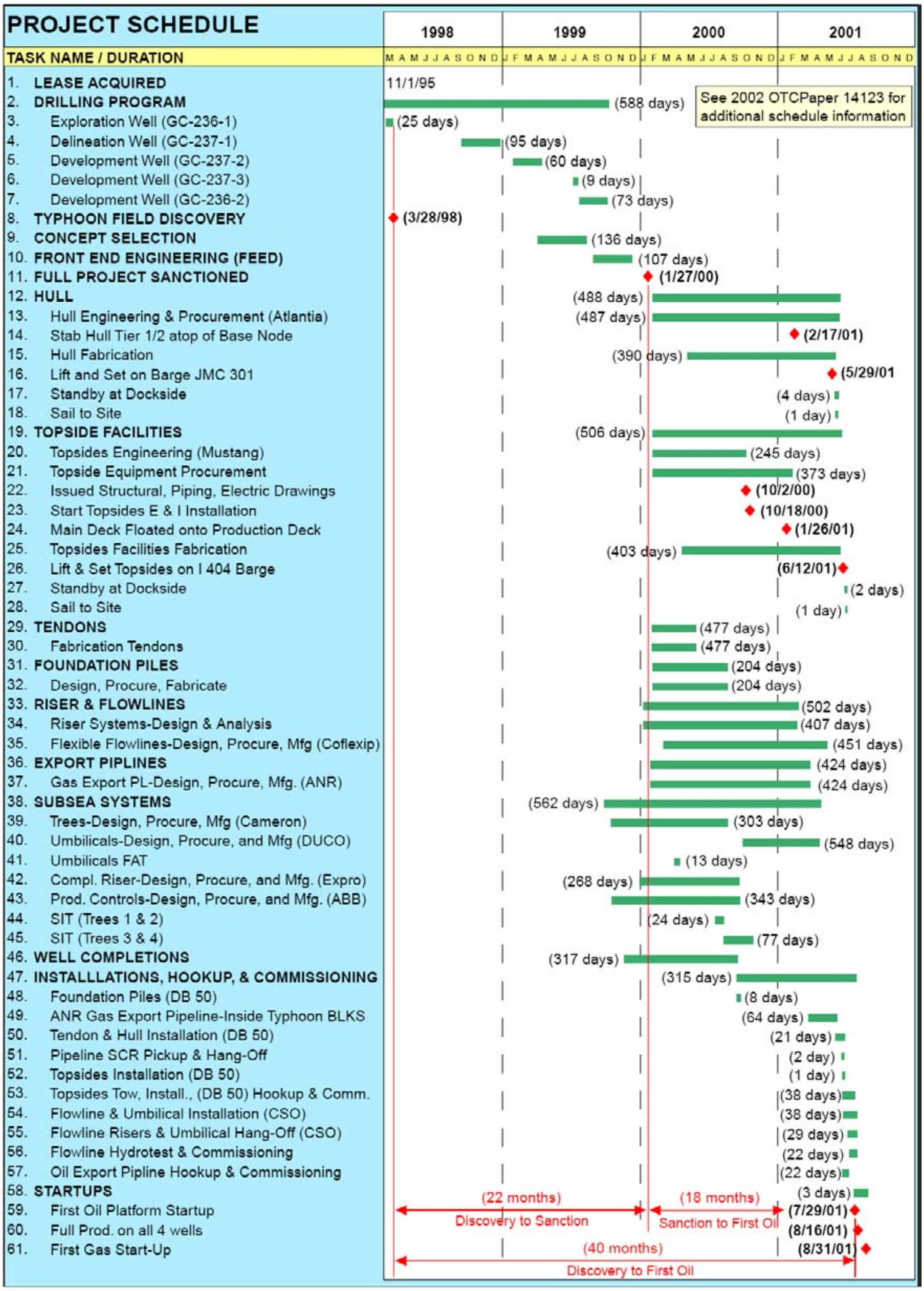


Chart 2 Project Schedule for the field development of the Typhoon project (Albaugh, 2003)

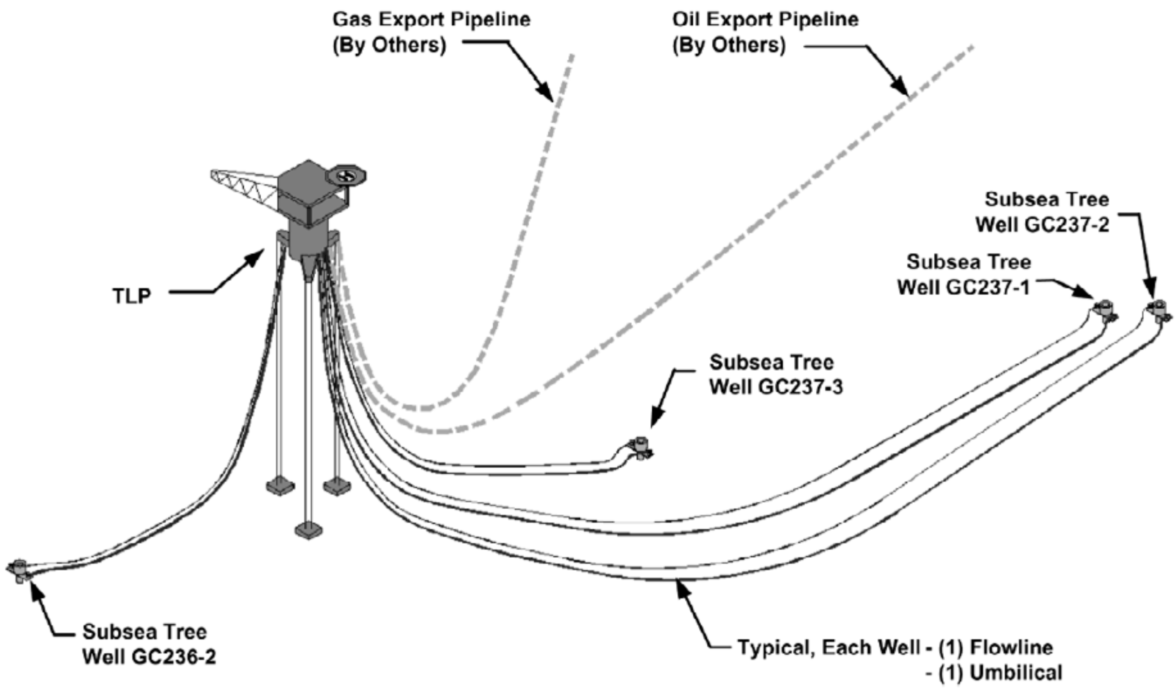


Figure 24 Conceptual visualization of the field development Typhoon (Reeg et. al, 2004).

The placement of the structure is made in a tow operation that can be wet or dry since the FPS is not entitled to have powerful motion systems.

Installation of Risers, export pipelines and flowlines once the main host is moored is not so much different than the ones performed for other floating units as SPAR or TLPs.

The mooring system is however of major importance since the design of the structure particularly for the weight that this system add to all the structure.

CONCLUSIONS:

The subsea tieback to shore is usually the concept that represents less complexity in terms of marine operations.

The technology and knowledge for the construction and installation of floating structures in deep water have been already tested and were successfully installed in comparative projects reviewed in this Annex.

Even though the subsea tieback represent a clear saving in term of capital costs, the selection of alternative concepts using floating structures would represent an increased recovery rate with respect to the subsea tieback concept and cannot be excluded under the exclusive consideration of the complexity of Marine Operations and Marine technology.

Floating structures represent an ample competence challenge but the investment in enhance the competence in this aspect would be necessary when the distances to shore or the size of the field make the concept more favorable to deploy.

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Annex E: Extended results of the recovery factor data analysis for oil and gas fields in the U.S. Gulf of Mexico.

E.I. Gas recovery factor from non associate gas fields

Figure 1 shows the best fitted probability distributions for the gas recovery factor from the observations of the non associate gas fields:

- Gas recovery factor combined for dry and wet tree (Beta General).
- Dry tree recovery factor (Triangular).
- Wet tree recovery factor (Triangular).

Table 1 Shows test the hypothesis that $\mu_{\text{dry tree}}$- $\mu_{\text{wet tree}}$ = 0 vs. $\mu_{\text{dry tree}}$- $\mu_{\text{wet tree}} \neq 0$ with μ calculated from the data sets. Table 2 summarizes the statistical input data and probabilities parameters for each set of data.

E. II. Oil recovery factor from non associate gas fields

Figure 2 shows the input data and best fitted probability distributions for the oil recovery factor from the combined observations for dry and wet tree of the non associate gas fields (Weibull). Table 3 summarizes the statistical input data and probability parameters.

E.III. Gas recovery factor from undersaturated oil fields

Figure 3 shows the best fitted probability distributions for the gas recovery factor from the observations of the undersaturated oil fields:

- Gas recovery factor combined for dry and wet tree (Beta General).
- Dry tree recovery factor (Triangular).
- Wet tree recovery factor (Triangular).

Table 4 Shows test the hypothesis that $\mu_{\text{dry tree}}$- $\mu_{\text{wet tree}}$ = 0 vs. $\mu_{\text{dry tree}}$- $\mu_{\text{wet tree}} \neq 0$ with μ calculated from the data sets. Table 5 summarizes the statistical input data and probabilities parameters for each set of data.

E. IV. Oil recovery factor from undersaturated oil fields

Figure 4 shows the best fitted probability distributions for the oil recovery factor from the observations of the undersaturated oil fields:

- Oil recovery factor combined for dry and wet tree (Extreme value).
- Oil recovery factor for dry tree (Extreme value).
- Oil recovery factor wet tree (Logistic).

Table 6 Shows test the hypothesis that $\mu_{\text{dry tree}}$- $\mu_{\text{wet tree}}$ = 0 vs. $\mu_{\text{dry tree}}$- $\mu_{\text{wet tree}}$ ≠ 0 with μ calculated from the data sets. Table 7 summarizes the statistical input data and probabilities parameters for each set of data.

E.V. Gas recovery factor from saturated oil fields

Figure 5 shows the best fitted probability distributions for the gas recovery factor from the observations of the saturated oil fields:

- Gas recovery factor combined for dry and wet tree (Extreme value).
- Gas recovery factor for dry tree (Normal).
- Gas recovery factor for wet tree (Normal).

Table 8 Shows test the hypothesis that $\mu_{\text{dry tree}}$- $\mu_{\text{wet tree}}$ = 0 vs. $\mu_{\text{dry tree}}$- $\mu_{\text{wet tree}}$ ≠ 0 with μ calculated from the data sets. Table 9 summarizes the statistical input data and probabilities parameters for each set of data.

E. VI. Oil recovery factor from saturated oil fields

Figure 6 shows the best fitted probability distributions for the oil recovery factor from the observations of the saturated oil fields:

- Oil recovery factor combined for dry and wet tree (Normal).
- Dry tree recovery factor (Triangular).
- Wet tree recovery factor (Exponencial).

Table 10 Shows test the hypothesis that $\mu_{\text{dry tree}}$- $\mu_{\text{wet tree}}$ = 0 vs. $\mu_{\text{dry tree}}$- $\mu_{\text{wet tree}}$ ≠ 0 with μ calculated from the data sets. Table 11 summarizes the statistical input data and probabilities parameters for each set of data.

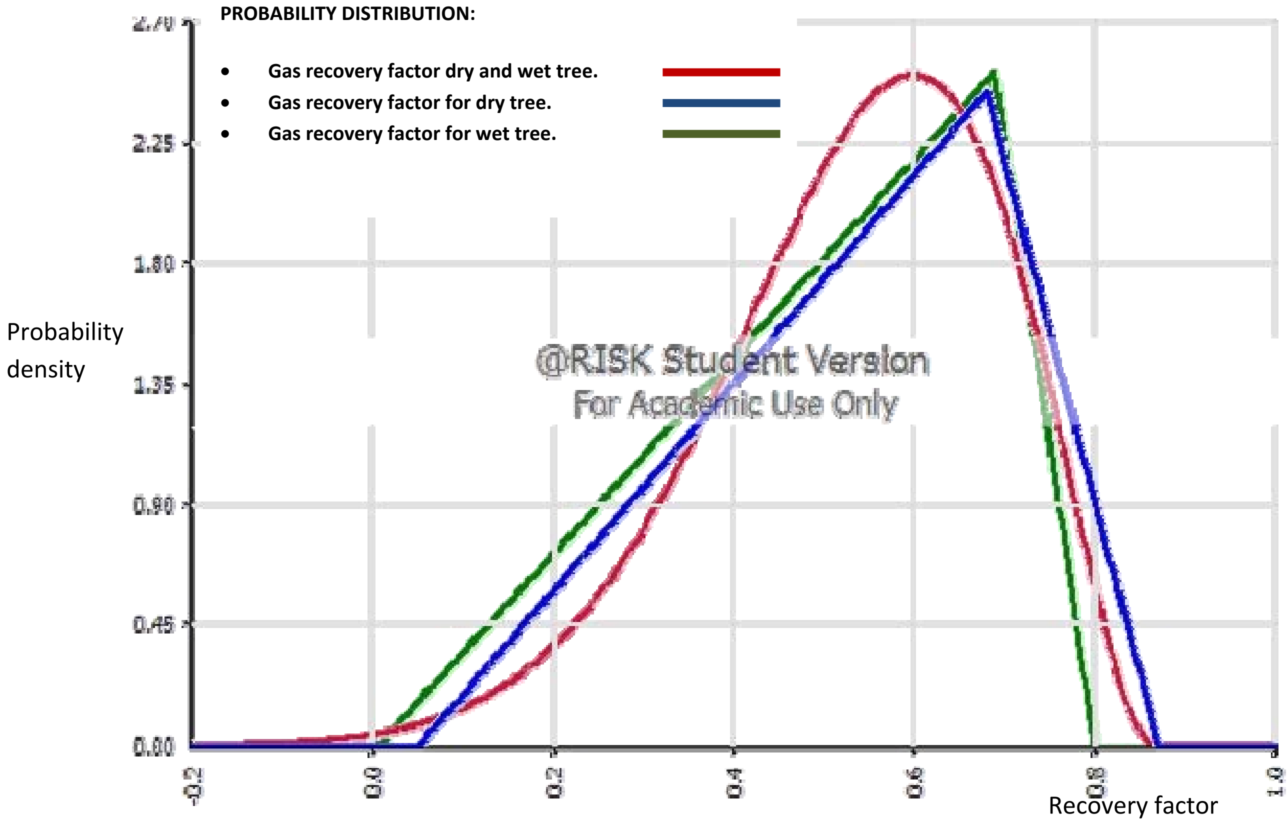


Figure 1 Best fitted probability distributions for the observations of gas recovery factor for combined dry and wet tree, gas recovery factor for dry tree and gas recovery factor for wet tree in the non associate gas fields in deep water of the Gulf of Mexico.

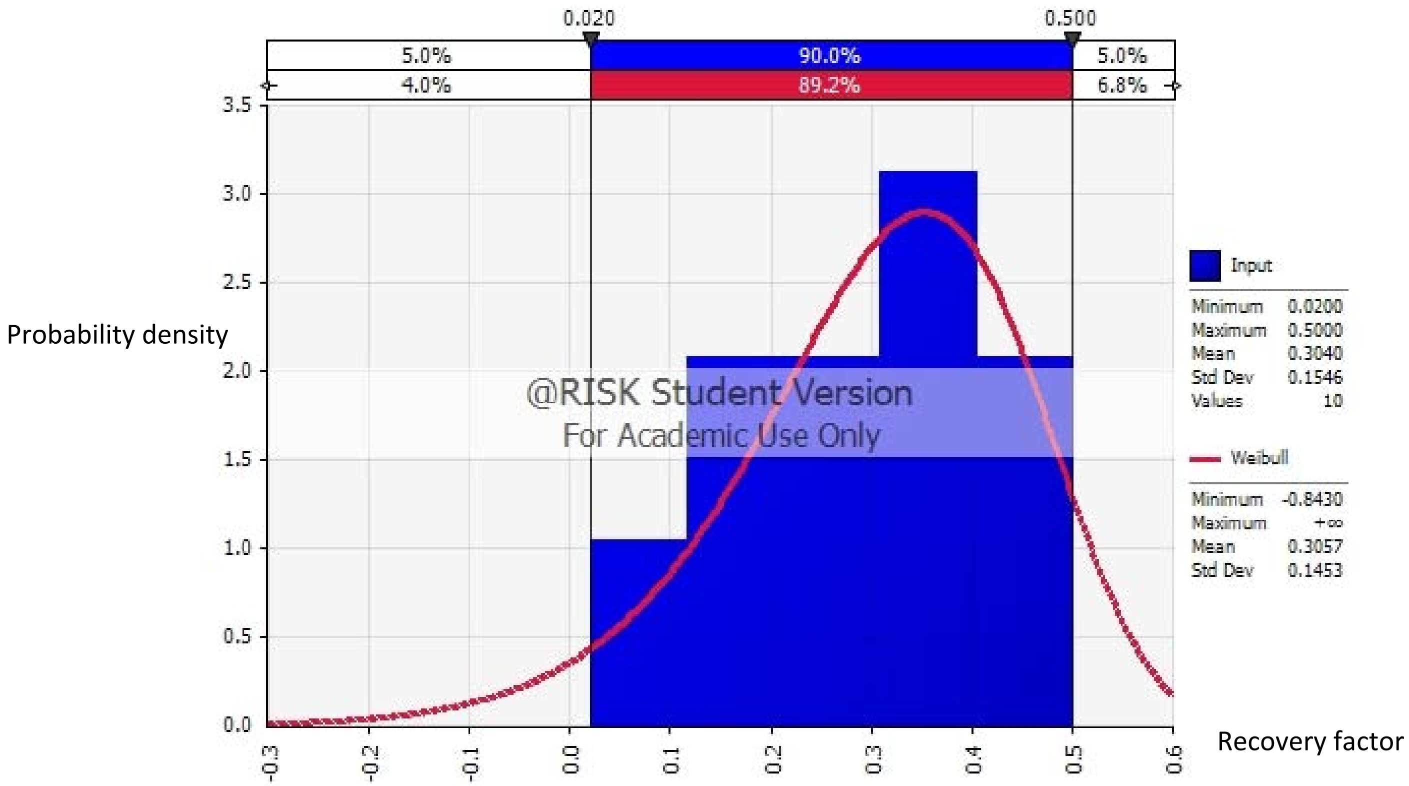


Figure 2 Best fitted probability distribution for the observations of oil recovery factor for dry and wet tree for the non associate gas fields in deep water of the Gulf of Mexico.

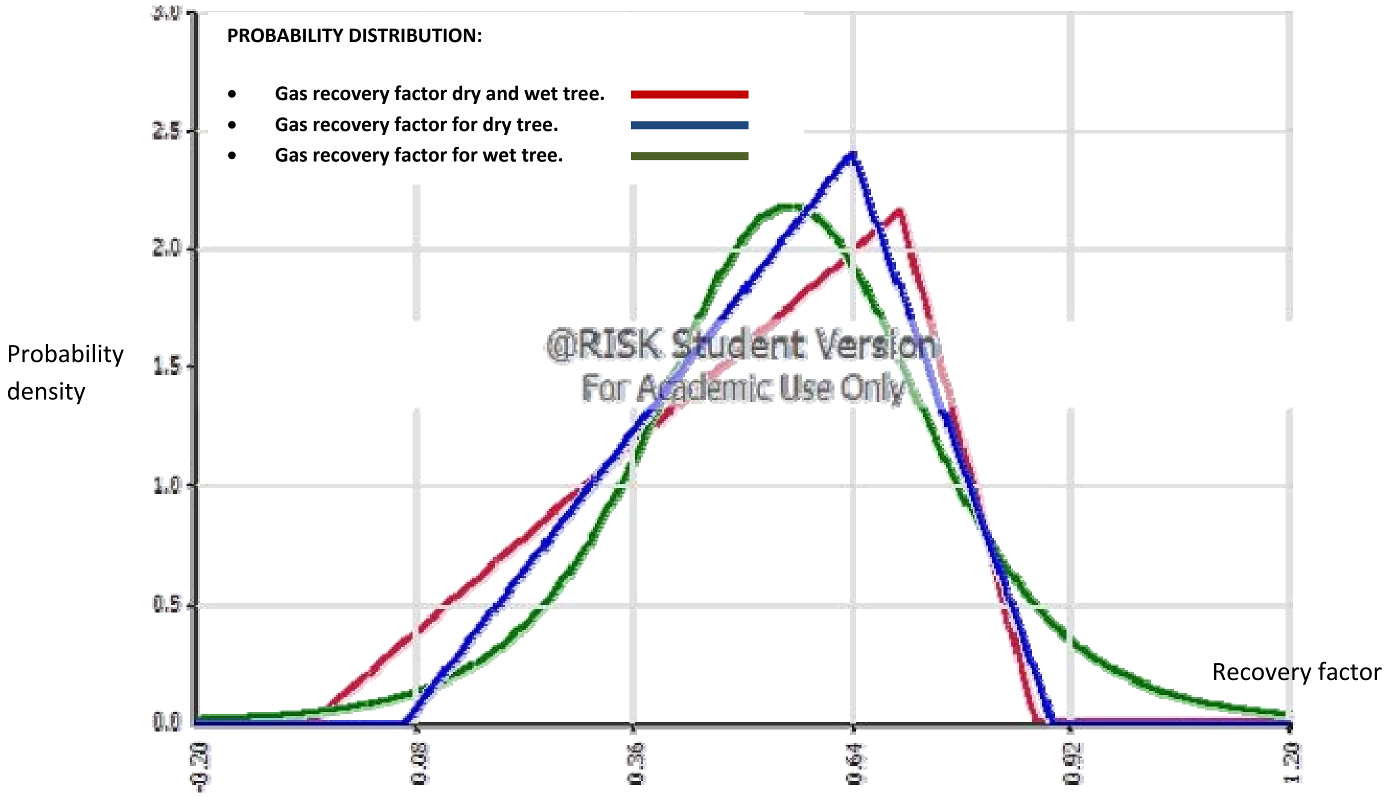


Figure 3 Best fitted probability distributions for the observations of gas recovery factor for combined dry and wet tree, gas recovery factor for dry tree and gas recovery factor for wet tree in the undersaturated oil fields in deep water of the Gulf of Mexico.

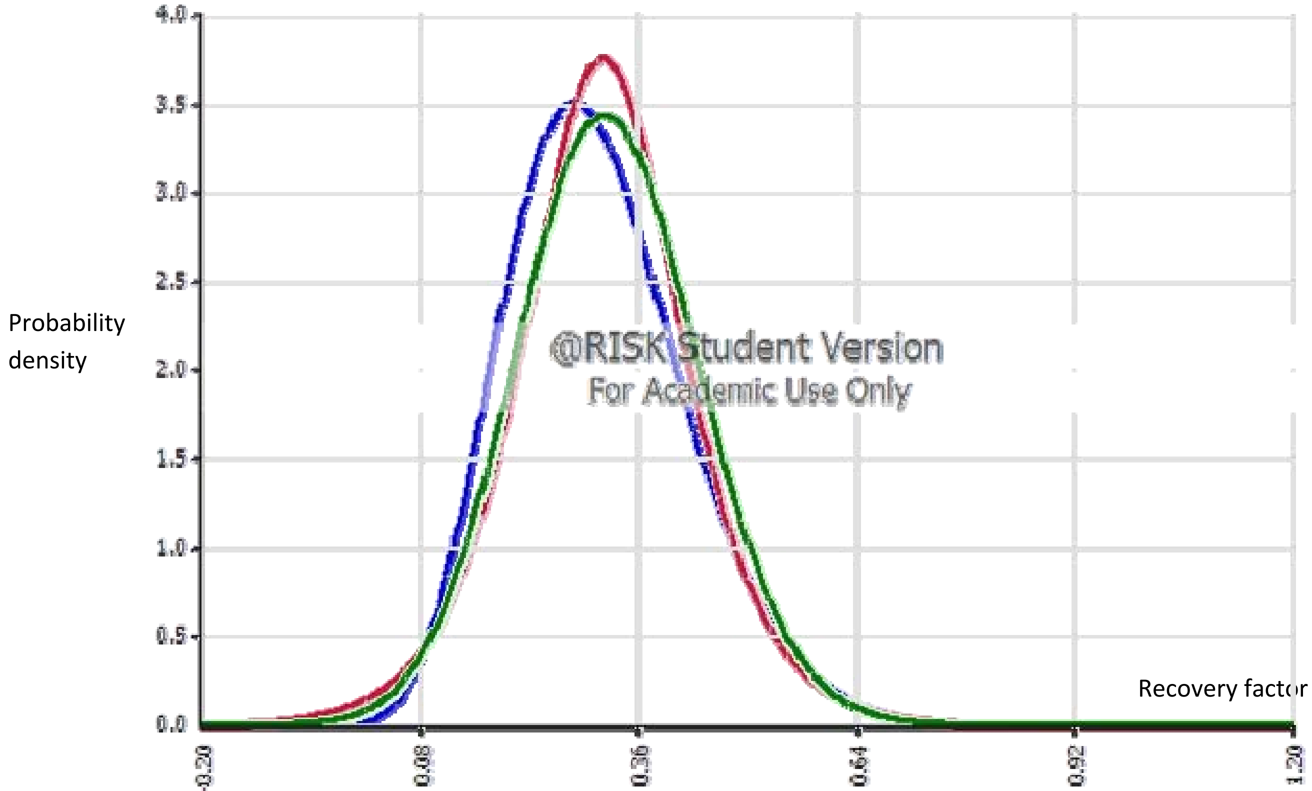


Figure 4 Best fitted probability distributions for the observations of oil recovery factor for combined dry and wet tree, oil recovery factor for dry tree and oil recovery factor for wet tree in the undersaturated oil fields in deep water of the Gulf of Mexico.

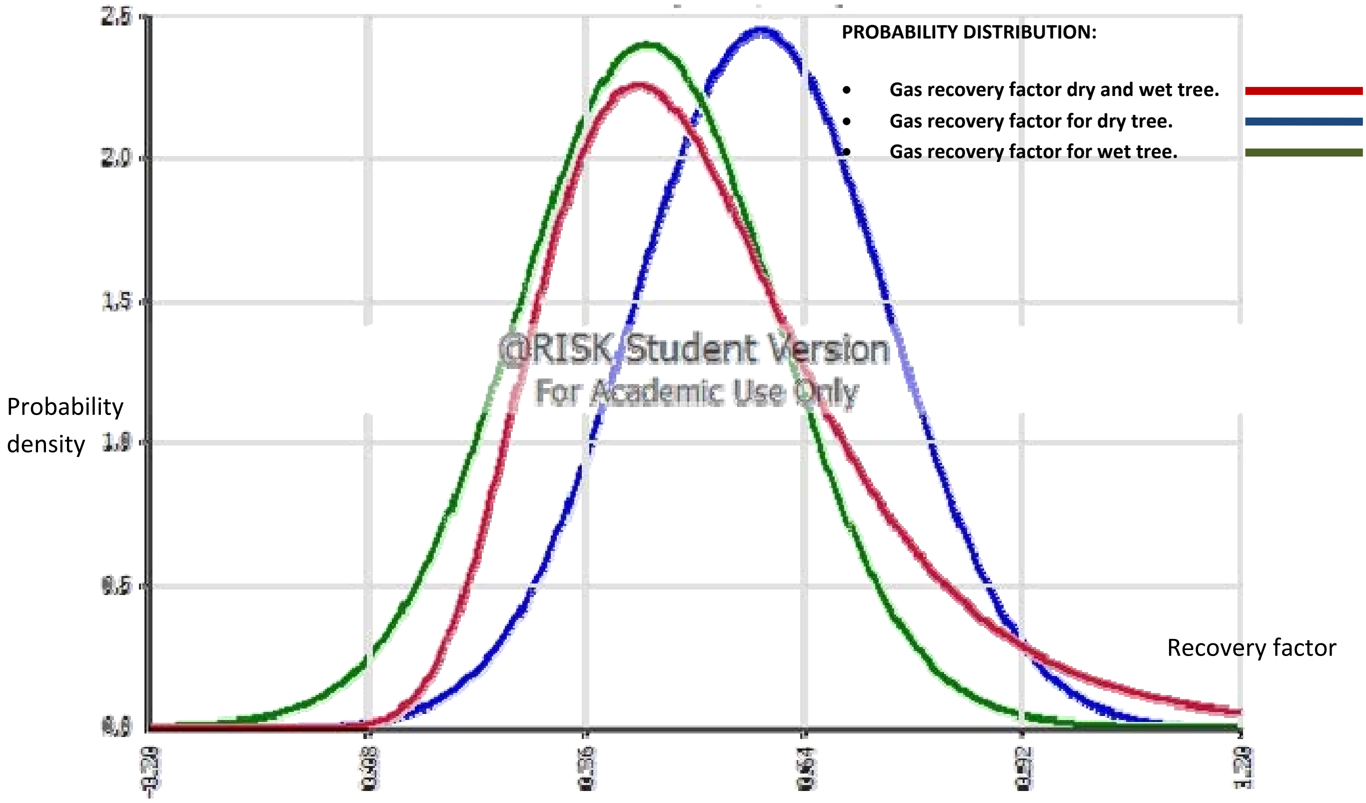


Figure 5 Best fitted probability distributions for the observations of gas recovery factor for combined dry and wet tree, gas recovery factor for dry tree and gas recovery factor for wet tree in the saturated oil fields in deep water of the Gulf of Mexico.

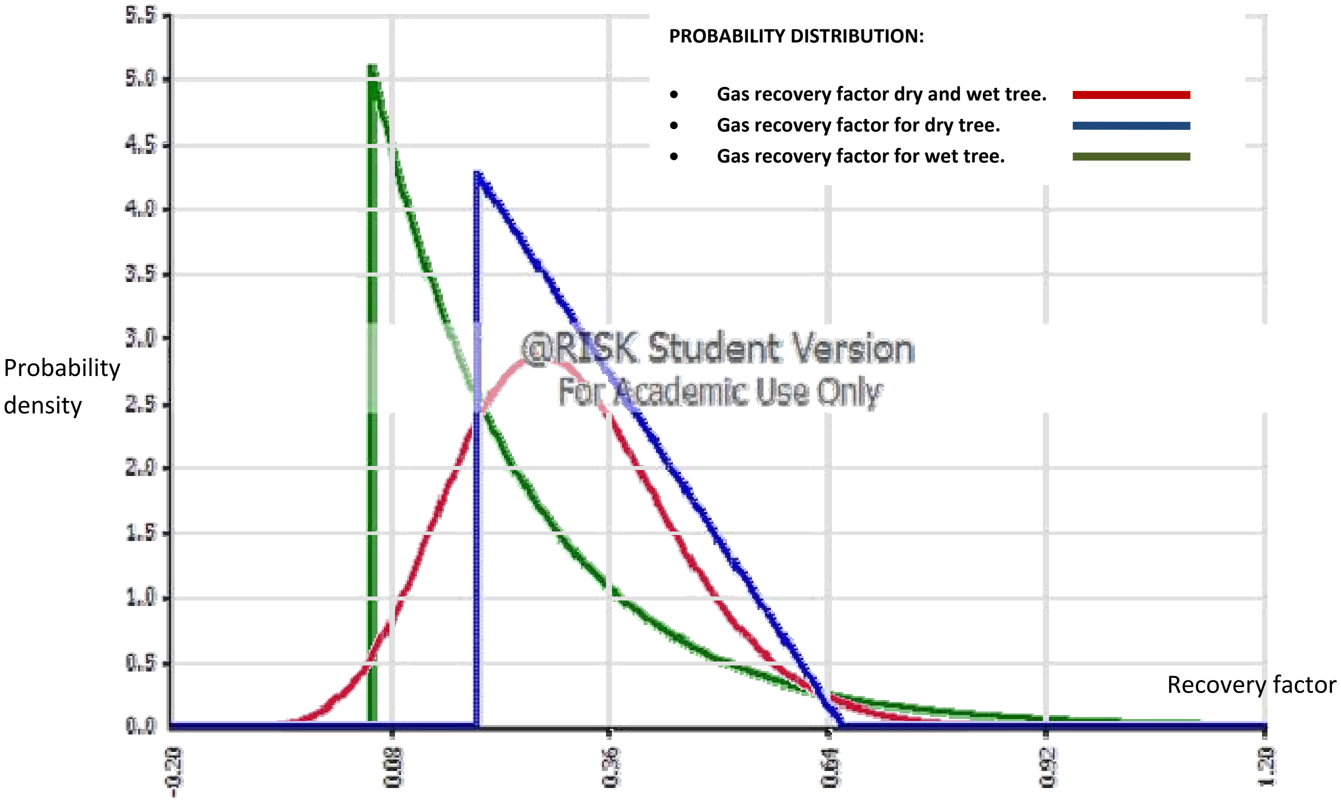


Figure 6 Best fitted probability distributions for the observations of oil recovery factor for combined dry and wet tree, oil recovery factor for dry tree and oil recovery factor for wet tree in the saturated oil fields in deep water of the Gulf of Mexico.

	GRF from dry tree	GRF from wet tree
Sample Summaries	Data Set #1	Data Set #2
Sample Size	36	167
Sample Mean	0.5272	0.5347
Sample Std Dev	0.1772	0.1678
	Equal	Unequal
Hypothesis Test (Difference of Means)	Variances	Variances
Hypothesized Mean Difference	0	0
Alternative Hypothesis	<> 0	<> 0
Sample Mean Difference	-0.0075	-0.0075
Standard Error of Difference	0.031142934	0.032258826
Degrees of Freedom	201	49
t-Test Statistic	-0.2411	-0.2328
p-Value	0.8097	0.8169
Null Hypoth. at 10% Significance	Don't Reject	Don't Reject
Null Hypoth. at 5% Significance	Don't Reject	Don't Reject
Null Hypoth. at 1% Significance	Don't Reject	Don't Reject
Equality of Variances Test		
Ratio of Sample Variances	1.1147	
p-Value	0.6357	

Table 1 Hypothesis test μ dry tree- μ wet tree = 0 vs. μ dry tree- μ wet tree ≠ 0 with μ calculated from the data sets regarding gas recovery factor in non associate gas fields.

	Gas recovery factor combined for dry and wet tree (Beta General).		Dry tree recovery factor (Triangular).		Wet tree recovery factor (Triangular).	
	Input	BetaGeneral	Input	Triangular	Input	Triangular
Function		0.531260598		0.534037667		0.4989306
Minimum	0.03	-0.5399	0.13	0.0507	0.03	0.00547
Maximum	0.85	0.8682	0.85	0.8714	0.79	0.8013
Mean	0.5334	0.5313	0.5272	0.534	0.5347	0.4989
Mode	0.2400 [est]	0.5981	0.6800 [est]	0.68	0.4500 [est]	0.69
Median	0.59	0.5505	0.585	0.5589	0.59	0.5274
Std. Deviation	0.1691	0.1607	0.1772	0.1753	0.1678	0.1759
Skewness	-1.0633	-0.6102	-0.6703	-0.4419	-1.1652	-0.5235
Kurtosis	3.6053	3.148	2.6811	2.4	3.8879	2.4
Percentil						
5%	0.18	0.2365	0.17	0.2114	0.18	0.1705
10%	0.27	0.3107	0.24	0.278	0.27	0.2389
15%	0.35	0.3598	0.35	0.329	0.38	0.2913
20%	0.4	0.398	0.36	0.3721	0.44	0.3356
25%	0.45	0.4301	0.39	0.41	0.47	0.3745
30%	0.48	0.4582	0.45	0.4443	0.5	0.4097
35%	0.5	0.4837	0.47	0.4759	0.51	0.4421
40%	0.52	0.5072	0.5	0.5052	0.53	0.4723
45%	0.56	0.5293	0.57	0.5328	0.56	0.5006
50%	0.59	0.5505	0.58	0.5589	0.59	0.5274
55%	0.6	0.571	0.6	0.5837	0.6	0.5529
60%	0.61	0.5912	0.61	0.6074	0.6	0.5772
65%	0.63	0.6112	0.65	0.6301	0.63	0.6005
70%	0.65	0.6314	0.66	0.652	0.64	0.623
75%	0.66	0.6522	0.67	0.6731	0.65	0.6447
80%	0.67	0.6741	0.68	0.6942	0.67	0.6656
85%	0.69	0.6978	0.69	0.7179	0.69	0.686
90%	0.7	0.725	0.7	0.7461	0.7	0.7072
95%	0.71	0.7598	0.7	0.7828	0.72	0.7348
Chi-Sq Statistic		52.5911		11.0556		34.7844
P-Value		0		0.0867		0.0009

Table 2 Statistical input data summary and probabilities parameters for best fitted probability distributions for the observations of gas recovery factor for combined dry and wet tree, gas recovery factor for dry tree and gas recovery factor for wet tree in the non associate gas fields in deep water of the Gulf of Mexico.

	Oil recovery factor combined for dry and wet tree (Extreme value).	
	Input	Weibull
Function		0.30572107
Minimum	0.02	-0.8429
Maximum	0.5	+Infinity
Mean	0.304	0.3058
Mode	0.3920 [est]	0.3531
Median	0.33	0.3214
Std. Deviation	0.1546	0.1454
Skewness	-0.4394	-0.6142
Kurtosis	2.4569	3.5118

Percentil		
5%	0.02	0.0417
10%	0.02	0.1115
15%	0.16	0.1562
20%	0.16	0.1902
25%	0.2	0.2182
30%	0.22	0.2426
35%	0.22	0.2644
40%	0.22	0.2845
45%	0.28	0.3034
50%	0.28	0.3214
55%	0.38	0.3389
60%	0.39	0.3562
65%	0.39	0.3735
70%	0.4	0.3912
75%	0.4	0.4097
80%	0.4	0.4296
85%	0.49	0.4519
90%	0.49	0.4786
95%	0.5	0.5158
Chi-Sq Statistic		0
P-Value		1

Table 3 Statistical input data summary and probability parameters for best fitted probability distribution for the observations of oil recovery factor for combined dry and wet tree in the non associate gas fields in deep water of the Gulf of Mexico.

	Dry tree gas recovery factor from undersaturated oil fields	Wet tree gas recovery factor from undersaturated oil fields
Sample Summaries	Data Set #7	Data Set #8
Sample Size	17	10
Sample Mean	0.5382	0.5100
Sample Std Dev	0.1950	0.2364
	Equal	Unequal
Hypothesis Test (Difference of Means)	Variances	Variances
Hypothesized Mean Difference	0	0
Alternative Hypothesis	<> 0	<> 0
Sample Mean Difference	0.0282	0.0282
Standard Error of Difference	0.084037065	0.088467858
Degrees of Freedom	25	16
t-Test Statistic	0.3360	0.3192
p-Value	0.7397	0.7537
Null Hypoth. at 10% Significance	Don't Reject	Don't Reject
Null Hypoth. at 5% Significance	Don't Reject	Don't Reject
Null Hypoth. at 1% Significance	Don't Reject	Don't Reject
Equality of Variances Test		
Ratio of Sample Variances	0.6806	
p-Value	0.4809	

Table 4 Hypothesis test μ dry tree- μ wet tree = 0 vs. μ dry tree- μ wet tree ≠ 0 with μ calculated from the data set, regarding gas recovery factor in undersaturated oil fields.

	Gas recovery factor combined for dry and wet tree (Triangular).		Dry tree recovery factor (Triangular).		Wet tree recovery factor (Logistic).	
	Input	Triang	Input	Triang	Input	Logistic
Function		0.506848		0.534870333		0.55868
Minimum	0.02	-0.0528	0.18	0.0665	0.02	-Infinity
Maximum	0.84	0.8734	0.84	0.8981	0.7	+Infinity
Mean	0.5278	0.5068	0.5382	0.5349	0.51	0.5587
Mode	0.7000 [est]	0.7	0.6400 [est]	0.64	0.5470 [est]	0.5587
Median	0.59	0.5376	0.59	0.5548	0.595	0.5587
Std. Deviation	0.2072	0.201	0.195	0.1738	0.2364	0.208
Skewness	-1.0303	-0.4878	-0.5642	-0.3409	-1.6178	0
Kurtosis	3.3295	2.4	2.4705	2.4	4.3673	4.2
Percentil						
5%	0.13	0.1339	0.18	0.221	0.02	0.2211
10%	0.18	0.2112	0.2	0.2849	0.02	0.3067
15%	0.27	0.2706	0.27	0.334	0.13	0.3598
20%	0.35	0.3206	0.35	0.3754	0.13	0.3997
25%	0.41	0.3647	0.41	0.4118	0.55	0.4327
30%	0.54	0.4045	0.5	0.4448	0.56	0.4615
35%	0.55	0.4412	0.5	0.4751	0.56	0.4877
40%	0.56	0.4753	0.54	0.5033	0.56	0.5122
45%	0.59	0.5073	0.57	0.5298	0.59	0.5357
50%	0.59	0.5376	0.59	0.5548	0.59	0.5587
55%	0.6	0.5664	0.6	0.5787	0.6	0.5817
60%	0.6	0.594	0.63	0.6014	0.6	0.6052
65%	0.63	0.6204	0.64	0.6233	0.6	0.6297
70%	0.64	0.6458	0.64	0.6443	0.65	0.6558
75%	0.65	0.6703	0.65	0.6664	0.65	0.6847
80%	0.7	0.694	0.7	0.6909	0.65	0.7176
85%	0.7	0.7182	0.7	0.7187	0.7	0.7576
90%	0.7	0.7466	0.78	0.7516	0.7	0.8106
95%	0.78	0.7838	0.84	0.7945	0.7	0.8963
Chi-Sq Statistic		3.1852		0.1176		1.6
P-Value		0.5273		0.9429		0.2059

Table 5 Statistical input data summary and probabilities parameters for best fitted probability distributions for the observations of gas recovery factor for combined dry and wet tree, gas recovery factor for dry tree and gas recovery factor for wet tree in the undersaturated oil fields in deep water of the Gulf of Mexico.

	Wet tree oil recovery factor from undersaturated oil fields	Dry tree oil recovery factor from undersaturated oil fields
Sample Summaries	**Data Set #10**	**Data Set #9**
Sample Size	268	175
Sample Mean	0.3207	0.3083
Sample Std Dev	0.1166	0.1170
	Equal	**Unequal**
Hypothesis Test (Difference of Means)	**Variances**	**Variances**
Hypothesized Mean Difference	0	0
Alternative Hypothesis	<> 0	<> 0
Sample Mean Difference	0.0125	0.0125
Standard Error of Difference	0.011344373	0.011353325
Degrees of Freedom	441	371
t-Test Statistic	1.0984	1.0975
p-Value	0.2726	0.2731
Null Hypoth. at 10% Significance	Don't Reject	Don't Reject
Null Hypoth. at 5% Significance	Don't Reject	Don't Reject
Null Hypoth. at 1% Significance	Don't Reject	Don't Reject
Equality of Variances Test		
Ratio of Sample Variances	0.9925	
p-Value	0.9489	

Table 6 Hypothesis test μ dry tree- μ wet tree = 0 vs. μ dry tree- μ wet tree ≠ 0 with μ calculated from the data set regarding oil recovery factor in undersaturated oil fields.

	Oil recovery factor combined for dry and wet tree (Logistic).		Dry tree recovery factor (Gamma).		Wet tree recovery factor (Log Normal).	
	Input	Logistic	Input	Gamma	Input	Lognorm
Function		0.313101		0.30828268		0.3207
Minimum	0.01	-Infinity	0.05	-0.1525	0.01	-3.7891
Maximum	0.65	+Infinity	0.65	+Infinity	0.63	+Infinity
Mean	0.3158	0.3131	0.3083	0.3083	0.3207	0.3207
Mode	0.1200 [est]	0.3131	0.2000 [est]	0.2786	0.1500 [est]	0.3158
Median	0.3	0.3131	0.29	0.2984	0.32	0.3191
Std. Deviation	0.1168	0.1206	0.117	0.117	0.1166	0.1163
Skewness	0.2214	0	0.4196	0.5077	0.0949	0.0849
Kurtosis	3.0192	4.2	2.8385	3.3867	3.2166	3.0128
Percentil						
5%	0.14	0.1174	0.14	0.1342	0.14	0.1323
10%	0.17	0.1671	0.17	0.1662	0.17	0.1728
15%	0.2	0.1978	0.2	0.1891	0.2	0.2004
20%	0.21	0.221	0.21	0.2081	0.23	0.2224
25%	0.23	0.2401	0.22	0.2249	0.24	0.2414
30%	0.25	0.2568	0.23	0.2405	0.26	0.2586
35%	0.27	0.272	0.25	0.2554	0.29	0.2745
40%	0.29	0.2862	0.27	0.2698	0.29	0.2898
45%	0.3	0.2998	0.28	0.2841	0.3	0.3045
50%	0.3	0.3131	0.29	0.2984	0.32	0.3191
55%	0.32	0.3264	0.3	0.3131	0.34	0.3337
60%	0.35	0.3401	0.31	0.3283	0.35	0.3487
65%	0.36	0.3542	0.35	0.3444	0.36	0.3641
70%	0.38	0.3694	0.37	0.3617	0.38	0.3805
75%	0.39	0.3861	0.39	0.3809	0.39	0.3983
80%	0.41	0.4052	0.42	0.4028	0.41	0.4181
85%	0.43	0.4284	0.44	0.429	0.43	0.4414
90%	0.46	0.4591	0.46	0.4631	0.47	0.4708
95%	0.52	0.5088	0.52	0.5161	0.51	0.5148
Chi-Sq Statistic		49.7652		20.12		27.0896
P-Value		0.0002		0.0923		0.0405

Table 7 Statistical input data summary and probabilities parameters for best fitted probability distributions for the observations of oil recovery factor for combined dry and wet tree, oil recovery factor for dry tree and oil recovery factor for wet tree in the undersaturated oil fields in deep water of the Gulf of Mexico.

	Dry tree gas recovery factor from saturated oil fields	Wet tree gas recovery factor from saturated oil fields
Sample Summaries	Data Set #3	Data Set #4
Sample Size	14	13
Sample Mean	0.5850	0.4385
Sample Std Dev	0.1629	0.1663
	Equal	Unequal
Hypothesis Test (Difference of Means)	Variances	Variances
Hypothesized Mean Difference	0	0
Alternative Hypothesis	<> 0	<> 0
Sample Mean Difference	0.1465	0.1465
Standard Error of Difference	0.063388249	0.063438446
Degrees of Freedom	25	24
t-Test Statistic	2.3118	2.3099
p-Value	0.0293	0.0298
Null Hypoth. at 10% Significance	Reject	Reject
Null Hypoth. at 5% Significance	Reject	Reject
Null Hypoth. at 1% Significance	Don't Reject	Don't Reject
Equality of Variances Test		
Ratio of Sample Variances	0.9597	
p-Value	0.9372	

Table 8 Hypothesis test μ dry tree- μ wet tree = 0 vs. μ dry tree- μ wet tree ≠ 0 with μ calculated from the data sets, regarding gas recovery factor in saturated oil fields.

	Gas recovery factor combined for dry and wet tree (Extreme Value).		Dry tree recovery factor (Normal).		Wet tree recovery factor (Normal).	
	Input	ExtValue	Input	Normal	Input	Normal
Function		0.520737369		0.585		0.43846
Minimum	0.18	-Infinity	0.29	-Infinity	0.18	-Infinity
Maximum	0.79	+Infinity	0.79	+Infinity	0.7	+Infinity
Mean	0.5144	0.5207	0.585	0.585	0.4385	0.4385
Mode	0.7000 [est]	0.4265	0.6533 [est]	0.585	0.3600 [est]	0.4385
Median	0.51	0.4863	0.625	0.585	0.4	0.4385
Std. Deviation	0.1778	0.2093	0.1629	0.1629	0.1663	0.1663
Skewness	-0.1469	1.1395	-0.7303	0	0.4009	0
Kurtosis	1.7693	5.4	2.5221	3	2.3126	3
Percentil						
5%	0.25	0.2475	0.29	0.317	0.18	0.1649
10%	0.29	0.2904	0.31	0.3762	0.25	0.2253
15%	0.31	0.322	0.37	0.4161	0.25	0.2661
20%	0.36	0.3489	0.37	0.4479	0.3	0.2985
25%	0.36	0.3732	0.51	0.4751	0.36	0.3263
30%	0.37	0.3962	0.55	0.4996	0.36	0.3512
35%	0.4	0.4186	0.55	0.5222	0.36	0.3744
40%	0.47	0.4408	0.59	0.5437	0.36	0.3963
45%	0.49	0.4633	0.61	0.5645	0.36	0.4176
50%	0.51	0.4863	0.61	0.585	0.4	0.4385
55%	0.55	0.5105	0.64	0.6055	0.47	0.4594
60%	0.61	0.5362	0.65	0.6263	0.47	0.4806
65%	0.64	0.564	0.67	0.6478	0.47	0.5026
70%	0.65	0.5948	0.67	0.6704	0.49	0.5257
75%	0.67	0.6299	0.7	0.6949	0.49	0.5506
80%	0.7	0.6713	0.73	0.7221	0.66	0.5784
85%	0.7	0.7231	0.73	0.7539	0.7	0.6108
90%	0.73	0.7938	0.78	0.7938	0.7	0.6516
95%	0.78	0.9113	0.79	0.853	0.7	0.712
Chi-Sq Statistic		0.963		0.1429		1.0769
P-Value		0.9154		0.9311		0.5836

Table 9 Statistical input data summary and probabilities parameters for best fitted probability distributions for the observations of gas recovery factor for combined dry and wet tree, gas recovery factor for dry tree and gas recovery factor for wet tree in the saturated oil fields in deep water of the Gulf of Mexico.

	Dry tree oil recovery factor from saturated oil fields	Wet tree oil recovery factor from saturated oil fields
Sample Summaries	Data Set #9	Data Set #10
Sample Size	14	13
Sample Mean	0.3429	0.2662
Sample Std Dev	0.1205	0.1605
	Unequal	Equal
Hypothesis Test (Difference of Means)	Variances	Variances
Hypothesized Mean Difference	0	0
Alternative Hypothesis	<> 0	<> 0
Sample Mean Difference	-0.0767	-0.0767
Standard Error of Difference	0.05495976	0.054371983
Degrees of Freedom	22	25
t-Test Statistic	-1.3956	-1.4107
p-Value	0.1768	0.1707
Null Hypoth. at 10% Significance	Don't Reject	Don't Reject
Null Hypoth. at 5% Significance	Don't Reject	Don't Reject
Null Hypoth. at 1% Significance	Don't Reject	Don't Reject
Equality of Variances Test		
Ratio of Sample Variances		1.7740
p-Value		0.3186

Table 10 Hypothesis test μ dry tree- μ wet tree = 0 vs. μ dry tree- μ wet tree ≠ 0 with μ calculated from the data set, regarding oil recovery factor in saturated oil fields.

	Oil recovery factor combined for dry and wet tree (Normal).		Dry tree recovery factor (Triangular).		Wet tree recovery factor (Exponential).	
	Input	Normal	Input	Triang	Input	Expon
Function		0.30593		0.345956667		0.251061
Minimum	0.07	-Infinity	0.19	0.19	0.07	0.0549
Maximum	0.6	+Infinity	0.6	0.6579	0.56	+Infinity
Mean	0.3059	0.3059	0.3429	0.346	0.2662	0.2511
Mode	0.2500 [est]	0.3059	0.2033 [est]	0.19	0.0967 [est]	0.0549
Median	0.29	0.3059	0.335	0.327	0.25	0.1909
Std. Deviation	0.1438	0.1438	0.1205	0.1103	0.1605	0.1962
Skewness	0.1881	0	0.5715	0.5657	0.4382	2
Kurtosis	2.2206	3	2.7491	2.4	1.8772	9
Percentil						
5%	0.11	0.0693	0.19	0.2018	0.07	0.065
10%	0.11	0.1216	0.21	0.214	0.11	0.0756
15%	0.15	0.1569	0.21	0.2265	0.11	0.0868
20%	0.17	0.1849	0.21	0.2394	0.11	0.0987
25%	0.19	0.2089	0.25	0.2527	0.11	0.1113
30%	0.21	0.2305	0.25	0.2664	0.11	0.1249
35%	0.25	0.2505	0.25	0.2807	0.15	0.1394
40%	0.25	0.2695	0.29	0.2955	0.17	0.1551
45%	0.29	0.2879	0.29	0.3109	0.17	0.1722
50%	0.29	0.3059	0.29	0.327	0.25	0.1909
55%	0.3	0.324	0.38	0.344	0.3	0.2115
60%	0.38	0.3424	0.39	0.362	0.3	0.2346
65%	0.39	0.3613	0.4	0.3811	0.35	0.2608
70%	0.4	0.3813	0.4	0.4016	0.4	0.2911
75%	0.41	0.4029	0.41	0.4239	0.4	0.3268
80%	0.41	0.427	0.46	0.4486	0.41	0.3706
85%	0.46	0.455	0.46	0.4767	0.47	0.427
90%	0.47	0.4902	0.47	0.5099	0.47	0.5066
95%	0.56	0.5425	0.6	0.5532	0.56	0.6425
Chi-Sq Statistic		1.7037		1		1.0769
P-Value		0.79		0.6065		0.5836

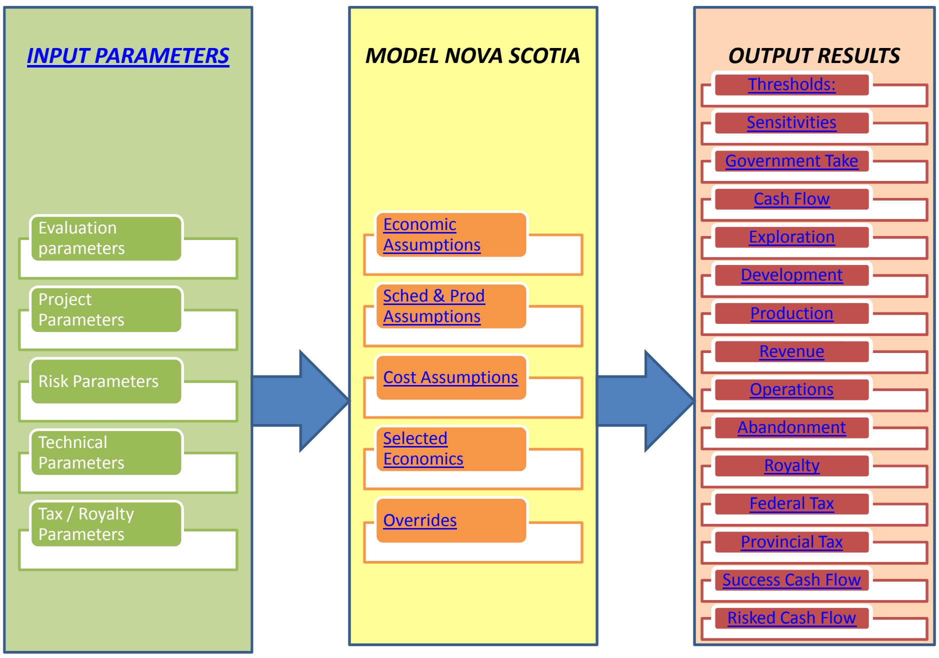
Table 11 Statistical input data summary and probabilities parameters for best fitted probability distributions for the observations of oil recovery factor for combined dry and wet tree, oil recovery factor for dry tree and oil recovery factor for wet tree in the saturated oil fields in deep water of the Gulf of Mexico.

Annex F: Nova Scotia Model Description

Reverse modelling of the Excel file

Reference: Nova Scotia, Department of Energy "Oil and Gas Exploration Economic Model", *Province of Nova Scotia, Canada, 2008. Available at internet* *http://www.gov.ns.ca/energy/oil-gas/offshore/economic-scoping-tool/default.asp* *Page last updated 2009-10-28.*

1



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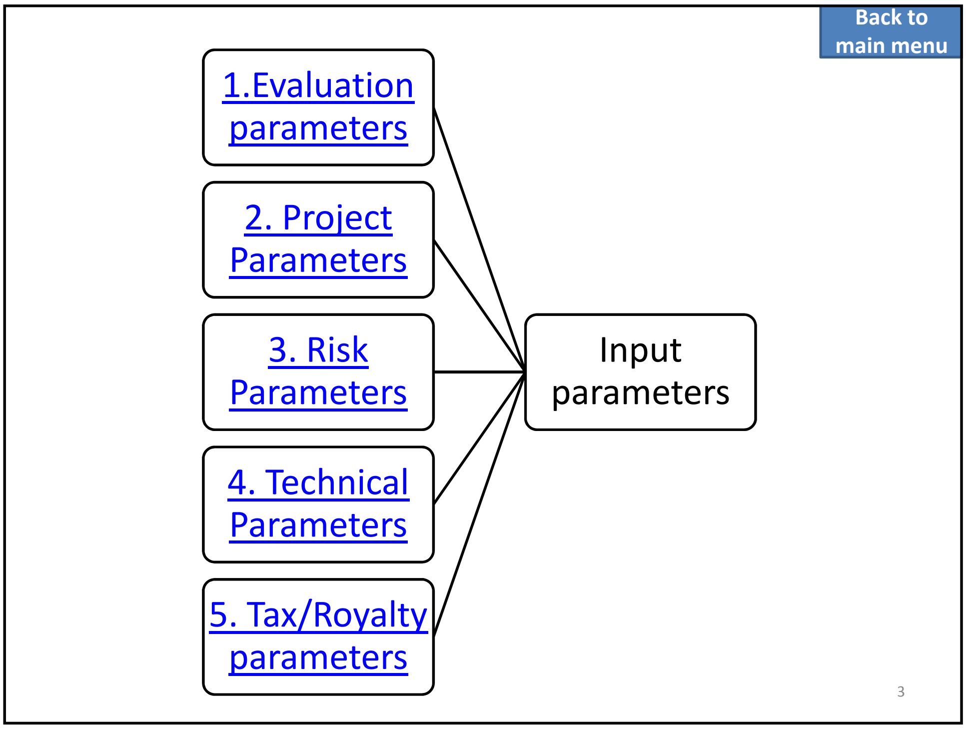
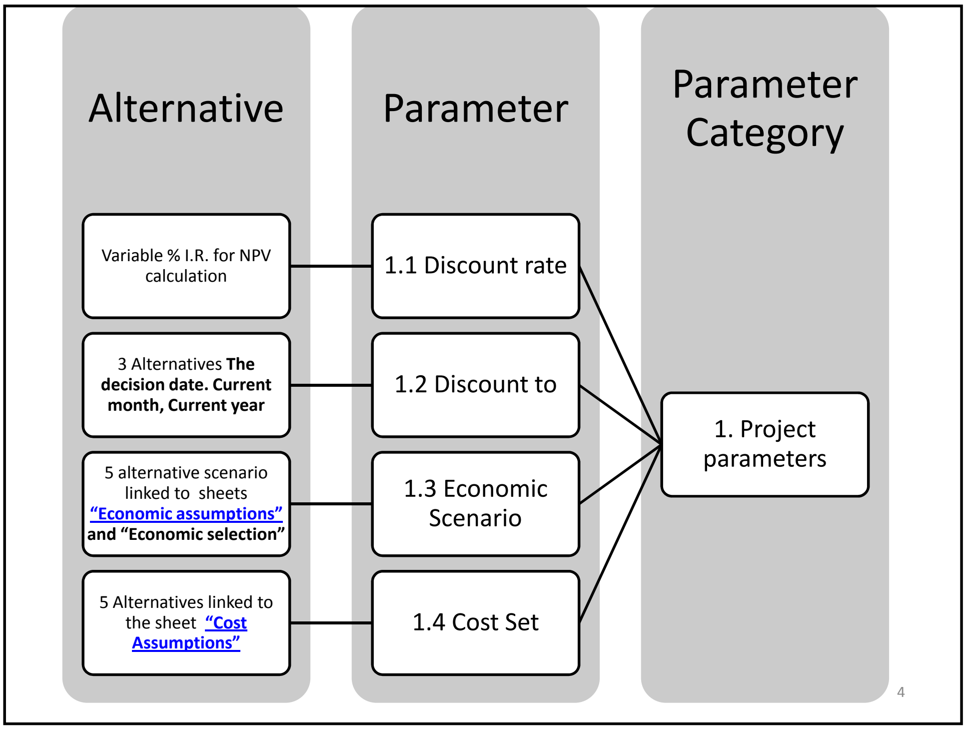
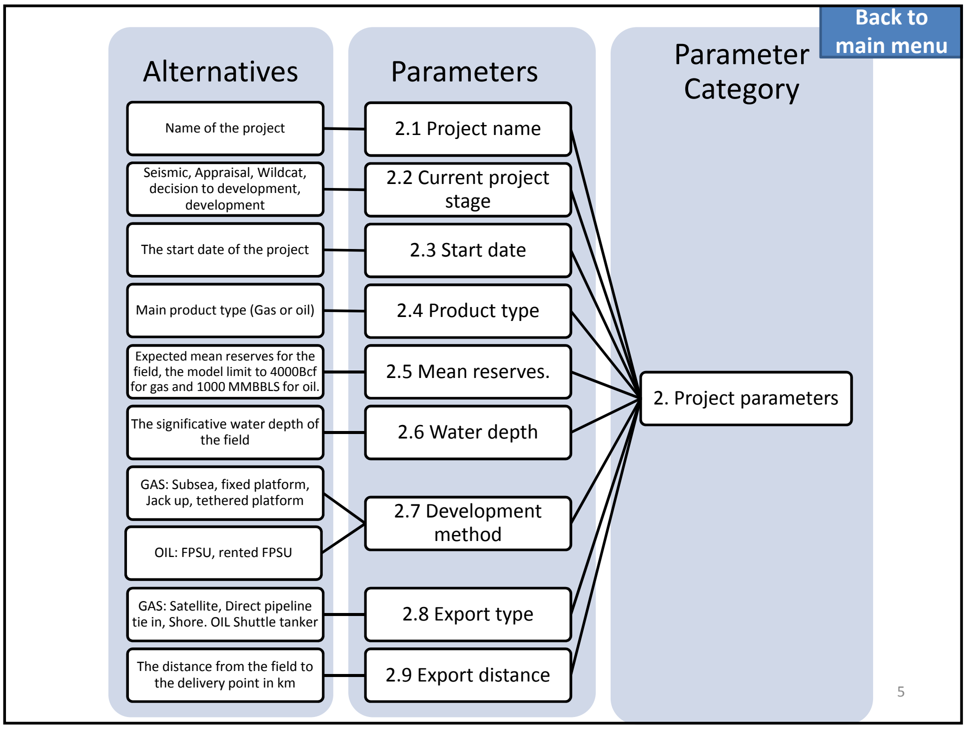
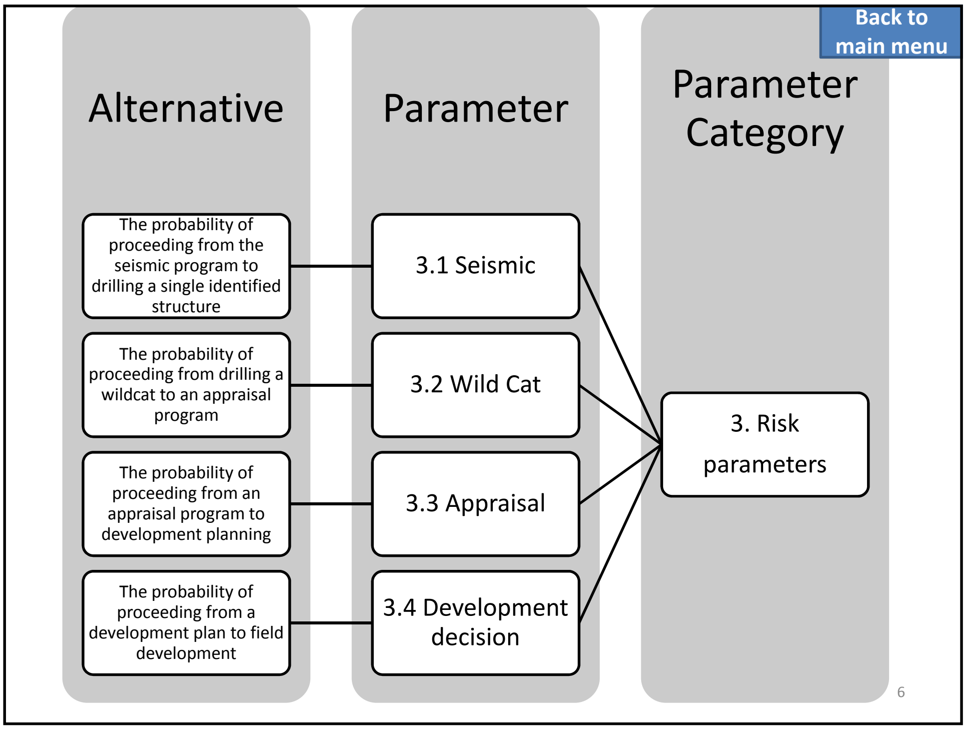


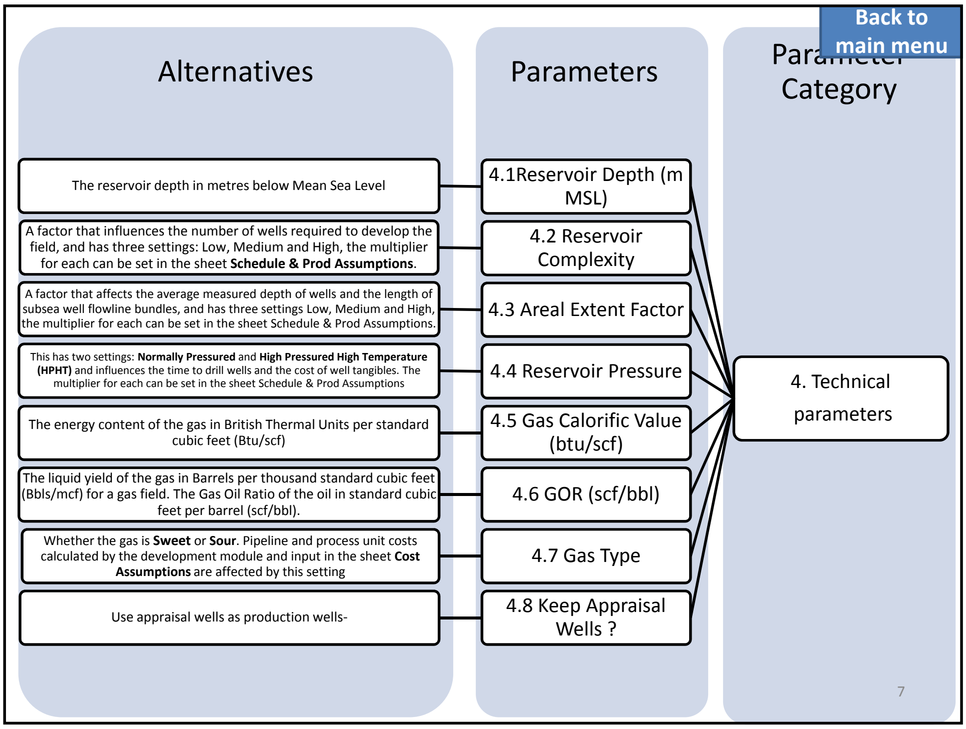
Back to main menu
1.Evaluation parameters
2. Project Parameters
3. Risk Parameters
4. Technical Parameters
5. Tax/Royalty parameters
Input parameters
3

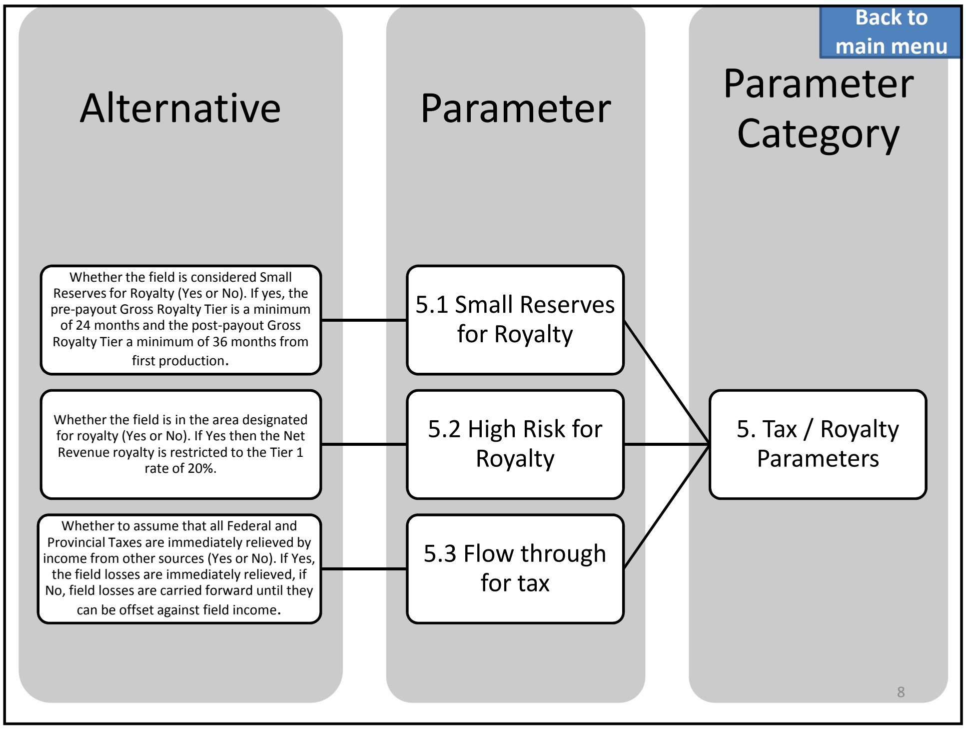


Alternative
Parameter
Parameter Category
Variable % I.R. for NPV calculation
1.1 Discount rate
3 Alternatives The decision date. Current month, Current year
1.2 Discount to
5 alternative scenario linked to sheets "Economic assumptions" and "Economic selection"
1.3 Economic Scenario
5 Alternatives linked to the sheet "Cost Assumptions"
1.4 Cost Set
1. Project parameters
4


Back to main menu
Alternatives
Parameters
Parameter Category
Name of the project
2.1 Project name
Seismic, Appraisal, Wildcat, decision to development, development
2.2 Current project stage
The start date of the project
2.3 Start date
Main product type (Gas or oil)
2.4 Product type
Expected mean reserves for the field, the model limit to 4000Bcf for gas and 1000 MMBBLS for oil.
2.5 Mean reserves.
The significative water depth of the field
2.6 Water depth
GAS: Subsea, fixed platform, Jack up, tethered platform
OIL: FPSU, rented FPSU
2.7 Development method
GAS: Satellite, Direct pipeline tie in, Shore. OIL Shuttle tanker
2.8 Export type
The distance from the field to the delivery point in km
2.9 Export distance
2. Project parameters
5


Back to main menu
Alternative
Parameter
Parameter Category
The probability of proceeding from the seismic program to drilling a single identified structure
3.1 Seismic
The probability of proceeding from drilling a wildcat to an appraisal program
3.2 Wild Cat
The probability of proceeding from an appraisal program to development planning
3.3 Appraisal
The probability of proceeding from a development plan to field development
3.4 Development decision
3. Risk parameters
6


Back to main menu
Alternatives
Parameters
Parameter Category
The reservoir depth in metres below Mean Sea Level
4.1Reservoir Depth (m MSL)
A factor that influences the number of wells required to develop the field, and has three settings: Low, Medium and High, the multiplier for each can be set in the sheet Schedule & Prod Assumptions.
4.2 Reservoir Complexity
A factor that affects the average measured depth of wells and the length of subsea well flowline bundles, and has three settings Low, Medium and High, the multiplier for each can be set in the sheet Schedule & Prod Assumptions.
4.3 Areal Extent Factor
This has two settings: Normally Pressured and High Pressured High Temperature (HPHT) and influences the time to drill wells and the cost of well tangibles. The multiplier for each can be set in the sheet Schedule & Prod Assumptions
4.4 Reservoir Pressure
The energy content of the gas in British Thermal Units per standard cubic feet (Btu/scf)
4.5 Gas Calorific Value (btu/scf)
The liquid yield of the gas in Barrels per thousand standard cubic feet (Bbls/mcf) for a gas field. The Gas Oil Ratio of the oil in standard cubic feet per barrel (scf/bbl).
4.6 GOR (scf/bbl)
Whether the gas is Sweet or Sour. Pipeline and process unit costs calculated by the development module and input in the sheet Cost Assumptions are affected by this setting
4.7 Gas Type
Use appraisal wells as production wells-
4.8 Keep Appraisal Wells ?
4. Technical parameters
7


Back to main menu
Alternative
Parameter
Parameter Category
Whether the field is considered Small Reserves for Royalty (Yes or No). If yes, the pre-payout Gross Royalty Tier is a minimum of 24 months and the post-payout Gross Royalty Tier a minimum of 36 months from first production.
5.1 Small Reserves for Royalty
Whether the field is in the area designated for royalty (Yes or No). If Yes then the Net Revenue royalty is restricted to the Tier 1 rate of 20%.
5.2 High Risk for Royalty
Whether to assume that all Federal and Provincial Taxes are immediately relieved by income from other sources (Yes or No). If Yes, the field losses are immediately relieved, if No, field losses are carried forward until they can be offset against field income.
5.3 Flow through for tax
5. Tax / Royalty Parameters
8

Back to main menu

Economic Assumptions

This sheet shows the assumptions for prices, exchange rates, inflation and interest rates, and allows the user to set-up five Scenarios by inputting data in the cell with the blue text and white and/or blue background, which can be selected in the Sheet **Inputs.**

Economic Scenarios

Scenario	**Scenario 1**						
Name	NYMEX	12/26/08					
Year	Market Condensate US$/BBL	Nymex Oil Price US$/BBL	Henry Hub Gas Price US$/MMBTU	Exchange Rate US$/$Cdn	Cost Inflation	Long-term Bond Rate	Short-term Interest Rate
Netback Differential	3.50	3.00	0.70				
2007	83.60	76.00	8.00	1.00	3.0%	5.0%	4.0%
2008	78.38	71.25	8.05	1.00	3.0%	5.0%	2.0%
2009	50.27	45.70	4.00	1.00	3.0%	3.0%	2.0%

9

Back to main menu

Sched & Prod Assumptions 1/4

This sheet contains the assumptions relating to production, number of wells and assumptions used in the model. The user is able to override the cells with blue text and white background

General Production and Schedule Assumptions

Profile Parameters

GAS

Reserves bcf	Plateau Rate %	Reserves on Plateau	Decline Factor
0	19.0%	50.0%	25.0%
200	17.0%	50.0%	25.0%
500	15.0%	50.0%	25.0%
1000	15.0%	50.0%	25.0%
2000	15.0%	50.0%	25.0%
3000	15.0%	50.0%	25.0%
1000000000	15.0%	50.0%	25.0%

OIL

Reserves MMBBLS	Plateau Rate %	Reserves on Plateau	Decline Factor
0	19.0%	40.0%	20.0%
100	17.0%	40.0%	20.0%
200	15.0%	40.0%	20.0%
500	15.0%	40.0%	20.0%
700	15.0%	40.0%	20.0%
900	15.0%	40.0%	20.0%
1000000000	15.0%	40.0%	20.0%

BOE Factor (MSCF/BBL)	4.8

Energy Equivalence Factor (MSCF/BBL)	5.6	for Gas @ 1000BTU/SCF
Gas Field Shrinkage Fuel and Other	6.0%	
Oilfield Fuel Requirement	3.0%	

% wells at start up	Start-up	Plateau
Oil	50%	70%
Gas	70%	90%

10

Back to main menu

Sched & Prod Assumptions 2/4

This sheet contains the assumptions relating to production, number of wells and assumptions used in the model. The user is able to override the cells with blue text and white background

Well Productivity Parameters

GAS

Reserves	Bcf per well
0	100
250	120
500	130
1000	140
2000	140
3000	140
1000000	140

OIL (includes water injection / gas disposal)

Reserves	MMBBLs/well
0	10
100	12
200	14
500	14
700	14
900	14
1000000000	14

Number of Drilling Centres

Wells	Number
1	1
10	2
30	3
50	4
70	5
1000000	5

Back to main menu

Sched & Prod Assumptions ¾

This sheet contains the assumptions relating to production, number of wells and assumptions used in the model. The user is able to override the cells with blue text and white background

Aerial Extent Multiplier on Well Length

Aerial Extent	Multiplier
Low	1.1
Medium	1.3
High	1.6

Reservoir Complexity Multiplier on Number of Wells

Reservoir Complexity	Multiplier
Low	1
Medium	1.2
High	1.4

Resevoir Pressure Multiplier on Well Time

Reservoir Pressure Type	Multiplier
Normally Pressured	1
HPHT	1.5

Resevoir Pressure Multiplier on Well Tangibles

Reservoir Pressure Type	Multiplier
Normally Pressured	1
HPHT	1.3

Back to main menu

Sched & Prod Assumptions 4/4

Subsea Bundle Length (km)

Aerial Extent	Length
Low	4
Medium	6
High	8

Number of Appraisal Wells (Success Case)

GAS

Reserves	Number
0	1
200	2
500	3
1000	4
10000000000	

OIL

Reserves	Number
0	1
20	1
50	2
100	3
1000000000	

Construct & Installation times

	Onshore Fabrication			Offshore Installation		
	Fixed	Variable	per	Fixed	Variable	per
Jackup Construct	650			20		
Platform Construct	250	1	metre	30		
FPSU Construct	650			30		
Tethered Structure	650			50		
Subsea Manifold	180			20		
Topsides (fixed platform)	400	0.2	MMSCFD	60		
Topsides (mobile)	400	0.2	MMSCFD	0		
Subsea Flowlines	150	5	well		5	well
Export Pipeline	150	0.1	km	20	0.5	km
Buffer Time	20%					

13

Back to main menu

Cost Assumptions_P 1/6

This sheet shows the unit cost and unit time assumptions used in the model. The user can set up to five costs sets and select the one to use in the sheet **Inputs.** The user is able to input data in the cells with blue text and/or white background.

Name of the variable of the set	*Units*	*Associated value*	
Name:		Demonstration	
Estimate Date:	Units	1-Jan-09	
Deepwater Limit	meters	200	
		Shallow Water	Deep Water
Seismic & Fixed Times			
Seismic Program Time	days	90.0	90.0
Seismic Program Cost	K$	7,500.0	7,500.0
Seismic Processing Time	days	180.0	180.0
Seismic Processing Cost	K$	3,500.0	3,500.0
Processing to Wildcat Time	days	120.0	120.0
Wildcat Review Time	days	90.0	90.0
Widcat Review Cost	K$	500.0	500.0
Wildcat to Appraisal Time	days	120.0	120.0
Appraisal Review Time	days	30.0	30.0
Appraisal Review Cost	K$	350.0	350.0
Time Between Appraisal Wells	days	90.0	90.0
Appraisal to Preliminary Engineering	days	180.0	180.0
Prelim Eng & Regulatory Prep	days	300.0	300.0
Regulatory Approval	days	180.0	180.0
Rig Rate	$/day	250,000.0	450,000.0
Exploration / Appraisal Well Drilling			
Fixed Cost per well	K$	4,000.0	8,000.0
Fixed Cost per metre	$/metre	2,300.0	3,400.0
Variable Cost per day (non-rig)	$/day	180,000.0	230,000.0
Fixed days	days	4.0	10.0
Average metres / day	metre/day	60.0	50.0

14

Back to main menu

Cost Assumptions_P 2/6

Name of the variable of the set	Units	Associated value	
		Shallow Water	Deep Water
Development Well Drilling			
Fixed Cost per well	K$	3,000.0	6,000.0
Fixed Cost per metre	$/metre	2,300.0	3,200.0
Variable Cost per day (non-rig)	$/day	90,000.0	230,000.0
Fixed days	days	2.0	4.0
Average metres / day	metre/day	40.0	40.0
Well Completion			
Fixed Cost per well	K$	700.0	700.0
Fixed Cost per metre	$/metre	900.0	900.0
Variable Cost per day (non-rig)	$/day	50,000.0	80,000.0
Fixed days	days	2.0	3.0
Average metres / day	metre/day	600.0	600.0
Reenter & clean keeper	days	4.0	4.0
Renenter predrill	days	2.0	2.0
Preliminary Engineering			
Fixed Cost	K$	5,000.0	5,000.0
Variable Cost	$/mcf	3.0	3.0
Gas Facilities			
Fixed Platform Fixed Cost	K$	7,000.0	
Fixed Platform Cost / Metre Water	K$/metre	320.0	
Fixed Platform Topside Fixed Cost	K$	25,000.0	
Fixed Platform Variable Cost	K$/MMSCFD	850.0	
Production Jack-up Fixed Cost	K$	190,000.0	

15

Back to main menu

Cost Assumptions_P 3/6

Name of the variable of the set	Units	Associated value	
		Shallow Water	Deep Water
Production Jack-up Topside Fixed Cost	K$	5,000.0	
Jack-up Topside Variable Cost	K$/MMSCFD	600.0	
Tehtered Structure Fixed Cost	K$		300,000.0
Tethered Structure Cost /Metr e Water	K$/metre		5.0
Tethered Structure Topside Fixed Cost	K$		5,000.0
Tethered Structure Variable Cost	K$/MMSCFD		1,000.0
Additional Fixed Process Cost Sour Gas	K$	20,000.0	20,000.0
Additional Variable Process Cost Sour Gas	K$/MMSCFD	300.0	300.0
Subsea Well Surface Equipment	K$	2,000.0	5,000.0
Subsea Well Flowline Bundle	K$/Km	1,500.0	3,500.0
Subsea Manifold Fixed Cost	K$	9,000.0	12,000.0
Subsea Manifold Cost	K$/well	300.0	600.0
Oil Facilities			
FPSU Fixed Cost	K$	250,000.0	350,000.0
FPSU Platform Cost /MetreWater	K$/metre	5.0	5.0
FPSU Platform Topside Fixed Cost	K$	200,000.0	250,000.0
FPSU Platform Variable Cost	K$/MMBBL	1,200.0	1,200.0
Rented FPSU Fixed Cost	K$/day	170.0	200.0
Rented FPSU Variable Cost	K$/MMBBL/day	2.5	2.5
Production Jack-up Topside Fixed Cost	K$	5,000.0	
Jack-up Topside Variable Cost	K$/MMSCFD	600.0	
Tehtered Structure Fixed Cost	K$		300,000.0
Tethered Structure Cost /Metr e Water	K$/metre		5.0
Tethered Structure Topside Fixed Cost	K$		5,000.0
Tethered Structure Variable Cost	K$/MMSCFD		1,000.0

16

Cost Assumptions_P 4/6

Back to main menu

Name of the variable of the set	Units	Associated value	
		Shallow Water	Deep Water
Additional Fixed Process Cost Sour Gas	K$	20,000.0	20,000.0
Additional Variable Process Cost Sour Gas	K$/MMSCFD	300.0	300.0
Subsea Well Surface Equipment	K$	2,000.0	5,000.0
Subsea Well Flowline Bundle	K$/Km	1,500.0	3,500.0
Subsea Manifold Fixed Cost	K$	9,000.0	12,000.0
Subsea Manifold Cost	K$/well	300.0	600.0
Oil Facilities			
FPSU Fixed Cost	K$	250,000.0	350,000.0
FPSU Platform Cost /MetreWater	K$/metre	5.0	5.0
FPSU Platform Topside Fixed Cost	K$	200,000.0	250,000.0
FPSU Platform Variable Cost	K$/MMBBL	1,200.0	1,200.0
Rented FPSU Fixed Cost	K$/day	170.0	200.0
Rented FPSU Variable Cost	K$/MMBBL/day	2.5	2.5
Export			
Export to Shore Pipeline Fixed Cost	K$	10,000.0	20,000.0
Export to Shore Pipeline Variable Cost	K$/km	1,000.0	1,200.0
Satellite Pipeline Fixed Cost - Sweet	K$	12,000.0	15,000.0
Satellite Pipeline Variable Cost - Sweet	K$/km	1,200.0	1,500.0
Satellite Pipeline Fixed Cost - Sour	K$	14,000.0	17,500.0
Satellite Pipeline Variable Cost - Sour	K$/km	1,400.0	1,750.0
Subsea Export Bundle Fixed Cost - Sweet	K$	7,000.0	8,750.0
Subsea Export Bundle Variable Cost - Sweet	K$/km	2,500.0	3,125.0
Subsea Export Bundle Fixed Cost - Sour	K$	10,000.0	12,500.0
Subsea Export Bundle Variable Cost - Sour	K$/km	3,500.0	4,375.0
Engineering and Project Management	%	0.1	0.1
Facilities Contingency	%	0.2	0.2

17

Cost Assumptions_P 5/6

Back to main menu

Name of the variable of the set	Units	Associated value	
		Shallow Water	Deep Water
Abandonment Cost			
Fixed Platform Fixed	K$	3,000.0	
Fixed Platform per depth	K$/metre	30.0	
Jack-up Fixed Cost	K$	5,000.0	
Tethered Structure Fixed Cost	K$		5,000.0
FPSU Fixed Cost	K$		5,000.0
Subsea Manifold	K$	2,000.0	3,000.0
Cost per Surface Well	K$	2,000.0	2,000.0
Cost per Subsea Well & Flowline Bundle	K$	3,500.0	3,500.0
Export Pipeline variable cost	K$/km	100.0	100.0
Satellite Pipeline variable cost	K$/km	150.0	250.0
Operating Costs			
Platform & Jack-up Facilities			
Fixed Cost /Year			
Subsea	K$	2,000.0	2,000.0
basic process, water knock out	K$	7,000.0	7,000.0
full process, sweet	K$	19,000.0	19,000.0
full process, sour	K$	25,000.0	25,000.0
Fixed Cost /Year / Capacity			
Subsea	$/MMSCFD	200.0	200.0
basic process, water knock out	$/MMSCFD	280.0	280.0
full process, sweet	$/MMSCFD	370.0	370.0
full process, sour	$/MMSCFD	530.0	530.0
Variable Cost			
Subsea	$/MCF	0.1	0.1
basic process, water knock out	$/MCF	0.1	0.1
full process, sweet	$/MCF	0.2	0.2

18

Cost Assumptions_P 6/6

Back to main menu

Name of the variable of the set	*Units*	*Associated value*	
		Shallow Water	Deep Water
full process, sour	$/MCF	0.2	0.2
Oil Costs			
Fixed Cost/Year	K$	10,000.0	12,000.0
Fixed Cost /Year / Capacity Sweet	$/MBOPD	250.0	250.0
Fixed Cost /Year / Capacity Sour	$/MBOPD	300.0	300.0
Variable Cost Sweet	$/BBL	2.5	2.5
Variable Cost Sour	$/BBL	3.2	3.2
Transport & Process Tariff			
Direct Pipeline Tie-in	$/MCF	0.4	0.4
Satellite to Main Platform - Sweet	$/MCF	0.6	0.6
Satellite to Main Platform - Sour	$/MCF	0.8	0.8
Subsea Process & Transport – Sweet	$/MCF	1.0	1.0
Subsea Process & Transport – Sour	$/MCF	1.2	1.2
Shuttle Tankers	$/BBL	0.7	0.7
Pipelines			
Fixed Cost /Year	K$	2,000.0	2,000.0
Variable Cost	K$ / km	40.0	40.0
Wells			
Subsea Intervention Cost	K$	3,500.0	10,000.0
Surface Intervention Cost	K$	2,500.0	
Intervention Frequency / Well	Years	5	5
full process, sour	$/MCF	0.2	0.2
Oil Costs			
Fixed Cost/Year	K$	10,000.0	12,000.0
Fixed Cost /Year / Capacity Sweet	$/MBOPD	250.0	250.0

Selected Economics

Back to main menu

This sheet shows the selected prices, exchange rate and interest rates for the evaluation

Prospect X **Selected Economic Assumptions**

Scenario	1		NYMEX
Offset	0		

Estimate Year	2009

	1	2	3	4	5	6	7		
Year	Ring Fence Condensate US$/BBL	Ring Fence Oil US$/BBL	Ring Fence Gas Price US$/MMBTU	Exchange Rate US$/$Cdn	Cost Inflation	Long-term Bond Rate	Short-term Interest Rate	Inflation Index	Index
2010	65.07	58.97	6.50	1.000	3.00%	3.00%	2.00%	1.0300	4
2011	71.78	65.08	7.20	1.000	3.00%	4.00%	3.00%	1.0609	5
2012	75.38	68.34	7.40	1.000	3.00%	4.00%	3.00%	1.0927	6
2013	77.86	70.59	7.41	1.000	3.00%	4.00%	3.00%	1.1255	7
2014	80.16	72.68	7.45	1.000	3.00%	4.00%	3.00%	1.1593	8
2015	82.78	75.06	7.55	1.000	3.00%	4.00%	3.00%	1.1941	9
2016	84.58	76.69	7.67	1.000	3.00%	4.00%	3.00%	1.2299	10

Back to main menu

Overrides 1/2

This sheet allows the user to override the cost and production calculations in the standard modules. The user can elect to override for stages individually or for all stages by entering data in cells with a white background.

Prospect X

-

Overriden Cost and Production

All Cost in Today's Money Estimate Year: *2009*

Seismic Costs & Schedule	Model Calculated

Exoloration Times and Uninflated Costs

	Input Duration (days)	Input Lag to Next Activity (days)	Input Cost K$
Seismic			
Seismic Processing			

Wildcat Costs & Schedule	Model Calculated

	Input Duration (days)	Input Lag to Next Activity (days)	Input Cost K$
Wildcat			
Wildcat Review			

Appraisal Costs & Schedule	Model Calculated

	Input Duration (days)	Input Lag to Next Activity (days)	Input Cost K$
Appraisal Well 1			
Appraisal Well 2			
Appraisal Well 3			
Appraisal Well 4			
Appraisal Well 5			

Development Planning	Model Calculated		-
Preliminary Engineering Cost		K$	-
Days to Development Start		days	-
Development & Production	Model Calculated		-

Back to main menu

Overrides 2/2

Uninflated Capital Costs, Production and Operating Costs from Development Start (M$)

	Wells	Main Structure	Topsides	Subsea & Flowlines	Export Pipeline	Engineering & Proj Man	Contingency	Total Costs	Gas Production (BCF)	Oil (MMbbls)	Condensate (MMbbls)	Operating Cost
Total	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0
Year from Development Start												
1								0.0				
2								0.0				
.....								0.0				
40								0.0				

Abandonment Cost	Model Calculated

Abadonment Cost (M$)	

Historical Costs	Model Calculated

Seismic	
Wildcat	
Appraisal	
Development Planning	
Costs for Royalty	
CDE Opening Balance	
CEE Opening Balance	

22

Back to main menu

Output Results 1/4

Thresholds:
This sheet calculates the Threshold Reserves, Reservoir Depth and Economic Scenario at which the prospect is economic for differing Current Project Stages. The user can adjust the required ranges for each of Reserves, Reservoir Depth and Economics Scenario by inputting in cells with the blue text against a white background. Values with negative NPV (at the selected discount rate) are below the Threshold for proceeding are shown in Orange and those above the Threshold are shown in Green.

The example below shows that for the basic set of parameters and assuming a threshold discount rate of 15%, a mean reserve of 100 bcf is uneconomic at all Stages of exploration, from 150 to 250 bcf. It is economic to proceed with Development Planning and Development, but drilling a Wildcat or Appraising a discovery is uneconomic. From 300 to 700 bcf it is economic to appraise a discovery, and above 700bcf it is economic to drill a Wildcat. Within the range of reserves specified it is not economic to run an exploratory seismic program.

SensitivitiesThis sheet enables the user to specify a range (up and down) for a number of critical parameters and see the effect on the resultant NPV and other evaulation parameters. The user may adjust the senstivity ranges in the cells in the top left hand corner of the Sheet and see the affect on the results presented in the tornado charts.

Government Take This sheet displays the percentage royalty and tax takes for different economic and reserves cases.

23

Back to main menu

Output Results 2/4

Cash Flow This sheet shows the detailed cash flow and start dates for the success case for the current prospect under evaluation and also shows the derivation of the risked evaluation.

Exploration This sheet is the exploration module. It calculates the number of wells, the timing and the costs of the exploration program.
he cell with the blue text and white and/or blue background, which can be selected in the Sheet **Inputs.**

Development This sheet is the development module. The start of development planning follows the end of exploration and the sheet calculates the number, type, timing and cost of development wells and development facilities.

Production This sheet is the production module. Production commences once the field facilities are commissioned and the initial production wells are completed. Dependent on the number of wells available at first production and the drilling program, the program calculates the number of days to plateau and the time on plateau, and thence the decline period. The parameters for plateau rate and decline rate may be adjusted in the sheet **Schedule & Prod Assumptions.**

24

Back to main menu

Output Results 3/4

Revenue This sheet calculates the gas and liquids revenue

Operations This sheet is the operations module and calculates the operating costs for the field life

Abandonment This sheet calculates the economic limit for the field and the abandonment cost. Production and operating costs are terminated at abandonment.

Royalty This sheet calculates the royalty for the success case. For prospects commencing after the initial seismic phase, historical costs are estimated, but can be overridden in Cell C101 of sheet **Overrides**. The royalty calculation estimates the month at which the change over between each royalty tier is made.

Federal Tax This sheet calculates the federal income tax payable for the field. As with royalty, the historical costs are estimated by the model but can be overridden by the user in cells C102 and C103 of sheet **Overrides.**

Provincial Tax This sheet calculates the provincial income tax payable for the field. As with royalty, the historical costs are estimated by the model but can be overridden by the user in cells C102 and C103 of sheet **Overrides.**

Back to main menu

Output Results 4/4

Success Cash Flow This sheet shows the success case cash flow for the prospect

Risked Cash Flow This sheet shows the risked cash flow for the field

Annex G: Design Basis for the Case Analysis

Mexico's deepwater areas.

Cantarell is a oil and gas field located in Mexico. Once considered the second largest of the world, it drop dramatically its production in 2007 after reach its peak of production in the earliest 2000's. With its fall the need of Exploratory works and field development increased considerably in basins that before were not considered to be commercially feasible.

PEMEX Exploración and Producción (PEP) is the only Operator allowed by the Mexican Laws to explode the hydrocarbon resources of Mexico. Carlos Morales, General Director of PEP in the Offshore Technology Conference (OTC) 2009 resumes on the deep water strategy of PEMEX (Morales, 2009):

Mexican petroleum basins

Six main geological basins are the current focus of our exploration efforts. "Deep water" is our new basin and is subject to a structured and strategic program to discover new reserves.

Basin	***Principal hydrocarbon***
Southeastern Basins	*Oil*
Tampico Misantla	*Oil*
Burgos	*Gas*
Veracruz	*Gas*
Sabinas	*Gas*
Mexican deep water	*Oil - Gas*

Table I: Hydrocarbon fluid characteristically found in the Mexican Basins

Figure I: Distribution map of the Basins in the Mexican territory.

New reserves distribution by basin.

At the present time, Southeastern Basins have contributed with the largest volumes of fresh reserves, located in shallow water, and reservoirs of Mesozoic age. This basin mainly produces heavy and light oil. However, the exploration wells in deep water of the Mexican side of the Gulf of Mexico are showing promising results.

Most of the reserves of crude oil, are concentrated in Cantarell, Ku-Maloob-Zaap (Southeastern Basins), Chicontepec, and Bermudez Complex (Tampico Misantla). Non associated gas is also present in Burgos, Veracruz, and Macuspana basins. Interestingly, a new non associated gas province prone has been discovered in deep water.

Estimation of prospective resources

Mexico's hydrocarbons potential has been calculated by PEMEX as 52.0 Billion barrels of oil equivalent (B.O.E.) Of that, 56% of the prospective resources are located in deep water of the Gulf of Mexico and 32% in the Southeastern of Mexico, where Pemex presently develops a large amount of its operations.

Basin	***2003***	***2004***	***2005***	***2006***	***2007***	***2008***	***Prospective Resources (Bboe)***	***As a % of Total Prospective Resources***
Mexican deep water	*0*	*32.6*	*0*	*349.3*	*138.9*	*0*	*29.5*	*56.7*
Southeastern	*380.6*	*632.1*	*778.1*	*487.6*	*865.2*	*1,372.90*	*16.7*	*32.1*
Tampico-Misantla	*91.4*	*105.5*	*29.6*	*0*	*0*	*0*	*3.1*	*6*
Burgos	*164.8*	*93*	*76.3*	*67.3*	*32.6*	*48.9*	*1.7*	*3.3*
Sabinas	*28.8*	*15.2*	*0*	*0*	*0*	*0*	*0.7*	*1.3*
Veracruz	*43.1*	*37.7*	*66.3*	*62*	*16.5*	*60.3*	*0.3*	*0.6*
Total	*708.7*	*916.1*	*950.3*	*966.2*	*1053.2*	*1482.1*	*52.0*	*100.0*

Table II: 3P Reserves discoveries in Millions of, prospective Resources in Billions of BOE.

In 2003-2005 the first comprehensive geological – geochemical modeling of the Gulf of Mexico was made. This modeling has allowed PEMEX to define and direct its exploratory strategy, classify exploratory leads by hydrocarbon type, and risk, and Model updating with drilled wells, and semiregional studies (See figure II).

Nine areas were defined as the most important for Mexican deep water, considering economical value, prospective resource size, hydrocarbon type, geological risk, proximity to production facilities, and environmental restrictions, as the most relevant criteria. See Figure III and table III.

Area	*Risk*	*Water depth (m)*
1. Perdido folded belt	*Low-Moderate*	*>2,000*
2. Oreos	*Moderate-High*	*800-2,000*
3. Nancan	*High*	*500-2,500*
4. Jaca-Patini	*Moderate-High*	*1000-1,500*
5. Nox-Hux	*Moderate*	*650-1,850*
6. Temoa	*High*	*850-1,950*
7. Han	*Moderate – High*	*450-2,250*
8. Holok	*Low-moderate (Western)*	*1,500-2,000*
	High (Eastern)	*600-1,100*
9. Lipax	*Moderate*	*950-2,000*

Table III: Mexican deep water areas after PEMEX.

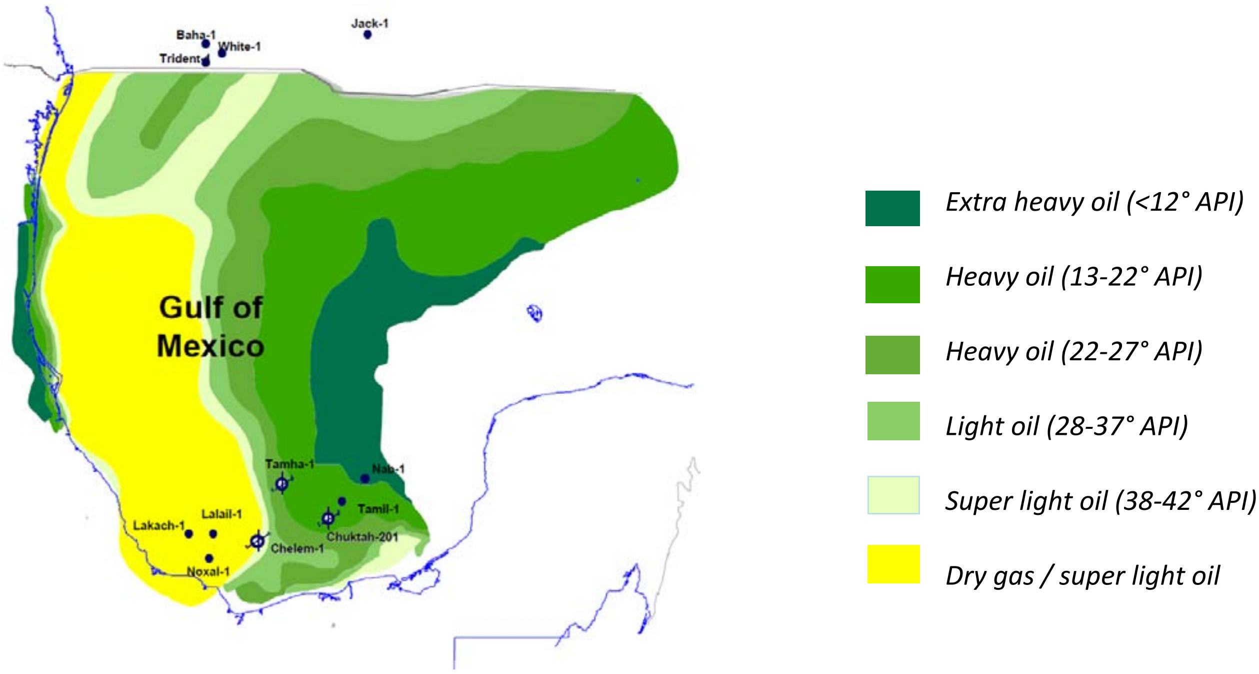


Figure II: Prospective hydrocarbon fluids in Mexican offshore areas

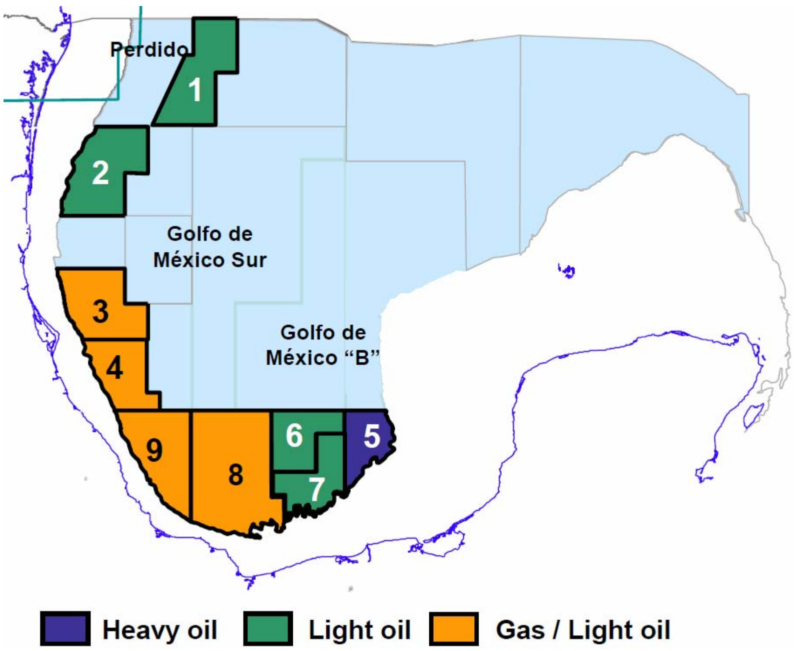


Figure III: Mexican deep water areas after PEMEX(See table III).

The integral business unit Holok-Temoa was created by PEP in 2007 to develop and manage the fields Lakach, Lalail and Noxal all of them with non associated gas reservoirs (i.e. dry gas reservoirs).

Below it is shown an extract from the published reserves in 2009, 2008 and 2007 for the Holok-Temoa Integral Business Unit (PEMEX, 2009, 2008 and 2007), amounts in red were obtained by direct interpolation of the published amounts.

Reserves by Field	Original in place volume			Hidrocarboons Reserves				Gas Reserves	
	Oil	Natural Gas	Crude Oil Equivalent	Oil	Condensate	Plant liquids	Dry Gas	Natural Gas	Dry Gas
	MMB	MMMCF	MMBOE	MMB	MMB	MMB	MMBOE	MMMCF	MMMCF
Proved	0	428.5	70.4	0	4.4	13.6	52.3	308.6	272.1
Lakach		428.50	70.4		4.4	13.6	52.3	308.5	272.1
Lalail									
Noxal									
Probable	0	910.4	130.1	0	6.8	20.4	102.9	606.9	535.2
Lakach		546.6	78.1		4.1	12.2	61.8	364.4	321.3
Lalail		363.9	52.0		2.7	8.2	41.1	242.6	213.9
Noxal									
2P	0	1,338.90	200.5	0	11.2	34	155.2	915.5	807.3
Lakach		975.1	148.5		8.5	25.8	114.1	672.9	593.4
Lalail		363.9	52.0		2.7	8.2	41.1	242.6	213.9
Noxal									
Possible	0	2,158.80	314.5	0	12	36.1	266.4	1,514.80	1,385.40
Lakach		757.6	106.6		3.0	8.9	94.8	628.90	581.1
Lalail		817.4	121.9		5.1	15.5	101.3	466.2	425.6
Noxal		583.6	85.9		3.9	11.7	70.3	420.2	379.1
Total (3P)	0	3,497.70	514.9	0	23.2	70.1	421.6	2,430.30	2,192.70
Lakach		1,732.70	255.1		11.5	34.7	208.9	1,301.80	1,174.5
Lalail		1,181.30	173.9		7.8	23.7	142.4	708.8	639.5
Noxal		583.60	85.9		3.9	11.7	70.3	420.2	379.1

Table IV. Reserves in charge of the Integral Unit Business Holok-Temoa.

1.0 Lakach Field

The field Lakach from where it is expected to get a gas production of 398 million of cubic feet per day (MMCFD) by the 2013 with a production expected to reach a maximum of 439 MMCFD in 2017. (Secretaría de Energía, 2008). Production test running there have returned from 25 to 30 mmcfd in a vertical well, the estimates published by PEMEX have been set the proved, probable and possible reserves of non associated natural gas in 308.5, 364.4 and 1,301.80 Billions of Cubic feet (BCF) respectively.

Reserves Lakach Field	Original in place volumen			Hidrocarboons Reserves				Gas Reserves	
	Oil	Natural Gas	Crude Oil Equivalent	Oil	Condensate	Plant liquids	Dry Gas	Natural Gas	Dry Gas
	MMB	MMMCF	MMBOE	MMB	MMB	MMB	MMBOE	MMMCF	MMMCF
Proven	0	428.5	70.4	0	4.4	13.6	52.3	308.6	272.1
Probables		546.6	78.1		4.1	12.2	61.8	364.4	321.3
2P		975.1	148.5		8.5	25.8	114.1	672.9	593.4
Possible		757.6	106.6		3.0	8.9	94.8	628.90	581.1
Total (3P)		1,732.70	255.1		11.5	34.7	208.9	1,301.80	1,174.5

Table 1.1 Reserves considered in the Lakach development project.

Below it is shown a probabilistic model of the reserves according to table 1.1. It was obtained by running a Monte Carlo simulation in the program @RISK for Excel 5.5, Industrial Version, Palisade 2009, with 10,000 iterations; results obtained are shown in the next page.

The model was designed to fulfill the requirements described in the document *"Guidelines for the Evaluation of Petroleum Reserves and Resources"* Pp. 45 (SPE, 2001).

> *Reserves are typically grouped in two fundamental ways:*
>
> *• As Proved (1P) Reserve entities alone, from which Proved Reserves are calculated.*
> *• On a cumulative basis, from which the Proved plus Probable (2P) or the Proved plus Probable plus Possible (3P) reserve is calculated…*
> *The definitions require that, when probabilistic methods are being used, there shall be at least a 90% probability (P90) that the quantity actually recovered will equal or exceed the estimate quoted. The definitions go on to state that there shall be at least a 50% probability that the quantities actually recovered will exceed the sum of the 2P reserves. Likewise, there shall be at least a 10% probability that the 3P reserves will be equalled or exceeded.*

Reserves Classification located in the Lakach Field from table 1.1	Base case MMBOE	Minimum	Most Likely	Maximum	Minimum MMBOE	Most Likely MMBOE	Maximum MMBOE
Proven	70.4	0%	90%	360%	0	63	253
Probable	78.1	0%	50%	238%	0	39	186
Posible	106.6	0%	25%	100%	0	27	107
Total	255						

Table 1.2 Parameters of the Monte Carlo model for simulation purposes.

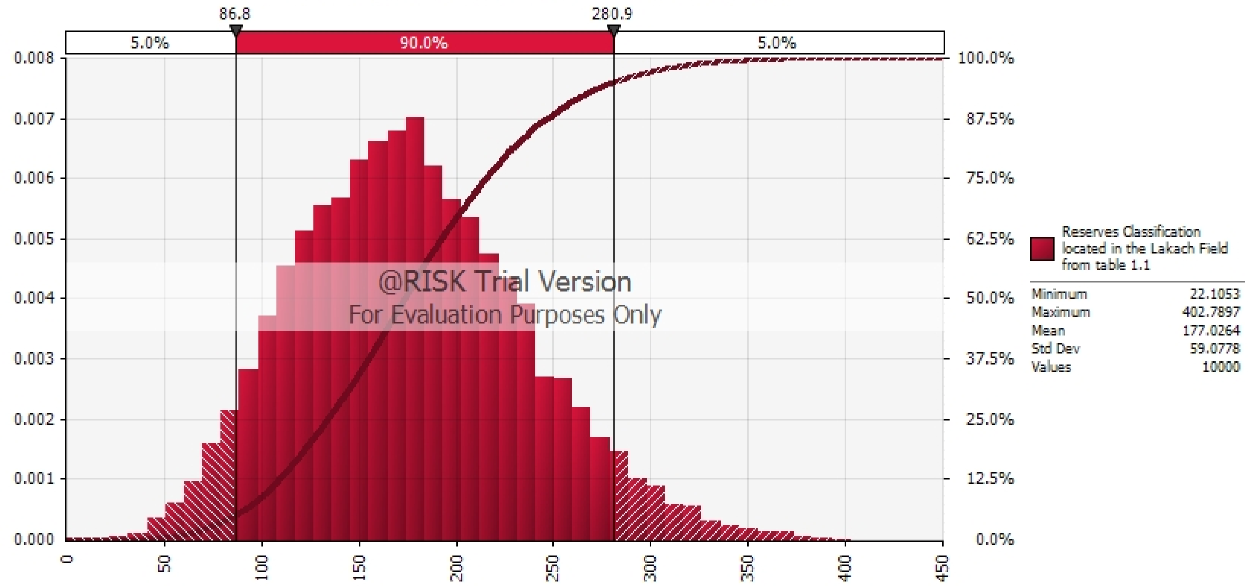


Figure 1.2 Results of simulation of the model of reserves located in the Lakach Field from table 1.2

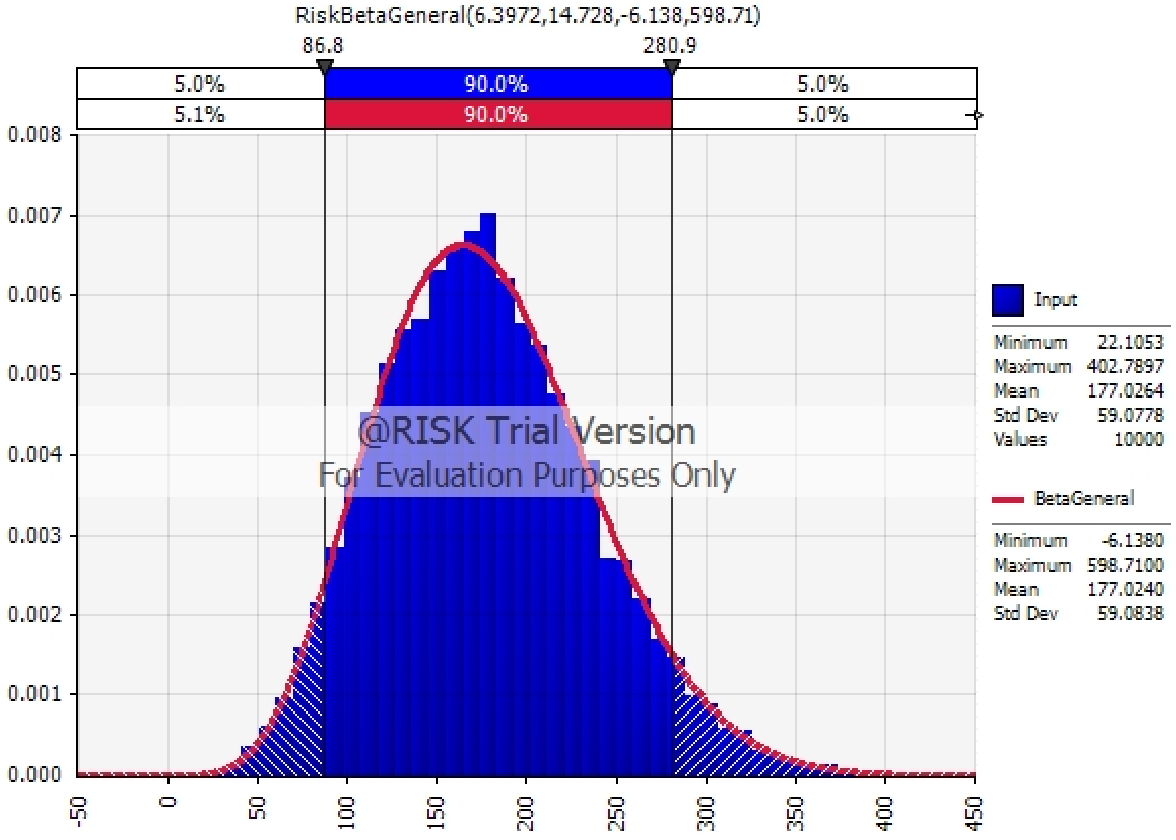


Figure 1.3 Fit comparisons for the model of reserves in the Lakach Field from table 1.2

Statistics		Percentile	
Minimum	22.11	5%	86.80
Maximum	402.79	10%	103.10
Mean	177.03	15%	114.79
Std Dev	59.08	20%	124.79
Variance	3490.18159	25%	133.95

Skewness	0.351521499	30%	143.07
Kurtosis	2.946435815	35%	151.05
Median	173.62	40%	158.92
Mode	181.54	45%	166.27
Left X	86.80	50%	173.62
Left P	5%	55%	180.95
Right X	280.90	60%	188.51
Right P	95%	65%	196.77
Diff X	194.11	70%	205.98
Diff P	90%	75%	215.45
#Errors	0	80%	226.01
Filter Min	Off	85%	238.86
Filter Max	Off	90%	255.92
#Filtered	0	95%	280.90

Table 1.3 Summary statistics from the simulation of the model of reserves in the Lakach Field from table 1.2

The Lakach development project has a total budget of 14,575.8 million Mexican pesos (approximately 1,100 Millions of USD) along 5 years from 2007 according to the information provided by the Ministry of Energy of Mexico in its 2nd. Inform of Results (SENER, 2008). The resources for this project are to be used in activities of delimitation of the reservoir and the offshore field development.

2.0 DESIGN BASIS

2.1 Reservoir characteristics

The following information has been taken from the document Hydrocarbon Reserves of Mexico Evaluation as of January 1, 2007. Pp 36-41 (Pemex, 2007).

Structural Geology

In the tectonic structure, the Lakach field is an anticline to the south of the Lakach-Labay alignment in a northwest-southeast direction. The alignment is located at the southeastern end of the Mexican Cordilleras, Figure 4.2. (See figure 2.1 in this document)

Stratigraphy

The stratigraphic column cut by the Lakach-1 well, which consists of rock the range from the Recent-Pleistocene to the Lower Miocene, is made up an interbedding of clay horizons with limolites and lithic sandstones. The rocks that form the Lower Miocene age reservoirs mostly consist of lithic sandstone and limolites, and correspond to turbiditic fans and submarine channels in a slope environment.

Seal

The rock seal of the upper and lower part of both reservoirs largely consists of shales more than 30 meters thick and with broad lateral distribution.

It is a combined type: structurally it is confined by an asymmetric anticline with its own closing at a reservoir level, whose dimensions are 10 kilometers long and 2 kilometers wide for reservoir

1 and 13 kilometers long by 2 kilometers wide for reservoir 2, where the structure has a normal fault with a low displacement in a northeast-southwest direction as a result of the lithostatic charge.

The seismic response of the reservoirs shows clear direct indicators of hydrocarbons; the limits of the anomalies are concordant with structural contours, as can be seen in Figure 4.3. (See figure 2.2 in this document) Bright spots were identified in the seismic interpretation, both at the crest of reservoir 1 (interval 3,174-3,212 meters below rotary table) and in reservoir 2 (interval 3,035-3,127 meters below rotary table), Figure 4.4. (See figure 2.3 in this document)

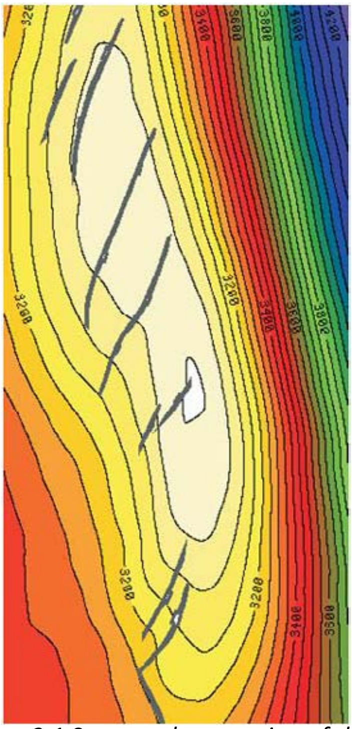


Figure 2.1 Structural contouring of the Lower Miocene top showing the structure's normal internal faults. (Figure 4.2, PEMEX, 2007)

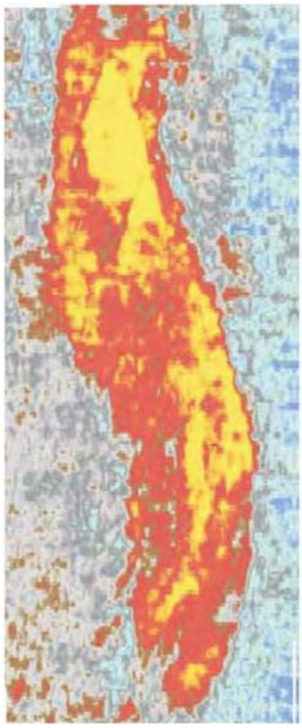


Figure 2.2 The amplitude anomaly of Lakach showing concordance with the structural contours. (Figure 4.3, PEMEX, 2007)

Trap

Source Rock

The results of the isotopic analyses of the gas samples recovered from the Lakach-1 well show an origin with an affinity to Upper Jurassic Kimmeridgian rocks that have high thermal maturity.

Reservoirs

Reservoir 1 is composed by lithic sandstone with fine to coarse granulometry, limestone-clay matrix and calcareous cement with primary intergranular and secondary moldic porosity of 15 to 28 percent, measured in the laboratory based on the cores cut in this reservoir. The production tests yielded 25 million cubic feet of gas per day.

Reservoir 2 is formed by fine to coarse grain lithic sandstone, limestone-clay matrix and little calcareous cement, with interbedding of conglomerate sandstones and poligmithic conglomerates.

The porosity is primary intergranular and secondary moldic of 15 to 25 percent and the water saturation is 31 percent, which means a net thickness of 38 meters. The production tests in reservoir 2 yielded 30 million cubic feet of gas per day.

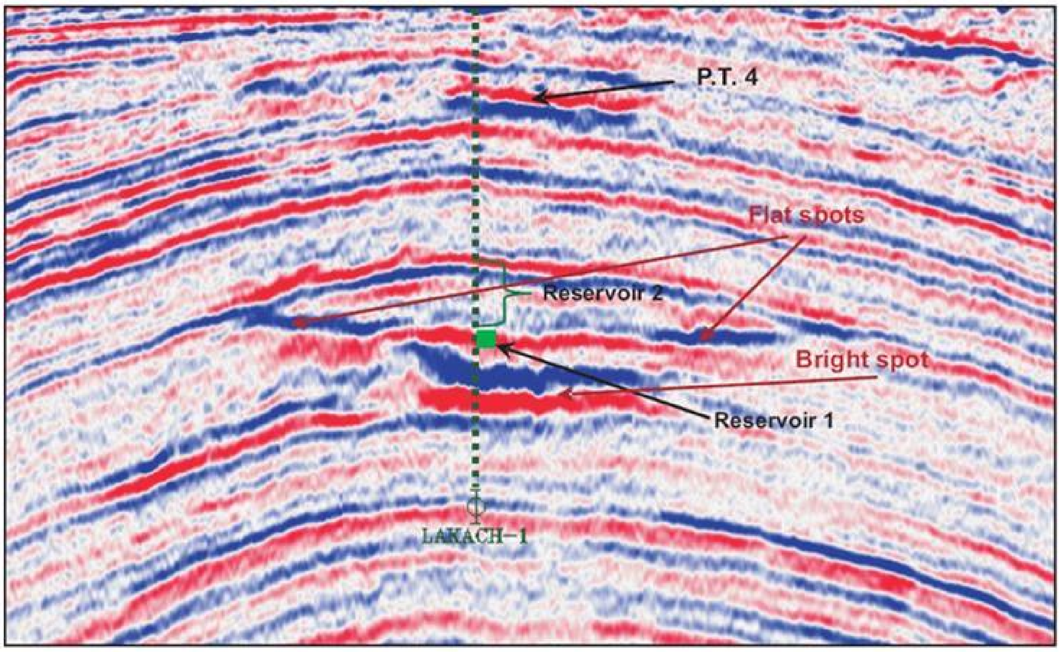


Figure 2.3 Seismic line where bright spots can be observed in the top of reservoirs 1 and 2, as well as the top of production test 4, and the flat spot at the base of reservoir 2. (Figure 4.4, PEMEX 2007)

2.2 Field location, water depth and wells location

Lakach-1 appraisal well is located in Mexican territorial waters of the Gulf of Mexico, off the coast of Veracruz, 131 kilometers northwest of the Port of Coatzacoalcos, Veracruz, in a water depth of 988 meters. It is geologically located in the southeastern portion of the Mexican Cordilleras.

According to the information released by Pegasus International on a concept study performed by the company on the Lakach field (Pegasus-International, 2008-2009), *Six subsea wells are suggested to be located in water depths ranging from 942-1145 meters.*

The Secretary of Environment and Natural Resources of México (Semarnat-2009) mention on the Lakach project that 8 wells distributed in the seismic polygon denominated Holok Poniente will be drilled by semisubmersibles platforms. The eight wells will be interconnected to Pipeline end terminations (PLET´s) and those to two submarine pipelines to the Compresion Station No.5 of Lerdo.

The well "Lakach-2DL" (PEMEX, Licitación…, 2008) establishes the coordinates of the system as Latitude = 19° 04´ 17.14´´ N; Longitude = 95° 16´ 16.52´´ W; Water dept 1,210 m. Considering it as the well at deepest water of the references it will be assumed that it is a well for delimitation purposes.

Since the locations of the wells have not been released It will be assumed by interpretation of the figure No. 1.2; and by using the data base of the General Bathymetric Chart of the Oceans

(GEBCO) (GEBCO, 2009) as a reference for a reasonable water depth assumptions the next locations and profundity of the wells.

Name of the well	Purpose	Water depth (m)	Latitude	Longitude
P1	Productive	942	95°16’ 32” W	19° 01´ 06” N
P2	Productive	968	95°16’ 10” W	19° 01´ 27” N
P3	Productive	1005	95°16’ 53” W	19° 02´ 03” N
P4	Productive	1054	95°16’ 55” W	19° 02´ 50” N
P5	Productive	1100	95°16’ 55” W	19° 02´ 20” N
P6	Productive	1145	95°16’ 08” W	19° 03´ 26” N
2DL	Delimitation	1210	95°16’ 32” W	19° 01´ 06” N

Table 2.1 Assumed location of wells of the lakach field.

2.3 Metocean characterization

So far, there is no available information from PEMEX regarding to the metocean conditions in the region. The most proximate zone documented is limited by the coordinates N 19°, W 93°30’, N 18°26’ y W 92° in an area knew as “Litoral Tabasco” in shallow waters located to the south east of the Holok-Temoa Area.

The Reference Norms “NRF-013-PEMEX-2005, Diseño de Líneas Submarinas en el Golfo de México (Design of submarine pipelines in the Gulf of Mexico)”, “NRF-003-PEMEX-2007, Diseño y evaluación de plataformas marinas fijas en el golfo de México (Design and Evaluation of Fixed Marine Platforms in the Gulf of Mexico” give references in their contents and annexes on the oceanographical conditions and meteorological data in Litoral Tabasco up to 200 m of water depth.

Hurricanes and tropical storms are commonly present in the Gulf of Mexico usually in the second semester of the year. However the conditions in the Mexican site is usually mildest than the present in the north Gulf of Mexico due the paths of the hurricanes is often directed to the north and the shield effect that produces the Yucatan peninsula weakening the strength of the hurricanes as they passed on firm land.

Consequently, the hurricane seasons in 2004-2005 did not affected the activities of the Mexican offshore facilities as it did in the US territorial waters; nevertheless it is likely to expect this kind of phenomena strengthened in the future years due the climatic change. Safety in the design is the most relevant way to avoid disasters, hence this is the criteria to consider for the most extreme conditions for the Gulf of Mexico as considered relevant to the Central Gulf of Mexico according to API 2 INT–MET.

The American Petroleum Institute, has released a document product of the re-evaluation of the metocean conditions due the impact of the hurricanes where changes in the expected conditions observed since the API RP2A were last updated are being proposed. The document is available on the API web site with the code:

API BULL 2INT-MET
Revision / Edition: 07 Chg: Date: 05/00/07
INTERIM GUIDANCE ON HURRICANE CONDITIONS IN THE GULF OF MEXICO

Based on this document at the OTC 2007 the paper "Development of Revised Gulf of Mexico Metocean Hurricane Conditions…" (Berek, 2007) was presented. From there, it is shown in the table 2.2 the Independent Extreme Values for Tropical Cyclone Winds, Waves, Currents and Surge, Central Gulf of Mexico.

Table 2.3 shows the suggested combination factors for combining independent extremes into load cases where the water depth is ≥ 150 m.

For the area Litoral Tabasco in NRF-013-PEMEX-2005, *Wave and currents will be considered in the direction toward S 11° 15' E and the current will be parallel to the batimetric profile. Batimetric profile to be considered uniform and regular.* Considering the proximity of that zone with the one in this study case, It will be assumed the same data.

Return Period (Years)	**10**	**25**	**50**	**100**	**200**	**1000**	**2000**	**10000**
Wind (10 m elevation)								
1 hour mean wind speed (m/s)	33.0	40.1	44.4	48.0	51.0	60.0	62.4	67.2
10 min mean wind speed (m/s)	36.5	44.9	50.1	54.5	58.2	69.5	72.5	78.7
1 min mean wind speed (m/s)	41.0	51.1	57.4	62.8	67.4	81.6	85.6	93.5
3 sec gust (m/s)	46.9	59.2	66.9	73.7	79.4	97.5	102.5	112.8
Waves, Water Depth ≥ 1000 m								
Significant Wave Height (m)	10.0	13.3	14.8	15.8	16.5	19.8	20.5	22.1
Maximum Wave Height (m)	17.7	23.5	26.1	27.9	29.1	34.9	36.3	39.1
Maximum Crest Elevation (m)	11.8	15.7	17.4	18.6	19.4	23.0	23.8	25.6
Peak Spectral Period (s)	13.0	14.4	15.0	15.4	15.7	17.2	17.5	18.2
Period of Maximum Wave (s)	11.7	13.0	13.5	13.9	14.1	15.5	15.8	16.4
Currents, Water Depth ≥ 150 m								
Surface Speed (m/s)	1.65	2.00	2.22	2.40	2.55	3.00	3.12	3.36
Speed at Mid-Depth (m/s)	1.24	1.50	1.67	1.80	1.91	2.25	2.34	2.52
0-Speed Depth (m)	69.3	84.2	93.2	100.8	107.1	126.0	131.0	141.1
Water Level, Water Depth ≥ 500 m								
Storm Surge (m)	0.32	0.52	0.66	0.80	0.93	1.13	1.22	1.41
Tidal Amplitude (m)	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42

Table 2.2: Independent Extreme Values for Tropical Cyclone Winds, Waves, Currents and Surge, Central Gulf of Mexico, 89.5° W to 86.5° W, Draft for API RP Development, (Table 1, Berek, 2007)

2.4 Seafloor soil

The seafloor soil characteristics should are not expected to present major challenges than in the sea floor of the North of the Gulf of Mexico, hence the soil will be considered suitable for pile foundation and drag anchor. This is another rough assumption for the case of study due the lack of official information but is based on the expected similitude of the sea floor in the area to the one presented in the deep water of the Bay of Campeche.

In the Area of the Bay of Campeche (Heideman 1994) and (Martinez 1996) documented soil with similar characteristics to the one that is found in the Northern Gulf of Mexico.

… Seafloor Soils

A study by Creager (1958) contains superficial soil information obtained from sampling stations all over the Bay of Campeche, including two stations near the area of interest. The soil samples were clay to silty clay, with kaolinite/illite/montmorillonite proportions of about 1.1/1/1.7 and calcium carbonate content of 14-18 %.

Fugro-McCIeiiand conducted an extensive investigation in 1993, including the area of interest (Dutt and Kubena, 1994). They found that the soil is normally consolidated siliceous clay similar to what is typically found offshore Louisiana and Texas, with a shear strength profile that increases linearly with depth at about 8-10 psf/ft. Consequently, pile foundation and drag anchor design are expected to be similar to those offshore Louisiana and Texas. (Heideman, 1994, P.p. 2)

… 4) Geotechnical data. - The typical soil in site basically is constituted for clay with a varying shear strength from 0.04 to 2.15 kg/cm^2 between O to 80 meters, considering a constant value of 1.20 kg/cm^2 up to the bottom of the hole. The consistency varies from low to high consolidation. (Martinez, 1996, P.p. 3)

Return Period (Years)	10	25	50	100	200	1000	2000	10000
Peak Wave Case:								
Wind Speed	1.00	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Wave Height	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Current (both speed and depth level)	0.80	0.80	0.75	0.75	0.75	0.75	0.75	0.75
Surge	0.90	0.80	0.70	0.70	0.70	0.70	0.70	0.70
Wind Direction from Wave (deg)	-15	-15	-15	-15	-15	-15	-15	-15
Current Direction from Wave (deg)	+15	+15	+15	+15	+15	+15	+15	+15
Peak Wind Case:								
Wind Speed	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Wave Height	1.00	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Current (both speed and depth level)	0.80	0.80	0.75	0.75	0.75	0.75	0.75	0.75
Surge	0.90	0.80	0.70	0.70	0.70	0.70	0.70	0.70
Wind Direction from Wave (deg)	-15	-15	-15	-15	-15	-15	-15	-15
Current Direction from Wave (deg)	+15	+15	+15	+15	+15	+15	+15	+15
Peak Current Case:								
Wind Speed	0.75	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Wave Height	0.75	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Current (both speed and depth level)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Surge	0.90	0.80	0.70	0.70	0.70	0.70	0.70	0.70
Wind Direction from Wave (deg)	0	0	0	0	0	0	0	0
Current Direction from Wave (deg)	+50	+50	+50	+50	+50	+50	+50	+50

Table 2.3: Factors for Combining Independent Extremes into Load Cases, WD ≥150 m, Draft for API RP Development, (Table 6, Berek, 2007)

2.5 Seismic Activity

The area of the development is typically active in comparison to the North of the Gulf of Mexico Region which is typically assumed as a Zone 0 region by API-RP2A peak ground acceleration.

(Heideman et. al., 1994) contribute to the discussion on the Bay of Campeche region by showing that apparently the most of the earthquakes have occurred onshore and relatively few near the area of the development. They stimate that the Bay of Campeche could be an API Zone 2 to 3 with peak ground acceleration of 0.1-0.2 g. However is suggested in their work to perform detailed seismic studies.

A study performed for the Minerals Management Service (MMS) in cooperation with the Offshore Technology Research Center Under (OTRC) (Brown et. al, 2003) shows that historically the North of the Gulf of Mexico is not subject to seismic activity as high and frequently as the south of the Gulf of Mexico. The figure 2.5 shows the epicenters of Earthquakes in GOM Region and Bay of Campeche Region 1974-2003 (Latitude Range 18°- 32° and Longitude Range -98° to -82°).

The data of the table 2.4 shows the lists the events that have occurred in the Bay of Campeche area from 1974 to 2003 contained within a rectangular area extending from 18° to 20° latitude and -98° to -90° longitude. The table gives information on the date, time, magnitude, and location of the seismic event.

In the period covered by the study in the Mexican territorial waters there were eight seismic events with Richter magnitudes between 3.1 and 3.9 and 18 events with between 4.1 and 4.7. Most of these events were located close to the coastline in the Bay of Campeche with depths less than 33 km, although some of the epicenters of these events were as deep as 250 km.

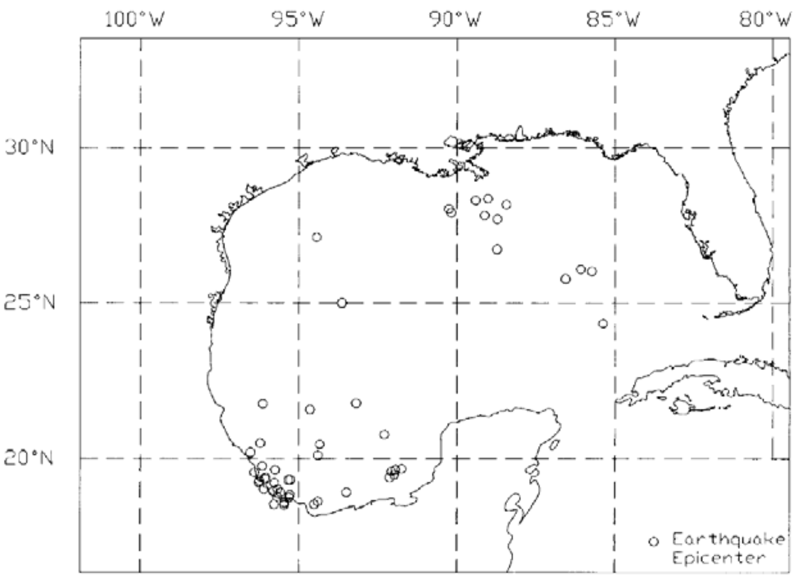


Figure 2.5 Recorded epicenters of Earthquakes in GOM Region and Bay of Campeche Region 1974-2003 (Latitude Range 18°-32° and Longitude Range -98° to -82°)

Year	TIME UTC (hhmmss.mm)	Latitude (degrees)	Longitude (degrees)	Magnitude (Richter)	Depth (km)
07/25/1974	95338.9	19.37	-96.25	4.5	76
09/20/1974	113326	18.91	-93.49	4.1	45
08/28/1977	235738.4	18.61	-94.39	3.8	33
12/31/1983	202132	18.77	-95.69	4.4	33
10/07/1985	195819.4	19.75	-96.17	N.A.	33
06/09/1986	214222.1	18.57	-95.46	N.A.	33
04/07/1987	20246.58	19.58	-92.09	4.7	10
08/14/1987	94032.46	19.01	-96.11	4.4	130
07/31/1990	73010.71	18.52	-94.51	4.7	33
11/23/1990	201737.9	18.5	-95.79	N.A.	10
11/27/1991	120033.3	19.22	-95.78	3.6	33
06/05/1992	34252.19	18.94	-95.82	4.4	39
04/12/1993	202034	18.74	-95.31	3.7	33
04/30/1993	114856.8	19.39	-96.06	N.A.	33
04/30/1993	150538.7	19.34	-96.08	3.4	33
11/10/1994	210315.7	19.31	-95.27	N.A.	33
04/11/1995	14231.51	18.77	-95.28	N.A.	33
03/14/1996	91211.94	19.53	-92	4.3	33
10/31/1996	21223.2	19.3	-95.33	3.6	10
03/18/1997	15944.66	19.64	-91.99	3.9	33
04/15/1997	11234.04	19.63	-95.76	3.8	250
07/11/1997	210830.7	19.39	-92.15	4.1	33
09/01/1997	105019.5	18.94	-95.84	4.3	33
09/23/1997	4716.77	19.66	-91.76	4.1	10
01/14/2000	222254.2	19.46	-92.01	4.3	10
03/24/2000	175830.8	18.91	-95.58	4.1	26
06/05/2000	115931.5	19.01	-95.68	4.4	20
08/11/2000	81955.3	19.55	-96.41	4.1	4
04/19/2001	214250.8	19.24	-95.9	4.1	16
07/09/2001	134642.8	19.24	-96.28	3.7	25
07/21/2001	951.19	19.42	-92.14	4.2	33
07/23/2001	65921.1	18.5	-95.47	4	26

Table 2.4 List of the seismic events that have occurred in the Bay of Campeche area, contained within a rectangular area extending from 18° to 20° latitude and -98° to -90° longitude.

2.6 Details of existing facilities and infrastructure.

2.6.1 Appraisal wells

Vertical appraisal well Lakach-1 discovered two reservoirs.

Reservoir 1 production tests yielded 25 million cubic feet of gas per day. The production tests in reservoir 2 yielded 30 million cubic feet of gas per day.

2.6.2 Compression Station onshore available to be connected to the development

Compression Station “Lerdo de Tejada” is one of the 8 compression stations operated by PEMEX Gas and Petroquímica Básica “PEMEX Gas and Basic Petrochemical” (PGPB).

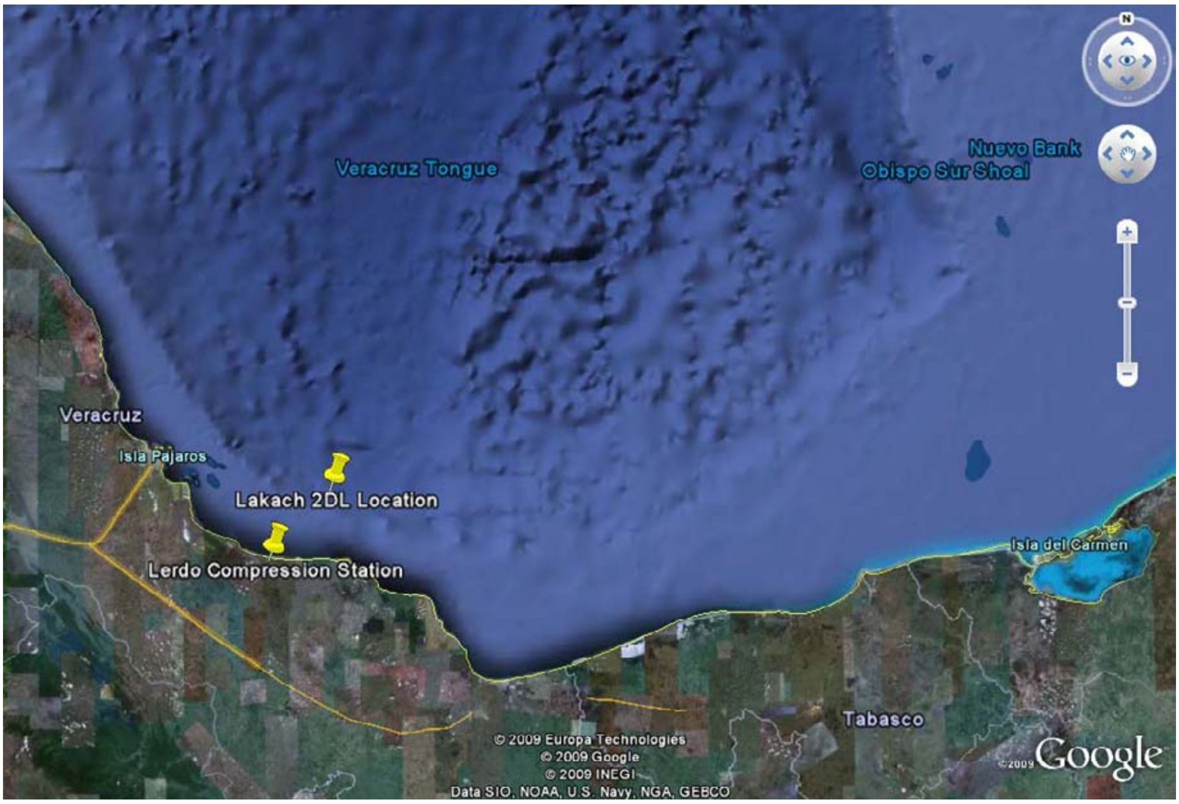


Figure 2.5 Location of Lerdo Compression Station and Lakach 2DL Location (Google Earth System @2009)

Characteristics of the Compression Station (CRE, 2009), are given in Table 2.5 while figure 2.6 shows the performance of an impellor installed in a turbo compressor in the mentioned compression station.

Gases Generator	General Electric LM-2500-PB
Nominal power	20.5 MW (27,500 HP)
Maximum speed	9,870
Number of installed units	2
Compressor centrifuge model	Clark- Dresser Centrifugal - 7.5
Design pressure	86.2 bars (1250 psia)
Maximum operation temperature	467 K (380 °F)
Nominal capability	18,358 CFM
Specific Consumption (ft3/hp/hr)	6.78
Maximum power on site	14.9 MW (20,000 HP)
Number of installed units	2

Table 2.4: Technical description of the Compression Station Lerdo, (CRE, 2009)

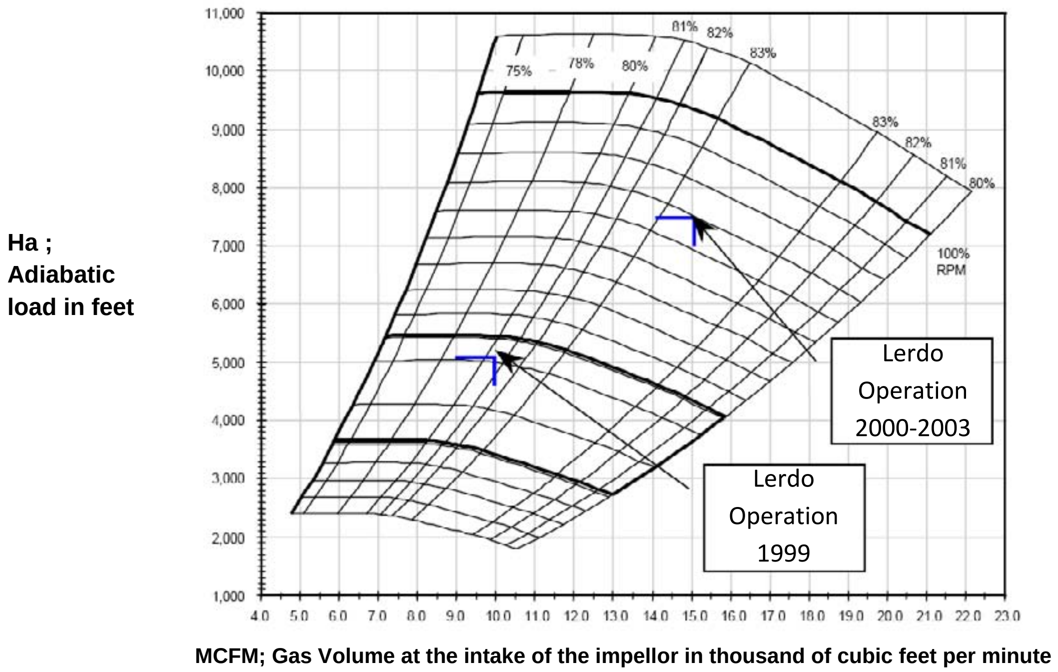


Figure 2.6 Proven performance of an impellor installed in a turbo compressor LAN-Clark model 75-75P (CRE, 2009)

2.6 Dynamically positioned drilling-vessel type.

PEMEX currently does not own drilling facilities that are able to operate in the water depths of the Lakach field, however they will have the availability of the rigs mentioned in table 2.6 through leasing (Reyes Heroles, 2009). These rigs are emplaced for exploration drilling but could be used to drilling and completion for the project, considering that it could save the handling of the contractual commitments.

Rig	Maximum water depth (feet)	Availability	Cost (US$/day)
Voyager	3,280	Oct-2007	335,000
Max Smith	7,000	Aug-2008	484,000
SS Petro Rig III	7,000	Jan-2010	495,000
SS Dragon	7,000	Jan-2010	503,000
SS Muralla	10,000	Sep-2010	530,000

Table 2.6 Availability of floating drilling units dynamically positioned, (Reyes Heroles, 2009)

3. The subsea production system concept of Lakach field

This concept has been revealed to be the chosen by PEMEX to develop the field. According to the information released by Pegasus International (Pegasus-International, 2008-2009) see figure 3.1 and 3.2. and Chart 3.1 for a schedule of the project.

- The field consist of six subsea wells that are located in water depths ranging from 942-1145 meters.
- Two Pipelines will be laid from Lerdo de Tejada Station at shore to 1145 meter water depth.
- It is considered the construction of two 18" pipelines to join the last subsea well in a configuration known as 'Daisy Chain'
- Each of two pipelines will receive production from three wells with maximum capacity of 67 MMSCFD per well for total of 400MMCFPD
- It is interpreted that the development will be divided in two productive sectors here denominated PS North and PS South.

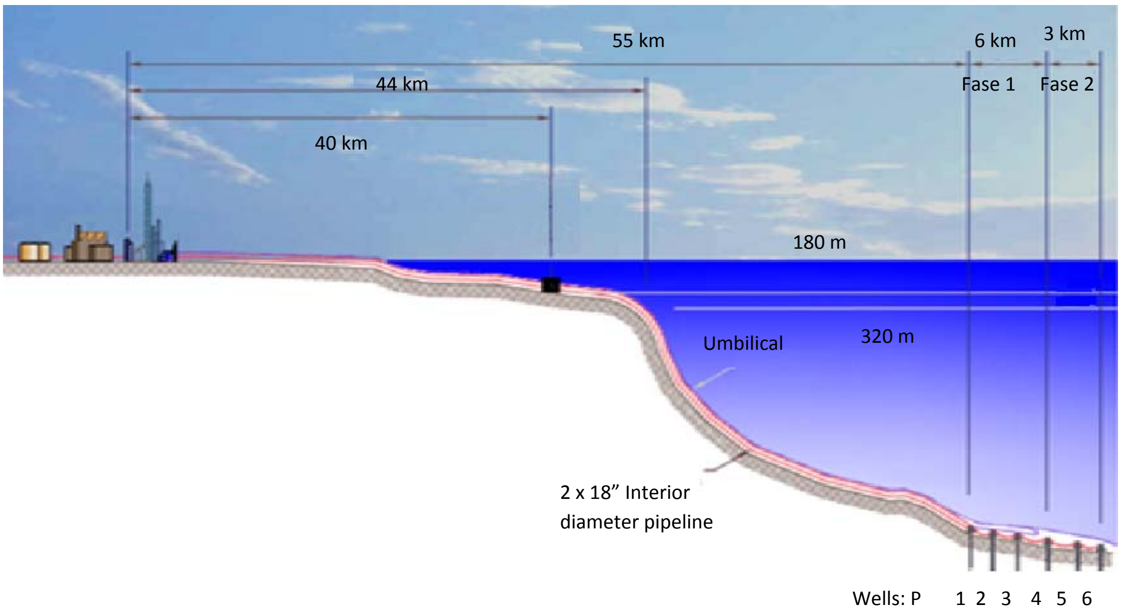


Figure 3.1. Conceptual design of the pipeline to Lakach field (Pegasus-International, 2008-2009)

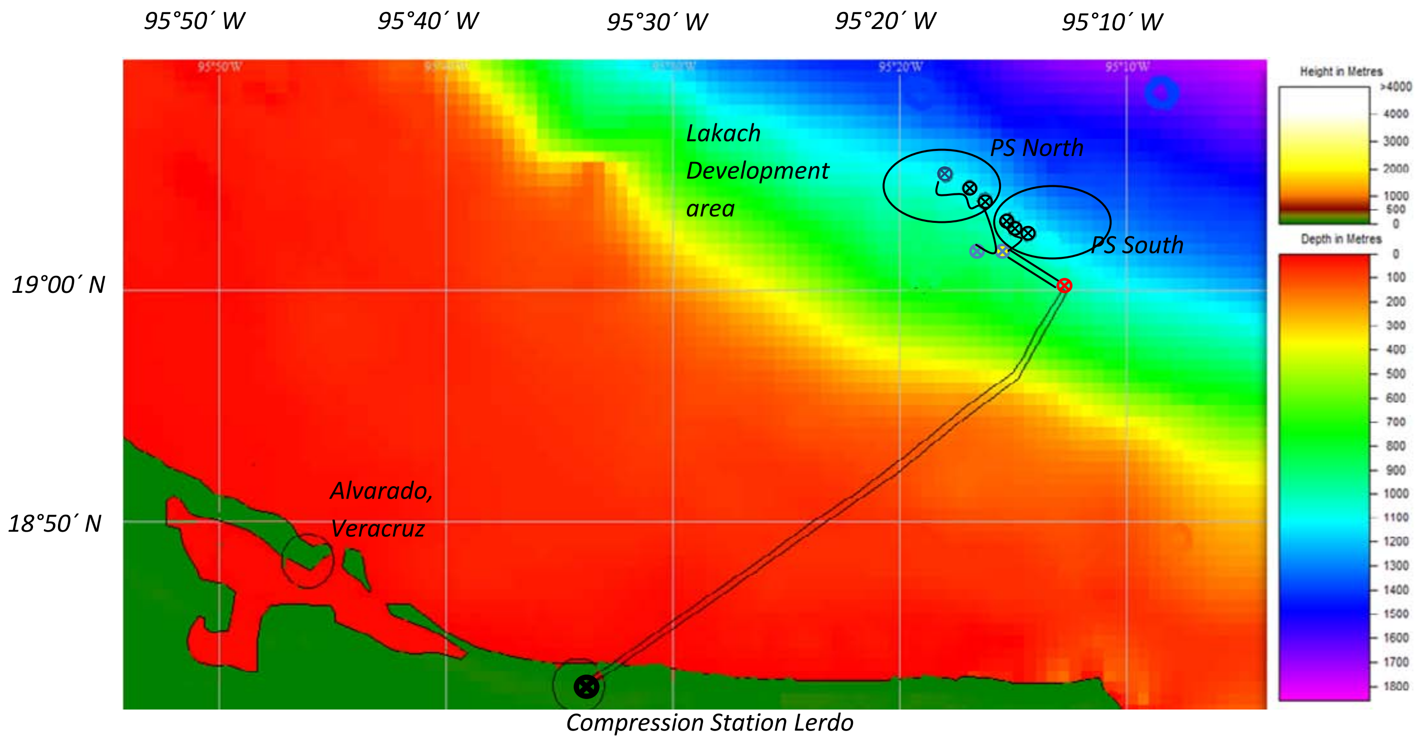


Figure 3.2. Path of the pipelines and illustration of the bathymetry in the area of the development, own interpretation from (GEBCO, 2009) and (PEMEX-RMSO, 2008)

Activity	Duration in days
Lakach Development Project	2081
1 Discovering	1
2 Studies and Permitions	561
3 Delimitation	692
4 Development	1796
4.1 Technical Assistance	1768
4.2 Pre FEL	33
4.3 FEL (VCD)	649
4.4 Well	1249
4.4.1 Definition of trayectory and completion termination	60
4.4.2 Procurement of well heads, well trees and production cassing.	1010
4.4.3 Drilling of development wells	1249
4.4.3.1 Pre-drilling studies South Sector	750
4.4.3.2 Drilling PS North	252
4.4.3.3 Drilling PS South	314
4.4.3.4 Completion PS South	217
4.4.3.5 Completion PS-North	182
4.4.3.6 Information processing	945
4.5 Infrastructure	1086
4.5.1 Bidding and assignation	144
4.5.2 EPCI of the Compression Station Lerdo	920
4.5.2.1 Detailed engineering	600
4.5.2.2 Procurement phase 1 (Modules 1 and 2 + 1 relief)	540
4.5.2.3 Construction, instalation and interconexion of equipment phase 1	600
4.5.2.4 Test and running phase 1	120
4.5.2.5 Procurement phase 2 (Modules 3 and 4)	90
4.5.2.6 Construction, instalation and interconexion of equipment phase 2	215
4.5.2.7 Test and running phase 2	45
4.5.3 EPCI of collection and transport pipelines	530
4.5.3.1 Engineering	150
4.5.3.2 Procurement	180
4.5.3.3 Construction and instalation	120
4.5.3.4 Comissioning	60
4.5.3.5 Tests	20
4.5.4 EPCI Umbilicals	785
4.5.5 EPCI Subsea systems	840
4.5.5.1 Detailed engineering	300
4.5.5.2 Procurement and construction	540
4.5.5.3 Subsea Integration test	60
4.5.5.4 Instalation	180
4.6 First production	1

Chart 3.1. Schedule of the Lakach Development project with subsea production system according to own interpretation from (PEMEX-RMSO, 2008)

4. Lalail field (Extracted entirely from PEMEX Exploración y Producción, “Hydrocarbon Reserves of Mexico Evaluation as of January 1, 2008” México, 2008.)

It is in the territorial waters of the Gulf of Mexico, off the coast of Veracruz, at 22 kilometers from the Tabscoob-1 well and 93 kilometers Northwest of the Port of Coatzacoalcos, Veracruz, in a water depth of 806 meters, Figure 4.1.

It is geologically located on the Eastern edge of the Salina del Istmo sub-basin in the Deep Gulf of Mexico Basin. The Lalail-1 well continued with the discovery a series of non-associated gas reservoirs in the deep waters of the Gulf of Mexico in Lower Miocene rocks.

Structural Geology

The field is on the Western edge of the Salina del Golfo Province, which like the Catemaco Folded Belt, has alignments in a Northeast to Southwest direction that are affected by saline bodies. The interpretation is that the salt in this area occurred mainly during the Pleistocene-Recent because there are signs of syntectonic folds and wedges derived from the Pliocene contraction.

The structure is an anticline that closes against reverse faults to the Northwest and Southeast and there is a fault to the Northeast of the well that divides the structure into two main blocks, Figure 4.2.

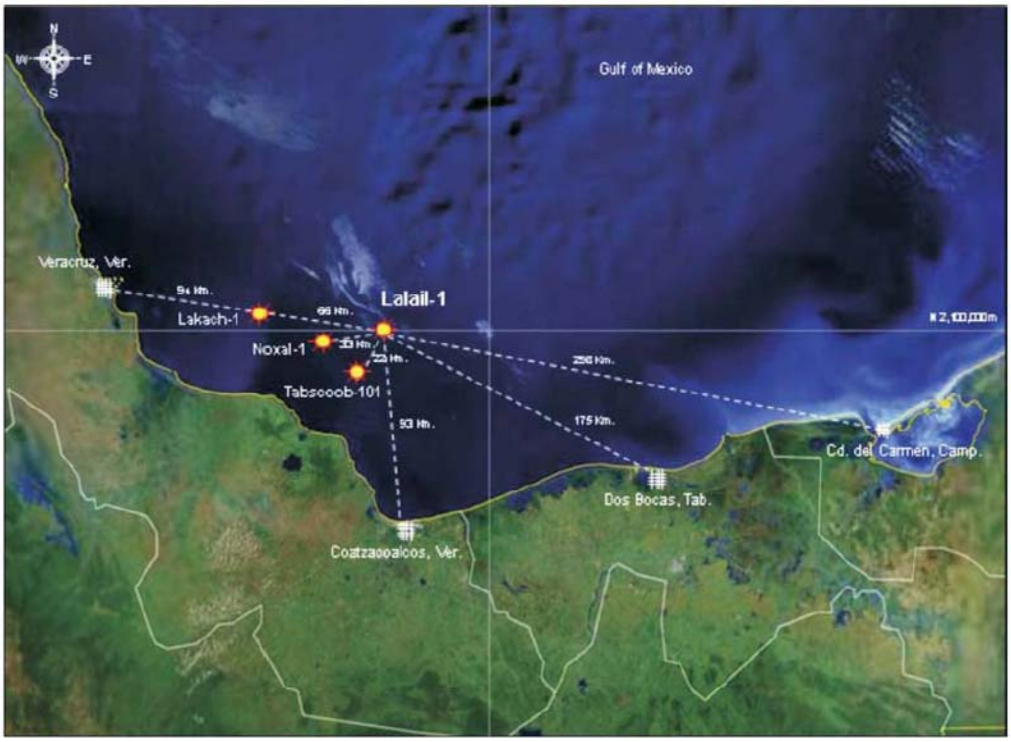


Figure 4.1 The Lalail-1 well is in the Gulf of Mexico Deepwater Basin, in a water depth of 806 meters and 93 kilometers from the port of Coatzacoalcos, Veracruz.

Stratigraphy

The geological column of the field covers siliclastic sedimentary rocks that range from the Lower Mioceneto the Recent Pleistocene. The chronostratigraphic crests were established through the analysis of planktonic foraminifer indexes in the channel and cores samples. The results of high-resolution bio-stratigraphic studies were used to illustratethat the deposit paleo-environment of the reservoir rocks corresponds to a complex of submarine fans distributed in a bathymetry that ranges between external neritic to upper bathyal.

Seal

The rock type for the Oligocene and Miocene Plays corresponds to layers of basin shales. According to the Tabscoob-1 well data, for the Oligocene, the thickness exceeds 100 meters, whereas in the sandy sequences of the Lower-Middle Miocene, in addition to clay interspersing 30 to 50 meters thick, there is a package of shales more than 500 meters thick that correspond to the secondary transgression of the Lower Pliocene. The shaly sequence of the Pliocene thins out to the North, in the direction of the deep waters of the Gulf of Mexico.

Trap

It is a combined trap; structurally it is confided by an asymmetric anticline with its own closing at a reservoir level, whose dimensions are 6 kilometers long by 2 kilometers wide, Figure 4.3.

Source Rock

The results of the biomarkers make it possible to define these hydrocarbons as generated by Upper Jurassic Tithonian rocks, in a carbonated marine environment with a degree of siliclastic influence.

Reservoirs

Two reservoirs were discovered by drilling this well. Reservoir 1 is located at the 2,347.0-2,431.5 meter interval, while reservoir 2 is between 2,257.0 and 2,333.5 meters. The storage rock of reservoir 1 consists of poorly sorted fine to coarse grain sands and lithic sandstones, almost without a matrix, the constituents are subrounded quartz grains, plagioclastic, muscovite, calcareous lithic fragments and abundant volcanic lithic fragments. The interangular primary and secondary moldic porosity ranges from 15 to 28 percent. A daily output of 18.1 million cubic feet of gas was obtained during the production tests.

Reservoir 2 is formed by fine to coarse grain lithic sandstone, limestone-clay matrix and little calcareous cementing, with interspersing of conglomerate sandstones and poligmithic conglomerates. The interangular primary and secondary moldic porosity ranges from 15 to 25 percent. A daily output of 3.2 million cubic feet of gas was obtained during the production tests in reservoir 2.

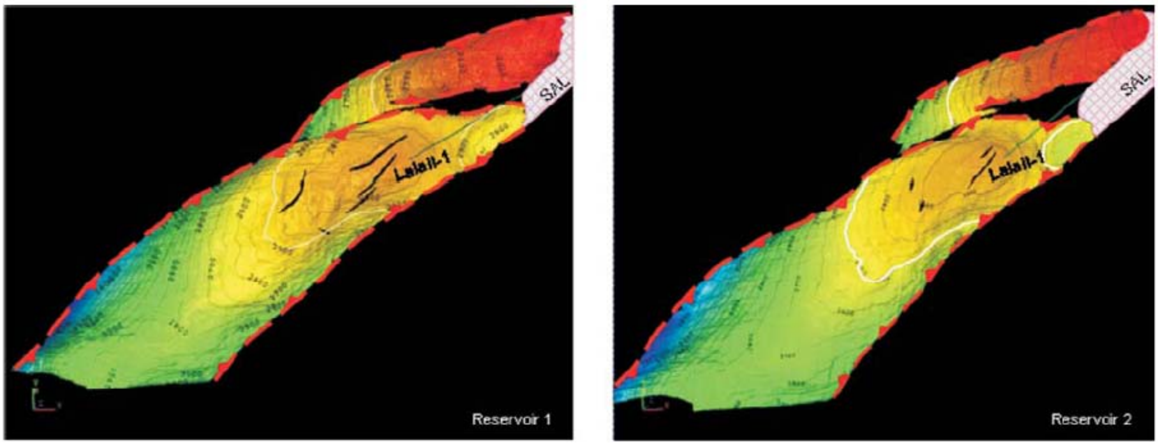


Figure 5.2 Structural maps showing the two reservoirs discovered in the Lalail field. It can be seen that the reservoirs are divided into two blocks.

Reserves

The original 3P volume of natural gas is 1,181.3 billion cubic feet. The estimated 3P reserves are 708.8 billion cubic feet of gas, which is equal to 138.9 million barrels of oil equivalent. The 2P reserves are estimated at 242.6 billion cubic feet of gas.

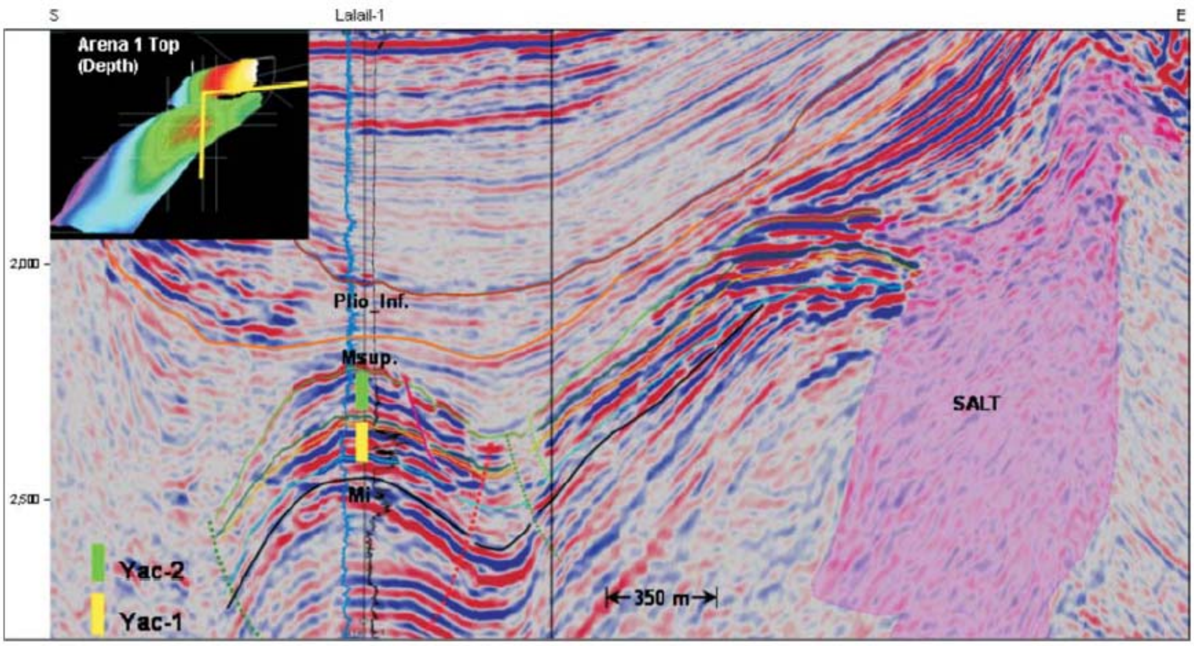


Figure 4.3 Seismic-structural section showing well Lalail-1 and the relationship between the structural and stratigraphic characteristics of the two reservoir blocks.

5. Noxal Field (Extracted entirely from PEMEX Exploración y Producción, "Hydrocarbon Reserves of Mexico Evaluation as of January 1, 2007" México, 2007.)

The Noxal-1 well is in territorial waters of the Gulf of Mexico, off the coast of Veracruz, at 102 kilometers northwest of the Port of Coatzacoalcos, Veracruz, in a water depth of 935 meters, Figure 5.1.

It is geologically located in the Catemaco Folded Belt. The Noxal-1 well found a new reservoir of non-associated gas in deepwater bathymetries of the Gulf of Mexico in sandstone interbedded with limolite of the Lower Pliocene.

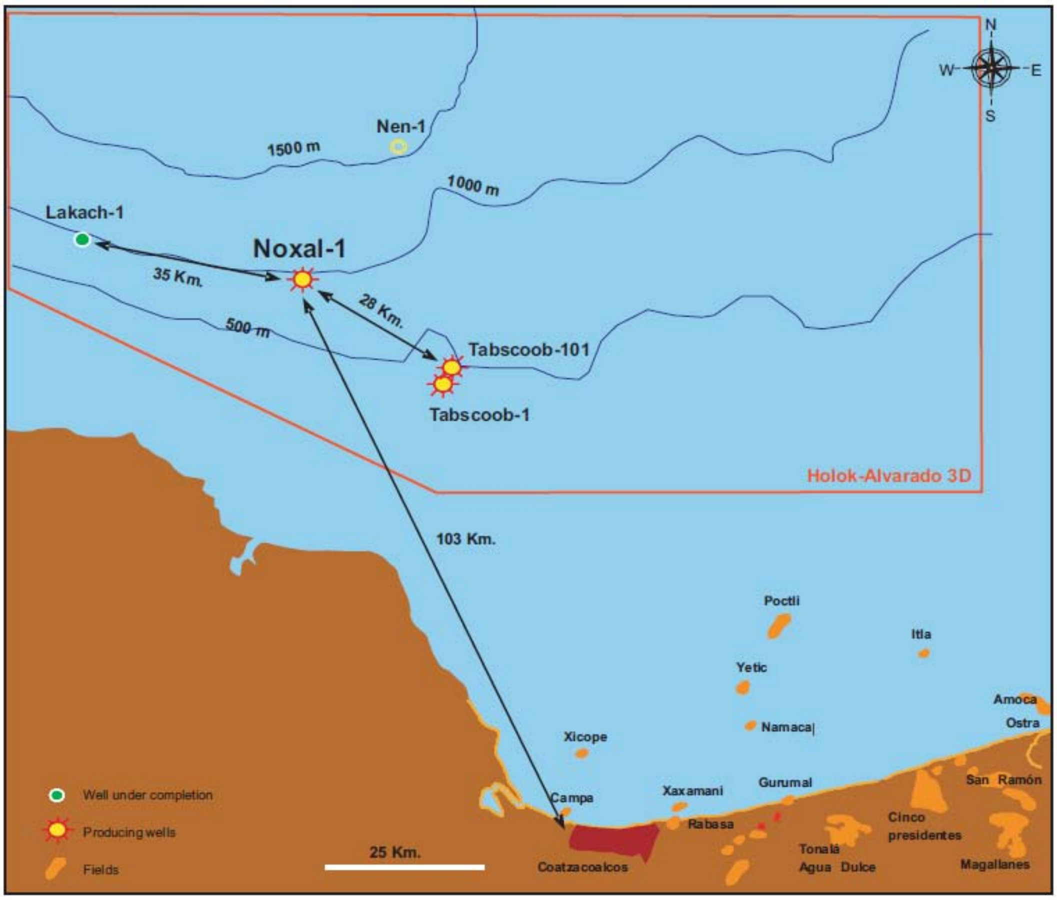


Figure 5.1 Location map of the Noxal-1 well.

Structural Geology

Within the tectonic framework, the study area is in the northwestern portion of the Catemaco Folded Belt, Figure 5.2, which is bounded to the east by the Salina del Istmo Basin and to the west with the spurs of the Mexican Cordilleras. Noxal is in the southern portion of the Noxal-Nen alignment and it is interpreted as a symmetrical anticline in a northwest-southeast direction, generated by expulsion during the tectonic compression of the Lower to Middle Miocene, which produces a reverse fault, Figure 5.3.

Stratigraphy

The stratigraphic column cut by the Noxal-1 well consists of rocks that range from the Recent-Pleistocene to the Lower Miocene, and it is made up of an interbedding of clay horizons with limolites and lithic sandstones. The chronostratigarphic crests were fixed by analyzing foraminifers in the channel and core samples cut by the well. The reservoir is at the Lower Pliocene level, which forms part of the turbiditic complexes and submarine channels deposited in a slope environment.

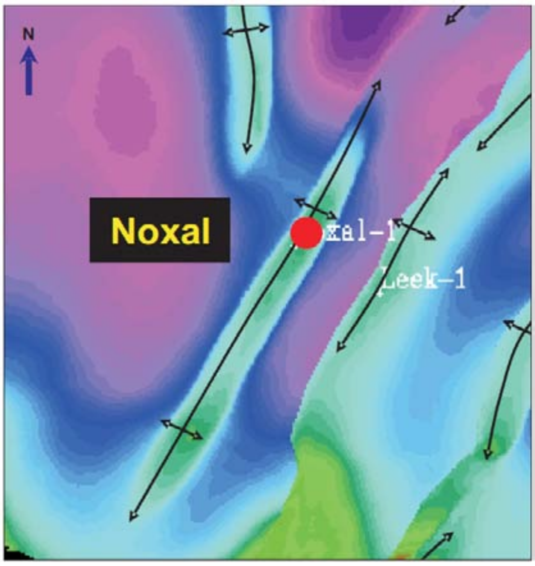


Figure 5.2 Structural contouring of the Lower Miocene top showing the location of the Noxal field within the Catemaco Folding Belt.

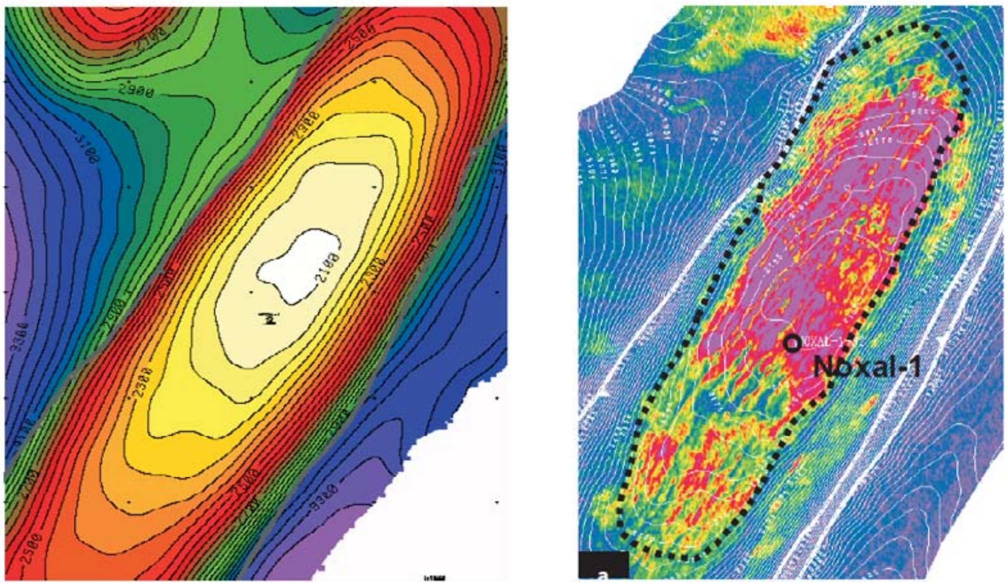


Figure 5.3 Structural contouring of the reservoir top with the amplitude anomaly superimposed. It is noted that the seismic amplitude anomaly is concordant with the structure

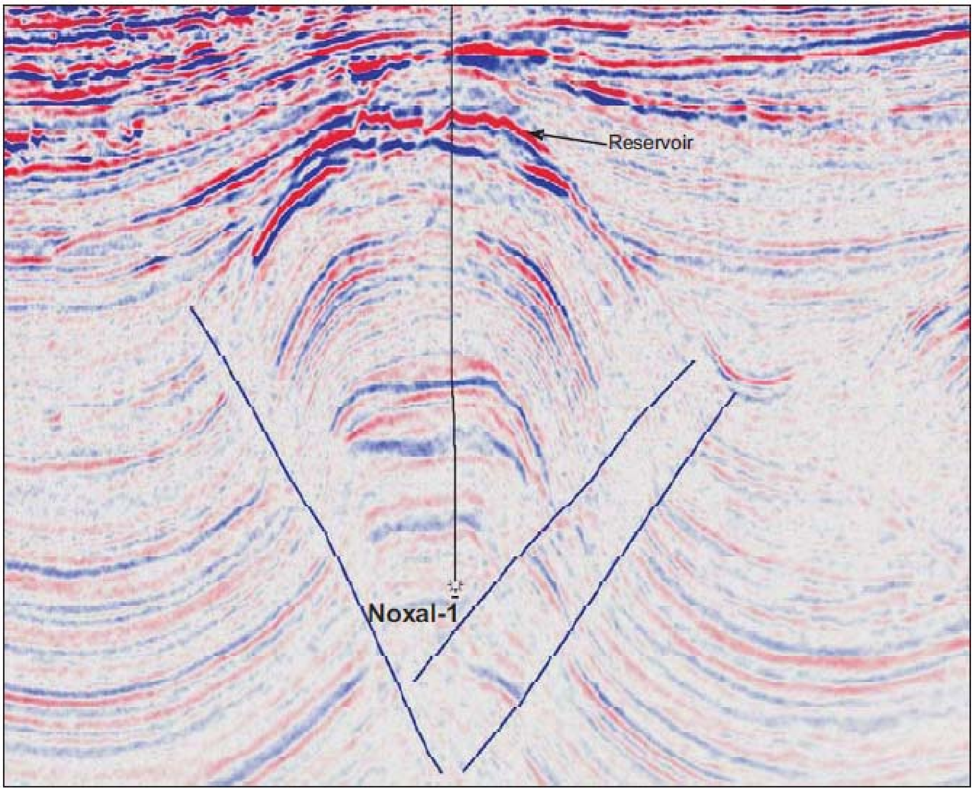


Figure 5.4 The seismic line passing through the Noxal-1 well showing the bright spots in the reservoir.

Trap

The trap is in an anticline with its own closing at the reservoir level and it is bounded by reverse faults on the northwestern and southeastern flanks. The dimensions are 9 kilometers long and 2 kilometers wide. According to the seismic interpretation, the reservoir horizon has bright spot anomalies, Figure 5.4. The limit of the width anomaly in the reservoir shows concordance with the structural contours.

Seal

The rock seal of the upper and lower part of reservoir consists of shales more than 200 meters thick.

Source Rock

The results of the isotopic analyses of the gas samples recovered from the Noxal-1 well show an origin with an affinity to Upper Jurassic Kimmeridgian rocks that have high thermal maturity.

Reservoir

The reservoir is composed by lithic sandstones with fine to very fine granulometry that graduates to limolite in the limestone-clay matrix and calcareous cement with primary intergranular and secondary moldic porosity of 16 to 22 percent, and water saturation of 30 to

50 percent. The Lower Pliocene reservoir produced 10 million cubic feet of gas per day and it is located at the 2,134-2,202 meter interval.

Reserves

The 3P original volume of natural gas is 583.6 billion cubic feet. The 3P original reserves are estimated at 420.2 billion cubic feet of dry gas, which is equal to 80.8 million barrels of oil equivalent. All the reserves have been classified as possible.

6. Nab Field (Extracted entirely from PEMEX Exploración y Producción, "Hydrocarbon Reserves of Mexico Evaluation as of January 1, 2005" México, 2005.)

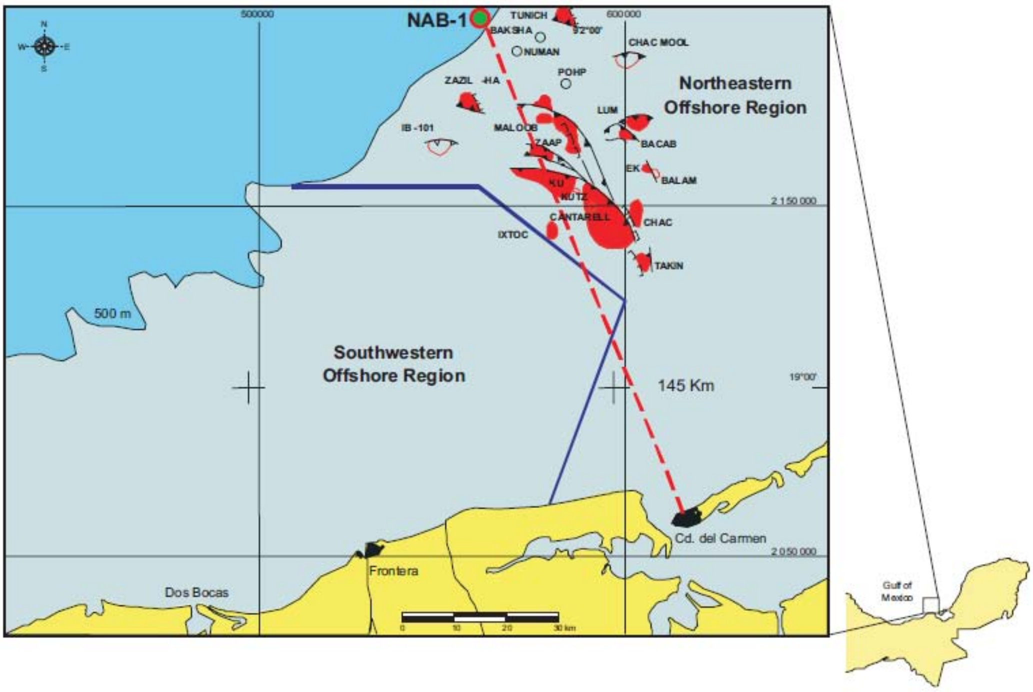


Figure 6.1 Location of the Nab-1 well in territorial waters of the Gulf of Mexico. The well was drilled in a 679-meter bathymetry.

The offshore well was drilled in territorial waters of the Gulf of Mexico, at approximately 145 kilometers Northwest of Ciudad del Carmen, Campeche. It was drilled to a depth of 4,050 meters in a water depth of 679 meters, which makes it the well with the deepest water depth drilled to date in Mexico. The objective was to evaluate the potential of the Upper Jurassic Kimmeridgian and the Upper Cretaceous Breccia, and it became a heavy oil producer in the carbonate rock of the Upper Cretaceous Breccia. Figure 6.1 shows the location of this well within the Sonda de Campeche.

Structural Geology

The structure of this field corresponds to a narrow block pushed out by compression. The block lies in a Northwest to Southeast direction and is bounded on both sides by reverse faults, Figures 6.2 and 6.3.

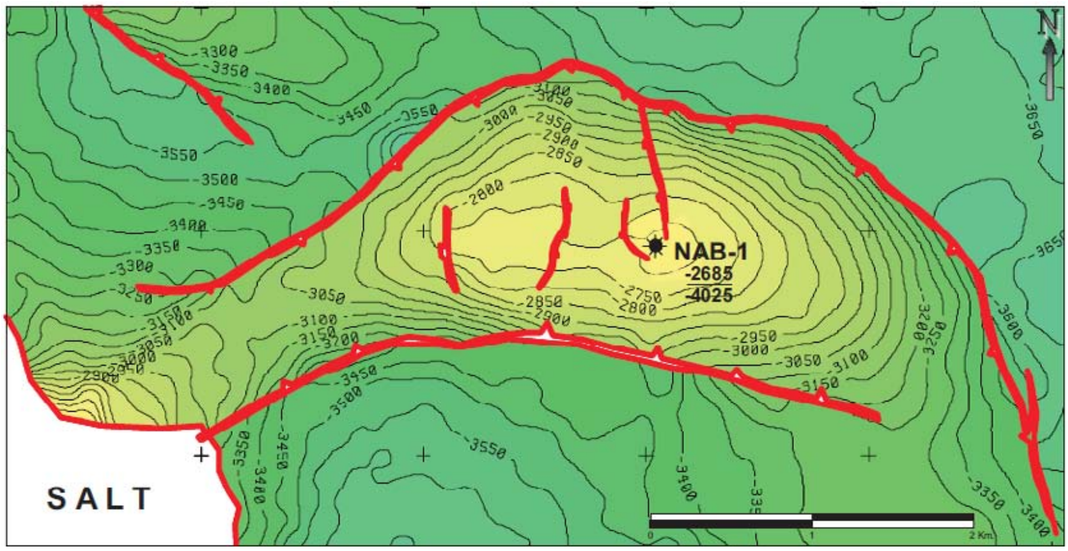


Figure 6.2 Structural configuration of the Upper Cretaceous Breccia crest. The reservoir is in an expelled structure caused by tectonic compression.

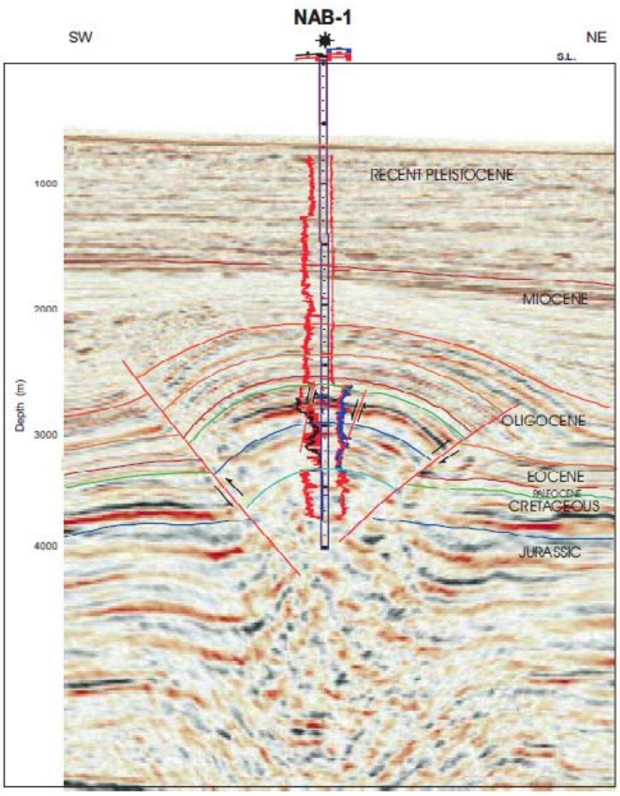


Figure 6.3 Deep seismic section showing the Nab field structure bounded by reverse faults.

Stratigraphy

The geological column drilled consists of sediments from the Upper Jurassic Kimmeridgian to the Recent. The Upper Jurassic Kimmeridgian sediments that were deposited in a shallow water depth, consist of slightly shaly micro to mesocrystalline dolomite with microfractures; the Upper Jurassic Tithonian sediments are made up of shaly and bituminous mudstone partly sandy, showing a deeper environment and restricted circulation. The Lower Cretaceous is associated with dolomites with poor oil saturation in fractures. The Middle Cretaceous is characterized by microcrystalline dolomite with intercrystalline porosity and in fractures, with slight mobile oil saturation. This formation is interspersed with thin bentonitic shale horizons.

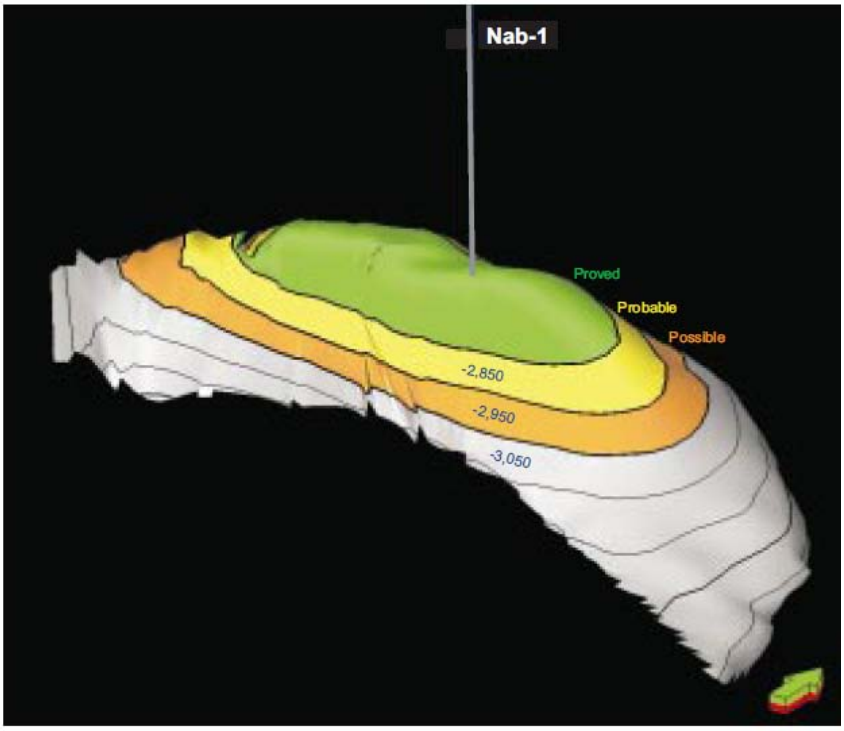


Figure 6.4 3D image of the Upper Cretaceous Breccia crest in the Nab field.

Mudstone to dolomitized and fractured wackestone were deposited in the Upper Cretaceous, with good heavy oil saturation. The Tertiary consists of interspersed shales with thin fine to medium grain sands alternations, while the Recent consists of poorly consolidated clays and sands.

Trap

At the Cretaceous and Upper Jurassic level, the trap is a structural type with a noticeable East-West orientation and affected by reverse faulting to the North and South, Figure 6.4.

Source Rock

The geochemical studies carried out in the area determined that the hydrocarbon source rock is of the Upper Jurassic Tithonian age and is made upof black bituminous shale and dark gray shaley limestone with abundant organic matter and broad regional distribution.

Seal

At a regional level, the seal is made up of plastic bentonitic shales partially calcareous of the Paleocene.

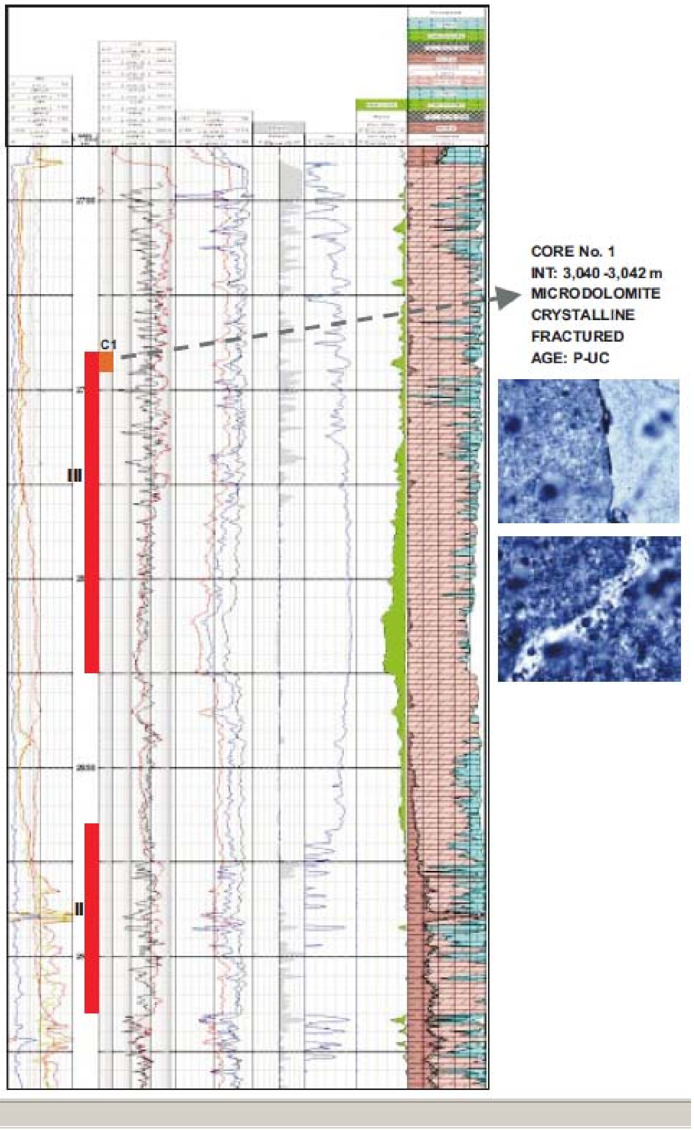


Figure 4.5 Petrophysical evaluation showing the intervals tested. Fractured dolomite can be seen in the thin lamina of the cores.

Reservoir

The Upper Cretaceous reservoir is composed of slightly argillaceous limestones with a microcrystalline and breccia texture. The porosity is of the secondary, intercrystalline type in fractures and dissolution cavities, with average porosity values of 7 percent and water saturation of 17 percent.

Three production tests were carried out. The first in the Upper Jurassic Kimmeridgian in a hole discovered that did not reveal the presence of hydrocarbons. The second was carried out in the Middle Cretaceous without flow and only one sample of heavy oil was recovered.

The third test was carried out in the Upper Cretaceous Breccia with 8.8 degrees API extra-heavy oil obtained and a production of 1,215 barrels per day and an initial pressure of 272 kg/cm2, using electorcentrifuge pumping. Figure 4.5 shows the processed well logs, indicating the oil and gas producer interval where the production test was made.

Reserves

The original volume of 3P oil reserves is 408.0 million barrels, while the original 3P oil equivalent reserves are estimated at 32.6 million barrels.

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