Real Options Analysis as a Decision Tool in Oil Field Developments

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To my family: Thank you for your love, support and encouragement always

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1. Abstract

This thesis shows the applicability and value of real options analysis in developing an oil field, and how its use along with decision analysis can maximize the returns on a given project and minimize the losses. It focuses on how capacity flexibility, the option to change the scale of a project, can significantly add value to a project especially in situations where technical uncertainties exist in a field development. This thesis first analyzes the Sample and Rother field case study, looking at the original project team's assumptions and expectations, the key uncertainties and the final outcomes. It then offers up an alternate approach to the problem using real options analysis that would have added more value to the project. It shows that for the given case study, it would have been beneficial to obtain the option to add capacity to the field development. It also recommends the level of capacity flexibility to include that adds the most expected value to maximize gains and minimize losses for various development scenarios.

Key words: Real Options (RO), Real Options analysis (ROA), Field Development, Exploration and Production, Appraisal well, Oil field, Net Present Value (NPV), Floating Production Facility (FPF), Tension Leg Platform (TLP), Direct Vertical Access (DVA) wells, Subsea wells (SS), Reservoir Compartmentalization, Expected Ultimate Recovery (EUR), Expected Value.

2. Introduction

Can real options analysis add value to planning the development of oil fields? and, more so than the use of traditional investments tools alone?

For the most part, the traditional methods used by project managers for making investment decisions have been the use of capital investment assessment tools such as payback, simple interest rate, discount or net present value (NPV), and internal rate of return (IRR). However, none of these methods take into account the uncertainty of variables that may exist in the future and so are inadequate for making a good investment decision particularly in large projects. Specifically, in oil field developments, investment decisions are usually based on NPV returns calculated for a given oil price premise which varies from company to company. However, this method is conceptually flawed because it assumes a single line of development for a project and simply incorporates the probability of failure into the overall expected value for the project. That probability of failure is carried as a discount rate, which in itself can be difficult to assign a value since the discount rate typically is adjusted for the level of risk associated with the project. Because of these reasons, the traditional methods for making investment decisions are not as effective in an oil field development project where several uncertainties exist.

Real Options Analysis (ROA) is a useful tool for making investment decisions, taking into account uncertainty and building flexibility in the system. ROA often deals with projects that do not have a lot of historical statistics, for example, a new oil field development. The application of real options makes use of risk to add value to a project and therein lays its potential benefit for a field development decision process.

A case study of the Sample and Rother oil field developments illustrates where real options analysis can be used to add value to a field development decision process. In order not to reveal any restricted information, the project data has been modified and the project described here may not be assumed to be any particular field development. For simplicity, the two main decisions available to the oil company are whether: 1) to develop the oil field, and if so, how, and 2) not to develop the oil field. So, the case is somewhat exaggerated, it is artificial, but the salient features resemble those of the Sample and Rother reservoirs.

For the field development case, the focus in this thesis is capacity flexibility, specifically the option to change the scale of the project in developing the oil field. This thesis shows that capacity flexibility can be a big contributor to the success of an oil field development, and further suggests what level of capacity flexibility is appropriate for the given project to add the most value. It is important to note that the level of capacity flexibility chosen in this thesis is specific to the case sited, and cannot be generalized for all oil field developments. Capacity flexibility looked at include the choice of what type of facility to build and the number of wells to drill and complete – eg, drilling and completing mostly platform wells, also known as direct vertical access wells (DVA) to a single structure, or alternatively having fewer DVA wells but more subsea wells tied-back from other nearby fields.

Many project managers question the applicability of real options in an oil field development. This is because it is not always clear how or where real options analysis can effectively be utilized in such a decision process, where the main uncertainties that exist are technical in nature (eg. reservoir properties) and/or are market uncertainties (eg. oil price). This thesis shows not only the applicability and value of real options analysis, but how its use along with decision analysis can maximize the returns on a given project and minimize the losses. It shows why traditional methods used for investment decisions in field developments may not be optimal given the level of uncertainty surrounding such projects.

The following is an excerpt from a speech given by Malcolm Brinded, at the time Royal Dutch Shell executive director of exploration and production.

> "Meeting the expanding needs of societies around the world for energy, without harming our environment, is one of the greatest challenges ever faced by mankind. It will require a transformation in how we supply and use energy. We will have to recover more from today's oil and gas fields and find ways to develop more difficult and unconventional resources, such as oil sands. We will have to continue to find more efficient ways of producing energy and cleaner fuels…." "There are many promising technological possibilities for tackling these challenges, and it will be engineers, with their skills and ingenuity, who will be at the heart of turning these possibilities into practical reality."

The speech was entitled, "Innovating to secure the energy we need" and was given at the 7th World Congress of Chemical Engineering meeting in Glasgow in July 2005.

We currently live in a variable oil price economy that more often than not involves high cost for field developments and high risk. Many in the energy sector, and indeed around the world, are starting to realize the enormity of the task of meeting the world's energy needs. We must continue to find new reserves of oil and gas, alternative sources of energy, as well as ways for maximizing production from the wells in reservoirs, ensuring that we have the right facilities in place to produce every drop we can in a way that is environmentally safe, cost effective and operationally sound. In addition to maximizing production from wells, oil companies must also make decisions that maximize overall returns, a sometimes contradictory notion, as well as minimize losses.

Many uncertainties exist in the oil industry: in oil prices, in oil and gas reserves in the ground, in geological and reservoir structures and more. These uncertainties must be considered and weighed when making decisions as to the future of any project. Project managers and designers in the oil industry are tasked with dealing with these uncertainties and coming up with the best choices for developing oil and gas fields. For the most part, the traditional methods used for making investment decisions have been the use of capital investment assessment tools such as payback, simple interest rate, discount or net present value (NPV), and internal rate of return (IRR). However, none of these methods take into account the unpredictability of certain variables that may exist in the future and so are inadequate for making a good investment decision particularly in large projects.

The Sample and Rother field development process is analyzed, specifically what methods were used in evaluating the various options for development, and what decisions were made based on the analysis and the outcome of the project. This thesis looks at how that project development might have been done differently using the real options analysis (ROA) approach. It explores how ROA could have benefited the project by building flexibility into the system, making the system robust in various future market conditions, and most importantly adding value to the project.

3. Current Methods for Decision Analysis

The more common traditional investment methods used in decision making in projects are NPV, IRR, ROI and payback. These methods are defined as follows:

NPV, the net present value, is defined as the difference between the sum of the discounted cash flows expected from the investment and the amount initially invested. The formula for NPV is:

$$\mathrm{NPV} = \sum_{t=0}^{N} \frac{C_t}{(1+i)^t},$$

where: t is the time of the cash flow, N is the total time of the project, i is the discount rate and C is the cash flow at that point in time. A positive NPV indicates a project is economic, and the higher the NPV number, the more desirable the project is.

IRR, the internal rate of return, is defined as the discount rate that makes the net present value of all cash flows from a particular project equal to zero. So, to find the internal rate of return, find the discount rate that makes the following equation zero, ie:

$$\mathrm{NPV} = \sum_{t=0}^{N} \frac{C_t}{(1+i)^t}$$

, where NPV=0 and i = IRR or the discount rate that makes NPV=0.

The higher a project's internal rate of return, the more desirable it is to undertake the project.

ROI, the return on investment, is a comparison/ratio of the money gained or lost on an investment to the amount of money invested. ROI can be calculated as follows:

$$\mathbf{ROI} = \frac{V_f - V_i}{V_i} = \frac{V_f}{V_i} - 1$$,

where: V_i is the initial investment and V_f is the final value, or the value at the end of the accounting period.

ROI = +100% when the final value is twice the initial value

ROI > 0 when the investment is profitable

ROI < 0 when the investment is at a loss

ROI = -100% when the investment can no longer be recovered

Payback or payback period is defined as the length of time required for the return on an investment to "repay" the sum of the original investment. Payback can be calculated as follows:

$$\textbf{Payback} = \frac{\textbf{Cost of Project}}{\textbf{Annual Net Cash Inflows}}$$

All other things being equal, the better investment is the one with the shorter payback period.

The project team working on the Sample and Rother oil field developments primarily used NPV (Net Present Value) to make their investment decisions. Other secondary investment assessment methods used by the team included PVPAT (Present Value Profit After Tax) and REPAT (Real Earning Power After Tax) to evaluate the project's profitability. PVPAT is defined as the present value of cash flows expected from the investment after tax. REPAT is defined as the discount rate that makes the net present value of all cash flows equal to zero. In other words, REPAT can also be referred to, and is more commonly known as Internal Rate of Return, or IRR.

As can be seen from the formulas of the more popular traditional investment methodologies, the calculations are very static and not dynamic or flexible enough to capture uncertainties that may exist in the future. Furthermore, many oil companies use a fixed oil price premise for future projects, which was also the case with the project team assigned to Sample and Rother. However, a fixed oil price in the project assessment phase fails to take into account the reality that oil prices do in fact fluctuate, sometimes rapidly and so can severely overestimate the projected gains from a project or underestimate a project's viability and so lose out on valuable opportunities. The investment assessment method used by the project team with a single line of development given their estimated oil volumes caused the team to overestimate the projected gains from undertaking the field development.

3.1 Expected Benefit of Real Options Applications on Projects

Real Options analysis is a useful tool for making investment decisions, taking into account uncertainty and building flexibility in the system. Chapter 4 provides a detailed description of Real Options. A Real Options (RO) approach would have been beneficial to the Sample and Rother oil field project team in providing the team with the ability to make use of options that would increase the upsides and minimize the downsides to the project. RO often deals with projects that do not have a lot of historical statistics, such as is the case in the development of a new oil field. The application of real options makes use of risk and uncertainty to add expected value to a project. In particular, a major benefit of applying real options to the Sample and Rother field developments is the added value in enabling the project team and managers to adjust the system as needed when relevant information becomes available. More about the applicability and benefit of real options to this case is discussed in chapter 4.

4. Real Options Analysis

This section of the thesis focuses on getting grounded in understanding what real options analysis is and how it works. To start with, some background on options valuation is provided.

The basic call option contract is defined as an agreement in which the buyer (holder) has the right (but not the obligation) to exercise by buying or selling an asset at a set price (strike price) on a future date (the exercise date or expiration); and the seller (writer) has the obligation to honor the terms of the contract. Options valuation originated from the financial market where options are bought at a certain price and exercised only if advantageous. The option holder has the right, but not an obligation to take action to buy (call option) or sell (put option) something, such as stocks, during a certain time limit, now or in the future, for a pre-determined price. For example, Bob may purchase a 1-year option to buy 100 shares of company X at $50 per share. If company X's shares trade above $50, Bob is likely to exercise the option. In doing so, Bob gets a net payoff equal to the price of the share at the time of option exercise, less the $50 he'll pay per share. If company X's shares trade below $50, Bob is not required to exercise the option and his losses are limited to the purchase price of the option. More information and examples of financial options can be found in (Higham, 2004).

Real options are similar to financial options, except that it applies the theory of options to real life projects.

4.1 What are Real Options?

A real option is the right, but not the obligation, to undertake some business decision. This kind of option is an actual tangible option (in the sense of "choice") that a business may gain by undertaking certain endeavors. These are called "real options" because they pertain to physical or tangible assets, such as equipment, rather than financial instruments. Real options analysis includes valuation of flexibility, and systematically increases values of projects. The value of real options increases as the project risk increases. A simple, everyday example of the application of real options is leasing a car. At the end of the specified car lease period, the lessee has the option to walk away, or buy the car for a purchase price predefined at the beginning of the lease contract.

Uncertainty about the future requires that certain decisions be flexible in nature. So, it is beneficial that decisions are flexible enough to take advantage of observation of outcomes in the future. This will permit for choices to be made later that allows for the project to maximize its upside and minimize the downside. Such choices may include the expansion, delay or closing of a project.

Decision tree analysis and NPV can be used as valuation methods for real options analysis. These valuation methods will be used in evaluating the Sample and Rother case. Decision Analysis (DA) is simply a tool used to provide structure for choice evaluation. In the Sample and Rother field case, this thesis will look at what real options exist to provide flexibility to the project development, use decision tree analysis to display various choices, and use NPV to calculate which choice path provides the greatest value.

4.2 Examples of Applications of Real Options

Before applying real options to a field development, and to better understand the application of real options, provided here are some simple real world examples of its use.

Tagus River Bridge – Lisbon (Gesner and Jardim, 1998)

In 1966, the Tagus River bridge was constructed in Lisbon. The design team proposed a four-lane roadway bridge that could be retrofitted to form a combined suspension/cable-stayed bridge for highway and railroad loading. The value of adding this real option, making the bridge stronger than needed at the time with the ability to expand, would be realized later in the future. At the time, the Tagus river bridge was the longest bridge in Europe and the world's longest continuous truss. The new bridge stimulated economic growth in the area and soon population and congestion in Lisbon grew. By 1993, the growth rate in Lisbon had significantly increased the traffic count across the Tagus river bridge, soaring beyond what the original planners had expected. Because the original design of the bridge allowed for it to be retrofitted in the future, by 1999 two automobile lanes and a railroad deck were added to the Tagus river bridge to alleviate the congestion.

Parking Garage Case Example (de Neufville et al, 2006)

This example put together by de Neufville et al shows the value of designing real options into a parking garage with an uncertain demand over the long term. Building a big garage could overestimate demand and cause the garage owners to overspend and lose money, while building a small garage could underestimate demand and cause the owners to lose potential revenue. Applying real options to the garage design, the owners could strengthen the structure of the parking garage. Building this real option into the design of the structure would allow for the addition of more floors in the future. In doing so, the case example showed that though some extra features such as the bigger columns were required (options), the garage owners were now able to build flexibility into the project, possibly reduce upfront cost (i.e., assuming not building bigger garage upfront), and increase the overall expected value. The parking garage case is another example of expanding the upside potential and reducing the downside risk.

5. Field Development Overview

When an oil field is discovered in the exploration phase, geologists, petrophysicists and reservoir engineers come up with estimated "oil initially in place" volumes – OIIP. If the main hydrocarbon phase is oil, then typically a 30-50% recovery factor is assigned to that field. This recovery factor assignment means that based on experience from several other field developments, the company can expect to produce 30-50% of the oil that they have found in that reservoir. If the main hydrocarbon phase is gas, then a 75-85% recovery factor is typically assigned to that field. This denotes that the company expects to produce 75-85% of the gas reserves in that field. Since oil and gas are commodities, one of the biggest differentiating factors among oil companies is cost competitiveness. So, companies must take a close look at their capital cost for project startup as well as operating cost. The lower the cost, the more shareholder value is built. So, any project that addresses recovery maximization must also address capital and operational cost effectiveness.

After finding hydrocarbon reserves, oil companies must determine what structures to put in place in order to produce the reserves. For example, fixed leg platforms, tension leg platforms (TLPs), subsea developments, and floating production, storage and offloading vessels (FPSO) are all types of structures that have been used in field developments. Some facility structures are more expensive than others, and the uncertainty around reserves in place vary from project to project, so it is up to the oil companies to determine what the best structure is to put in place that will develop those reserves for the life of the field. In addition to cost, safety, environment, laws, regulations, contract terms, and even egos, to name a few, are other factors that also influence development decisions. Once the decision is made on the facility structure to put in place, the size of the facility must also be taken into consideration.

5.1 Sample and Rother Fields Overview

Sample and Rother are oil fields located offshore in the Gulf of Mexico, in over 3000 feet of water. During the initial exploration phase, the two fields were discovered. The Sample field was first discovered via a seismic survey. An exploration well was drilled four years later, and appraisal wells drilled seven years after and then nine years after the initial exploration well. The first exploration well drilled at Sample put the oil reserves in place at about 80 million barrels of oil. The second increased the estimated reserves to 200 million barrels. When the first Rother exploration well was drilled, estimated oil in place was about 220 million barrels, which dropped down to about 100 million barrels after the second exploration well was drilled. There remained some key uncertainties around the actual amount of oil in place in both the Sample and Rother fields. Some explanations for the large variability in estimated reserves were possible fault blocks that compartmentalized the reservoirs and subseismic barriers/baffles. The major technical issue revolved around reservoir continuity and connectivity.

Initial analysis done by the project team was to put a tanker system, a floating production facility that would fit in the middle of the two fields and produce both fields. Several iterations were made of the type of field structure to build, including a Floating Production Facility (FPF) with subsea wells tied-in to it, a Tension Leg Platform (TLP) with direct vertical access (DVA) wells from the platform and with subsea wells tied-in to it.

The estimate assumptions for the project team's base case were as follows:

1. Develop the Rother field as a floating hub site equipped to receive, process and export production from other nearby prospects
    a. Ultimate facility capacity: 150,000barrels per day (bpd) and 300 million standard cubic feet per day(mmscf/d) (2 x 75,000 barrels per day processing trains).
    b. 3000+ feet of water
2. Hub prospects include the following:
    a. Rother field – 80,000 bpd, 160 mmscf/d, 10 wells (Primary field development)
    b. Sample field – 40,000 bpd, 80 mmscf/d, 4 wells (Secondary field development)
3. A standardized subsea system would be utilized including the following:
    a. Interchangeable subsea trees
    b. Subsea manifold at each prospect location
    c. Insulated flowlines/manifold
4. A Floating Production Facility (FPF). See Figure 1 below.
5. Project execution drivers include the following:
    a. Form team by June following first appraisal well drill, Project work plan completed by September, Design basis completed by October of same year
    b. Drilling another appraisal well by September of same year- optional
    c. Beginning design, vessel identification and procurement of all long lead time items by July of same year
    d. Purchasing a vessel by October of same year
    e. Start development drilling by January of following year
    f. Predrill and complete as many wells as possible prior to FPF installation as "base case"
    g. Rother production top priority

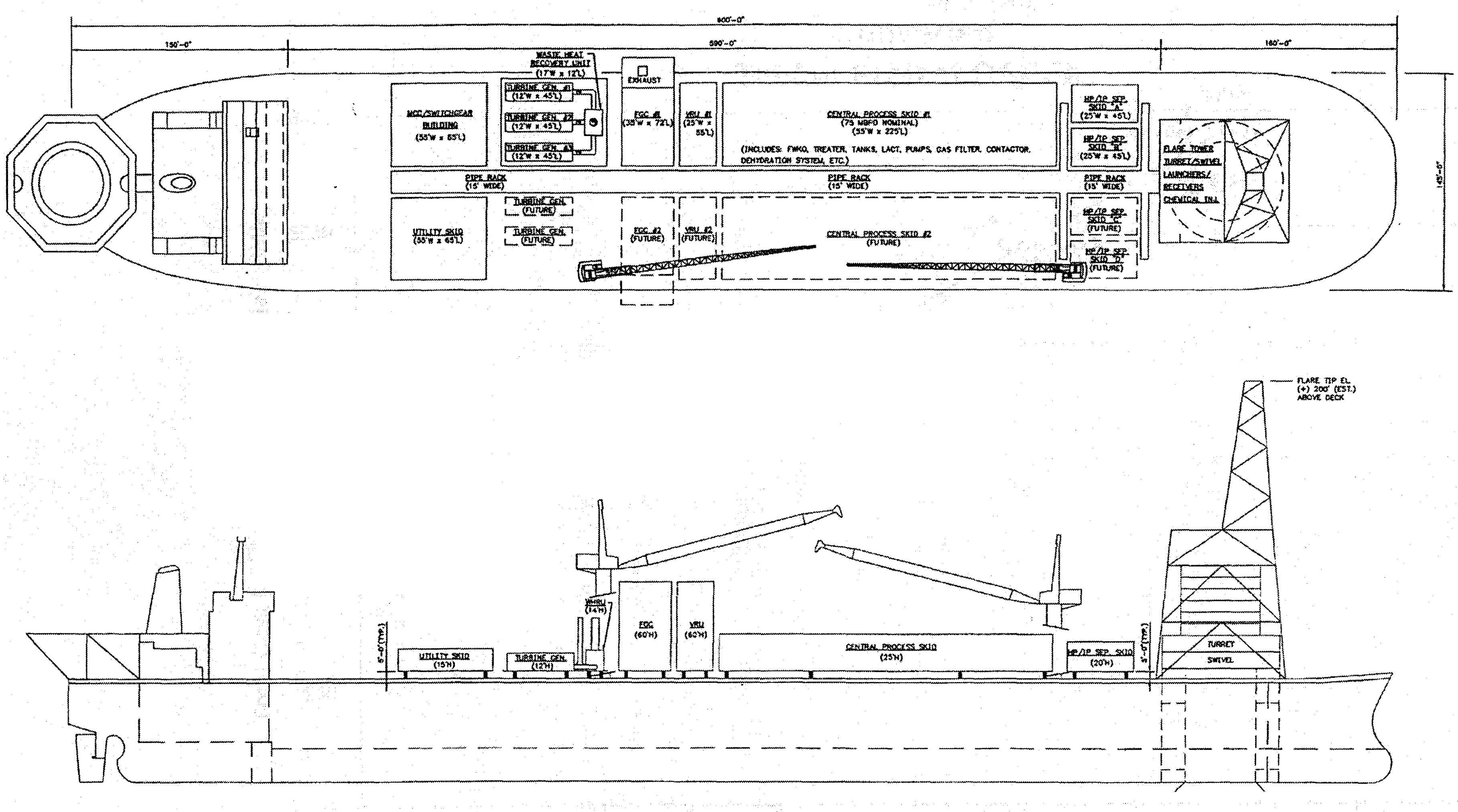


Figure 1: Floating Production Facility (FPF)

The initial development choices looked at were as follows:

Scenario #1: Develop prospect Rother area (reservoirs A and B) with an FPF

Scenario #2: Develop prospect Rother area (reservoirs A and B), and prospect Sample area utilizing two drilling rigs with an FPF

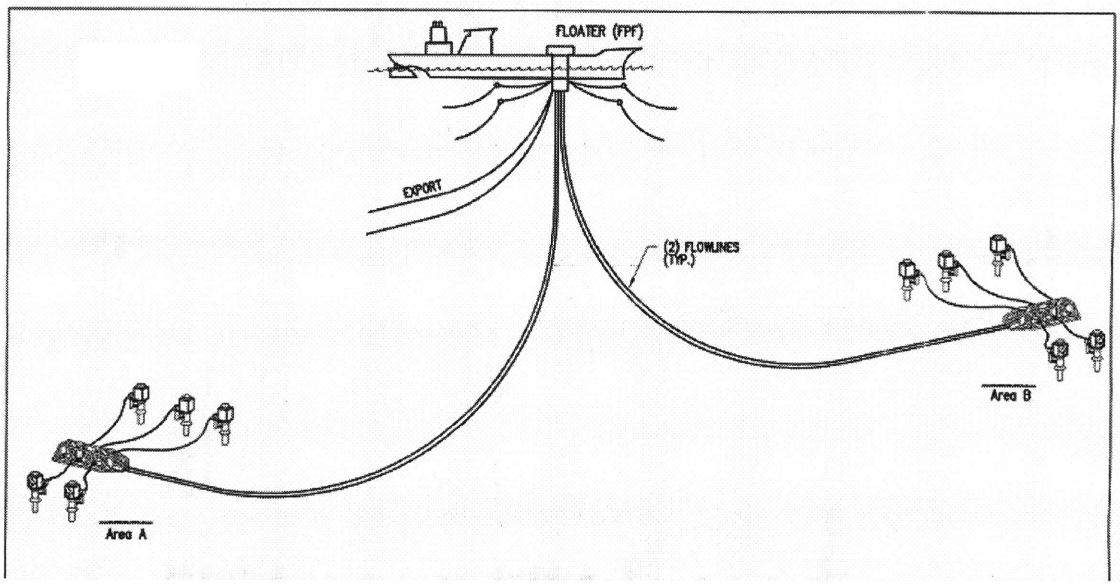


Figure 2: Scenario 1 – Develop Rother area A and B to FPF

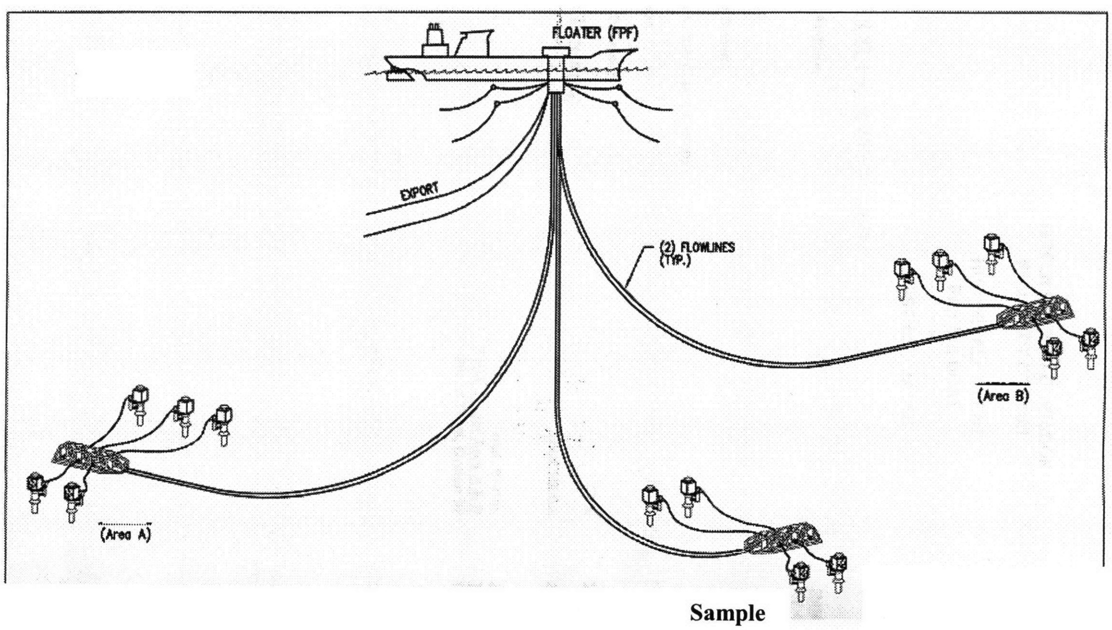


Figure 3: Scenario 2 – Develop Rother A, B and Sample to FPF

Table 1: Scenario 1, the Capital Expense (CAPEX) estimate breakdown

Rother Area A	**$MM ($P_{50}$ Basis)**
Drill (exluding appraisal well - keeper) (x 4 wells)	62 (drill total for 4 wells)
Complete (x 5 wells)	54 (complete total for 5 wells)
Subsea System	53
Flowlines [(2) 8"x12" infield and (2) 16" Export]	84
Umbilicals	5
Vessel (P_{90} $162 million)	134
Process Facilities	85
Engineering and Project Management (Vessel and Topside Facility)	40
Sub-total	518
Capitalized Staff (4%)	21
Rother Area A, Total	**539**

Rother Area B	**$MM ($P_{50}$ Basis)**
Drill (x 5 wells)	78
Complete (x 5 wells)	54
Subsea System	54
Flowlines (dual 8" pipe-in-pipe)	19
Umbilicals	5
Sub-total	210
Capitalized Staff (4%)	8
Rother Area B, Total	**218**
Grand Total, Scenario #1	**757**

Estimated Operating Expense (OPEX) was as follows:

Floater - $6MM/year

Subsea Systems - $65,000/well/month (where subsea well count varied from 2 to 5 wells)

P_{50} case denotes most likely case and is what is used for project development. P_{10} and P_{90} denote best and worse case scenario respectively.

Table 2: Scenario 2, the Capital Expense (CAPEX) estimate breakdown

Sample Field Addition	**$MM ($P_{50}$ Basis)**
Drill	62
Complete	43
Subsea System	45
Flowlines (dual 8" pipe-in-pipe)	19
Umbilicals	5
Facility Expansion	45
Sub-total	219
Capitalized Staff (4%)	9
Sample, Total	**228**
Grand Total, Scenario #2 (add Scenario #1 cost)	**985**

The project team recommended the use of a FPF to produce the reserves, potentially saving $30 million dollars (~10%) compared to using the TLP. However, the decision was made by management to produce the fields using a Tension Leg Platform (TLP) facility because of the drilling capabilities a TLP would provide and other business issues.

As field exploration continued, a total of 7 fields were found with potential tie-backs to the TLP. Following the results of the second appraisal well and the variation in the expected ultimate recovery from both fields, the decision was made that the primary field development would instead be the Sample field. The development choices for the Sample field were:

1. 12 direct vertical access wells[1] with 2 subsea tie-backs[2], or
2. 8 wells with 5 subsea tie-backs.

The latter option was chosen. Sample was going to be a hub with 8 direct vertical access wells (DVA wells), and 5 subsea tiebacks. The Rother fields would be the secondary field development, produced through subsea wells to the Sample hub.

Table 3: Sample field development Capital Expenses (CAPEX)

Component	**Cost ($MM)**
Structure	291
Topsides	197
Drilling and Completion	189
Direct Charged Costs	137
Sample field, Total	**815**

[1] Direct Vertical Access or DVA wells are wells that are drilled from the platform and produced directly to the platform
[2] Subsea tie-backs are wells drilled by a floating rig at a location away from the platform and then tied back to the platform via flowlines.

The new estimate Assumptions/Schedule and Milestones for the Project Team were as follows:

Table 4: Updated Estimate Assumptions/Schedule and Milestones for the Project Team

Activity	**Timing**
Fabrication bid awards	January, two years after 2nd appraisal well drill
Begin batch drilling	August, two years after 2nd appraisal well drill
Complete batch drilling	December, two years after 2nd appraisal well drill
Hull and topsides delivery	September, three years after 2nd appraisal well drill
Begin installation	February, four years after 2nd appraisal well drill
First Production	May, four years after 2nd appraisal well drill

In the end, Sample was developed as a TLP with 8 DVA wells and 5 subsea well tie-ins, with a total capacity of 100,000 barrels oil per day (bopd) and 150 million standard cubic feet per day (mmscf/d) of gas.

5.2 Key Uncertainties

Several uncertainties existed for both the subsurface development of the Sample and Rother fields as well as the surface facility development. The key issues were around the subsurface, where analyses were based on educated guesses about what was happening 20,000+ feet below surface. As in most subsurface developments, there are several uncertainties, but the key issue that this thesis focuses on, and which is specific to the Sample case, is reservoir connectivity and the heterogeneity of the sand. This key technical uncertainty around the connectivity of the reservoirs affected estimates of the size of the reservoir and amount of oil in place. The uncertainties surrounding the subsurface also affected planning for the surface facility. As most surface facilities consist of hardware that can be seen, physically handled and understood, this area by itself generally presents few uncertainties. The surface uncertainties for the most part result from subsurface uncertainties, being: the size of the structure to build, how many direct access wells to plan for to drill and complete, how much production to plan for, as well as how many subsea tie-backs to provide for.

5.3 Project Evaluation and Profitability analysis

The project team for the Sample and Rother fields development project included geologists, reservoir engineers, petrophysicists, economists, facility engineers, production engineers and project engineers. Experts in their fields represented the various disciplines. Because of this experience level, the review process for the project relied heavily on individual review of the data and recommendations being made to management. The general rule of thumb at the time was that a project could continue to progress as long as there was less than a 10% chance of losing money at the given oil price premise[3]. This process of review meant that recommendations passed or failed based on how well an engineer or other discipline expert was able to make their case to management. In turn, for the most part, management trusted the recommendations they received since they were coming from experts in their respective disciplines.

Economists for the project team used Present Value Profit After Tax (PVPAT) and Real Earning Power After Tax (REPAT) as a means of gauging the profitability of the project. Using these methods, the project team ran "look forward" economics (also known as short term economic

[3] The price premise used by oil companies is highly confidential and so that information is not provided here.

forecasting) as well as life cycle economics using a fixed oil price premise. The evaluation method used by the project team put expected ultimate recovery (EUR) from both fields to be about 270 million barrels of oil equivalent (mmboe)[4] with estimated total oil in place around 840mmboe. Five years after the project startup, estimates of total oil in place shrank to around 625mmboe, with an EUR of 200mmboe (based on approximately 32% recovery ratio). In addition to the EUR decreasing by 25%, this also meant that the length of time that it will take to produce those reserves, as well as the cost of producing it will significantly increase due to the compartmentalized nature of the reservoir. If oil prices had been the same as the price premise used in the project development, the actual NPV of the project would have been much lower given the increased cost to get the reserves later. Initial lookback at the project, also known as the first post-project execution review, showed the effect of the increased cost of multiple wells to recover reserves in various compartments, along with the reduced reserves as the reservoir was not as vast and continuous as initially thought, reduced the NPV by as much as 25%. Fortunately for the team, their oil price assumptions were wrong, and the increase in oil prices over time helped the project attain its financial goals. So, even though the project turned out to be profitable, it was unsuccessful based on what was expected from the project evaluation methods used.

[4] MMBOE is millions of barrels of oil equivalent, where 1 BOE = 5800 cubic feet. Convert the gas stream to BOE and add to barrels of oil to get the total barrels of oil equivalent.

6. Application of Real Options Analysis to Case

Real options analysis is applied to the Sample and Rother field case. Using real options, this thesis explores an improved system of developing the fields in terms of capacity and initial capital expenditure given the key technical uncertainty around the connectivity of the reservoir. Reservoir connectivity in turn affects estimates of the size of reservoir and the amount of oil in place.

Using real options, this thesis determines an improved physical structure to put in place for the Sample offshore field development in a way that is cost efficient, and takes into account uncertainties that exist in the project. This thesis assesses what real options exist for capturing remaining reserves and for determining at what point to exercise call-like options such as expanding field operations, and if and when to exercise put-like options such as abandoning or temporarily shutting down field operations. The specific real option designs proposed in this case are:

1. Real option designed into the surface facility size to allow for expanding surface handling capacity as needed.
2. Adding more slots to the facility chosen, with the option of drilling those wells only if needed at a later time in the future. This real option will provide an 'expansion' option for the subsurface in the future, ie, having more wells to drain various parts of the reservoir if it is highly compartmentalized.

The ultimate goal of this thesis is to show how real options can aid in making the decision on what field structure to put in place that maximizes production for the given field for the duration of the field life in a way that cost efficient in a high tech, high cost, high risk, and variable oil price economy.

6.1 Framing the Process

While many engineers have the tendency to jump right into a project to start solving it, it is important to take a step back to understand all the information that is available and needed. Therefore, in applying a real options approach to this case, this thesis also adopts the use of decision tree analysis and NPV for valuation. A process of six steps is used to help clarify what the facts are, what uncertainties exist, what decisions need to be made and the approach that is taken using real options to maximize the expected value based on the decisions made. The six steps are:

1. Identify the facts, uncertainties and decisions to be made
2. Break decisions up into a decision hierarchy (i.e., organizing and ranking decisions) to better focus on the problem
3. Identify the options based on the problem focus derived from the decision hierarchy
4. Create decision tree - calculate the value of rigid design
5. Create decision tree - calculate the value of building in the real options
6. Make final recommendation based on selection that maximizes collection of value matrices given the decision criteria

6.2 Value of Building in Real Options Given Uncertainty

Step 1: Identify the facts, uncertainties and decisions to be made

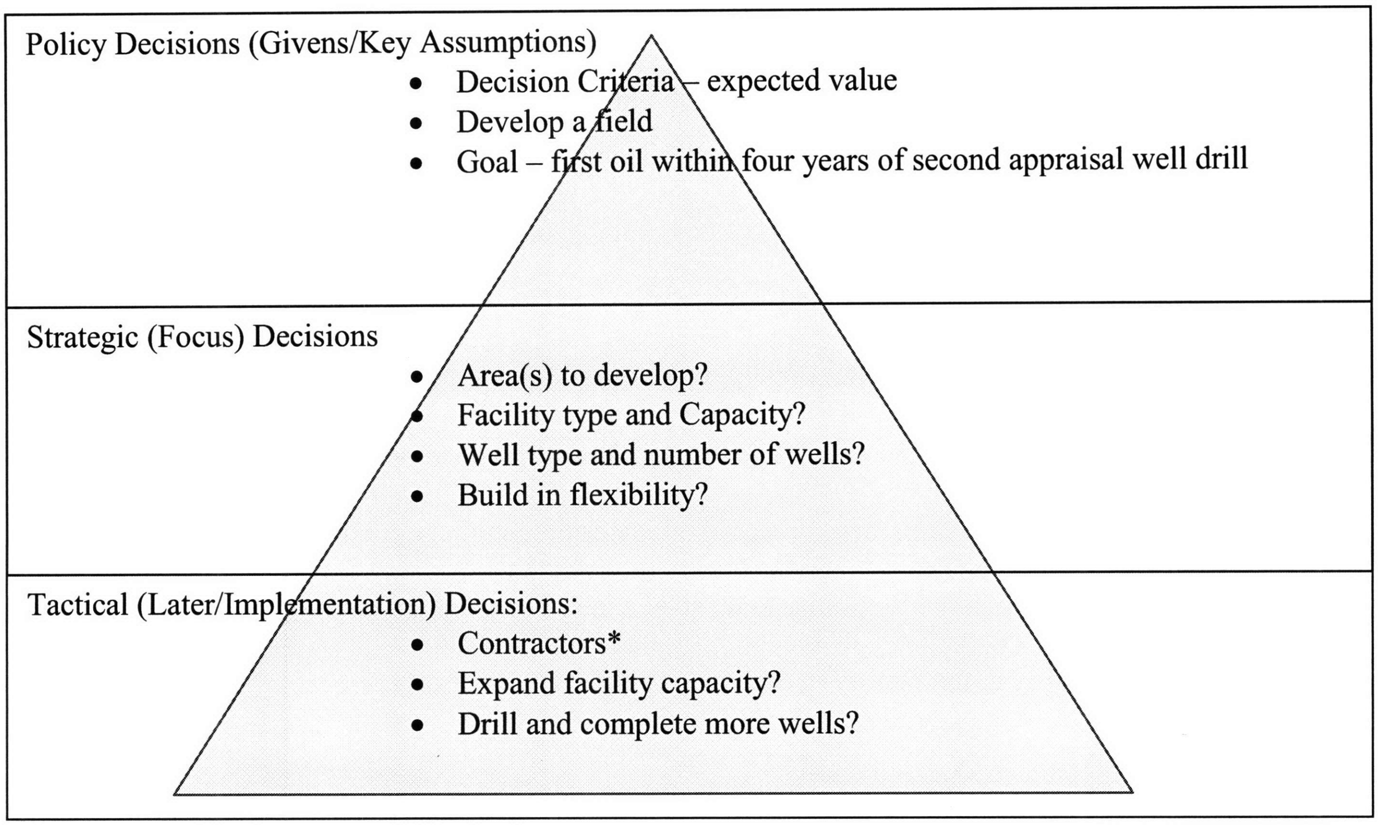
Though it is easy to assume that the project team already knows what the facts are as well as the key uncertainties, it is not always clear to everyone what key decisions need to be made to progress the project. Therefore, listing these points down in a simple table is a very easy straightforward way to ensure everyone is on the same page. Table 5 below lists the main facts, decisions and areas of uncertainty that existed in this project.

Table 5: Categorized Issues

Category	**Issues**
Fact	Field is offshore in 3000+ feet of water
Uncertainty	Extent of reservoir compartmentalization, which in turn affects the expected reserves in the Sample field (80, 150, 200 mmbo)
Uncertainty	Extent of reservoir compartmentalization, which in turn affects the expected reserves in the Rother field (100, 150, 220 mmbo)
Uncertainty	Extent of reservoir compartmentalization, which in turn affects the expected reserves for a combined Sample and Rother field development
Uncertainty	Future price of oil
Decision	What type of facility to put in place (TLP, FPSO, SPAR)
Decision	How many wells to drill and complete

Step 2: Break decisions up into a decision hierarchy to better focus on the problem

Figure 4 displays a decision hierarchy for developing the Sample and Rother fields.



* not covered in the scope of this thesis

Figure 4: Decision Hierarchy

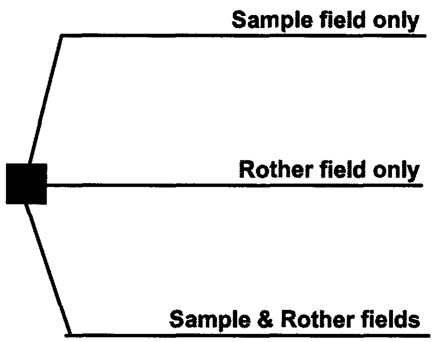
The top section of the decision hierarchy triangle relays how policy decisions will be made. The stakeholders clearly want three things to be done: 1) a decision to be made on how the field will be developed based on which option offers the highest expected value, 2) the development of at least one of the fields, and 3) having first production within four years from the time the second appraisal well was drilled.

The mid-section of the triangle focuses on decisions yet to be made. This is where real options have the greatest value. Those decisions to be made include what area(s) to develop, ie, the Sample field, the Rother field or both fields. The mid-section also focuses on what type of facility to put in place and the capacity to construct for, which in turn depends on the area of development. The types of wells to put in place, as well as the number of wells, and whether to build flexibility into the system are other key decisions that need to be made.

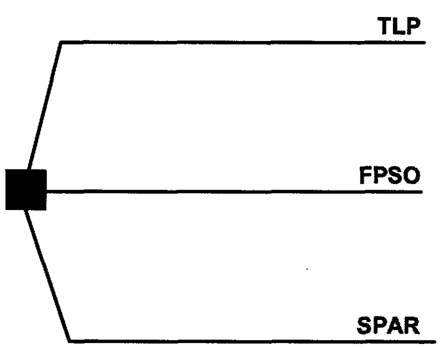
Step 3: Identify the Options

Step 3 identifies the options based on the problem focus derived from the decision hierarchy. See Figure 5. The development choices are broken down into development area, facility and production wells. In this case, these choices include drilling and completing a set number of wells now, or building in the flexibility to do so at a later time. Another choice includes building in flexibility to the facility in order to expand it at a later time.

Development Area Choices



Facility Choices



Production Well Choices

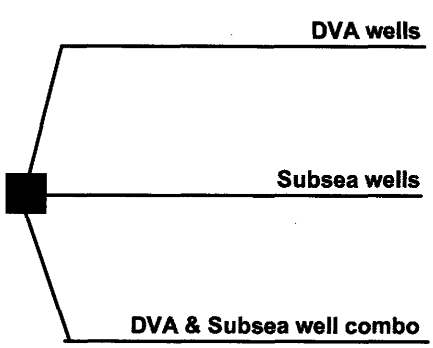


Figure 5: Development Choices

Steps 4 and 5: Create decision tree - calculate the value of rigid design and the value of building in real options

The development choices include what area(s) to develop, what facility to develop with as well as the type of production wells to utilize. The company management made the decision to use a TLP facility due to its drilling capabilities. Calculations for the decision trees that will be presented can be found in Appendix A. The calculations simply show capital expenditures (CAPEX) for the developments, and do not include operating expenses (OPEX), taxes, royalties or other such related operating expenses.

Sample Field Development ONLY

Step 1:

Two choices are presented for developing the Sample field: TLP with 5 DVA wells, or TLP with 8 DVA wells. Using the most likely reserves case for the development design and assessment, the expected value of this development choice is $8.3 billion. See Figure 6. The most likely/expected case of reserves for the Sample field is 150 MMBO. However, this case is unrealistic as the actual reserves could vary.

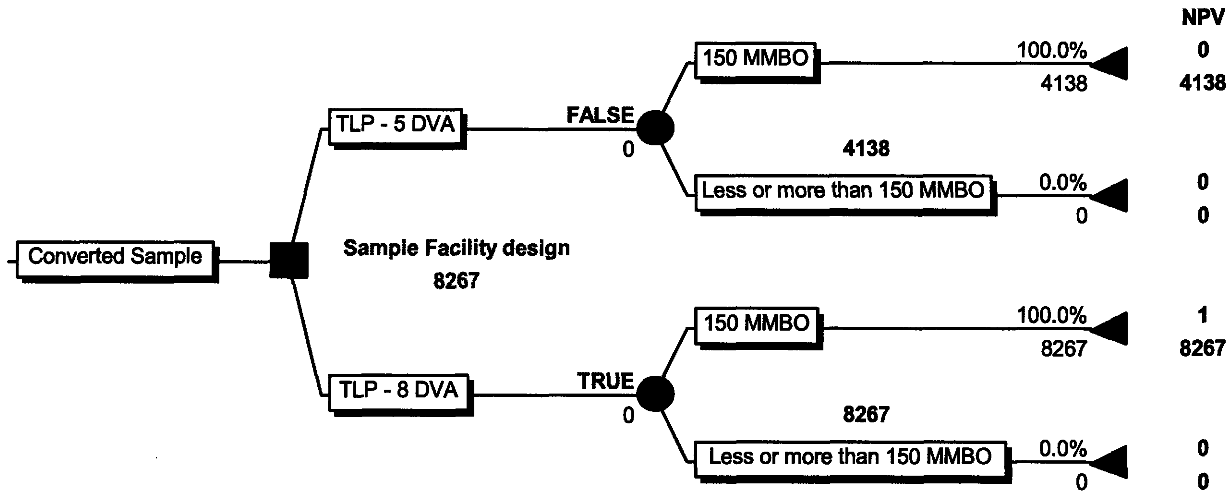


Figure 6: Expected value of Sample area development based on 100% probability of most likely case of reserves

Step 2:

Again, the two development choices are presented: TLP with 5 DVA wells, or TLP with 8 DVA wells. However, this time the reserves uncertainty is taken into account, a more realistic approach. There are three possibilities of reserves in place for Sample field: 80MMBO, 150 MMBO and 200 MMBO. The expected value of this development choice is $8.1 billion. See Figure 7.

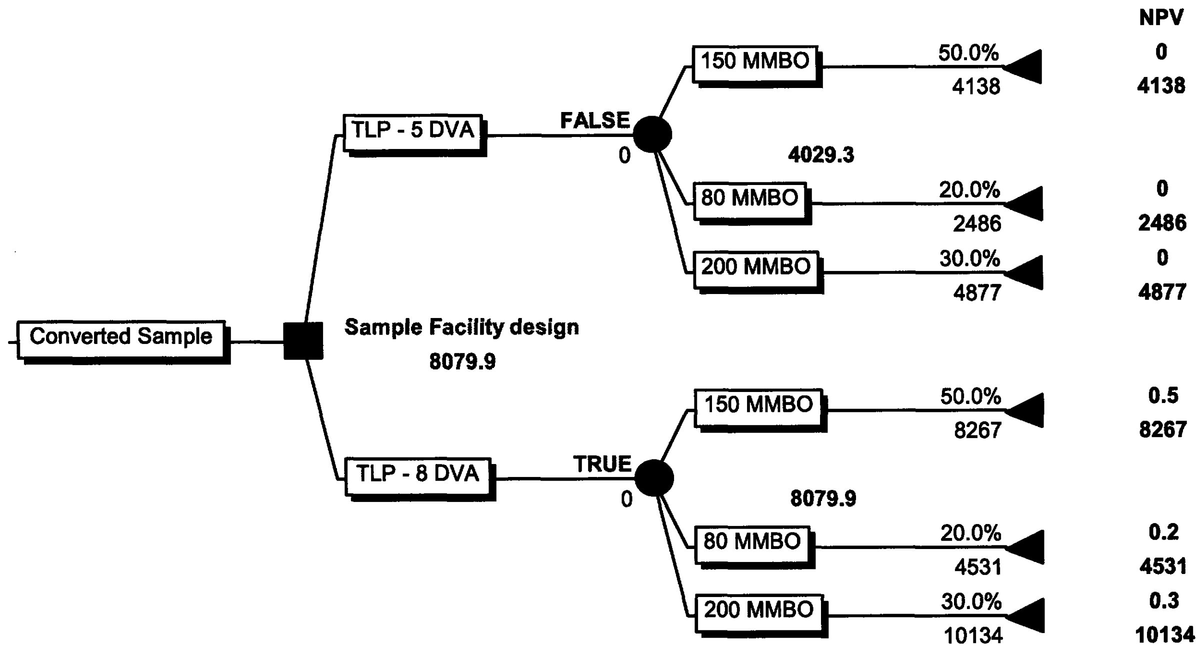


Figure 7: Expected value of Sample area development with probabilities for various reserve cases

Step 3: Build in real options and decide whether or not to exercise the option

Here, real options are built into the facility design. First, three choices are presented: develop the field with 5 DVA + 3 extra slots, 8 DVA + 2 extra slots, or 8 DVA + 4 extra slots.

Again, the three possibilities of reserves in place for the Sample field are: 80MMBO, 150 MMBO and 200 MMBO. The expected value of the development choice when real options is applied is $9.6 billion, which is $1.5 billion more than the development without real options built in. See Figure 8. Figure 8 shows the expected value if an option is exercised or not. An option is only exercised if the expected value of doing so is greater than not exercising the option.

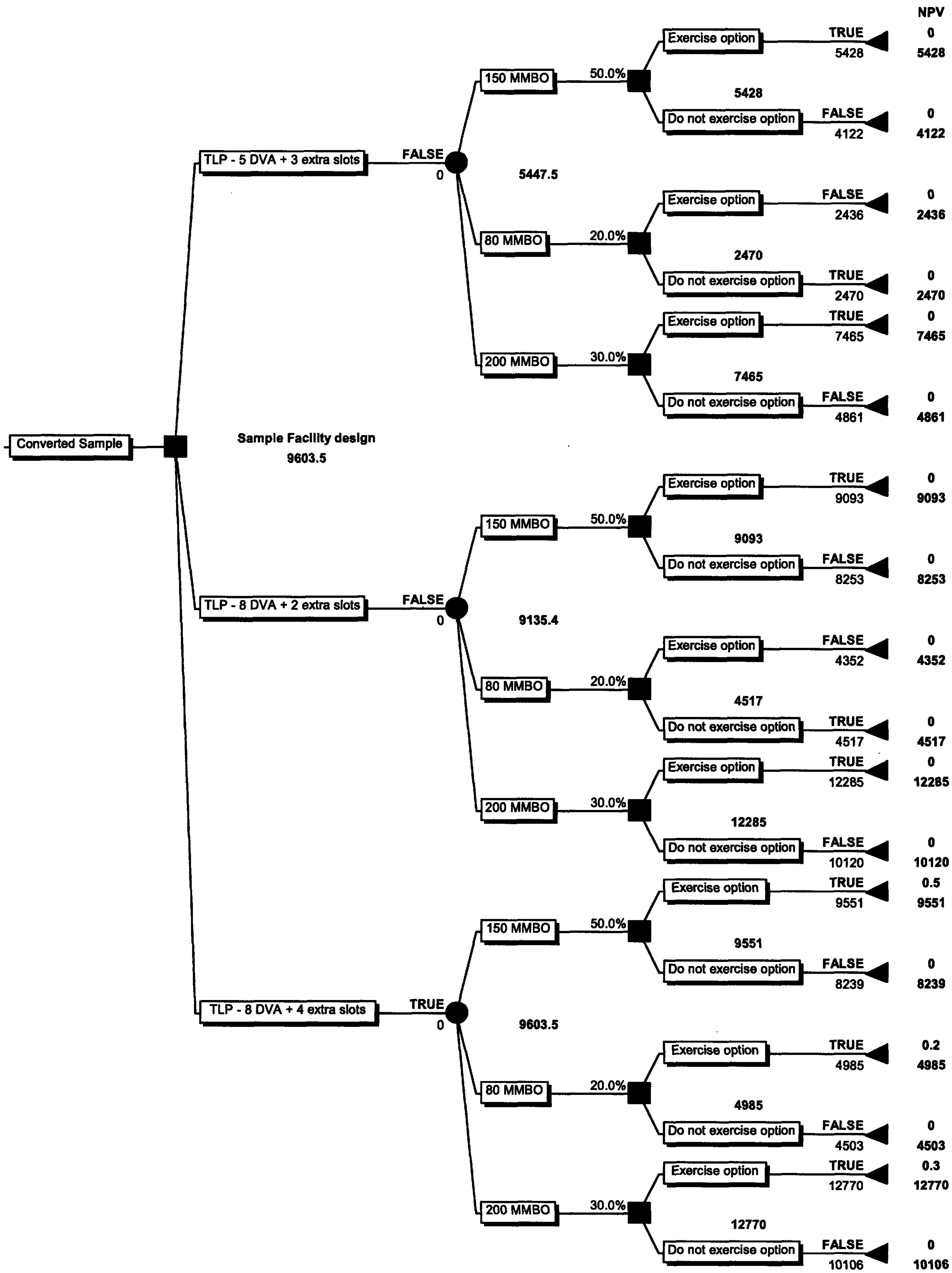


Figure 8: Expected value of Sample area development with real options built in

Value at Risk for the Sample Field:

A Value-at-risk (VaR) analysis displays the cumulative density function (CDF) of the possible outcomes of a design. The value at risk is the minimum loss that might exist at any probability.

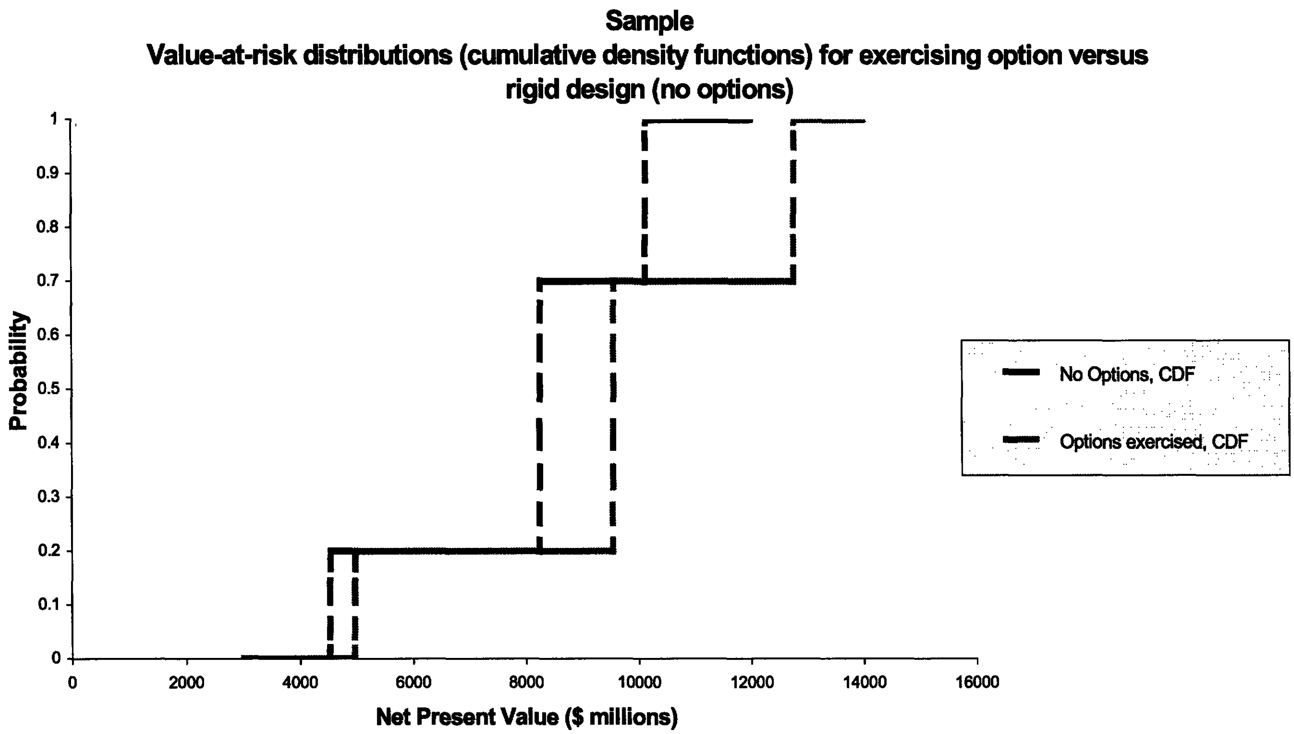


Figure 9: Value at risk distribution for the Sample field development

See Figure 9 and Table 6. This shows that by simply investing an additional $28 million in CAPEX to build in options during the project development stage, the expected realized gain is $1.5 billion, a return of $54 for every dollar spent.

Table 6: Comparison of Economic Values for the Sample Field

Sample		
	Design	
($ million)	Rigid design/No Options	Design with Options
E(NPV)	8080	9604
Std (NPV)	1949	2697
Min	4531	4985
Max	10134	12770
Initial CAPEX	685	713
Cost of Option	28	
Benefit of Option	1524	
Cost Benefit Ratio	54	

Rother Field Development ONLY

Step 1:

Two choices are presented for developing the Rother field: TLP with 5 DVA wells, or TLP with 8 DVA wells. Using the most likely reserves case for the development design and assessment, the expected value of this development choice is $5.8 billion. See Figure 10. The most likely/expected case of reserves for the Rother field is 100 MMBO. Again, this case is unrealistic as the actual reserves could vary.

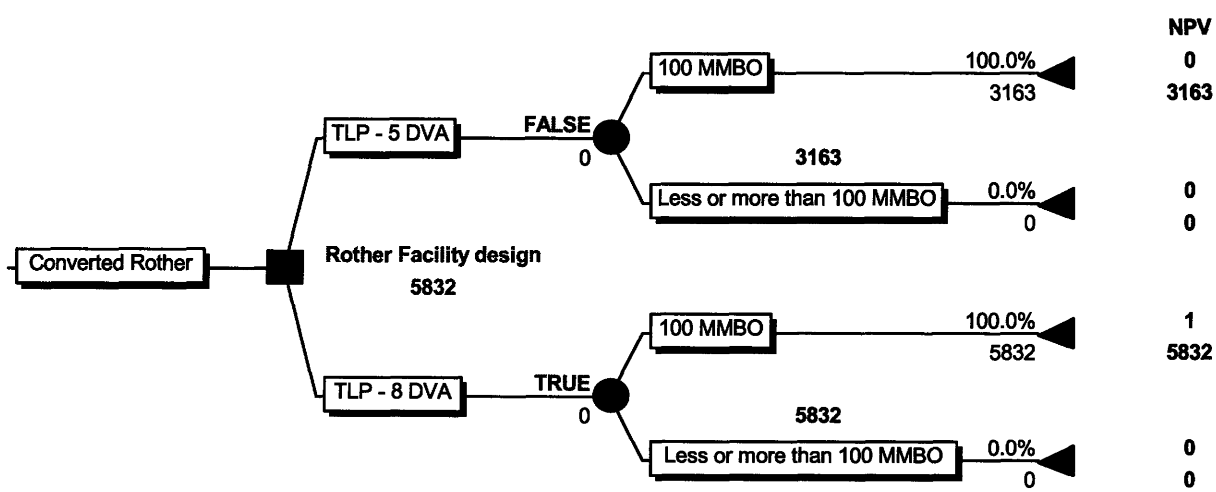


Figure 10: Expected value of Rother area development based on 100% probability of most likely case of reserves

Step 2:

Taking the reserves uncertainty into account, the three possibilities of reserves in place for the Rother field are: 100MMBO, 150 MMBO and 220 MMBO. The two choices presented for developing the field are: TLP with 5 DVA wells, or TLP with 8 DVA wells. The expected value of this Rother field development is $7.2 billion. See Figure 11.

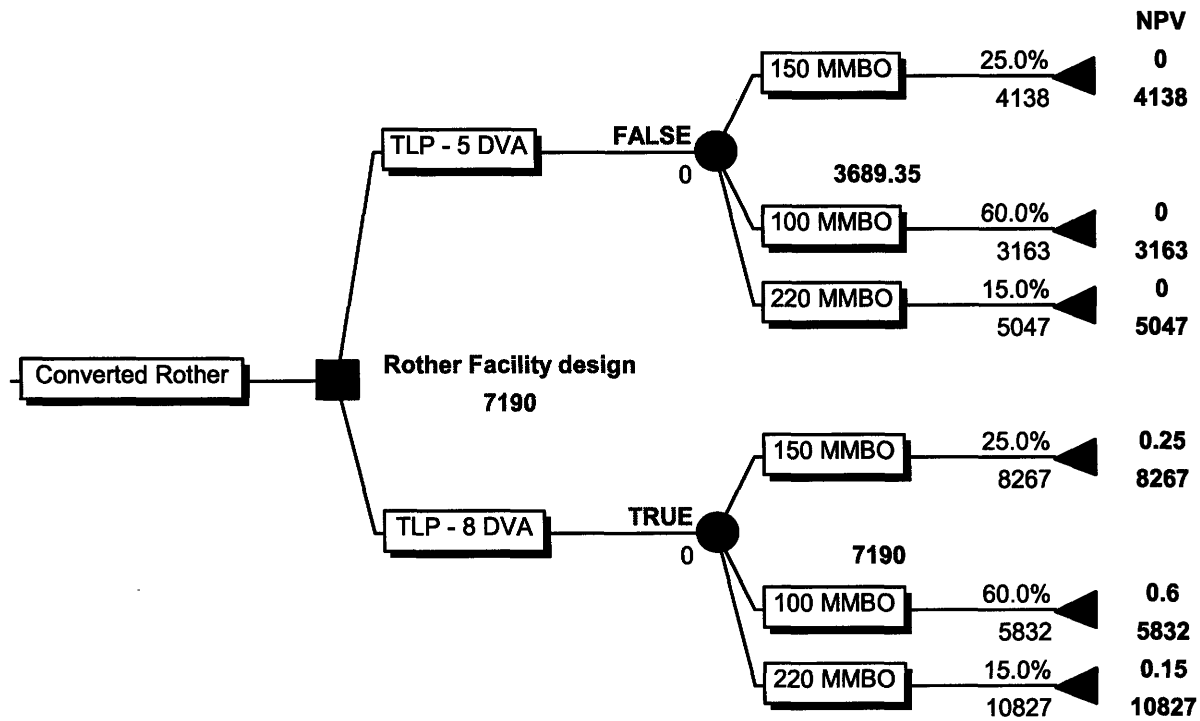


Figure 11: Expected value of Rother area development with probabilities for various reserve cases

Step 3: Build in real options and decide whether or not to exercise the option

The three possibilities of reserves in place for the Rother field are: 100MMBO, 150 MMBO and 220 MMBO. For this case, real options are built into the facility design for the Rother field. The development options are: 5 DVA + 4 extra slots, 8 DVA + 2 extra slots, or 8 DVA + 4 extra slots. The expected value of the development choice when real options is applied is $8.1 billion, which is $900 million more than the development without real options built in. See Figure 12.

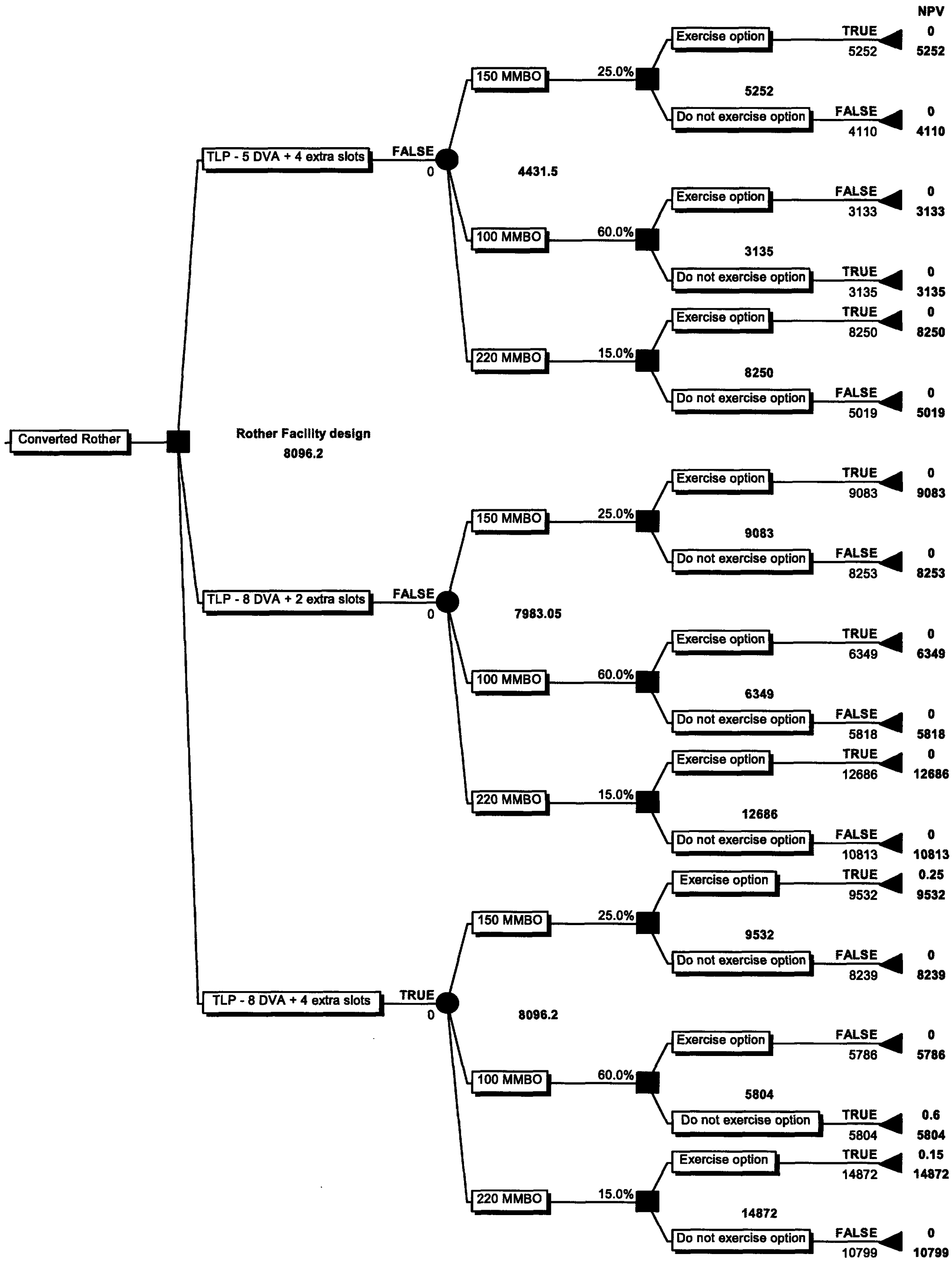


Figure 12: Expected value of Rother area development with real options built in

Value at Risk for the Rother Field:

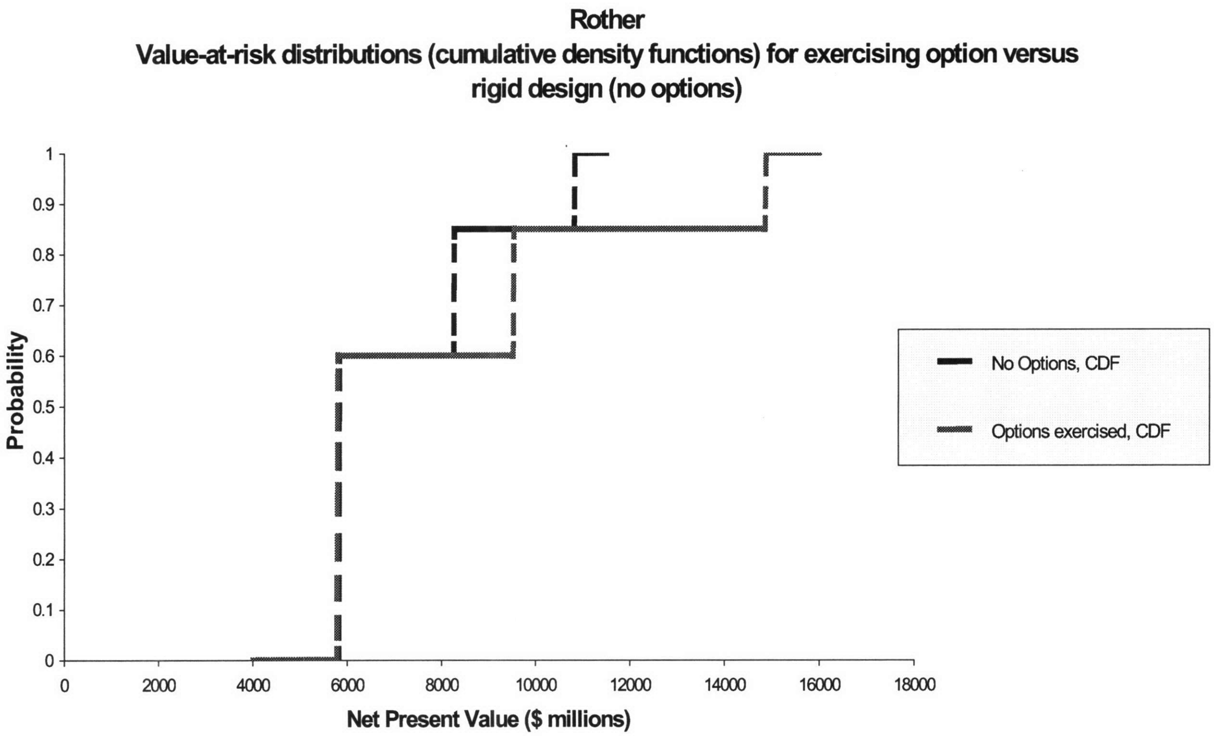


Figure 13: Value at risk distribution for the Rother field development

Table 7: Comparison of Economic Values for the Rother Field

Rother		
	Design	
($ million)	Rigid design/No Options	Design with Options
E(NPV)	7190	8096
Std (NPV)	1838	3248
Min	5832	5804
Max	10827	14872
Initial CAPEX	685	713
Cost of Option	28	
Benefit of Option	906	
Cost Benefit Ratio	32	

Sample and Rother Fields Development COMBINED

Step 1: Get reserve probabilities for the combined field development

First, a run is made with probabilities for the Sample field development, and then for the Rother field development to come up with probabilities for the Sample and Rother fields combined development. From this analysis, four EUR probabilities were chosen to use for the Sample and Rother combined developments: 210, 270, 350 and 420 MMBO. The results can be seen in Figure 14 and 15.

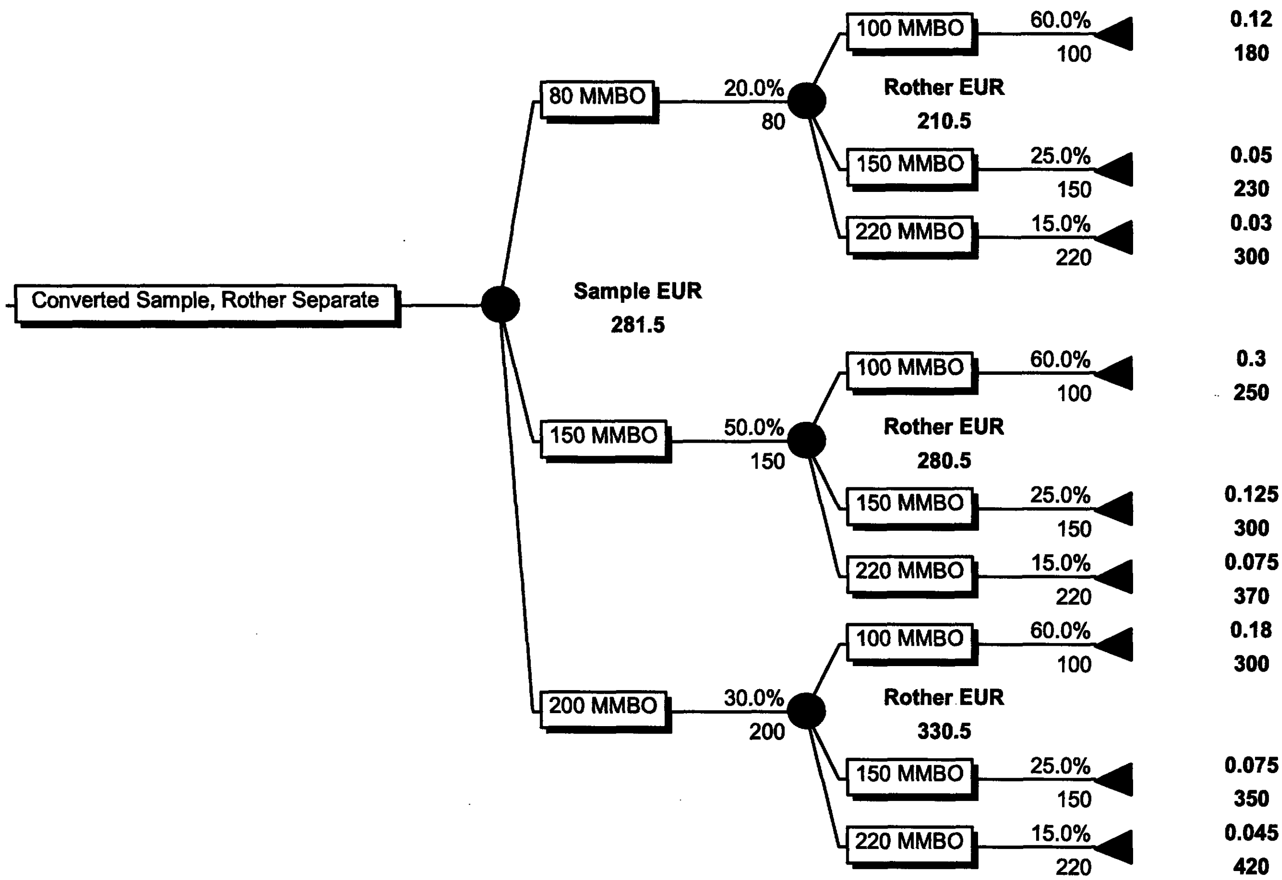


Figure 14: Probabilities for the Sample and Rother field developments combined

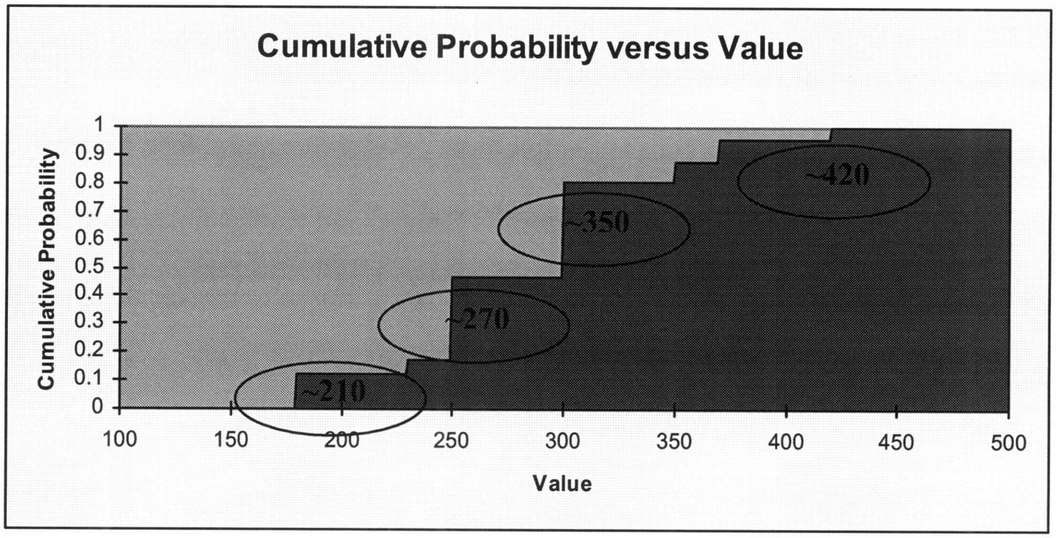


Figure 15: Cumulative Probabilities for the Sample and Rother fields combined

Step 2:

Because of the location of the fields, a combination of TLP DVA wells and subsea wells will be used for the field developments. The two choices for the developments are: TLP with 8 DVA + 5 SS wells, or TLP with 10 DVA + 5 SS wells. Using simply the most likely reserves case for development, there is a 50-50 chance the EUR is 270 MMBO or 350 MMBO for Sample and Rother fields combined. The expected value of this development is $29.7 billion. See Figure 16.

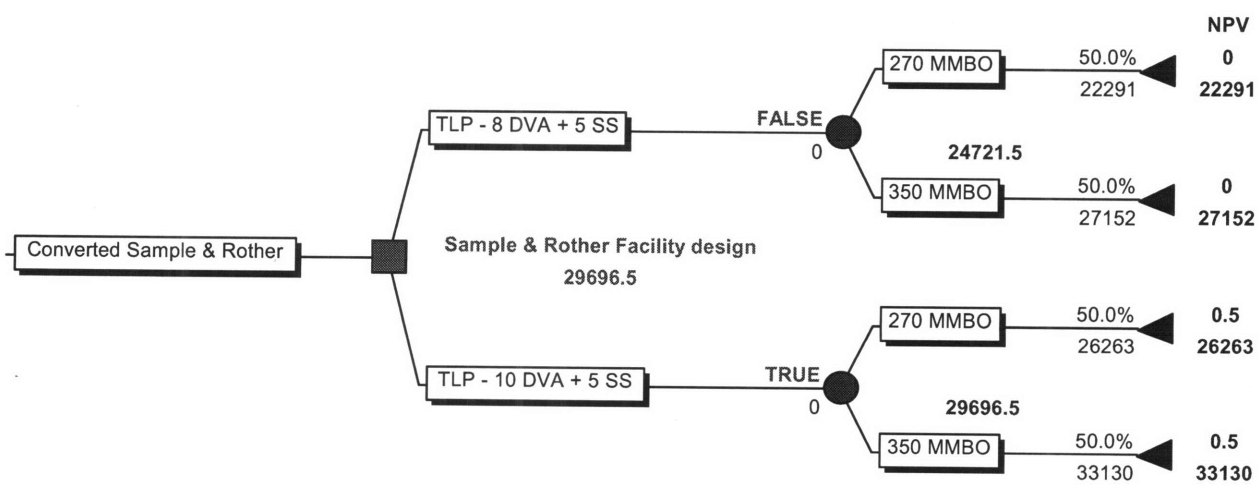


Figure 16: Expected value of developing the Sample and Rother fields using the most likely case for reserves only

Step 3:

Taking the reserves uncertainty into account, the four possibilities of reserves in place for the Sample and Rother fields combined are: 210MMBO, 270 MMBO, 350 MMBO and 420 MMBO. The two choices presented for developing the fields are: TLP with 8 DVA + 5 SS wells, or TLP with 10 DVA + 5 SS wells. The expected value of this development is $29.5 billion. See Figure 17.

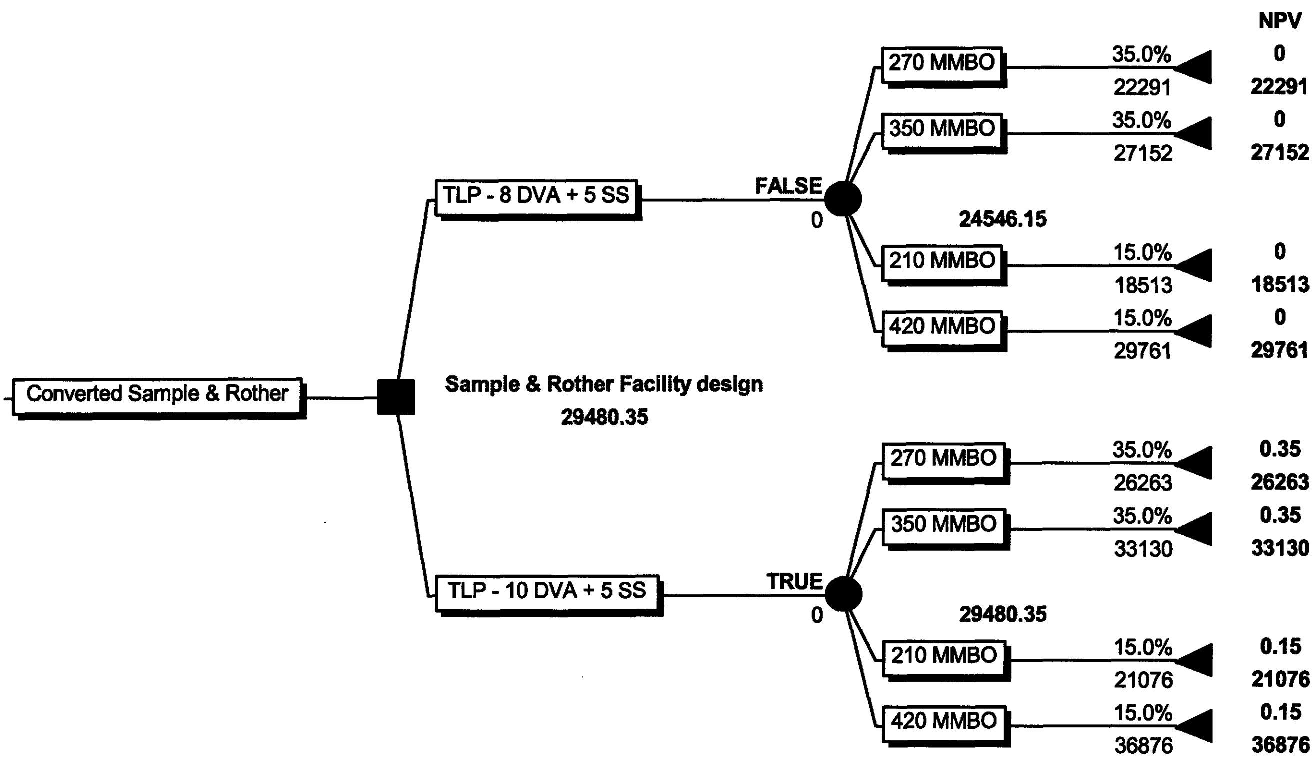


Figure 17: Expected value of Sample and Rother area developments with probabilities for various reserve cases

Step 4: Build in real options and decide whether or not to exercise the option

The four possibilities of reserves in place for the Sample and Rother fields combined development are: 210MMBO, 270 MMBO, 350 MMBO and 420 MMBO. For this case, real options are built into the facility design. The development choices are: TLP with 8 DVA + 5 SS + 2 extra DVA + 2 extra SS wells, or TLP with 10 DVA + 5 SS + 2 extra DVA + 2 extra SS wells. See Figure 18.

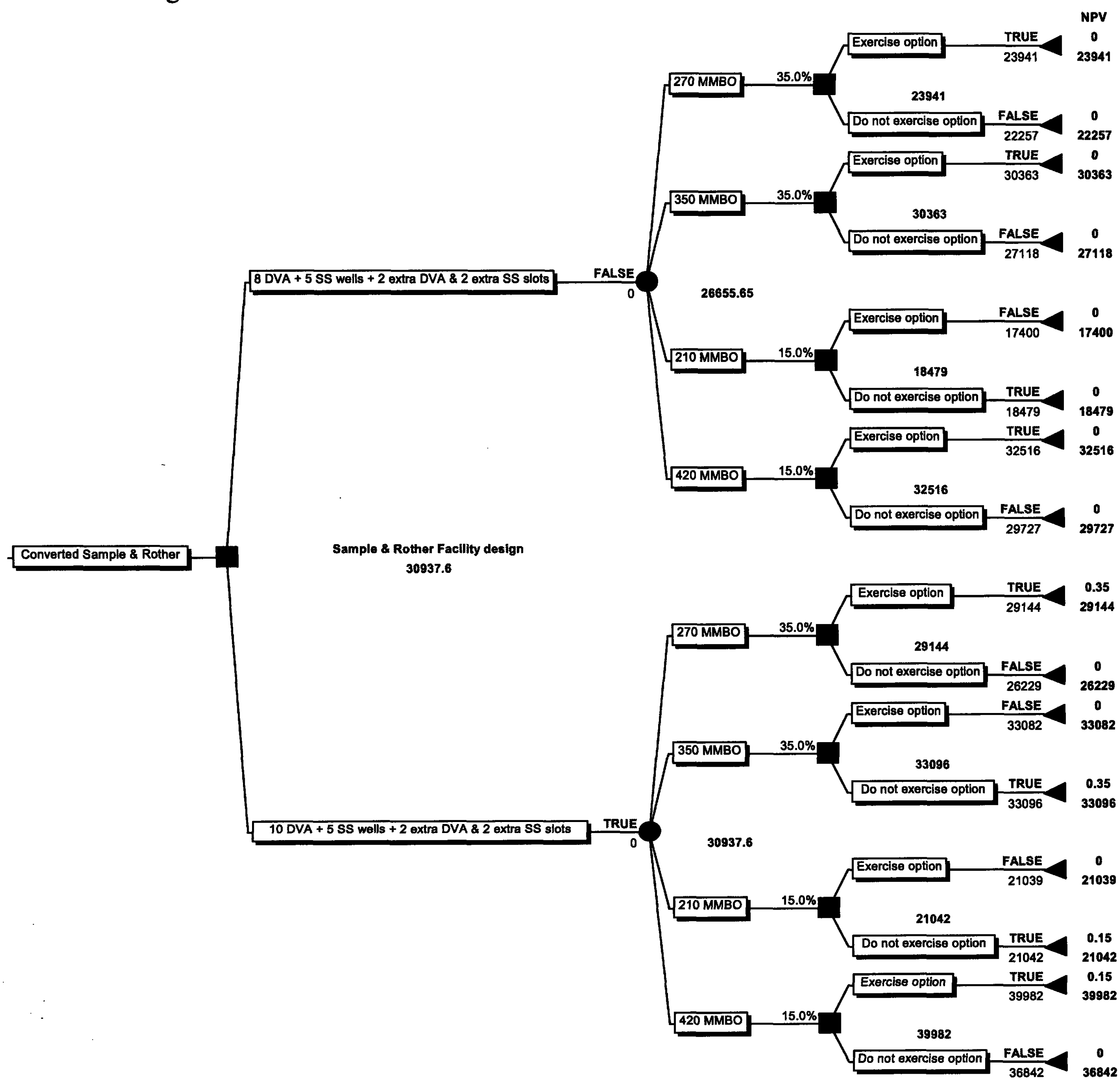


Figure 18: Expected value of the Sample and Rother area combined developments with real options built in

The expected value of the Sample and Rother development choice when real options is applied is $31 billion, which is $1.5 billion more than the development without real options built in.

Value at Risk for the Sample and Rother Combined Development:

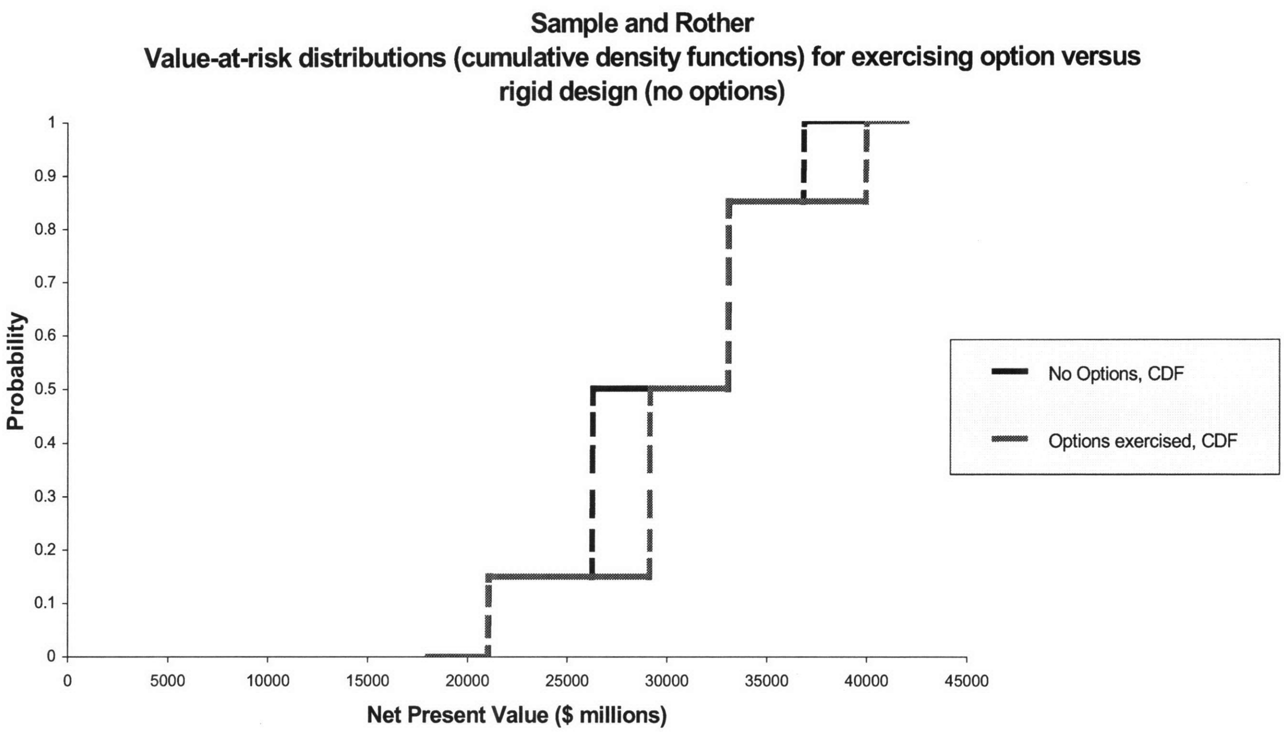


Figure 19: Value at risk distribution for the Sample and Rother field development

Table 8: Comparison of Economic Values for the Sample and Rother Field Combined Development

Sample and Rother		
	Design	
($ million)	Rigid design/No Options	Design with Options
E(NPV)	29480	30938
Std (NPV)	5204	5451
Min	21076	21042
Max	36876	39982
Initial CAPEX	1056	1090
Cost of Option	34	
Benefit of Option	1458	
Cost Benefit Ratio	43	

Step 5: Given oil price uncertainty, determine real options solution to go with, and when to exercise option or not

The earlier decision trees were done at a price premise of $15/bbl. The field development is also evaluated at different price points: at $10/bbl for the low case, and $20/bbl for the high case. Given the uncertainty in oil prices, the decision to exercise an option or not may change. See Figures 20 and 21 for expected values with options at $10 per barrel and $20 per barrel price markets.

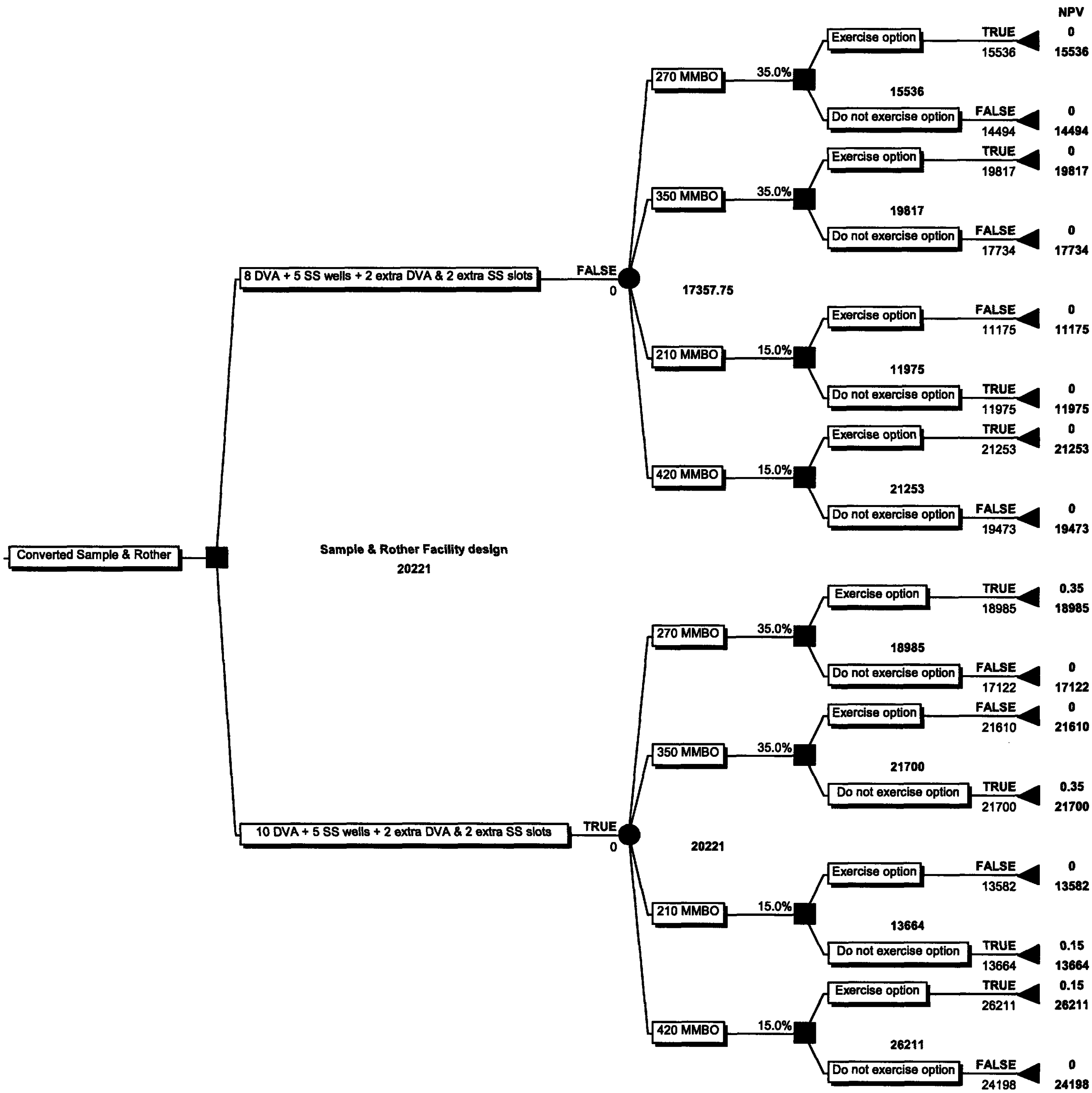


Figure 20: Expected value of Sample and Rother field developments at $10 per barrel with real options built in

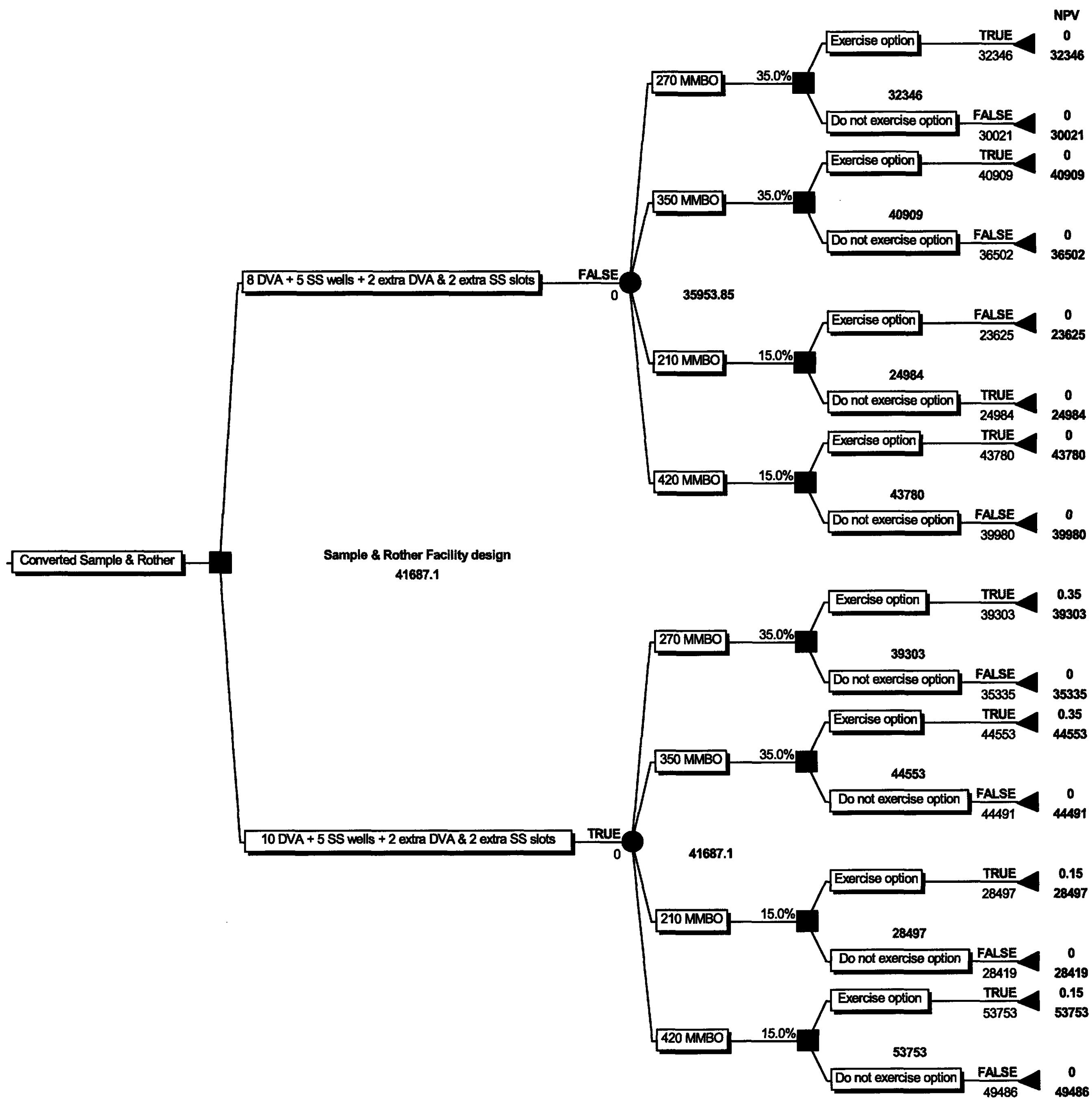


Figure 21: Expected value of Sample and Rother field developments at $20 per barrel with real options built in

The preceding three decision trees, that is, Sample and Rother developments at $10/bbl, $15/bbl and $20/bbl price markets, with real options built in, assumes an equal distribution in probabilities around the uncertainty in oil price.

If the probability that oil price will be $10/bbl is 15%, $15/bbl is 65% and $20/bbl is 20%, the expected value of the chosen development is now:

0.15(Expected value @ $10/bbl) + 0.65(Expected value @ $15/bbl) + 0.20(Expected value @ $20/bbl)

Based on the case that yields the highest expected value, the decision tree favors developing the fields with: 10 DVA + 5 SS wells + 2 extra DVA and 2 extra SS slots.

Given the uncertainty in oil price, the mean NPV for this development is = $31,480MM

[That is: (0.15 x 20221) + (0.65 x 30938) + (0.20 x 41687)]

Using the Sample and Rother field developments to illustrate, it is clear that real options adds flexibility and thus more expected value to a project like an oil field development, versus developing with a rigid design.

6.3 Recommendation

The field development strategy that maximizes the expected value of the project is to develop both the Sample and Rother fields. In addition, expected value is maximized by building in flexibility to the project. For this field development, value is maximized building in real options to the project and chosing the path (to exercise or not exercise the option) that yields the highest expected value. In this case, the decision tree favors developing the fields with: 10 DVA wells and 5 subsea wells, with the ability to add 2 extra DVA and 2 extra subsea wells in the future. This option entails starting out with a smaller facility size with the capability for further expansion in the future. This built in option will allow expanding the facility and well count at a later date. Doing so increases the expected value of the project compared to the single path of development method used by the project team.

7. Conclusion

Oil exploration is a risky business; it is expensive to drill an exploratory well and the information obtained from such ventures isn't always accurate. It cost even more to develop an entire oil field in an environment with much uncertainty. With the application of real options in conjunction with decision analysis, this thesis showed how the Sample and Rother project team could have maximized the expected value of the project, decreased waste that may be associated with unneeded upfront CAPEX, and built in flexibility to the project to take advantage of the unknown given the uncertainty in the future. This could not have been accomplished with an otherwise rigid assessment method. However, the use of real options analysis in this thesis is limited in that it does not fully take into account how decisions may be impacted by more complex criteria. As noted earlier in the thesis, several other factors can contribute to the decision process for a field development, including safety, environment, laws, regulations and contract terms.

This thesis started by exploring current investment assessment tools that showed a clear lack of flexibility and consideration of uncertainties. It reviewed what real options analysis is and how it can be applied. Following an overview of the case, this thesis showed how more value could have been added to the Sample and Rother field developments through the use of real options analysis.

Using real options analysis on the Sample and Rother field developments showed that this method added more expected value compared to the method used by the project team. In reaching this conclusion, several development choices were looked at. The development choices included whether to develop the Sample or Rother field separately or combined, what type of facility to use for developing the field, and what production well combination to use for field development. The analysis showed that an improved go-forward design would have been to start with 10 DVA and 5 subsea wells, with the capability to expand it at a later time with 2 additional DVA wells and 2 additional subsea wells.

The results of the real options analysis of this project showed the optimal field development strategy given the various reserves expectations. The project team's base case was a single path of development for the Sample and Rother fields with 8 DVA wells and 5 subsea tie-backs. Using the team's method, the expected value is lower than if real options had been built into the design. For the various scenarios, using real options analysis yields the most expected value.

The use of Real Option analysis can add more value to oil field developments compared to traditional methods of making investment decisions. Since real options adds flexiblility to projects, it can save upfront capital expenditure for instance in the amount of money spent on initial facility size/capacity since alternatively some limited capacity could have been added with the flexibility to add more at a later time. For example, this could mean having one production train of 50,000bopd with the ability to add an additional production train if needed. For the Sample and Rother field case, fewer wells could also have been drilled upfront with the ability to add more wells if needed at a later date to maximize draining the reservoir in various compartments and increase expected value. This could have been accomplished by providing additional well slots on the platform. Overall, this thesis showed that real options analysis can be applied to oil field developments, and that in addition, it provides for achieving a higher expected value compared to using traditional investment assessment methods alone.

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Appendix

A.

NPV Calculations:
Spreadsheet Construction for NPV calculations, view 1:

Discount rate	10%	
Price per barrel (Low case)	$10	dollars per barrel
Price per barrel (Mid case)	$15	dollars per barrel
Price per barrel (High Case)	$20	dollars per barrel
Capacity - Production per well per year	1.825	million barrels per yeai *[ie: (avg 5000bopd*365days)/1000000]*
Reserves (Low case)	210	million barrels
Reserves (Mid case)	270	million barrels
Reserves (Mid case)	350	million barrels
Reserves (High case)	420	million barrels

Upfront Cost

Cost of TLP	291	million dollars
Base cost of TLP Process Facility (Topsides cost with up to 5 wells)	150	million dollars
Additional cost of TLP Process Facility per well (for more than 5 wells)	5	million dollars per well
Cost per DVA well	23.625	million dollars per well
Cost per SS well	45	million dollars per well
Cost for umbilicals	5	million dollars
Cost per flowline	42	million dollars
Engineering and Project Management Cost	40	million dollars
Upfront cost for expandable facility (option) **(up to 3 more wells)**	10	million dollars
Upfront cost for expandable facility (option) **(up to 6 more wells)**	20	million dollars
Upfront cost for expandable facility (option) **(up to 9 more wells)**	30	million dollars
Cost for additional DVA well slot (option)	2	million dollars per slot
Cost for additional subsea well slot (option)	5	million dollars per slot

Later Cost

Cost of additional DVA well (if option exercised)	28	million dollars per well
Cost of additional subsea well (if option exercised)	55	million dollars per well
Facility expansion cost per well (if option exercised)	20	million dollars per well
If extra flowline needed, cost per flowline	46	million dollars per flowline

Spreadsheet Construction for NPV calculations, view 2:

	Year	0	1	2	3	4	5	6	7	8	9
				expect to know reservoir characteristics now, so implement option (if choose to) in 2nd year							
	Amount of Reserves (million barrels)	210									
	Number of DVA wells	**10**	10	**10**	10	10	10	10	10	10	10
	Number of subsea wells	**5**	5	**5**	5	5	5	5	5	5	5
	Production per well per year (million barrels per year)	27.375	27.375	27.375	27.375	27.375	27.375	27.375	27.375	27.375	27.375
			27.375	27.375	27.375	13.6875	13.6875	13.6875	13.6875	13.6875	13.6875
	Field life (years)	**7.7**	**6.7**	**5.7**	**4.7**	**3.7**	**2.7**	**1.7**	**0.7**	**(0.3)**	**(1.3)**
	Remaining Reserves	210	182.6	155.3	127.9	100.5	73.1	45.8	18.4	(9.0)	(36.4)
	Price of Oil (dollar per barrel)	$15	$15	$15	$15	$15	$15	$15	$15	$15	$15
	Revenue (million dollars)		$6,159	$6,159	$6,159	$3,080	$3,080	$3,080	$3,080	$3,080	$3,080
	Cost of TLP	291									
	Base cost of TLP Process Facility (Topsides cost with up to 5 wells)	150									
	Process Facility additional cost if more than 5 wells	25									
	Cost per DVA well	236.25									
	Cost per SS well	225									
	Number of umbilicals	**1**									
	Number of flowlines	**2**									
	Cost for umbilicals	5									
	Cost per flowline	84									
	Engineering and Project Management Cost	40									
10	Upfront cost for expandable facility (option) **(up to 3 more wells)**										
20	Upfront cost for expandable facility (option) **(up to 6 more wells)**										
30	Upfront cost for expandable facility (option) **(up to 9 more wells)**										
	Number of additional DVA well slots	**0**									
	Number of additional subsea well slots	**0**									
	Total number of well slots	**0**									
	Cost for additional DVA well slot (option)	0									
	Cost for additional subsea well slot (option)	0									
	Investment (million dollars)	1056	0	0	0	0	0	0	0	0	0
	Number of additional DVA wells	**0**									
	Number of additional subsea wells	**0**									
	Cost of additional DVA well (if option exercised)	28									
	Cost of additional subsea well (if option exercised)	55									
	Facility expansion cost per well (if option exercised)	20									
	Extra flowline (if needed)	46									
	Net value (million dollars)	-1056	6159	6159	6159	3080	3080	3080	3080	3080	3080
		-1056	6159	6159	6159	3080	3080	3080	3080	0	0
		-1056	6159	6159	6159	3080	3080	3080	2067	0	0
	Discount factor at 10%	1.0	0.9	0.8	0.8	0.7	0.6	0.6	0.5	0.5	0.4
	Present value (million dollars)	-1056	5599	5090	4628	2103	1912	1738	1061	0	0
	NPV (million dollars)	**21076**									

B.

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List of Abbreviations:

BOE	Barrels of Oil Equivalent (1 BOE = 5800 cubic feet of gas)
BP	Business Plan (eg, BP03 – Business Plan for 2003)
CAPEX	Capital Expenditures
DA	Decision Analysis
DVA	Direct Vertical Access (well)
EUR	Expected Ultimate Recovery
EV	Expected Value
FID	Final Investment Decision
LE	Latest Estimate
MMBOE	Million Barrels of Oil Equivalent
MMSCF/D	Millions of Standard Cubic Feet per Day (measure of gas produced in a reservoir)
NPV	Net Present Value
OIIP	Oil Initially In Place
OPEX	Operating Expenditures
PVPAT	Present Value Profit After Tax
RO	Real Options
ROA	Real Options Analysis
REPAT	Real Earning Power After Tax
TLP	Tension Leg Platform