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Abstract

A small model oil field Tesla has been created based on assumptions and data from an existing field. With a lifetime of 8 years and expected total production of 8 million Sm^3 oil, it is a marginal development, where the development concept influence the net present value (NPV), which decides whether this field is going to be developed or not.

The made assumptions are thoroughly described, and used for inputs in Acona Cost Estimation Software (ACES).The assumptions mainly apply to the subsea system, process concept and platform. Production profiles are also calculated, and these are important for dimensioning the process facilities. These assumptions were applied to 8 platform concepts and by using ACES the results in form of technical-, cost- and NPV reports were calculated.

These results provided insight in e.g. which components on a production platform required great amount of structural material, the different amount of vessel days required for different marine operations, the basis for NPV calculations and how different platform concepts affected the NPV.

The major differences between concepts and their NPV was that wet trees with subsea system is more expensive than dry trees, and drilling facilities are costly investments for a small field with a small amount of wells. The option of leasing production facilities gave a larger positive NPV than purchasing the facilities, and tie-back of close-by discoveries can extend lifetime and provide a higher NPV.

The discussion summarizes what other factors can have an effect on the decided concept, and it is concluded that a jacket platform with dry trees is the most suitable development concept for the model field, due to its high NPV of 2955 million NOK, at an oil price of 75,76 USD/bbl.

Acknowledgment

I would like to thank my supervisor, Jonas Odland, for introducing me to offshore field development, and giving me the possibility to write a master thesis on the subject. I am grateful for the possibility I got to use ACES in my result calculations, and also want to thank Luis Pereira for help with the software.

To my dearest friends and family: Thank you for always supporting me, always encouraging me and having more faith in me than I had myself.

Abbreviations

ACES	Acona Cost Estimating Software
API	American Petroleum Institute
CAPEX	Capital expenditure
FPSO	Floating production, storage and offloading unit
FSU	Floating Storage Unit
GI	Gas injection
GoM	Gulf of Mexico
GWI	Gas and water injection
mD	milidarcy
Mill	Million
MODU	Mobile drilling unit
NCS	Norwegian Continental Shelf
NOK	Norwegian kroners
NPV	Net present value
O.e	Oil equivalent
OPEX	Operating expenses
PLET	Pipeline end termination
PW	Production well
ROV	Remotely operated vehicle
Sm^3	Standard cubic meter
TUC	Technical unit cost
TVD	True vertical depth
USD	US Dollars
WI	Water injection

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3 Introduction

World's energy demand is increasing (1) and although renewable energy is getting more and more important, fossil fuel have still a strong case in the world (2). Small oil and gas fields are highly depending on the technical solution and the oil and gas price and tariff. Small changes in oil price can make a development non profitable and therefore also not necessary to develop.

When developing an oil field it is more and more important to consider solutions that can extend the life time or even reuse after the lifetime of a field. One should consider and take into account close by fields and prospects, consider tie-back to the developing field, or maybe use the production facilities for processing oil and gas from nearby fields after the field is empty. These factors should be looked into together with the economic aspects for the development decision.

In this thesis Acona Cost Estimation Software (ACES) has been used to look into the total economy of a model field. With the help of ACES one is able to put together technical solutions for a field development, and calculate cost estimations based on previous experience and todays cost from the NCS. Technical and economical differences in the different concepts will be indicated, these will be discussed and projects with positive net present value will be determined.

A model field named Tesla is created based on data from an exciting North Sea field. For this model several development concepts are created and discussed. While every aspect of this field is based on assumptions, many of the assumptions will be thoroughly explained to show a better picture of why the selected concept is the most preferable concept.

4 Boundary conditions and assumptions

An existing North Sea field has been used as a basis to give realistic data for the model field in this thesis. The basis oil field is located in the North Sea but is not yet developed.

The main data used as basis for the model field:

Field location:	South North Sea
Reservoir geology:	Reservoir depth: 2290 m Geology Initial reservoir pressure: 245 bar
Field reserves and lifetime:	Tesla: 8 mill Sm^3 oil, 270 mill Sm^3 gas Robben: 3,2 mill Sm^3 oil
Wells and well layout:	6 wells: 4 production, 2 water injection wells
Technological solution:	Satellite wells Injection of water and gas to keep production rates high
Size of platform and integrated storage:	40 beds on platform 95 500 m^3 storage

Other assumptions that are not based on this existing field will be explained thoroughly in chapter 7.

5 Method

To calculate economical results and discuss a suitable solution for the field development of a marginal field, a model field is created. Relevant data are collected from an existing field and from assumptions. Acona Cost Estimation Software(ACES) is used for calculation of cost. ACES provides technical reports, cost reports and NPV reports, which are thoroughly discussed. A suitable development concept is in the conclusion selected and given reason for.

1. Acona Cost Estimation Software

Acona Cost Estimating Software is a web based software that provides cost and weight estimations, Pre-tax NPV and execution schedules (3). ACESs database is based on previous experience from projects on the NCS. Economical parameters are updated quarterly and the cost attribute database is based on HIS/CERA UCCI (4). *"IHS UCCI tracks the costs of equipment, facilities, materials and personnel (both skilled and unskilled) used in the construction of a geographically diversified portfolio of 28 onshore, offshore, pipeline and LNG projects."* (5)

2. Basis for cost calculations

Estimating cost is a complicated task, with several steps that needs to be considered before an accurate result is presented.

Design basis is the starting task of cost calculation. In design basis the design of the system and concept is developed and described along with technical quantities. Previous project experience and marked analysis are also important factor for calculating the correct cost.

A detailed weight estimation and a description of all marine operations related to the project needs to be included in the technical basis. The weight estimate is important when cost is calculated, because several cost estimation equations contains weight as a parameter.

5.2.1 Equations

The equations are taken from the subject OFF515 Offshore field development (6):

5.2.1.1 Engineering, Hook-up and commissioning, Management

$$Cost_{engineering} = p \times r \times W$$

$$Cost_{hook-up\ and\ commissioning} = p \times r \times W$$

$$Cost_{management} = p \times r \times W$$

where;

p = productivity; number of man-hours per tonne (MHR/tonne)

r = man-hour rate (USD/MHR)

W = total weight (tonnes)

The productivity depends on location (regional practice) and complexity of facility. The man-hour rate for engineering depends on location of the engineering contractor, while for hook-up where the work is done (offshore/onshore).

5.2.1.2 Procurement (cost of materials)

$$Cost_{materials} = \sum (c_i \times W_i)$$

where:

W_i = weight for weight category (i); (tonnes)

c_i = cost per tonne for weight category (i); (USD/tonne), including freight

i = weight category (equipment, electrical, instrument, piping, etc.)

For bulk materials and steel it is necessary to include a percentage (say 5-10% for waste)

5.2.1.3 Fabrication

$$Cost_{fabrication} = \sum (p_i \times r_i \times W_i)$$

where:

p_i = productivity; number of man-hours per tonne (MHR/tonne)

r_i = man-hour rate (USD/MHR)

W_i = weight for weight category (i) (tonnes)

The productivity p_i depends on weight category (i) and location (regional practice). The man-hour rate depends on the location of the fabrication site. Normally the same man-hour rate is used for all weight categories at the same site.

5.2.1.4 Marine operations

The cost of marine operations is based on a systematic and thorough description of the operations.

$$Cost_{marine\ operations} = \sum (d_i \times T_i)$$

where:

T_i = time needed for operation (i); (days)

d_i = overall day-rate for operation (i); (USD/day)

i = operation category

The day-rate (d) depends on type of vessel needed for the operation. High oil price often means high day-rates, because the level of activity is higher with high oil prices.

The day-rate has to be paid for a certain number of days (T). In general the time can be calculated as:

$$T = T_{m/d} + T_{wow} + T_{operation}$$

where:

$T_{m/d}$ = time for mobilization and de-mobilization of vessel

T_{wow} = time for waiting-on-weather (non-productive time)

$T_{operation}$ = time for executing the operation (based on expected efficiency)

The time for mobilization and de-mobilization of vessel is primarily related to the location. The time for waiting-on-weather depends on environmental conditions for the relevant location and season, and on the characteristics/robustness of the vessel. The time for executing the operation depends on type of operation and characteristic of vessel. Normally an expensive vessel can do the operation faster than a cheap vessel.

Marine operations are of special importance for pipelines. For pipelines the time is often calculated as:

$$T_{operation} = {}^{L}/_{R} + T_{tie-ins}$$

where:

L = length of pipeline (m)

R = lay-rate (m/day)

$T_{tie\text{-}ins}$ = the time needed for tie-ins (days).

6 Design basis and assumptions

The model field Tesla is located in the south part of the North Sea, about 150 km from shore (Egersund), in block 8/2 and partly in block 17/12. Water depth is between 105 and 120 m.

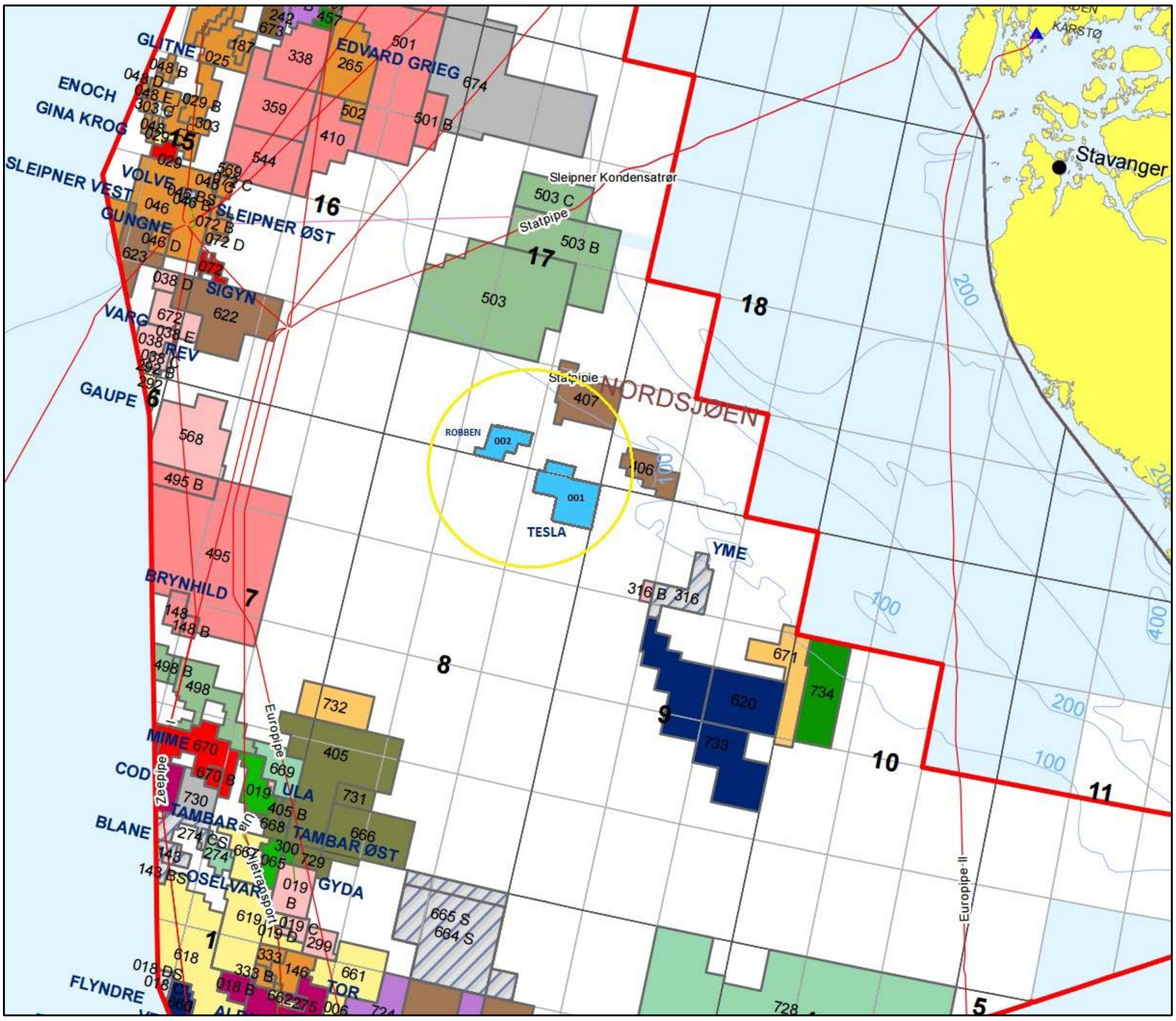

Figure 1: Location of model field Tesla on the NCS (7)

1. Geology of the reservoir

Tesla is located in the south part of the North Sea, an area called Egersund basin (8). Egersund basin contains reservoir rocks that are mostly middle Jurassic, Bryne (sandstones, siltstones, shales and coals (9)) and Sandnes (sandstone (10)) formation. Most of the oil is in the Bryne formation. The reservoir is flat with an oil column at about 26 m and a semi pervious permeability with about 5000 mD. The field pressure is low, it is therefore necessary to employ water injection to uphold good production rates and obtain a high recovery factor. The reservoir contains small amount of gas. The gas will not be exported, only used as fuel or re-injected in the reservoir.

2. Nearby discovery

The Oil discovery Robben is located in block 17/11 just about 13 km north west from Tesla. The discovery is estimated to contain 3,2 million Sm^3 o.e. Analysis of the Robben oil shows similar qualities to the Tesla oil.

3. Production and production profiles

Tesla is estimated to produce for 8 years with production profiles that are shown in figure 2-4. These profiles are assumed with a reasonable decline in production of oil and gas, and an incline in production of water. A total of 8 million Sm^3 oil, 270 million Sm^3 gas and 18,7 million Sm^3 water is estimated in Tesla. Robben is estimated contain 3,2 million Sm^3 oil and to produce for 5 years. If Robben is developed as a tie-back to Tesla it will start producing in year 6, and the lifetime of Tesla will be exceeded to 10 years. Maximum production and daily production will not have significant changes and therefore the process facilities on platform will stay the same. From the production profiles yearly production is assumed and maximal and daily production is calculated.

Stream days are used for calculating daily and maximal production. Stream days are the assumed days a year the facilities are producing as planned. In these calculations, 340 stream days is a reasonable assumption.

6.3.1 Oil production Tesla

Accumulated oil production is about 8 million Sm^3.

Per year: 8 million Sm^3 / 8 years = 1 million Sm^3/year

Per day: 1 million Sm^3 / 340 days = 2941 Sm^3/day. Round up to 3000 Sm^3/day.

Maximal production is in year 1: 3 million Sm^3

Maximal production per day:

3 million Sm^3 / 340 days = 8824 Sm^3/day Round up to 9000 Sm^3/day.

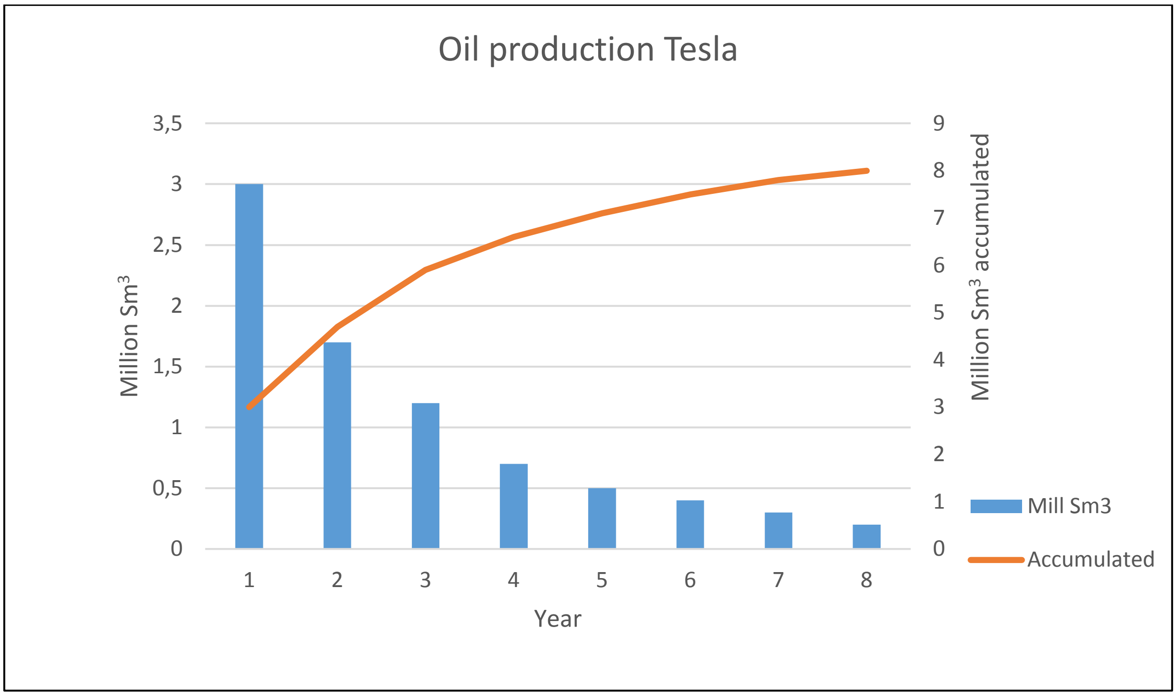

Figure 2: Graphical representation of oil production on Tesla

6.3.2 Gas production Tesla

Accumulated gas production is about 270 million Sm^3.

Per year: 270 million Sm^3 / 8 years = 33 750 000 Sm^3/year

Per day: 33 750 000 Sm^3 / 340 days = 99 265 Sm^3/day. <u>Round up to 0,1 million m^3/day.</u>

Maximal production is in year 1: 100 million Sm^3

Maximal production per day:

100 million Sm^3 / 340 days = 294 118 Sm^3/day. <u>Round up to 0,3 million Sm^3/day.</u>

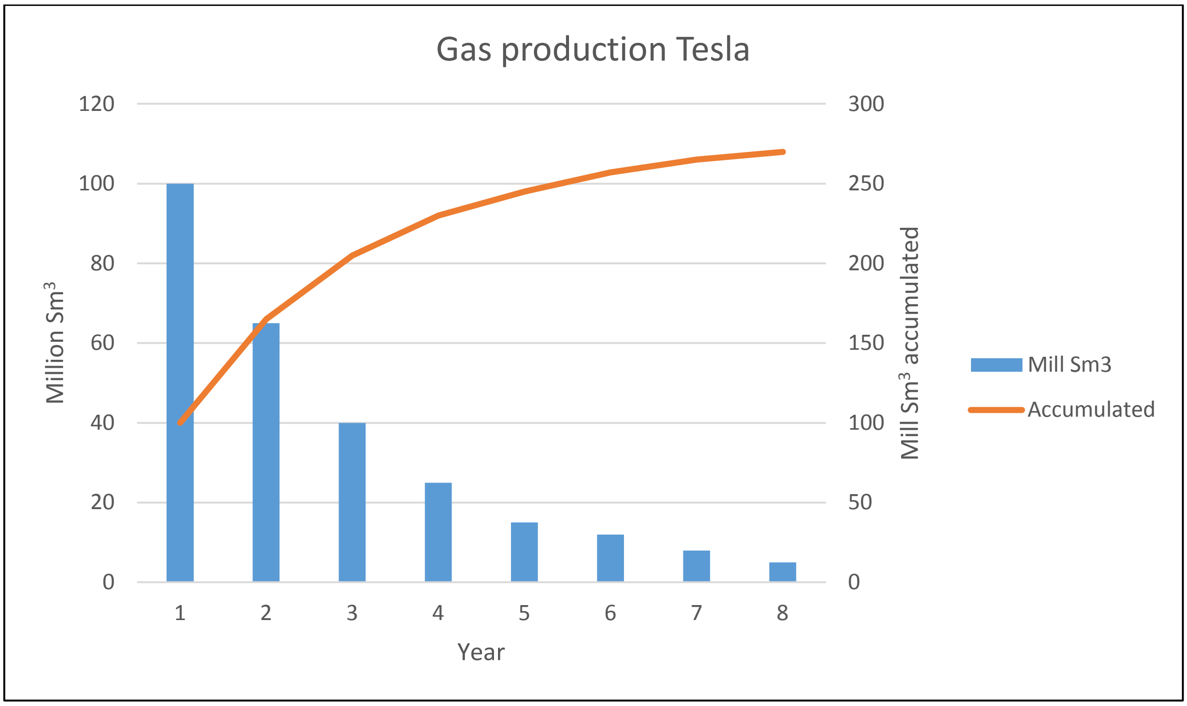

Figure 3: Graphical representation of gas production on Tesla

6.3.3 Water production Tesla

Accumulated water production is about 18,7 million Sm^3.

Per year: 18,7 million Sm^3 / 8 years = 2,34 million Sm3/year

Per day: 2,34 million Sm^3 / 340 days = 6882 Sm^3/day. Round up to 7000 Sm^3/day.

Maximal production is in year 8: 3,3 million Sm^3

Maximal production per day:

3,3 million Sm^3 / 340 days = 9706 Sm^3/day. Round up to 10 000 Sm^3/day.

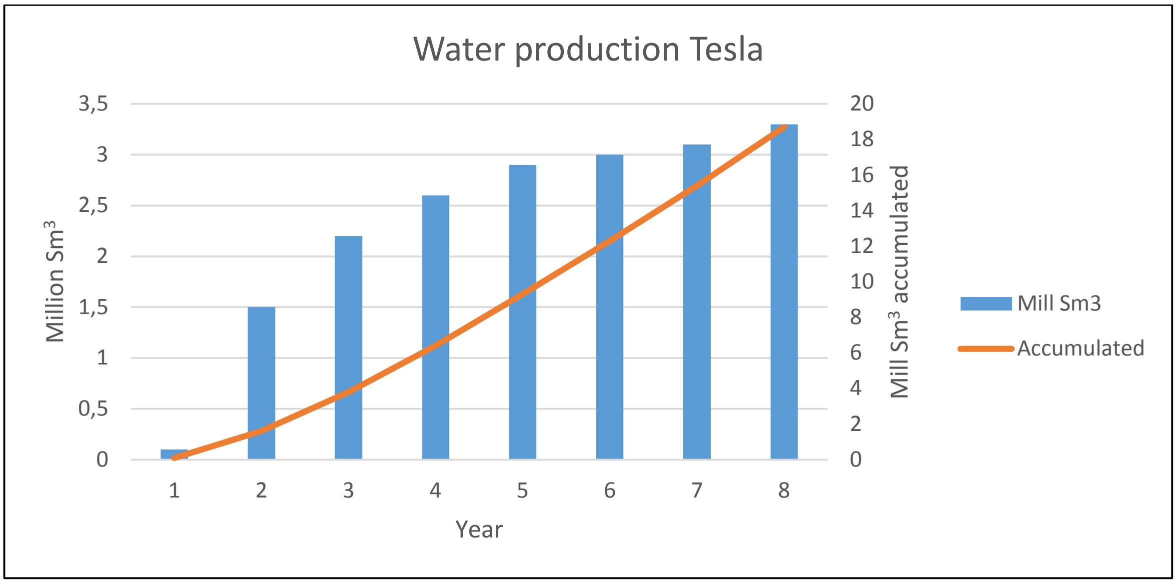

Figure 4: Graphical representation of water production on Tesla

6.3.4 Oil production Robben

Accumulated oil production is about 3,2 million Sm^3.

Per year: 3,2 million Sm^3 / 5 years = 640 000 Sm^3/year

Per day: 640 000 Sm^3 / 340 days = 1882 Sm^3/day. Round up to 2000 Sm^3/day.

Maximal production is in year 1: 1,3 million Sm^3

Maximal production per day:

1,3 million Sm^3 / 340 days = 3824 Sm^3/day. Round up to 4000 Sm^3/day.

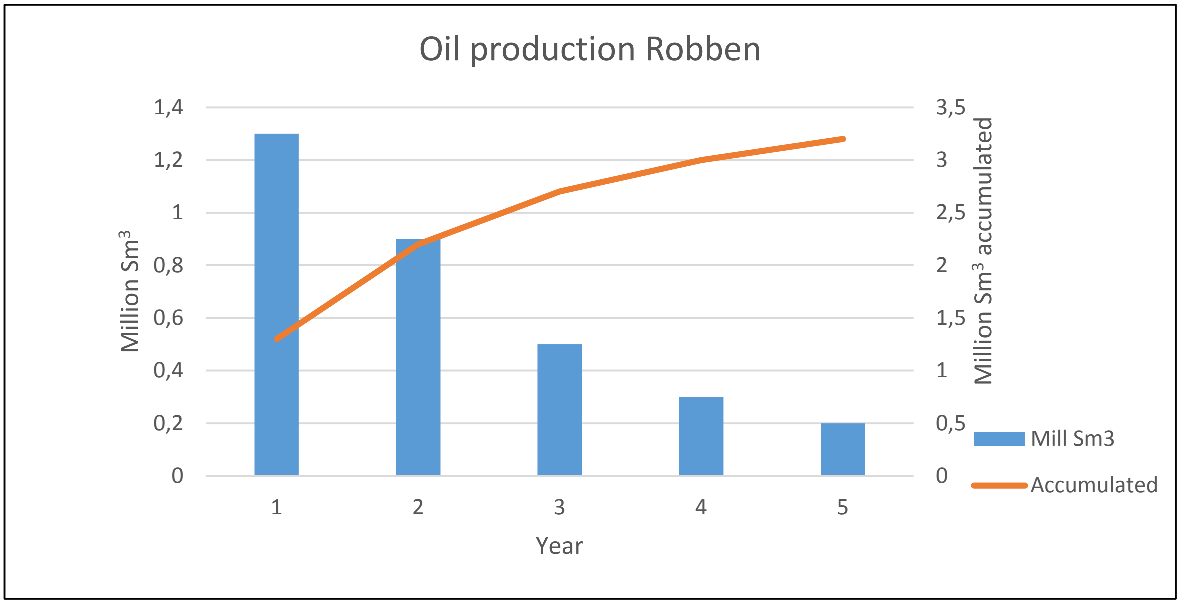

Figure 5: Graphical representation of oil production on Robben

6.3.5 Water production Robben

Accumulated water production is about 8,1 million Sm^3.

Per year: 8,1 million Sm^3 / 5 years = 1,62 million Sm^3/year

Per day: 2 million Sm^3 / 340 days = 4765 Sm^3/day. Round up to 5000 Sm^3/day.

Maximal production is in year 5: 3 million Sm^3/year

Maximal production per day:

3 million Sm^3 / 340 days = 8824 Sm^3/day. Round up to 9 000 Sm^3/day.

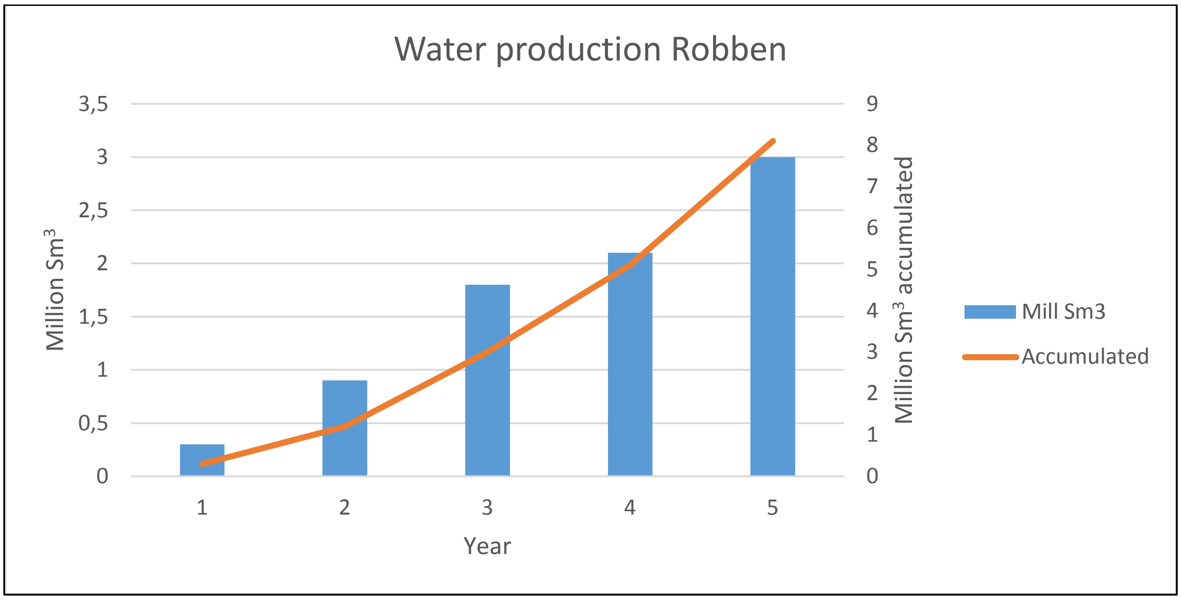

Figure 6:Graphical representation of water production on Robben

6.3.6 Oil production with Robben as tie-back

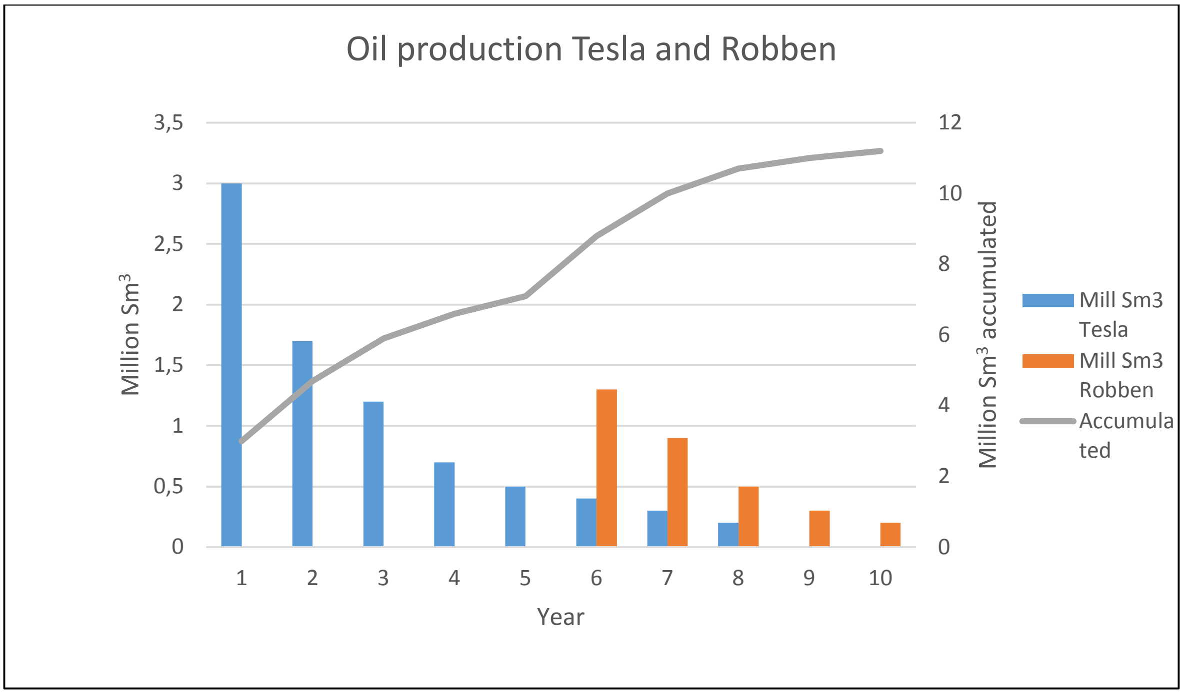

Figure 7: Graphical representation of oil production on Tesla and Robben

6.3.7 Maximum liquid capacity

Maximum liquid capacity is important regarding the dimensioning of the process facilities. The ACES User Manual (11) suggests an equation for calculating maximum liquid capacity:

$$\left(\text{oil}^{\frac{3}{2}} + \text{water}^{\frac{3}{2}}\right)^{\frac{2}{3}}$$

Assuming the values used in this equation are maximum values for water and oil:

$$\left(9000^{\frac{3}{2}} + 10\,000^{\frac{3}{2}}\right)^{\frac{2}{3}} = 15\,091$$

<u>Round up to 16 000 Sm^3/day.</u>

This is without consideration of the Robben oil because it will not add considerable amount of liquid.

4. Wells and subsea solution

The Tesla field is going to be developed with 6 wells, where 4 are production wells and 2 water injection wells (WI). One of the water injection wells is going to be a satellite well, located about 2 km south for the platform. The other water injection well is also going to be a gas injection well, where gas is injected alternating with water.

The depth is set to 2290 m for all the wells, with a horizontal reach of 1200 m. When developing with dry trees, one of the water injection well is assumed to have a horizontal reach of 2000 m because all wells start at the platform.

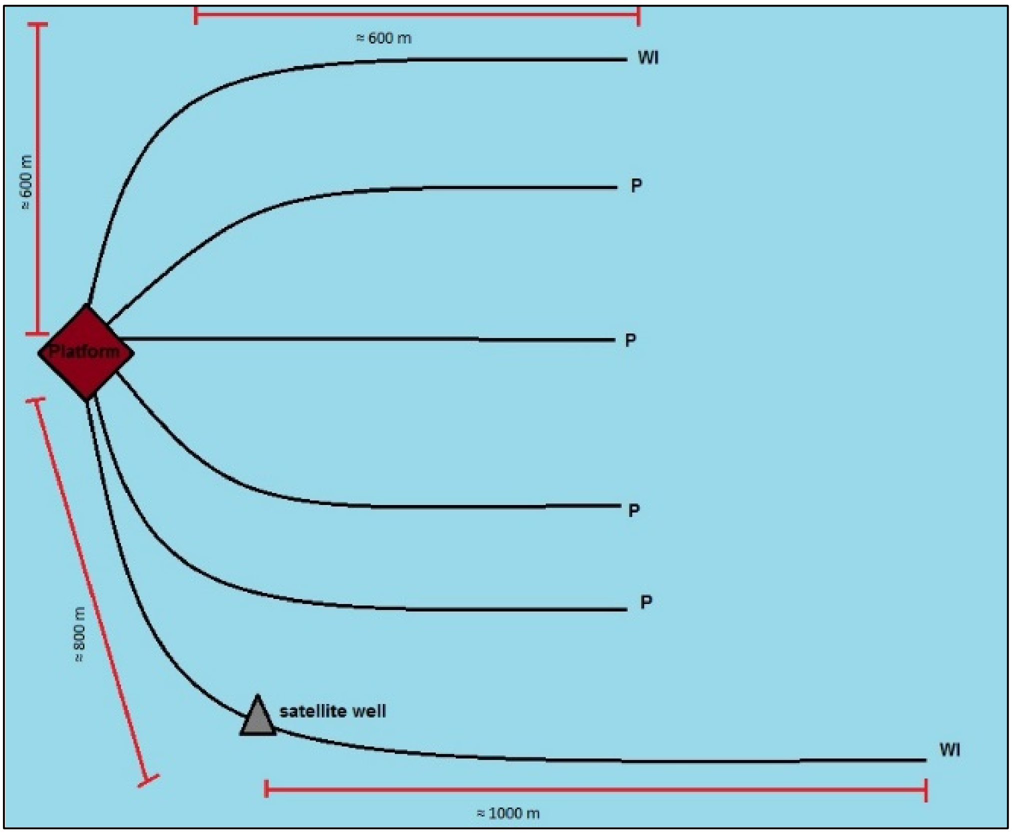

Figure 8: Well overview

The horizontal section is assumed to be 500 m on all wells, this is to avoid a too short radius.

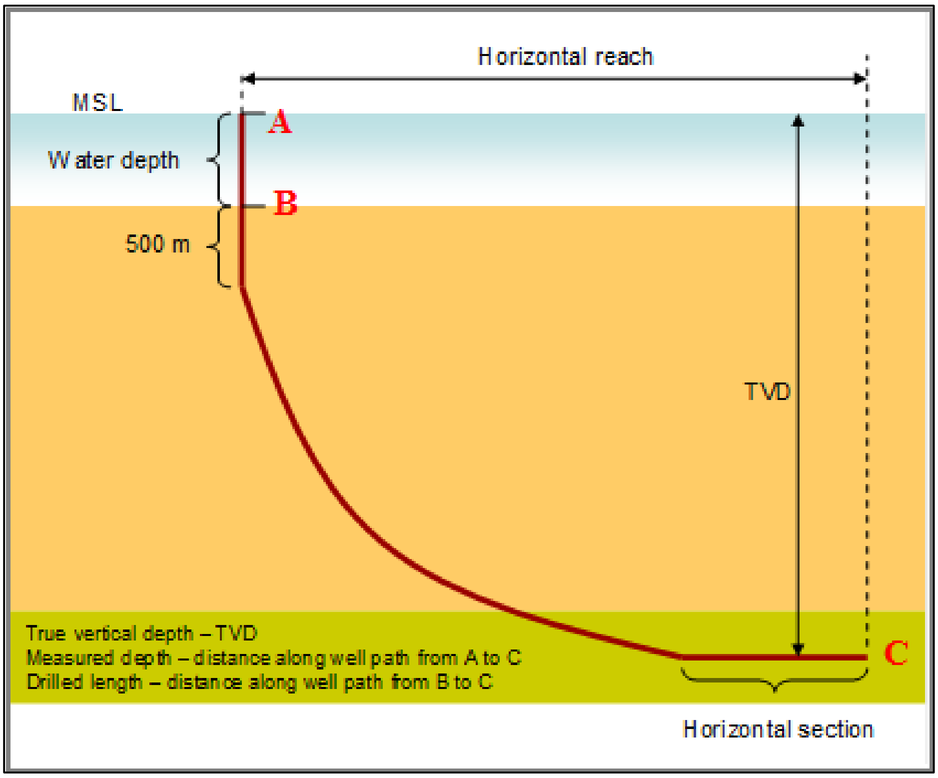

Figure 9: TVD, horizontal reach and horizontal section of well (11)

6.4.1 Subsea system

The subsea systems of solutions containing wet trees will include wells, templates and manifolds.

The basis is 4 production wells and 1 water/gas injection well located close to the production platform (at maximum 300 m distance from platform), and a distant satellite water injection well. The platform wells are on a template around a manifold, and the satellite well are also connected to this manifold.

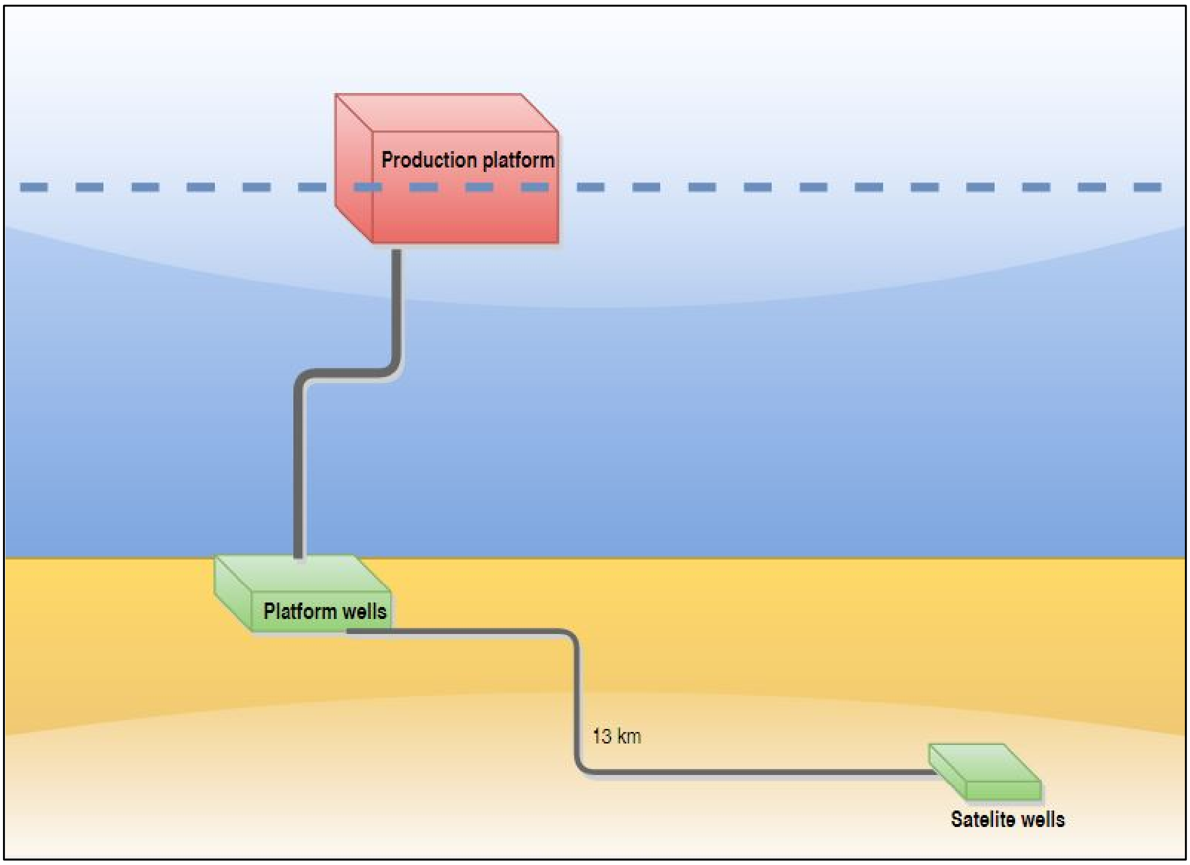

Figure 10: Production platform, wells at platform and satellite wells

Because of the number of wells in the model field, a 4 and 6 slot template is suitable. FMC Technologies is delivering about 45 % of subsea trees and manifolds on the NCS (12) and have a lot of different template and manifolds available, including 4 and 6 slots.

6.4.1.1 4 slot template

All the production wells are located on the template. The injection wells are "both" satellites, but one is close to the template, connected with a spool. The other satellite is 2 km away, connected with a pipe.

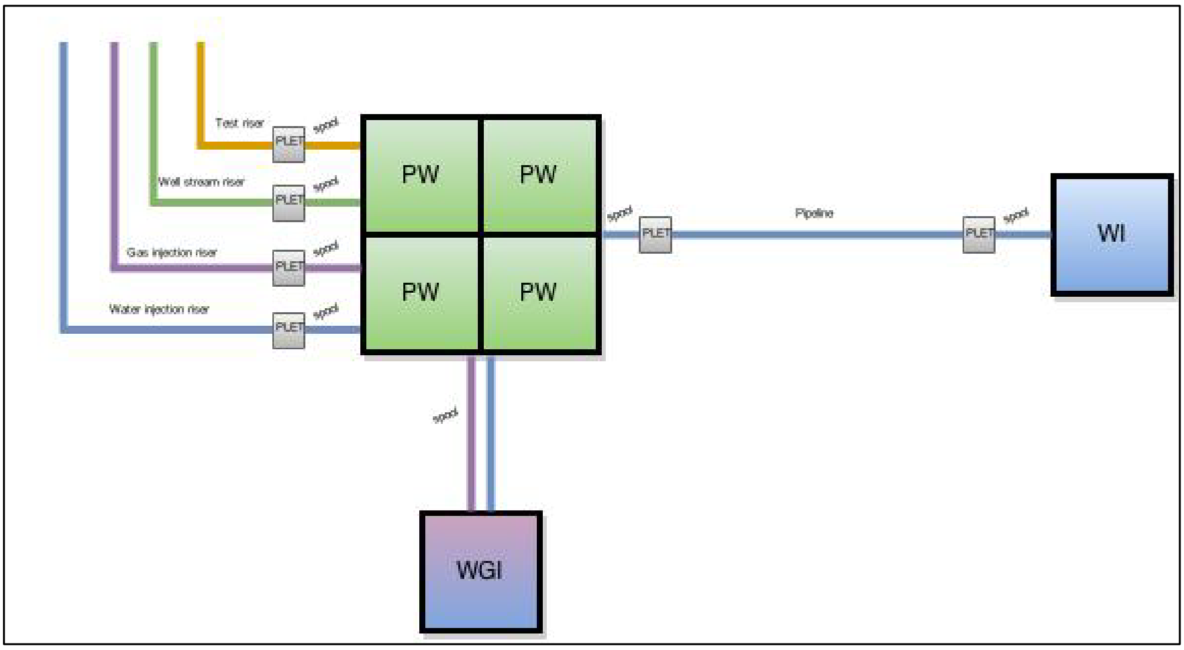

Figure 11: Subsea system with a 4 slot template

6.4.1.2 6 slot template

The 6 slot template contains all the production wells and a water/gas injection well. There will be an open slot in the template. The satellite water injection well will be located 2 km away.

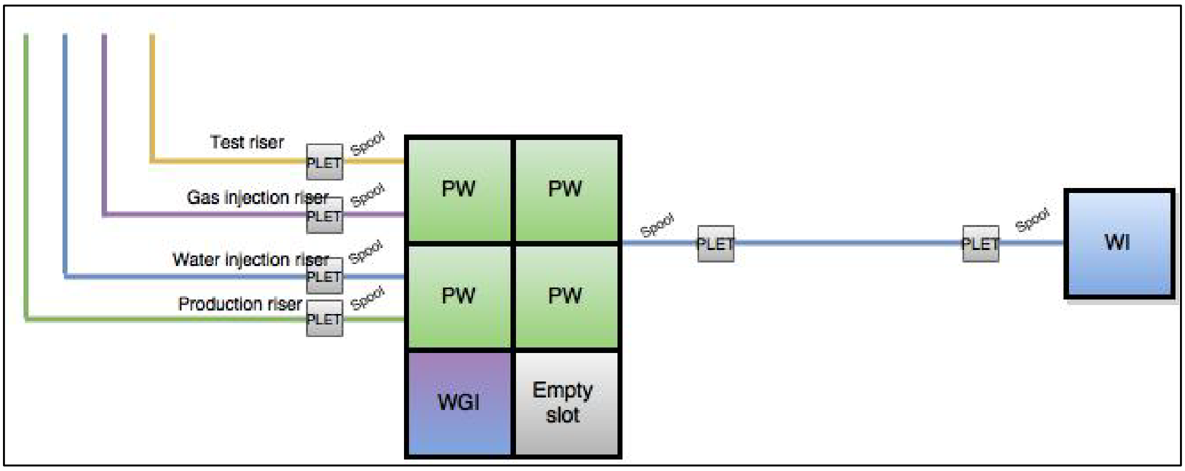

Figure 12: Subsea system with a 6 slot template

In this project all the subsea developments will have 4 slot manifold/template, this is because a larger template will be more expensive and unnecessary because of the free slot.

6.4.1.3 Robben tie-back

If the small discovery Robben was to be built out, it is assumed to have one production well and one water injection well connected to a manifold. The manifold is connected with a 13 km long pipeline to the existing manifold or directly to the production platform if it originally is a dry tree solution.

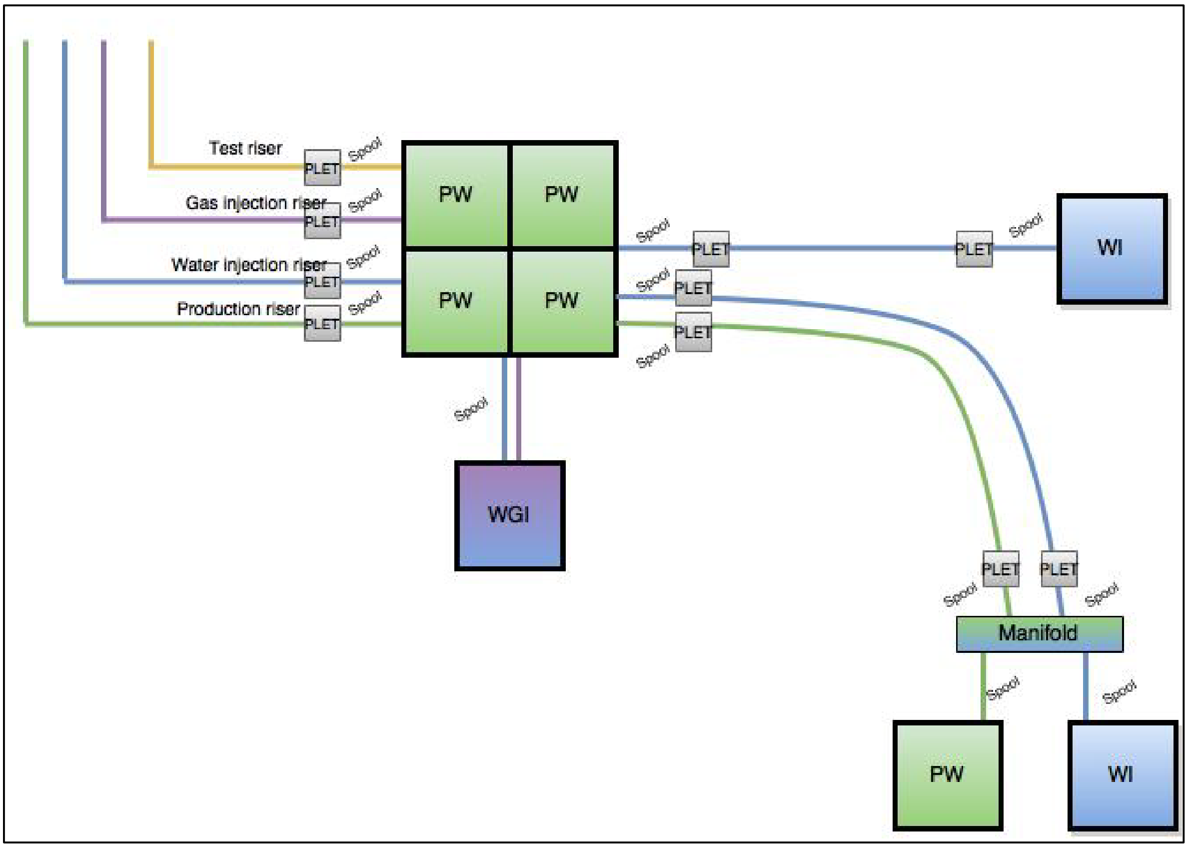

Figure 13: Subsea system with Robben tie-back

6.4.2 Umbilical, flowline and riser system

The umbilical, flowline and riser system is only relevant for solutions with a subsea system. The solution is shown in Figure 11. Necessary flowlines are; well stream, well test, water injection and gas injection. Usually risers are connected to a riser base before it is connected further to a pipeline or a pipeline end termination (PLET). But since the distance from platform is short (max 300 m) it is not necessary to have a riser base. The riser connects directly to a PLET, either it is a J-tube or flexible riser.

6.4.2.1 Riser

For the floating concepts, a flexible riser is most suitable, since they can accommodate the motions from waves and currents. For a fixed platform with wet trees, a J-tube riser is the most basic suitable riser concept.

6.4.2.2 Pipe material, surface cover option and lay method

In this case a clad material is found suitable for the project. Clad is a base material and a corrosion resistant material linked together. Advantages of Clad is smaller wall thickness compared to many other standard materials, weight saving and therefore material cost reduction (13). Clad pipes can be laid in many ways, but reel lay is possibly the most suitable for our project. Reel lay is suitable for shallow water as well as for deep water and have a high production rate (14). Insulations can prevent hydrate formation and wax formation and is applied on all flowlines. This section is applicable on all subsea solutions on this field.

Figure 14: A reel-lay vessel (14)

6.4.2.3 Gravel dumping code

A safety zone of 500 m around the production facility is set. Inside this area the subsea equipment is only going to be protected against falling objects. Outside this area there is a need for gravel dumping on pipelines due to fishing activities in these parts of the North Sea. The gravel dumping code is assumed to be medium outside the safety area.

6.4.2.4 Pipe diameter and wall thickness

Pipe diameter and wall thickness highly depend on flow capacity and pressure. The flow capacity which is set for well stream flowline is 10 000 Sm^3 o.e per day, 10 000 Sm^3 o.e per day for the water injection flowline from platform to the platform well, 300 000 Sm^3 o.e per day to the gas injection flowline and 5000 Sm^3 o.e per day to the satellite well flowline. These numbers are calculated from chapter 7.3.

Inlet pressure of 300 bar and pressure drop of 20 bar is set for all the groups. From that, the program calculates a suggested diameter and wall thickness. The suggested well stream pipe diameter is 8 in with a 9 mm thickness. This is used for all the pipes, except for the satellite water injection well, which is given a diameter of 6 in and 7 mm wall thickness.

5. Platform

The most significant difference between the various concepts is the platform concept. The different platform concepts are going to be explained in Chapter 9.

A number of 40 beds is set and is going to be applied to all the concepts. An integrated storage capacity of 95 500 m^3 is applied to the solutions with integrated storage. A proposed storage capacity for a tanker is in ACES User Manual (11) suggested to be 150 000 m^3.

6.5.1 Drilling and drilling package

For a small field like this a complete platform drilling package is not necessary. Drilling will be executed by a MODU of the jack-up type. For fields on deeper water, a semi-submersible MODU could have done the drilling operation. For drilling of the dry trees on the jacket we need to have extra equipment, and a jack up drilling package is applied.

6.5.2 Dry trees vs. wet trees

There are advantages and disadvantages with both alternatives. With a dry tree solution the trees and well control is at surface, easily accessed by people and with a direct access to the wells if well intervention is needed. But because of this access at surface there is also a safety risk. Wet trees are on the seabed and isolated to people, but accessible from surface or by ROVs.

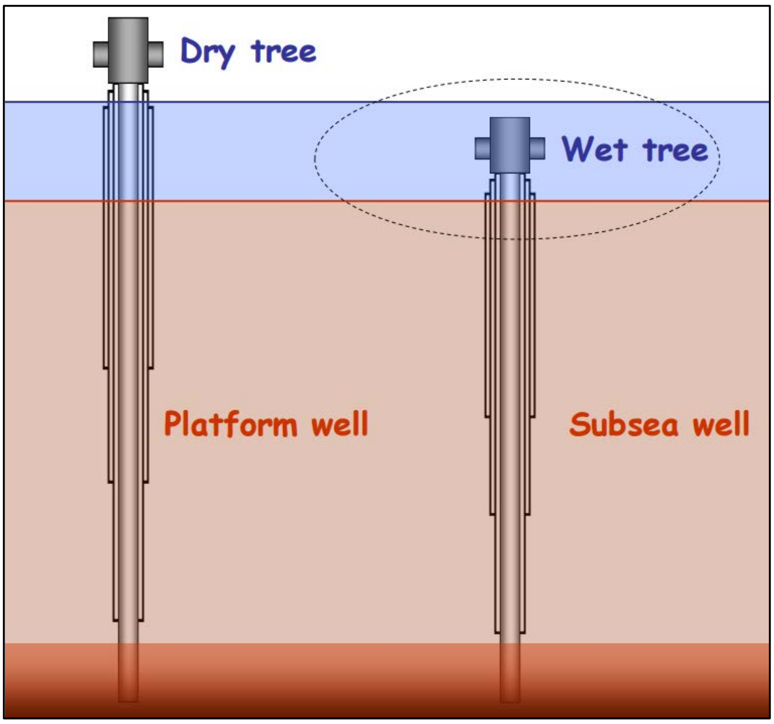

Figure 15: Dry tree vs. wet tree (15)

6.5.3 Process concept

Calculations in Chapter 7.3 has determined a daily production of oil and gas, water and gas injection capacities, produced water treatment capacity and maximum liquid capacity. These are important when designing process facilities.

Oil condensate density:

It is necessary to assume a reasonable oil density. API gravity is a measure for how dense oil is in relation to water. Oil is classified as light, medium, heavy and extra heavy depending on the API gravity. Light oil have an API gravity at more than 31,2, medium between 22,3 and 31,1, heavy less than 22,3 and extra heavy less than 10 (16). Less dense oil is more preferable than heavy oil, because it contains more hydrocarbons. A medium dense oil, with an API gravity at 27 is assumed.

6.5.3.1 Gas conditioning and dehydration

Raw gas has often significant concentrations of H_2S and or C3+, and can therefore not be used directly in gas engines, because of the danger of corrosion and carbon built up in the engine (17). Gas conditioning is therefore needed if the gas is going to be used as fuel. Gas also often contains large amounts of water, and to prevent the water freezing in pipelines or hydrate formation we remove the water by a glycol dehydration unit (18).

6. Construction site of platform: Norway or Far East

Some of the first platforms and rigs on the NCS was built in Norway and was made of concrete, where both the concrete legs and topside was built on shore in Norway and transported offshore (19). These platforms were replaced by cheaper floating steel platforms and subsea installations (20). In 2013 only one out of four contracts for large offshore installation were won by Norwegian yards. The price is an important factor in the choice of yard, even though earlier experience have showed delays, over expenditure and quality issues (21), Asian yards have an advantage in cheaper labours.

Capex Platform built in NORWAY Overview (mill.NOK)

Cost elemen	Engineering	Procurement	Construction	**SUM EPC**	Marine op	**SUM EPCI**	Management	**Base estimate**	Contingency	**Total**
Topsides	1146	1526	1368	4040	34	4074	570	4644	697	5341
Substructure	304	379	407	1089	210	1300	182	1482	222	1704
Piles, anchor	0	180	0	180	210	391	55	445	67	512
Sum Platfor	**1449**	**2086**	**1775**	**5310**	**455**	**5764**	**807**	**6571**	**986**	**7557**

Capex Platform built in FAR EAST Overview (mill.NOK)

Cost elemen	Engineering	Procurement	Construction	**SUM EPC**	Marine op	**SUM EPCI**	Management	**Base estimate**	Contingency	**Total**
Topsides	1146	1526	587	3259	34	3292	461	3753	563	4316
Substructure	304	373	261	938	210	1148	161	1309	196	1505
Piles, anchor	0	145	0	145	210	355	50	405	61	466
Sum Platfor	**1449**	**2044**	**848**	**4341**	**455**	**4796**	**671**	**5467**	**820**	**6287**

Table 1: CAPEX platform built in Norway vs. Far East overview

An example from the concept jacket with dry trees, shows the difference between a platform built in Norway and in FAR EAST. Engineering is similar because the program is set to engineer everything in Norway. The construction cost in Norway is nearly double the construction cost in Far East. A total of 1270 mill NOK is the difference, making it about 20% more expensive to construct the platform in Norway (15).

Figure 16: Construction of the Martin Linge jacket substructure in Verdal, Norway (22)

Only 1 of the topsides of 10 ongoing field developments in Norway at the start of 2015 was constructed in Norway (23). Of the 10 developments, 5 were jacket structures, but only 2 are built in Norway. Still, the other 3 are constructed in Europe.

Based on this research, it is assumed that the jacket structure is built in Norway while topside is built in Far East. For all other concept solutions, everything is built Far East.

7. Storage options

Building an export pipeline is a large investment, especially for a small field. There is a possibility to connect to a nearby existing pipeline, but for this model field the closest export pipeline for gas is about 75 km away and 150 km for oil.

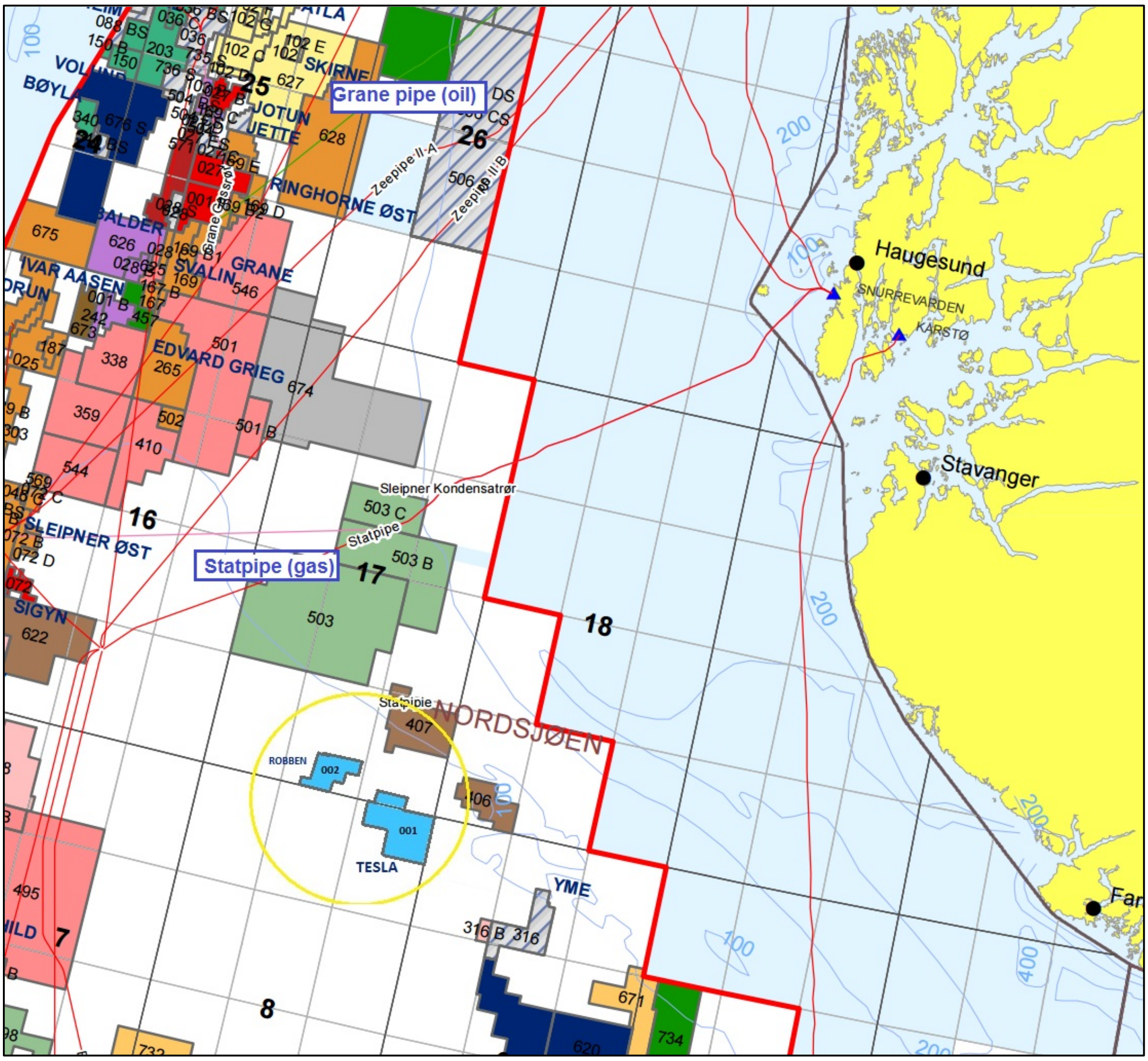

Figure 17: Model field Tesla and closest pipeline overview (7)

The option is then either to have a production facility with integrated storage or external storage as e.g. floating storage unit (FSU), storage in buoy or subsea storage. Subsea storage and buoy are good in areas with harsh weather conditions, where there is no possibilities to access with a shuttle tanker (24). ACES have only two storage options: internal storage in platform and an FSU, so the subsea storage and buoy will not be considered.

In concepts with an FSU, the FSU will permanently be on the field and processed oil will be stored. A shuttle tanker will offload the oil via an offloading buoy or turret loading, and transport it to shore.

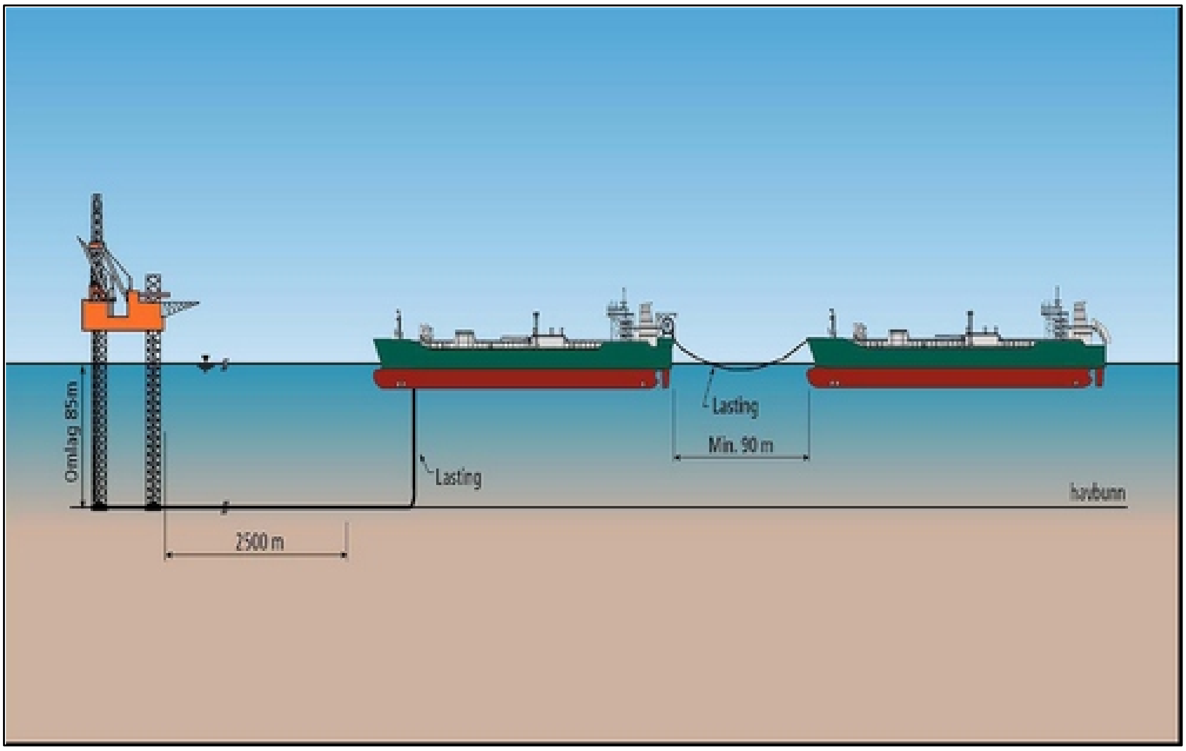

Figure 18: Example of a FSU loading system (25)

6.7.1.1 Lease or purchase FSU

Not all concept solutions have integrated storage in the production facilities. A FSU may be needed. This FSU can either be leased or bought. Since the model field has only 8 years of expected lifetime, to lease a FSU will be cheaper than investing in it. There are also several companies which deliver this leasing service. ACES also has this option as a standard.

8. Lease or purchase of production unit

In cases where the lifetime of a field is relatively small, perhaps under 10 years, it might be economically reasonable to lease a production unit instead of purchasing one. The lease price depends on the unit; a large brand new unit will cost more than a used smaller unit. In addition to that, the market price will have an impact.

9. Removal and abandonment

After a field has reached its lifetime and cannot be used for other purposes e.g. host platform for tie back and satellite fields, it is shut down. The wells are plugged and the platform abandoned.

Jacket platforms and concrete platforms are decommissioned offshore, piece by piece in the opposite order of installation. The topside is often divided into small pieces, lifted off and transported to shore for further scrapping. The jacket structure is cut in smaller pieces by a ROV, and lifted up by crane or by a flotation tank, and then transported to shore (26).

Figure 19: Decommissioning of a jacket platform (27)

The concrete Condeep platforms are more difficult to decommission and often involve larger risk. An alternative there is to remove topside and the top of the concrete structure, so that ship traffic can pass without risk. This was considered on one of the abandoned fields on the NCS, Frigg (26). At that time the conclusion was that this would be even more risky than total removal, and it was decided to let the concrete structures stand, with a solar driven warning light to warn ship traffic.

Figure 20: What is left of the decommissioned concrete platform Frigg (28)

A floating platform or a MOPU is somewhat easier to decommission. After well plugging the platform disconnects all the risers, export risers and umbilicals. The pipes and flowlines needs to be cleaned, and then either removed by reverse reel lay (if they were reel laid) or by cutting and lifting. Pipelines that are buried can be left in situ, often without major intervention (29). Other subsea structures are also cut and lifted by crane or a floatation tank, and transported to shore. With a floating production platform or semi-submersible the anchors are loosened and the platform is transported or towed to shore. A MOPU raise the legs and is towed to shore.

The advantage with FPSO, Semi-submersible and MOPU is that they can be reused. After serving a smaller field with short lifetime, the platform often only need smaller modifications and upgrades, if the unit is constructed with a longer lifetime than the field. Therefore the cost of abandonment of a field may be smaller than for a jacket platform. ACES does not take into account that the unit can be reused and the economic aspects of that, and assumes that everything is scrapped. Although the same procedures are applied, removal of a jacket platform requires a larger amount of marine operations, which will have a large effect on the removal cost.

Removal Cost for Semi Submerssible Overview mill.NOK

	Engineering	Decommissioning	Removal operations	Dismantling	Sub-total	Management	Base estimate	Contingency	TOTAL
Well plugging and abandon	39	0	893	0	931	93	1024	154	1178
Platform topsides	18	45	0	82	146	15	160	24	184
Platform substructure	13	8	27	24	72	7	79	12	91
Mooring lines, piles, anchor	2	8	29	3	42	4	47	7	54
Risers, conductors	0	0	17	0	18	2	19	3	22
Flowlines, umbilicals and ca	0	2	16	0	18	2	20	3	23
Export pipelines	0	0	0	0	0	0	0	0	0
Subsea equipment and stru	6	24	76	9	114	11	126	19	145
Sea bottom clean-up	1	0	23	0	24	2	27	4	31
TOTAL	**79**	**88**	**1081**	**118**	**1366**	**137**	**1502**	**225**	**1728**

Removal Cost for Jacket Overview mill.NOK

	Engineering	Decommissioning	Removal operations	Dismantling	Sub-total	Management	Base estimate	Contingency	TOTAL
Well plugging and abandon	39	0	893	0	931	93	1024	154	1178
Platform topsides	18	52	304	79	453	45	499	75	573
Platform substructure	21	13	400	59	492	49	542	81	623
Mooring lines, piles, anchor	0	0	0	0	0	0	0	0	0
Risers, conductors	0	0	19	0	20	2	22	3	25
Flowlines, umbilicals and ca	0	2	16	0	18	2	20	3	22
Export pipelines	0	0	0	0	0	0	0	0	0
Subsea equipment and stru	6	24	76	9	114	11	126	19	145
Sea bottom clean-up	1	0	24	0	25	2	27	4	31
TOTAL	**85**	**91**	**1730**	**147**	**2054**	**205**	**2259**	**339**	**2598**

Table 2: Removal cost for semi-submersible vs. jacket platform overview

The removal operations for jacket are 649 mill NOK larger than for the semi-submersible, and 870 mill NOK larger in total. The total removal cost for a jacket platform is about 50 % larger than for a semi-submersible.

Assuming the production unit at the model field is brand new and reusable, removal costs can be disregarded in the NPV calculations, but included in discussion and whether it is a determinant in the concept decision process.

7 Possible concepts

There are several concepts that can be implemented on an oil field.

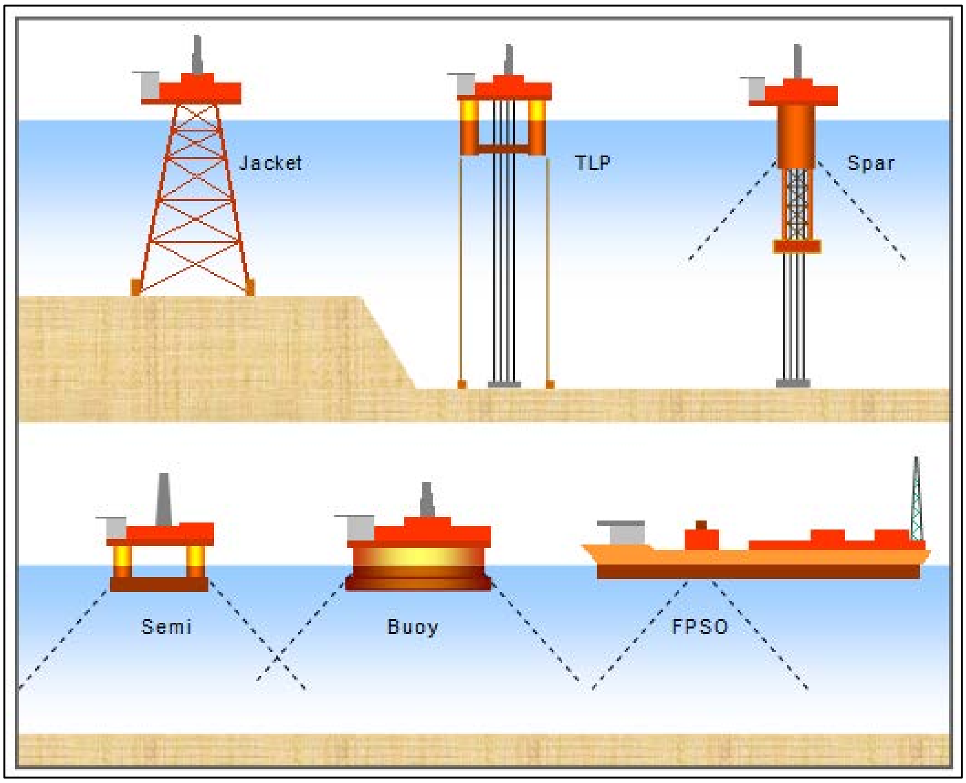

Figure 21: Platform concept overview (11)

- Jacket
- Compliant tower
- Fixed concrete platform
- Jack-up platform
- Semi-submersible
- Tension leg platform(TLP) and mini TLP
- Spar
- Classic spar
- Truss Spar
- Shallow buoy
- Ship shaped, different mooring systems.
- Tie-back

Figure 22 shows what possibilities the different concepts have regarding drilling, production and storage. Even though several of the concepts have the same application, it is no matter of course that they are as good for a development.

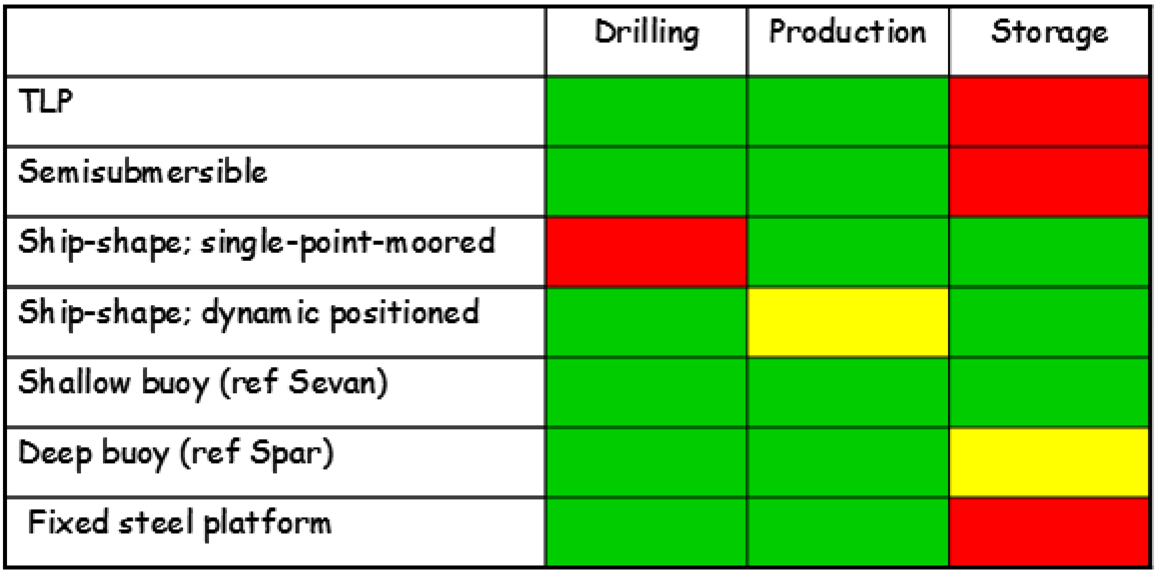

Figure 22: Drilling, production and storage possibilities of different platform concepts (11)

8 Concept screening and shortlisting

1. Fixed concrete platform

After the first oil discovery on the NCS the concrete platforms Condeep were widely used. These were large concrete structures built on shore, towed offshore with help of buoyance and sunk down onto sea bottom. They had storage capacity in the concrete hull. Troll A is the highest Condeep platform, standing at a water depth of 300 m, it is the world's largest manmade construction that have ever been moved (30). For large fields with long lifetime they were good solutions at that time.

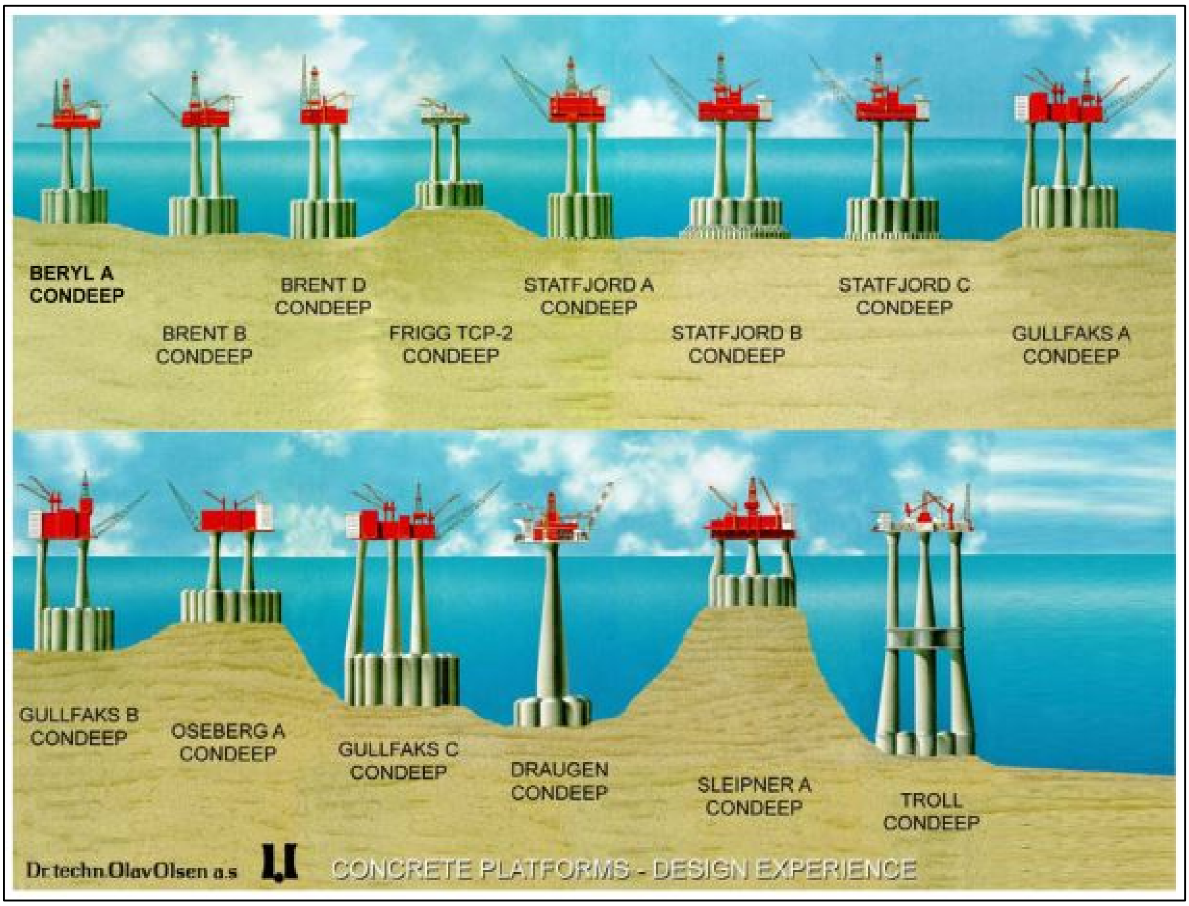

Figure 23: Condeep platform overview (31)

Condeep platforms are no longer produced in Norway, they have been oust by jacket structures, semisubmersibles and FPSO (20). ACES has not a concrete platform in its database and therefore it will therefore not be considered as a concept.

2. Jacket platform

Jacket structures are common on the NCS, of the 95 permanent structures (including FPSO and semi-submersible) that are in service 58 of them are jacket structures (not including flare towers) and 3 are in installation phase (9).

Jacket structures varies in number of legs, where 4, 6 and 8 are common and they are not suitable for deep waters. Since the model field Tesla has a water depth at about 120m, a jacket structure is suitable. A jacket platform can have a drilling rig and production facilities, but no integrated storage.

The drilling can be done from a drilling rig on platform or from an external vessel or jack-up. If the amount of wells is small, as it is on the model field, drilling from a jack-up is less expensive than investing in a drilling rig on the platform. An increasing amount of the wells on jacket platforms are nowadays drilled through the jacket structure.

Figure 24: A jack-up drilling through a jacket substructure (32)

Both wet trees and dry trees are suitable with the jacket structure, and both concepts are going to be considered in the results, but without a drilling facility on platform.

3. Compliant tower

Compliant towers are fixed steel platforms, very similar to traditional jacket platforms, but with a different dynamic response, making them useful in greater water depths than the jacket platform (33). They do not have any integrated storage.

Compliant towers are not very common because floating production facilities like semi-submersible, FPSO and spar, and subsea developments have appeared to be better and cheaper solutions. Compliant towers have never been used on the NCS and since the depth of the field is about 120 m, a compliant tower will not be considered.

4. Jack-up platform

A jack-up platform or a Mobile Offshore Production Unit (MPOU) is a steel platform with submersible legs. When transported the legs are raised and the platform is floating. When the platform does operations, the legs are lowered and the platform is standing on the sea bottom or on a foundation. They have no integrated storage, but some MOPUs have a storage tank on sea bottom which also function as a foundation for the unit.

Jack-up platforms are often used as drilling and intervention rigs (Mobile Offshore Drilling Unit – MODU) due to their mobility, but also for production platforms. Although they are not suitable for deep waters, newer rigs can easily do operations at 150 m depths (34).

The advantage of a MOPU versus for instance a jacket is the removal operation is easier, just a reversal of the installation (35). MOPUs can also be reused for other fields.

Figure 25: Volve jack-up drilling and production platform (36)

It is common that a jack-up production also have drilling facilities on platform which are used for drilling the wells. But it is also possible to drill the wells before the arrival of a production platform. Complete drilling facilities are expensive, and a jack-up rig without drilling facilities will be considered.

5. Semi-submersible

There are many semi-submersible platforms on the NCS, but only 9 of them function as a production units, the others are drilling and intervention rigs or floating living quarters (flotels). Semi-submersibles do not have the possibility for integrated storage. They are suitable for both shallow, deep and ultra-deep waters. The semisubmersible drilling rigs are particularly useful for deep water drilling where jack-ups do not reach. Although steel is the most common material for the hull of a semisubmersible, concrete hulls have also been made. Troll B platform was the world's first semisubmersible production platform with a concrete hull (37), built by the Norwegian company Kvaerner. Troll B was delivered in 1995 and is still producing on the Troll oil field on the NCS.

Semi-submersible platforms can be reused after the field's lifetime. An example of this is a semi-submersible platform now called Northern Producer. It was originally a drilling rig built in 1976, but converted to a floating production unit in 1991. After conversion it has produced oil on the Emerald field in the UK sector of the North Sea and is now producing on West Don oil field also in UK (38).

Figure 26: The semi-submersible platform Northern Producer (38)

6. Tension leg platform

A tension leg platform (TLP) is a floating production platform, but in comparison to FPSOs a TLP can have dry trees due to its small vertical motions (39). TLP have been constructed in both concrete and steel, but steel is the most common type now. A TLP does not have possibility for integrated storage. They are designed with columns and pontoons, often 4 columns. After construction a TLP is towed offshore and moored with tension legs that are anchored to the sea bottom. The tension legs are tubulars that are connected to the sea bottom and stay under constant tension after installation to the platform. TLP are suitable for large water depths. There are two TLP on the NCS, Heidrun and Snorre A, where Heidrun is a concrete TLP and Snorre A is a steel TLP.

Figure 27: Heidrun concrete TLP (40)

Mini TLP are smaller TLP, with one column and star shaped pontoon. These have been popular in the Gulf of Mexico for smaller deepwater fields (41).

Since one of the advantages with a TLP is the possibility of dry trees, this solution will be considered. A TLP usually have a drilling facilities, because drilling of additional wells and heavy well intervention is not possible from an external rig after the TLP is in place. The alternative is not to have drilling facilities, but therefore also not have the possibility to drill new wells. Because of this the reservoir behaviour needs to be well predicted and the number of well set before starting drilling. A TLP with dry trees and a drilling rig, and a TLP without drilling rig is considered.

7. Spar platform

A spar platform is a floating platform with a deep draft cylindrical hull, moored with mooring lines and anchors. The spar platform are less affected by wave, wind and current, because about 90 percent of the structure is under water (39). Usually a spar platform is used with dry trees and have drilling facilities, but wet trees and wet satellite trees are also possible. Spar platforms are widely used in the gulf of Mexico and in deep water and harsh weather conditions, where the deepest platform is Perdido at a water depth about 2450 m in the Gulf of Mexico (42).

The first spar platform on the NCS is planned to be located on the Aasta Hansteen field in the North Sea. Standing on a depth of 1300 m it is also going to be the first development on the NCS with a platform deeper than 1000 m (43).

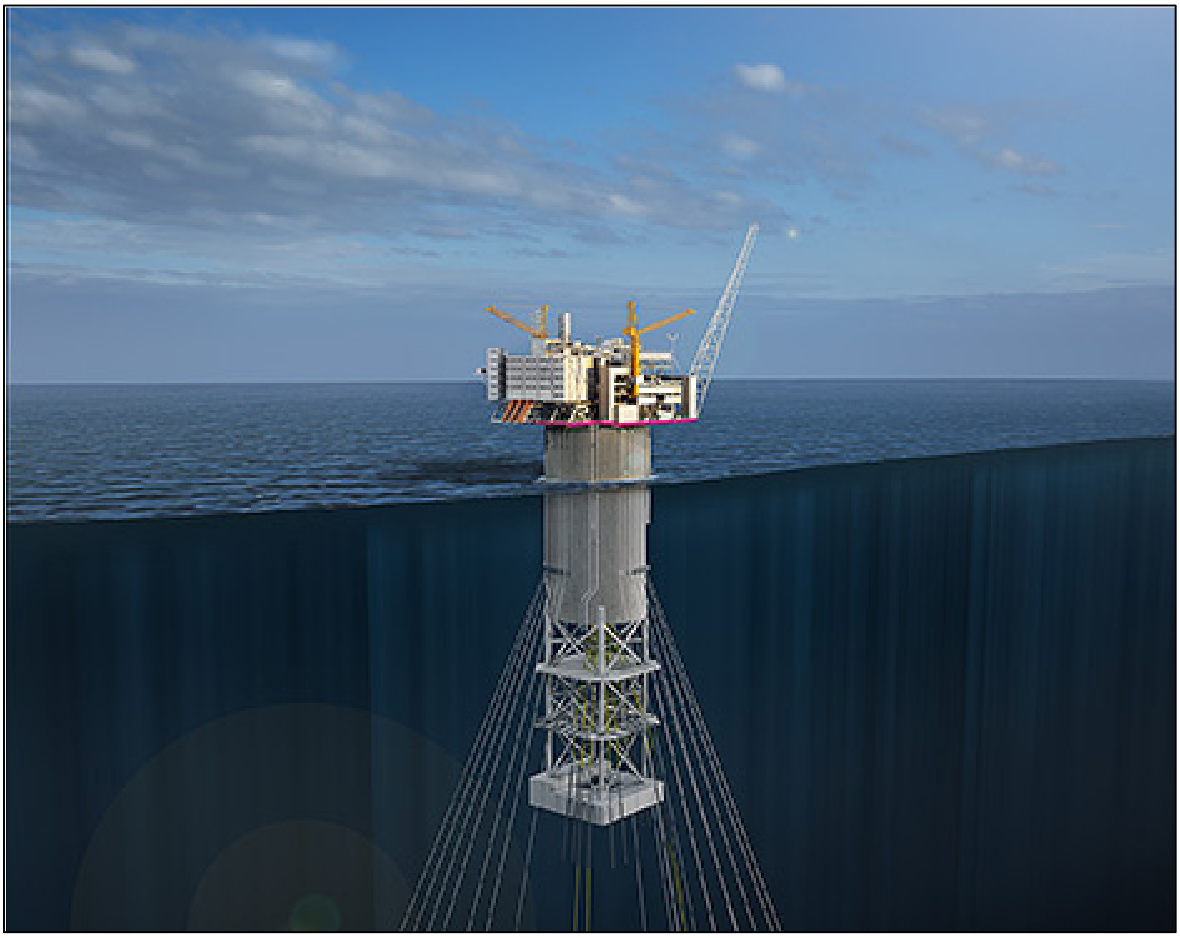

Figure 28: Aasta Hansteen spar platform (44)

There are different spar types depending on their hull. The classic spar have a hollow cylindrical structure (39). In the truss spar the lower section of the cylindrical hull is replaced by truss. The cell spar have a number of small cylindrical structures. A spar platform also have a possibility to have storage inside the hull.

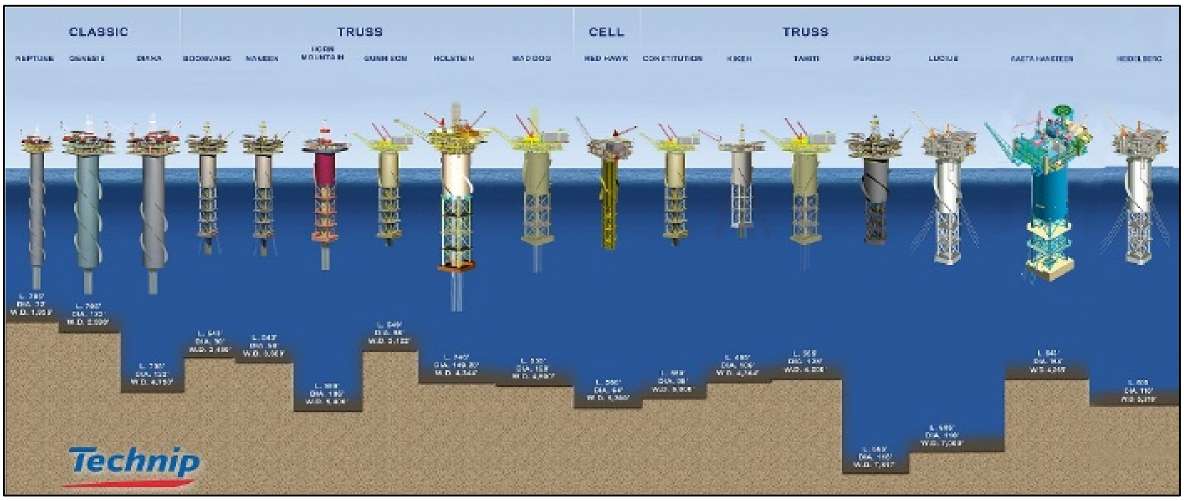

Figure 29: Spar platform overview (45)

Because of the small water depth on the model field, a spar platform is not a concept that will be considered.

8. FPSO – Ship shaped

A FPSO is a floating production, storage and offloading unit. They are often ship shaped, but also shallow buoys (Sevan) and spar platforms are considered to be FPSO (46). They are mobile and therefore easier to remove, and can be reused for other fields and purposes. On the NCS there are currently 9 FPSO in service as, all of them are ship shaped. One FPSO is installing, this one is a Sevan buoy (9).

Ship shaped FPSO often have weather vanning capabilities to minimize environmental loads (46). Single point mooring with external or internal turrets will let the ship position itself in a direction that will reduce the weather impact on the ship. Vessels that are spread moored do not have this possibility and because of that they are often moored in environments where it is either constantly calm weather or with a dominant wind or wave direction. The external turret often occurs on ship shaped vessels that have been converted from an oil tanker, while the internal turret is in purpose-built ships. Some turrets are disconnectable, in very bad weather they can disconnect and leave the location, and reconnect when they get back.

Figure 30: External turret vs. internal turret (47)

The ship shaped FPSO can be reused for other fields and location, and giving a possible income after the end of the fields lifetime.

A ship shaped FPSO will be considered for this model field, with internal storage there is also no need for leasing a FSU.

9. FPSO – Buoy

A buoy is a floating unit with a circular hull, much like a spar platform, but the hull us a lot wider and not that deep as a spar. It has an advantage of having a circular shape, because it gives the same hydrodynamic resistance from any direction and usually does not required a turret or a swivel (46). A buoy can have drilling facilities, production and storage. A Sevan FPSO is a buoy, built by the Norwegian company Sevan Marine. Buoys can be reused like other FPSO.

Figure 31: The Sevan buoy Goliat(48)

A buoy FPSO of the type Sevan is a suitable solution and will be considered.

10. Tie-back

Subsea tie-back is a connection between a satellite field and an exciting production facility or shore. There is then no need for a new platform, the recovered oil or gas will be produced on the existing production facilities at the host field, which will lower the initial investments for the satellite field.

An example of tie back fields on the NCS is Volund, Vilje Sør and Bøyla, three smaller fields which are tied back to the Alvheim field. The distance between Alvheim and Volund, Vilje Sør and Bøyla are respectively 10 km, 20 km and 28 km and the fields are estimated to contain 11,3 Sm^3 million o.e, 13,4 million Sm^3 o.e and 3,6 million Sm^3 o.e. The oil and/or gas is transported by pipelines to the Alvheim FPSO where it is processed and oil is transported by shuttle tanker to shore and gas via a pipeline to a British pipeline system (9).

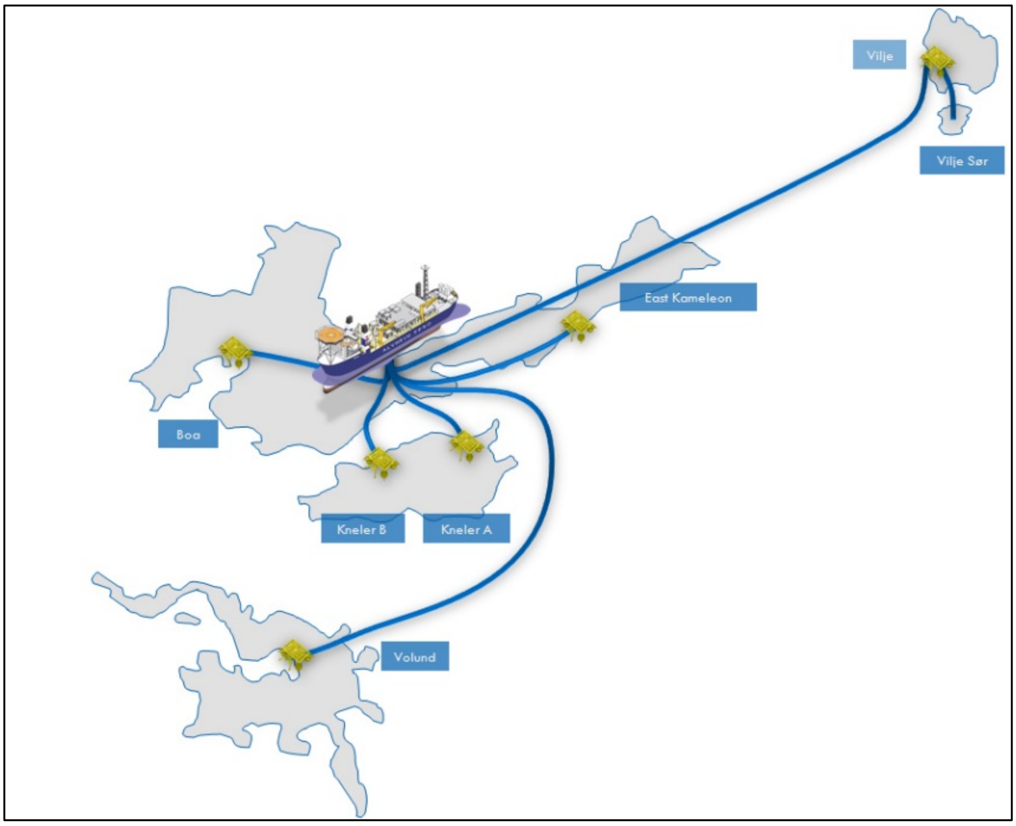

Figure 32: The tie-back solution for Volve field (9)

Snøhvit field is also a tie back field, not to an existing field but to shore. It is located 140 km from shore in northern Norway and is a large gas field containing 218 billion Sm^3 gas. Gas is transported via pipeline to shore where it is used for liquefied natural gas production.

Assuming there is a field close to Tesla with enough production capacity to take on the oil, Tesla could be built as a tie-back to an exciting field. A tie-back is a good solution for a field of small size and short lifetime, but this will not be considered in this project.

9 Concept RESULTS

When the question is how a field is going to be developed, the net present value is the most important element in the concept decision. The net present value (NPV) is the sum of present values of incoming and outgoing cash flows, of the project lifetime. A positive NPV is important in the decision of developing a field. The basis for NPV calculations are CAPEX for facilities and for wells, OPEX, lease costs, removal and abandonment, and prices and tariffs of oil and gas.

Capital expenditures (CAPEX) includes cost a company have related to acquisition or upgrading physical assets. In this case, CAPEX includes all costs related to execution of the field development project. ACES divides CAPEX into facilities and wells. Facilities CAPEX includes engineering, procurement, construction, installation and other marine operations and completion of production facilities. Management is also included. Well CAPEX includes drilling and completion of wells.

Operating expenditure (OPEX) are costs a company have related to normal business operations (49). OPEX includes cost related to operation and maintenance of facilities and wells.

Cost related to removal and abandonment includes plugging wells and remove structures and equipment and sea bottom clean up.

The oil price is set by ACES to be 75,76 USD/bbl and the tariff to be 1,79 USD/bbl. ACES provides a technical report, cost report and NPV report for the results. The technical report provides information about weights, giving a weight summary distributed on the main components of a production platform and the subsea system. Summary of vessel days distributed on the different marine operations and fuel consumption both for the project execution and production phase. Also a cost summary for platform, subsea production, export pipelines and wells is given.

NPV reports sums up the basis for NPV calculations, including CAPEX, OPEX and oil price and tariffs. It also shows the pre-tax NPV and economic indicators, including technical unit cost (TUC). TUC is the cost for producing and selling one unit (barrel) of oil, and includes all CAPEX and OPEX. If the oil price (USD/bbl) exceeds the TUC, the NPV is going to be positive. With a large difference between the oil price and TUC (with oil price above TUC) the oil price can drop more before the NPV for the project is negative. The complete Technical and NPV reports, in addition to Cost reports, for each concept is shown in Appendices A-H.

1. Jacket platform – dry trees

TECHNICAL REPORT Jacket with dry trees

Tesla

Parameters and indicators

Summary of weights (steel and metals)	tonnes
Topside weight	6792
Substructure weight	9002
Conductors	485
Tensioned well risers	0
Piles or anchors	2760
Mooring lines	0
Subsea equipment and structures	0
Other subsea structures	0
Flowlines	0
Flowline risers and J-tubes	0
Umbilicals and cables	0
Export pipelines	0
Wells	8474
Total weight	**27513**

Summary of marine operations - vessel days	days
Platform construction and installation	73
Mooring system installation	0
Subsea templates	0
Other subsea equipment	0
Flowlines/pipelines (S-lay and J-lay)	0
Flowlines/pipelines (Reel-lay)	0
Umbilicals and cables	0
Risers	0
Gravel dumping	0
Trenching	0
Surveys	0
Total number of vessel days	**73**

Summary of costs	mill.USD	mill.NOK
Platform	1048	6287
Subsea production	0	0
Export pipelines	0	0
Wells	261	1565
Total costs	**1309**	**7852**

Average cost per tonne of steel	
USD/tonne	47564
NOK/tonne	285382

Use of steel and metals	tonnes	kg/boe
All facilities	19039	0,378
Wells	8474	0,168
Total	**27513**	**0,547**

Fuel consumption (tonnes) - project execution	
Drilling rig	3704
Drilling services	2344
Platform installation	619
Subsea equipment installation	0
Pipelines, umbilicals, cables, risers	0
Gravel dumping, trenching, surveys	0
Total for project execution	**6667**

Fuel consumption (tonnes) - production phase	
Production operations per year	8845
Production operations services per year	4785
Well maintenance operations per year	0

Table 3: Technical report - Jacket with dry trees

A jacket with dry trees have a larger topside and substructure weight due to a drilling package for jack-up drilling. Without any subsea equipment, the amount of vessel days are relatively small and regards only the marine operations for platform installation. This also affects the fuel consumption.

NPV Report Jacket with dry trees			
Recoverable Volumes – oil field units			
Recoverable volume of oil		50,3	mill.bbl
Recoverable volume of gas		0,0	bill.scft
Daily Production – oil field units			
Oil		51693	bpd
Gas		0	mill scft/d
Basis for NPV calculations			
Capex facilities		6287	mill.NOK
Capex wells		1565	mill.NOK
Opex	495	3964	mill.NOK
Lease costs		1905	mill.NOK
Removal and abandonment		0	mill.NOK
Cost reference year		2015	
Currency (NOK/USD)		6	NOK/USD
Discount rate		10,00	percent
Price and Tariff			
Oil price		71,76	USD/bbl
Gas price		0,00	NOK/scm
Oil tariff		1,79	USD/bbl
Gas tariff		0,00	NOK/scm

Table 4: NPV Report - Jacket with dry trees part 1

NPV Report Jacket with dry trees								
Economic Indicators (pre-tax)								
NPV	**NPV**	IRR	PI	Capex	Opex	Tariffs	TUC	TUC
mill.NOK	mill.USD	percent	-	USD/boe	USD/boe	USD/boe	USD/boe	NOK/scm
2955	**493**	26,03	0,47	26,01	19,44	1,79	55,20	2083

Table 5: NPV Report - Jacket with dry trees part 2

A jacket platform with dry trees gives a pre-tax NPV of 2955 mill. NOK, almost 3 billion NOK. The lease cost is 1905 mill. NOK and does only include the lease of FSU. The lease of drilling rig is included in well CAPEX.

2. Jacket platform – wet trees

TECHNICAL REPORT Jacket with wet trees

Tesla

Parameters and indicators

Summary of weights (steel and metals)	tonnes
Topside weight	5495
Substructure weight	8150
Conductors	0
Tensioned well risers	0
Piles or anchors	2498
Mooring lines	0
Subsea equipment and structures	1329
Other subsea structures	181
Flowlines	198
Flowline risers and J-tubes	102
Umbilicals and cables	97
Export pipelines	0
Wells	8353
Total weight	**26403**

Summary of marine operations – vessel days	days
Platform construction and installation	67
Mooring system installation	0
Subsea templates	17
Other subsea equipment	92
Flowlines/pipelines (S-lay and J-lay)	0
Flowlines/pipelines (Reel-lay)	18
Umbilicals and cables	31
Risers	0
Gravel dumping	5
Trenching	3
Surveys	1
Total number of vessel days	**234**

Summary of costs	mill.USD	mill.NOK
Platform	875	5252
Subsea production	459	2755
Export pipelines	0	0
Wells	347	2085
Total costs	**1682**	**10092**

Average cost per tonne of steel	
USD/tonne	63707
NOK/tonne	382241

Use of steel and metals	tonnes	kg/boe
All facilities	18050	0,359
Wells	8353	0,166
Total	**26403**	**0,525**

Fuel consumption (tonnes) – project execution	
Drilling rig	4847
Drilling services	2344
Platform installation	567
Subsea equipment installation	926
Pipelines, umbilicals, cables, risers	417
Gravel dumping, trenching, surveys	76
Total for project execution	**9177**

Fuel consumption (tonnes) – production phase	
Production operations per year	8659
Production operations services per year	4996
Well maintenance operations per year	237

Table 6: Technical report - Jacket with wet trees

A jacket platform with a wet tree solution add 1907 tonnes in subsea equipment, including structures, flowlines, risers and umbilicals in addition to the weight of the platform. The wells are also more complex, weighing more than wells with dry trees would does.

The wet tree solution has vessel days for all the subsea equipment and structures, lay of pipelines, flowlines and umbilicals, gravel dumping, trenching, and surveys, in addition to platform construction and installation. The total amount of vessel days are 234 where 167 of them concern preparation and installation of subsea system. For each vessel day the amount of fuel consumption increase.

NPV Report Jacket with wet trees		
Recoverable Volumes - oil field units		
Recoverable volume of oil		50,3 mill.bbl
Recoverable volume of gas		0,0 bill.scft
Daily Production - oil field units		
Oil		51693 bpd
Gas		0 mill scft/d

Basis for NPV calculations		
Capex facilities		8008 mill.NOK
Capex wells		2085 mill.NOK
Opex	537	4300 mill.NOK
Lease costs		1905 mill.NOK
Removal and abandonment		0 mill.NOK
Cost reference year		2015
Currency (NOK/USD)		6 NOK/USD
Discount rate		10,00 percent
Price and Tariff		
Oil price		71,76 USD/bbl
Gas price		0,00 NOK/scm
Oil tariff		1,79 USD/bbl
Gas tariff		0,00 NOK/scm

Table 7: NPV Report - Jacket with wet trees part 1

NPV Report Jacket with wet trees								
Economic Indicators (pre-tax)								
NPV	**NPV**	IRR	PI	Capex	Opex	Tariffs	TUC	TUC
mill.NOK	mill.USD	percent	-	USD/boe	USD/boe	USD/boe	USD/boe	NOK/scm
998	**166**	14,62	0,12	33,43	20,55	1,79	66,17	2497

Table 8: NPV Report - Jacket with wet trees part 2

The jacket platform with wet trees and subsea solution has a lower NPV than the jacket with dry trees. The pre-tax NPV is 998 mill. NOK, almost 2 billion NOK less than the jacket solution with dry trees.

3. Jack-up

Because of software issues, the technical report for a jack-up platform is not provided.

NPV Report Jack-up			
Recoverable Volumes – oil field units			
Recoverable volume of oil		50,3	mill.bbl
Recoverable volume of gas		0,0	bill.scft
Daily Production – oil field units			
Oil		51693	bpd
Gas		0	mill scft/d
Basis for NPV calculations			
Capex facilities		8941	mill.NOK
Capex wells		2085	mill.NOK
Opex	542	4337	mill.NOK
Lease costs		1905	mill.NOK
Removal and abandonment		0	mill.NOK
Cost reference year		2015	
Currency (NOK/USD)		6	NOK/USD
Discount rate		10,00	percent
Price and Tariff			
Oil price		71,76	USD/bbl
Gas price		0,00	NOK/scm
Oil tariff		1,79	USD/bbl
Gas tariff		0,00	NOK/scm

Table 9: NPV Report - Jack-up part 1

NPV Report Jack-up

Economic Indicators (pre-tax)

NPV	NPV	IRR	PI	Capex	Opex	Tariffs	TUC	TUC
mill.NOK	mill.USD	percent	-	USD/boe	USD/boe	USD/boe	USD/boe	NOK/scm
210	**35**	10,91	0,02	36,52	20,68	1,79	70,58	2664

Table 10: NPV Report - Jack-up part 2

In Table 9 the CAPEX for facilities is shown. While the technical report is not available, the somewhat large CAPEX facilities cost indicated a reasonable amount of structural material. The subsea system is assumed to cost approximately the same as for other concepts with subsea solutions.

The pre-tax NPV is only 210 mill. NOK.

4. Semi-submersible platform

TECHNICAL REPORT Semi–submersible

Tesla

Parameters and indicators

Summary of weights (steel and metals)	tonnes
Topside weight	5687
Substructure weight	5024
Conductors	0
Tensioned well risers	0
Piles or anchors	653
Mooring lines	1991
Subsea equipment and structures	1329
Other subsea structures	181
Flowlines	198
Flowline risers and J–tubes	58
Umbilicals and cables	97
Export pipelines	0
Wells	7589
Total weight	**22807**

Summary of marine operations – vessel days	days
Platform construction and installation	119
Mooring system installation	21
Subsea templates	17
Other subsea equipment	92
Flowlines/pipelines (S–lay and J–lay)	0
Flowlines/pipelines (Reel–lay)	18
Umbilicals and cables	31
Risers	17
Gravel dumping	5
Trenching	3
Surveys	1
Total number of vessel days	**324**

Summary of costs	mill.USD	mill.NOK
Platform	834	5005
Subsea production	482	2891
Export pipelines	0	0
Wells	347	2085
Total costs	**1663**	**9980**

Average cost per tonne of steel	
USD/tonne	72932
NOK/tonne	437590

Use of steel and metals	tonnes	kg/boe
All facilities	15218	0,302
Wells	7589	0,151
Total	**22807**	**0,453**

Fuel consumption (tonnes) – project execution	
Drilling rig	4847
Drilling services	2344
Platform installation	1188
Subsea equipment installation	926
Pipelines, umbilicals, cables, risers	564
Gravel dumping, trenching, surveys	76
Total for project execution	**9945**

Fuel consumption (tonnes) – production phase	
Production operations per year	8659
Production operations services per year	4996
Well maintenance operations per year	237

Table 11: Technical report - Semi-submersible

The semi-submersible hull does not need a lot of structural steel, less than several other concepts, saving weight and materials.

NPV Report Semi-submersible		
Recoverable Volumes – oil field units		
Recoverable volume of oil		50,3 mill.bbl
Recoverable volume of gas		0,0 bill.scft
Daily Production – oil field units		
Oil		51693 bpd
Gas		0 mill scft/d

Basis for NPV calculations		
Capex facilities		7896 mill.NOK
Capex wells		2085 mill.NOK
Opex	537	4294 mill.NOK
Lease costs		1905 mill.NOK
Removal and abandonment		0 mill.NOK
Cost reference year		2015
Currency (NOK/USD)		6 NOK/USD
Discount rate		10,00 percent
Price and Tariff		
Oil price		71,76 USD/bbl
Gas price		0,00 NOK/scm
Oil tariff		1,79 USD/bbl
Gas tariff		0,00 NOK/scm

Table 12: NPV Report - Semi-submersible part 1

NPV Report Semi-submersible								
Economic Indicators (pre-tax)								
NPV	**NPV**	IRR	PI	Capex	Opex	Tariffs	TUC	TUC
mill.NOK	mill.USD	percent	-	USD/boe	USD/boe	USD/boe	USD/boe	NOK/scm
1094	**182**	15,11	0,14	33,06	20,53	1,79	65,63	2477

Table 13: NPV Report - Semi-submersible part 2

5. Tension leg platform with drilling facilities

TECHNICAL REPORT TLP with drilling facilities

Tesla

Parameters and indicators

Summary of weights (steel and metals)	tonnes
Topside weight	11817
Substructure weight	14152
Conductors	0
Tensioned well risers	118
Piles or anchors	897
Mooring lines	768
Subsea equipment and structures	0
Other subsea structures	0
Flowlines	0
Flowline risers and J-tubes	0
Umbilicals and cables	0
Export pipelines	0
Wells	7709
Total weight	**35462**

Summary of marine operations - vessel days	days
Platform construction and installation	121
Mooring system installation	111
Subsea templates	0
Other subsea equipment	0
Flowlines/pipelines (S-lay and J-lay)	0
Flowlines/pipelines (Reel-lay)	0
Umbilicals and cables	0
Risers	0
Gravel dumping	0
Trenching	0
Surveys	0
Total number of vessel days	**233**

Summary of costs	mill.USD	mill.NOK
Platform	1713	10278
Subsea production	0	0
Export pipelines	0	0
Wells	162	974
Total costs	**1875**	**11252**

Average cost per tonne of steel	
USD/tonne	52882
NOK/tonne	317289

Use of steel and metals	tonnes	kg/boe
All facilities	27753	0,552
Wells	7709	0,153
Total	**35462**	**0,705**

Fuel consumption (tonnes) - project execution	
Drilling rig	1976
Drilling services	2344
Platform installation	1978
Subsea equipment installation	0
Pipelines, umbilicals, cables, risers	0
Gravel dumping, trenching, surveys	0
Total for project execution	**6298**

Fuel consumption (tonnes) - production phase	
Production operations per year	19401
Production operations services per year	4866
Well maintenance operations per year	96

Table 14: Technical report - TLP with drilling facilities

A complete drilling package adds a large amount of weight to the construction. This increases the material cost drastically. Even though a TLP with dry trees does not have any subsea equipment it has mooring lines/tension legs and anchors in addition to weight of the platform. The heavier the platform is, the more mooring it needs, which requires more vessel days for installation of the mooring system, an already advanced operation for TLP. Mooring system installation requires 111 vessel days, almost half the total vessel day amount.

NPV Report TLP with drilling facilities			
Recoverable Volumes – oil field units			
Recoverable volume of oil		50,3	mill.bbl
Recoverable volume of gas		0,0	bill.scft
Daily Production – oil field units			
Oil		51693	bpd
Gas		0	mill scft/d

Basis for NPV calculations			
Capex facilities		10278	mill.NOK
Capex wells		974	mill.NOK
Opex	537	4296	mill.NOK
Lease costs		1905	mill.NOK
Removal and abandonment		0	mill.NOK
Cost reference year		2015	
Currency (NOK/USD)		6	NOK/USD
Discount rate		10,00	percent
Price and Tariff			
Oil price		71,76	USD/bbl
Gas price		0,00	NOK/scm
Oil tariff		1,79	USD/bbl
Gas tariff		0,00	NOK/scm

Table 15: NPV Report - TLP with drilling facilities part 1

NPV Report TLP with drilling facilities

Economic Indicators (pre-tax)

NPV	NPV	IRR	PI	Capex	Opex	Tariffs	TUC	TUC
mill.NOK	mill.USD	percent	–	USD/boe	USD/boe	USD/boe	USD/boe	NOK/scm
5	1	10,02	0,00	37,27	20,54	1,79	71,73	2707

Table 16: NPV Report - TLP with drilling facilities part 2

A drilling package is a heavy and expensive piece of equipment, increasing CAPEX for facilities, but it is cheaper to drill from a platform drilling rig, which lowers the well CAPEX. Still, the low well CAPEX cannot count for the high facilities CAPEX, and the pre-tax NPV is just 5 mill. NOK.

6. Tension leg platform without drilling facilities

TECHNICAL REPORT Tension leg platform

Tesla

Parameters and indicators

Summary of weights (steel and metals)	tonnes
Topside weight	5903
Substructure weight	7390
Conductors	0
Tensioned well risers	72
Piles or anchors	543
Mooring lines	501
Subsea equipment and structures	0
Other subsea structures	0
Flowlines	0
Flowline risers and J-tubes	0
Umbilicals and cables	0
Export pipelines	0
Wells	7709
Total weight	**22118**

Summary of marine operations - vessel days	days
Platform construction and installation	119
Mooring system installation	72
Subsea templates	0
Other subsea equipment	0
Flowlines/pipelines (S-lay and J-lay)	0
Flowlines/pipelines (Reel-lay)	0
Umbilicals and cables	0
Risers	0
Gravel dumping	0
Trenching	0
Surveys	0
Total number of vessel days	**191**

Summary of costs	mill.USD	mill.NOK
Platform	935	5609
Subsea production	0	0
Export pipelines	0	0
Wells	261	1565
Total costs	**1196**	**7174**

Average cost per tonne of steel	
USD/tonne	54057
NOK/tonne	324339

Use of steel and metals	tonnes	kg/boe
All facilities	14409	0,286
Wells	7709	0,153
Total	**22118**	**0,440**

Fuel consumption (tonnes) - project execution	
Drilling rig	3704
Drilling services	2344
Platform installation	1626
Subsea equipment installation	0
Pipelines, umbilicals, cables, risers	0
Gravel dumping, trenching, surveys	0
Total for project execution	**7675**

Fuel consumption (tonnes) - production phase	
Production operations per year	8845
Production operations services per year	4993
Well maintenance operations per year	237

Table 17: Technical report - TLP without drilling facilities

Without drilling facilities and subsea equipment, this TLP has less weight than several other concepts. This decreases the amount of vessel days.

NPV Report Tension leg platform			
Recoverable Volumes - oil field units			
Recoverable volume of oil		50,3	mill.bbl
Recoverable volume of gas		0,0	bill.scft
Daily Production - oil field units			
Oil		51693	bpd
Gas		0	mill scft/d

Basis for NPV calculations			
Capex facilities		5609	mill.NOK
Capex wells		1565	mill.NOK
Opex	487	3899	mill.NOK
Lease costs		1905	mill.NOK
Removal and abandonment		0	mill.NOK
Cost reference year		2015	
Currency (NOK/USD)		6	NOK/USD
Discount rate		10,00	percent
Price and Tariff			
Oil price		71,76	USD/bbl
Gas price		0,00	NOK/scm
Oil tariff		1,79	USD/bbl
Gas tariff		0,00	NOK/scm

Table 18: NPV Report - TLP part 1

NPV Report Tension leg platform								
Economic Indicators (pre-tax)								
NPV	**NPV**	IRR	PI	Capex	Opex	Tariffs	TUC	TUC
mill.NOK	mill.USD	percent	-	USD/boe	USD/boe	USD/boe	USD/boe	NOK/scm
3571	**595**	30,93	0,62	23,76	19,23	1,79	51,76	1953

Table 19: NPV Report - TLP part 2

Because the dry tree system is similar in every dry tree concepts, the lowest CAPEX facilities gives the highest pre-tax NPV of 3571 mill. NOK for TLP without drilling facilities.

7. FPSO – Ship shaped

TECHNICAL REPORT FPSO Ship shaped

Tesla

Parameters and indicators

Summary of weights (steel and metals)	tonnes
Topside weight	6547
Substructure weight	23908
Conductors	0
Tensioned well risers	0
Piles or anchors	657
Mooring lines	2691
Subsea equipment and structures	1329
Other subsea structures	181
Flowlines	162
Flowline risers and J-tubes	58
Umbilicals and cables	97
Export pipelines	34
Wells	7589
Total weight	**43253**

Summary of marine operations - vessel days	days
Platform construction and installation	123
Mooring system installation	47
Subsea templates	17
Other subsea equipment	92
Flowlines/pipelines (S-lay and J-lay)	0
Flowlines/pipelines (Reel-lay)	18
Umbilicals and cables	31
Risers	17
Gravel dumping	5
Trenching	3
Surveys	1
Total number of vessel days	**354**

Summary of costs	mill.USD	mill.NOK
Platform	1374	8246
Subsea production	479	2872
Export pipelines	1	9
Wells	347	2085
Total costs	**2202**	**13211**

Average cost per tonne of steel	
USD/tonne	50906
NOK/tonne	305434

Use of steel and metals	tonnes	kg/boe
All facilities	35665	0,709
Wells	7589	0,151
Total	**43253**	**0,860**

Fuel consumption (tonnes) - project execution	
Drilling rig	4847
Drilling services	2344
Platform installation	1444
Subsea equipment installation	926
Pipelines, umbilicals, cables, risers	564
Gravel dumping, trenching, surveys	76
Total for project execution	**10201**

Fuel consumption (tonnes) - production phase	
Production operations per year	14619
Production operations services per year	4983
Well maintenance operations per year	237

Table 20: Technical report - FPSO Ship shaped

The ship shaped FPSO have a large hull for storage capacity and this means large material costs and more mooring. The larger a vessel is the more/larger mooring lines it needs. Fuel consumption for production operations are large because of storage capacity.

NVP Report FPSO Ship shaped		
Recoverable Volumes – oil field units		
Recoverable volume of oil		50,3 mill.bbl
Recoverable volume of gas		0,0 bill.scft
Daily Production – oil field units		
Oil		51693 bpd
Gas		0 mill scft/d

Basis for NPV calculations		
Capex facilities		11126 mill.NOK
Capex wells		2085 mill.NOK
Opex	557	4457 mill.NOK
Lease costs		0 mill.NOK
Removal and abandonment		0 mill.NOK
Cost reference year		2015
Currency (NOK/USD)		6 NOK/USD
Discount rate		10,00 percent
Price and Tariff		
Oil price		71,76 USD/bbl
Gas price		0,00 NOK/scm
Oil tariff		1,79 USD/bbl
Gas tariff		0,00 NOK/scm

Table 21: NPV Report - FPSO Ship shaped part 1

NVP Report FPSO Ship shaped								
Economic Indicators (pre-tax)								
NPV	**NPV**	IRR	PI	Capex	Opex	Tariffs	TUC	TUC
mill.NOK	mill.USD	percent	-	USD/boe	USD/boe	USD/boe	USD/boe	NOK/scm
-606	**-101**	7,86	-0,06	43,76	14,76	1,79	75,16	2836

Table 22: NPV Report - FPSO Ships shaped part 2

Because the subsea solution is similar in every subsea solution concepts, the crucial factor is facilities CAPEX. A ship shaped FPSO have a large hull for internal storage, therefore no lease cost for FSU, but a high CAPEX facilities. The pre-tax NPV is – 606 mill. NOK, a net loss of over a half billion NOK.

8. FPSO – Buoy

TECHNICAL REPORT FPSO – Buoy

Tesla

Parameters and indicators

Summary of weights (steel and metals)	tonnes
Topside weight	6852
Substructure weight	19917
Conductors	0
Tensioned well risers	0
Piles or anchors	802
Mooring lines	3438
Subsea equipment and structures	1329
Other subsea structures	181
Flowlines	162
Flowline risers and J-tubes	58
Umbilicals and cables	97
Export pipelines	34
Wells	7589
Total weight	**40460**

Summary of marine operations – vessel days	days
Platform construction and installation	167
Mooring system installation	56
Subsea templates	17
Other subsea equipment	92
Flowlines/pipelines (S-lay and J-lay)	0
Flowlines/pipelines (Reel-lay)	18
Umbilicals and cables	31
Risers	17
Gravel dumping	5
Trenching	3
Surveys	1
Total number of vessel days	**407**

Summary of costs	mill.USD	mill.NOK
Platform	1287	7723
Subsea production	479	2872
Export pipelines	1	9
Wells	347	2085
Total costs	**2115**	**12689**

Average cost per tonne of steel	
USD/tonne	52268
NOK/tonne	313608

Use of steel and metals	tonnes	kg/boe
All facilities	32871	0,653
Wells	7589	0,151
Total	**40460**	**0,804**

Fuel consumption (tonnes) – project execution	
Drilling rig	4847
Drilling services	2344
Platform installation	1891
Subsea equipment installation	926
Pipelines, umbilicals, cables, risers	564
Gravel dumping, trenching, surveys	76
Total for project execution	**10648**

Fuel consumption (tonnes) – production phase	
Production operations per year	14619
Production operations services per year	4983
Well maintenance operations per year	237

Table 23: Technical report - FPSO Buoy

The size of the buoy and its hull adds a large amount of weight and material cost. The vessel day amount for platform construction and installation and mooring system installation is over half of the vessel day needed for the marine operations. Because the buoy has internal storage, it is going to use more fuel consumption during production operations per year.

NPV Report FPSO Buoy			
Recoverable Volumes – oil field units			
Recoverable volume of oil		50,3	mill.bbl
Recoverable volume of gas		0,0	bill.scft
Daily Production – oil field units			
Oil		51693	bpd
Gas		0	mill scft/d
Basis for NPV calculations			
Capex facilities		10604	mill.NOK
Capex wells		2085	mill.NOK
Opex	554	4435	mill.NOK
Lease costs		0	mill.NOK
Removal and abandonment		0	mill.NOK
Cost reference year		2015	
Currency (NOK/USD)		6	NOK/USD
Discount rate		10,00	percent
Price and Tariff			
Oil price		71,76	USD/bbl
Gas price		0,00	NOK/scm
Oil tariff		1,79	USD/bbl
Gas tariff		0,00	NOK/scm

Table 24: NPV Report - FPSO Buoy part 1

NPV Report FPSO Buoy								
Economic Indicators (pre-tax)								
NPV	**NPV**	IRR	PI	Capex	Opex	Tariffs	TUC	TUC
mill.NOK	mill.USD	percent	-	USD/boe	USD/boe	USD/boe	USD/boe	NOK/scm
-13	**-2**	9,95	0,00	42,03	14,69	1,79	71,84	2711

Table 25: NPV Report - FPSO Buoy part 2

Because of high facilities CAPEX the pre-tax NPV for a FPSO buoy -13 mill. NOK.

10 Discussion

Reviewing the calculated results in Chapter 10 a large difference in the NPV results can be seen. There is 4177 mill NOK between the concepts with highest NPV, a TLP without drilling facilities, and the lowest NPV, a ship shaped FPSO.

	Jacket platform dry trees	Jacket platform wet trees	Jack-up	Semi-submersible platform	TLP with drilling facilities	TLP without drilling facilities	FPSO Ship shaped	FPSO Buoy
CAPEX (mill. NOK)	7852	10093	11026	9981	11252	7174	13211	12689
OPEX (mill. NOK)	3964	4300	4337	4294	4296	3899	4457	4435
NPV (mill. NOK)	2955	998	210	1094	5	3571	-606	-13

Table 26: Summary of results

A clear trend in the results show that wet trees and subsea system is expensive, giving a lover NPV than for solutions with dry trees. The subsea system requires more materials and equipment raising the cost, in addition to about 184 vessel days only for installation of templates, pipelines and other subsea equipment. For the additional vessel day's fuel consumption is added.

But there are exceptions, a TLP dry trees and drilling facilities is more expensive than some of the wet tree solutions. Drilling facilities adds a reasonably large amount of cost because of more materials and equipment. Although the well CAPEX is lower for a concept with drilling facilities because there is no need for renting an external drilling rig, the saved cost is nowhere near the cost of the facilities. A larger amount of wells and days spent on drilling would have justified the cost of drilling facilities. The platform drilling rate is set to 66 000 USD/day, while MODU drilling with a jack-up is set to 350 000 USD/day. For a MODU with a semi-submersible, which can drill on deeper waters than a jack-up, the drilling rate is set to 525 000 USD/day. These rates are given in NPV appendices.

Concepts with integrated storage have the smallest NPV of all the concepts. That is mainly because of the size of platform with storage capacity. The buoy and the ship shaped FPSO have a large hull, with a lot of materials that increase the facilities CAPEX. To have a storage capacity integrated is a large investment. For a small field with short lifetime it will be less expensive to rent, while for large fields with a long life time, investing in a production platform with storage facilities may pay off.

1. Robben as tie-back

Considering to tie in the small discovery Robben as a tie-back development is a way to extend the lifetime of Tesla and also increase the NPV. Extending production time for 10 years with the additional 3,2 million Sm^3 gives following pre-tax NVP:

Concept	**NPV (mill. NOK)**	**NPV with Robben tie-back (mill. NOK)**	**Difference in NPV (mill. NOK)**
Jacket with wet trees	998	1837	839
Jacket with dry trees	2955	2850	-105
Semi-submersible	1094	1882	788
TLP without drilling facilities	3571	3467	-104

Table 27: NPV with Robben tie-back

Only 4 of the concepts with positive NPV are considered.

The trend is that concepts with wet trees achieve higher NPV with Robben, while dry tree solutions achieve lower NPV. An explanation for this is the need of additional equipment on topside, the need of risers and additional subsea equipment. The subsea system requires more vessel days both for drilling and installation, and for fuel consumption. These expenses are higher than the additional income, and gives therefore a negative difference in NPV. Concepts with wet trees have additional amount of cost regarding subsea equipment and pipelines, but they have no need for extra equipment on the platform, and the extra income gives larger NPV with Robben. This factor is important in the decision of a concept, especially if a field is located close to other discoveries or prospects.

2. Removal and abandonment

Even with Robben as a tie-back to Tesla, a lifetime of 10 years is not a long time. If there is no discoveries close by, the field will be shut down and platform decommissioned. The removal of different concepts are discussed in Chapter 7.9. Assuming the floating units can be reused, the cost for removal is larger for the jacket structures. A floating production unit can be sold or leased for other projects, giving an income after the fields lifetime. This should be taken into consideration when deciding for a field development concept.

3. Leased production unit

A floating production unit or a jack-up can be leased the same way a FSU can be leased. The facilities CAPEX will then only include any possible subsea structures and equipment. This may be a good solution for smaller fields with short lifetime. The longer the lifetime, the larger total lease costs get. For concepts without integrated storage, the lease for storage capacity is included in NPV. Leasing a production unit gives following NVP:

Concept	**NPV (mill. NOK)**	**NPV with lease of production platform (mill. NOK)**	**Difference in NPV (mill. NOK)**
Jack-up	210	1511	1301
Semi-submersible	1094	1832	738
TLP with drilling facilities	5	1500	1495
TLP without drilling facilities	3571	4496	925
FPSO Ship shaped	- 606	1216	1822
FPSO Buoy	- 13	1421	1434

Table 28: Summary of NVP with leased production unit

Each project has a larger NPV when the production unit is leased. The difference in NPV between purchased and leased production unit is depending on lease rate for each unit. Still, all the concepts with negative NPV have a positive NPV when the production unit is leased. Leasing a unit should be considered, especially with a short field lifetime.

11 Conclusion

The small model field Tesla, containing 8 mill Sm^3 with a lifetime of 8 years have possibilities for several development concepts. The most suitable concepts are explained and the net present value is calculated with the help of the cost estimation software ACES. NPV is the deciding factor when choosing a development concept, a project with positive NPV is profitable.

The result trend is that the more structural steel, equipment and vessel days a concepts needs, the more expensive it is, in the worst case giving a negative NPV. Concepts with drilling facilities, subsea system and a large hull for integrated storage have a lower NVP than concepts with jack-up drilling, try trees and a leased storage unit.

A tension leg platform with dry trees and predrilled wells has the highest NPV, and looks like a good solution, but it is not a very flexible solution. Heavy well intervention is not possible, and the tie-back of Robben decreases the total NPV.

The dry tree jacket platform gives, after the TLP, the highest NPV. Even with dry trees it is a flexible solution, because well intervention can be done from an external jack-up MODU. The decreasing NPV with Robben tie-back is still larger than for other concepts (except TLP), and after the first satellite is installed, the following are less expensive. In other words, the jacket platform is ready for new discoveries. The dry tree jacket has also higher NPV than the concepts with a leased production unit (except TLP). All though the removal costs are high for a jacket platform, the calculated NPV of 2256 mill. NOK including removal, does not exceed the NPV of e.g. a semi-submersible without removal included.

Choosing a concept with high NPV will not only mean a higher profit, the NPV compensates for drops in the oil price. Low oil prices put pressure on small marginal oil fields, making it harder to develop them with positive NPV. The current oil price situation has led to postponement of several field developments on the NCS.

For the model field Tesla, a jacket platform without drilling facilities and with dry trees gives a positive NPV of 2955 million NOK with an oil price of 71,76 USD/bbl. This development would produce a positive NPV at oil prices down to 55,20 USD/bbl , and is therefore the best solution.

12 References

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13 Appendices

Appendix A: Jacket platform with dry trees

A.1. Technical report

A.2. Cost report

A.3. NPV report

Appendix B: Jacket platform with wet trees

B.1.Technical report

B.2. Cost report

B.3. NPV report

Appendix C: Jack-up platform

C.1. Cost report

C.2. NPV report

Appendix D: Semi-submersible platform

D.1. Technical report

D.2. Cost report

D.3. NPV report

Appendix E: Tension leg platform with drilling facilities

E.1. Technical report

E.2. Cost report

E.3. NPV report

Appendix F: Tension leg platform without drilling facilities

F.1. Technical report

F.2. Cost report

F.3. NPV report

Appendix G: FPSO Ship shaped

G.1. Technical report

G.2. Cost report

G.3. NPV report

Appendix H: FPSO Buoy

H.1. Technical report

H.2. Cost report

H.2. NPV report