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Facility Planning and Value of Information Using a Tank Reservoir Model: A Case Study in Reserve Uncertainty

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Facility Planning and Value of Information Using a Tank Reservoir Model: A Case Study in Reserve Uncertainty

by

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Dedication

This thesis is dedicated to Umadutt, Ajay, Kusum, and Aakanksha

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Abstract

Facility Planning and Value of Information Using a Tank Reservoir Model: A Case Study in Reserve Uncertainty

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This thesis presents a methodology to incorporate reservoir uncertainties and estimate the loss in project value when facility planning decisions are based on erroneous estimates of input variables. We propose a tank model along with integrated asset development model to simulate the concept selection process. The model endogenizes drilling decisions and includes an option to expand. Key decision variables included in the model are number of pre-drill wells, initial facility capacity and number of well slots. Comparison is made between project value derived under erroneous estimates for reserve size and under an alternate hypothesis. The results suggest loss in project value of up to 40% when reservoir estimates are erroneous. Moreover, both optimistic and pessimistic reserve estimates results in a loss in project value. However, loss in project value is bigger when reserve size is underestimated than when it is overestimated.

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CHAPTER 1: INTRODUCTION

Oil and gas project investment decision process involves collecting information, and making estimates about inputs needed to compute the project's net present value (NPV). The NPV obtained is then used to rank and choose competing project development options. The choice of development option is therefore only as good as the estimates about inputs. The choice of development option forms the foundation of an oil and gas project and determines initial capacity of facilities, well slots, production rates and project schedule (Jablonowski et al., 2008). Moreover, previous studies by Evans (2005), and Walkup and Ligon (2006) show that the choice of development option has a large impact on value ultimately derived from the project. Thus, a decision maker would ideally like to have precise estimates about inputs. However, obtaining accurate estimates in the early stage of an oil and gas project is often either extremely costly or infeasible. Thus, most oil and gas project development decisions are based on uncertain estimates of inputs. In this study we focus on quantifying the impact on project value if project development decisions are based on erroneous estimates of inputs. This can be valuable for a decision maker contemplating whether to collect more information to obtain precise estimates for inputs or plan the project with current estimates.

The most popular decision criteria used in the oil and gas Exploration and Production (E&P) industry is discounted cash flow analysis (Brashear et al., 2000). These DCF analyses generally use a single NPV number as a measure of the profitability of the project. However, a major limitation of using a single value for NPV is that it fails to account for the uncertainties in estimates about inputs (Uman et al., 1979). Thus, we use an integrated asset development model to analyze the impact of project uncertainties on project value. The use of integrated asset development model in making project decisions is widely accepted as best practice (Begg et al., 2000; Narayanan et al., 2003; Bilderbeck and Beck 2005; Cullick et al., 2005; Camargo de Abrea et al., 2006; Carreras et al., 2006; Guyaguler et al., 2006; Laughton et al., 2006; van Essen et al., 2006; Woodhead 2006; Jablonowski et al., 2008).

One of the main components of asset development model requires modeling the production from reservoir. We use a tank model similar to Paul (2007) for reservoir modeling. A tank model assumes that reservoir properties are constant throughout the reservoir. This is never true in reality, but is reasonable assumption to make at early stages of an E&P project, when we have limited information about the reservoir. At later stages tank model can be easily extended to account for spatial variation in geology by dividing the reservoir in numerous small tanks, with each tank having fixed geology and reservoir properties. Another important modeling choice requires selecting which facility design decisions and input variable to study. In this study we mainly focused on three main facility configurations decisions -- number of pre-drill wells, initial facility capacity and number of well slots. While there are several uncertainties involved in an E&P project reserve size is one of the most important of them. The reserve estimates drives most major facility development decisions, including the depletion plan, well counts and facility design (Jablonowski et al., 2008). Thus, in this study we have focused on estimating the impact of reserve uncertainty on project value.

In order to estimate the impact of erroneous inputs, first, we establish a methodology for optimal decision making under uncertainty using the integrated asset development model, and thereafter conduct a Value of Information (VOI) analysis. The VOI analysis uses a null and alternate hypothesis set up. In this set up, we assume an initial value for the input variable of interest (reserve size in our case) and call it our null hypothesis. This null hypothesis is then used to choose optimal facility configurations and compute expected NPV. However, if the actual realization is according to an alternate hypothesis (the estimates are erroneous) the value derived from the project will differ from that expected under null hypothesis. We then compute the project value based on the alternate hypothesis, which is assumed to be true realization. The difference between project value when facility configuration decisions are based on alternate hypothesis and when they are based on erroneous estimates is analyzed to assess the impact of erroneous estimate on project value. The approach is similar in form to standard VOI analysis (Coopersmith et al., 2006; Bickel et al., 2006; Gilbert et al., 2007; and Jablonowski et al., 2008). Any resulting difference can be interpreted as the result of choosing sub-optimal facility capacity. This difference can also be understood as the maximum amount a decision maker would be willing to pay to verify the alternate hypothesis.

CHAPTER 2: PROBLEM STATEMENT

In this section we discuss the unique aspects of a deepwater E&P project, identify the major design decisions and uncertainties facing a decision maker and provide a framework for the problem we are going to study.

2.1 Introduction

A deep water E&P project is capital intensive and is surrounded by several uncertainties. Although, seismic technology and geophysical techniques used to obtain information from a reservoir are much more advanced now, there still remains significant amount of uncertainty about the reserve geology and properties at early stages of an E&P project. Thus, it is necessary for a decision maker to quantify and incorporate project uncertainties in the facility development process. Moreover, a decision maker is not only interested in taking account of project uncertainties, but also wants to identify input variables that have the largest impact on the project value. He may then choose to obtain more information on these input variables so as to take better facility planning decisions. However, getting better estimates entails more capital investment. Thus, he faces a tradeoff between investing more or planning the project with current estimates and suffering a loss if he ends up choosing sub-optimal facility configuration. Even if, the decision maker chooses to obtain more information, he would like to know, what is the maximum he should pay? This study tries to answer these twin questions, what is the cost of erroneous estimate of input variables on project value, and what is the maximum amount a decision maker should be willing to pay for getting more information on input variables?

Both these questions have been actively discussed in the E&P literature. Recent studies have advocated a holistic, integrated approach to assessing the impact of uncertainty on oil and gas investment decision making (Begg et al., 2001; Begg et al., 2008; Willams et al., 2004). There approach involves trading-off some technical rigor for a more complete assessment of the impact of uncertainty on the investment decision making process. However, using a holistic approach may sometime lead to large complex models which require specifying complex dependencies between input variables. These models can also be slow to solve due to their size. We use a similar stochastic framework, where uncertainties are defined using a probability distribution, but imply one-variable-at-a-time approach instead of using a holistic model. Our approach has the advantage of being simple, fast and cheap as compared to holistic models. Other studies have argued using a portfolio theory approach where instead of analyzing projects on individual basis a portfolio of projects is analyzed (Ball and Salvage 1999). This method involves quantifying the risk of a project, which itself can be subjective. Moreover, different E&P companies may have different risk tolerance and thus the outcomes will be dependent on the individual organization. Furthermore, the best outcome may suggest investing 20% in project A, 40% and in B and 60% in C. This kind of investment strategy is possible for financial assets, but in E&P projects where a company has 100% interest in assets, holding a share of the asset may not be a feasible option. Due to these limitations we believe it is better to analyze projects on an individual basis than using a portfolio approach.

2.2 Deepwater Projects

As the world energy demand is increasing, oil Exploration and Production companies are drilling further out into the sea and deeper under the ocean floor to access the remaining packets of oil and natural gas in the world. A “deepwater” E&P project is defined as one with production facility located in a water depth equal to or greater than

1000 ft (US department of interior, MMS, OCS, 2004). Figure 2.1 shows water depth and completion depths division of a deep water and shallow water E&P project in Gulf of Mexico. The complexity of deepwater project makes it highly capital intensive and technically challenging. For example, an onshore oil well may cost in the range of 1-15 million dollars, while deepwater well costs lies in the range of 100-300 million dollars.

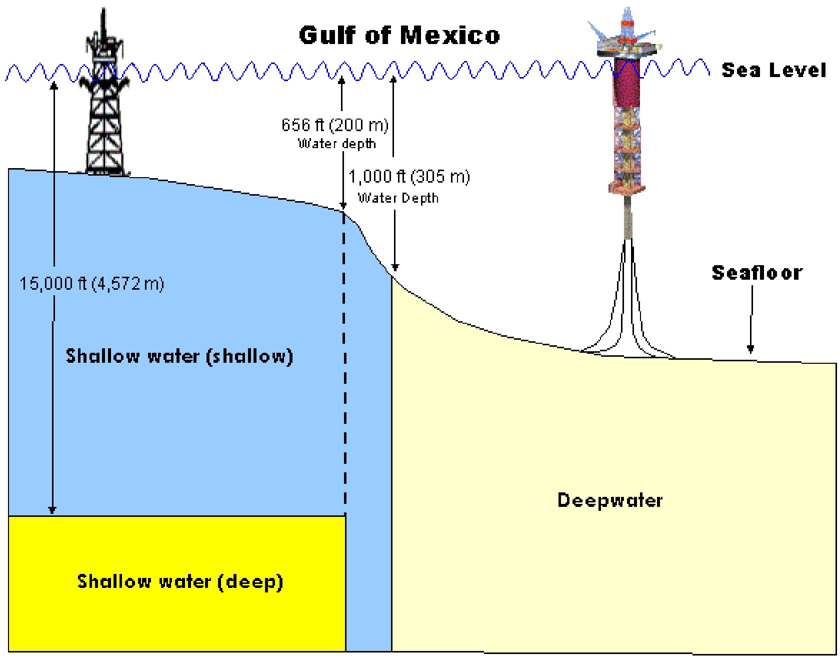


Figure 2.1: Shallow and Deepwater Projects (US DOE, MMS, OCS, 2004)

The life of a typical oil project can be divided into four stages, exploration, appraisal, development and production. Before the development and production stage we have limited information about the field and there is a greater amount of uncertainty in estimates about the field. Unfortunately, these estimates about input variables are the ones that are used to make facility design and development decisions. However, as the project life progresses we collect more data about the field and the uncertainties about reservoir estimates decrease. At this stage we update our initial estimates about reservoir properties to reflect more closely the actual reservoir properties. This is what we say as the realization of uncertainties. At this stage we cannot make major design changes in the facility. However, having the flexibility to expand the facility after the realization of reservoir uncertainties is generally useful. In this study we estimate the value of having a facility expansion option. Figure 2.2 shows a typical timeline of an E&P project with facility expansion option.

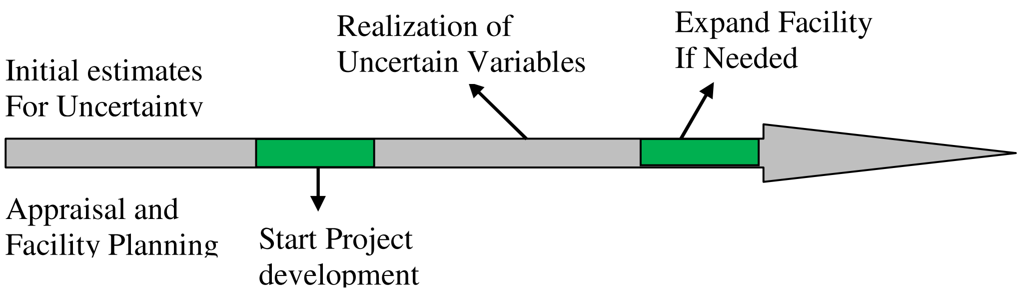


Figure 2.2: Project Time-Line

2.3 Major Uncertainties in Deepwater Projects

There are several uncertainties facing a deepwater project. They can be mainly classified into three broad categories, Geological, Regulatory or Macroeconomic, and Natural. Regulatory and Natural risks are less frequent and more difficult to account for than geological uncertainties. Thus, in our study we focus mainly on the Geological uncertainties facing an E&P project. Previous studies show that these uncertainties play a significant role in the E&P decision making process (Camargo de Abreu et al., 2006; Suslick et al., 2003).

2.3.1 Reserve Size

Reserve size is the total amount of commercially and technologically recoverable hydrocarbon reserves present below the Earth's surface. The amount of oil reserves present in the field plays a major role in field development decisions (Jablonowski et al., 2008). At initial stages of the project we estimate the reserve size using exploratory drilling, seismic survey and geo-statistical tools. At this stage we have limited data available about the field and therefore the estimates are uncertain. As the life of the project progress and we start producing from the field we obtain more information and uncertainty about reserve estimate decreases. However, a decision maker has to take facility development decisions based on initial estimates for reserve size. Thus, it is necessary to know the impact of uncertainty in reserve size on project value. If the uncertainty is large it may be optimal to postpone development of the field and collect more information.

Equation (1) below shows an analytical representation for reserve size based on volumetric considerations.

$$N_r = \frac{7758 A h \emptyset (1 - S_w) R_f}{B_0} \tag{1}$$

Where,

N_r = recoverable oil reserve (stock tank barrels, STB)

A = area of the reservoir (acres)

h = net pay thickness (feet)

ϕ = porosity

S_w = average water saturation

R_f = recovery factor

B_0 = oil formation volume factor (reservoir barrels / stock tank barrels, RB/STB)

2.3.2 DEGREE OF COMPARTMENTALIZATION

A petroleum reservoir usually has several faults, joints, and folds, which result in significant spatial variation in reservoir geology. Moreover, there are also changes in pore-system connectivity, hydrodynamic gradients and overpressure (Elshahawi 2005). Due to these spatial variations in reservoir properties most if not all reservoirs are to some extent compartmentalized. Figure 2.3 shows a cross section of the reservoir with grids of different color representing different compartments. Compartmentalization leads to division of reservoir in vertical and lateral segments, such that there are barriers to fluid flow and different compartments do not communicate or have limited communication with each other during oil production. In addition, different compartments may have different oil-water and different gas/oil ratio. This can lead to significant spatial variation of reserves, which may affect siting and surface facility design decisions. Moreover, different degree of compartmentalization will need different number of wells to drain the reservoir. More complex reservoir with large number of compartments will need more number of wells. Thus, knowledge about degree of compartmentalization during field appraisal has a large impact on the decisions to develop the field or not, what development strategy to use, and on the value ultimately derived from the project (Smalley 1996).

The best method to know the degree of compartmentalization is from dynamic production data obtained from the field. Unfortunately, this is not available at the field appraisal stage of the project. Although, well test analyses and 3-D seismic tools can provide estimates about degree of compartmentalization, but these estimates suffer from usual statistical biases. Thus, the decision maker has to take facility design decision based on uncertain estimates. The importance of knowing the degree of compartmentalization cannot be overstated, and so the E&P literature is very rich on discussion about identifying compartmentalization. However, there remains a debate on the best technique to use to identify reservoir compartmentalization. Some studies suggest techniques like Down-hole fluid Analysis to be best in identifying compartmentalization (Fujisawa et al., 2005). While, others suggest combining analyses from different methods like well tests, 3-D seismic and fluid analysis to best predict compartmentalization (Smalley 1996). In our study the focus is on estimating the impact of reserve uncertainty. Thus, we have used a single tank reservoir model with no spatial variation in geology, and therefore no compartmentalization. This leads to a constant drainage potential for each well in the reservoir. This is just a simplifying assumption and can be easily relaxed and analyzed using a methodology similar to that used for analyzing reserve uncertainty.

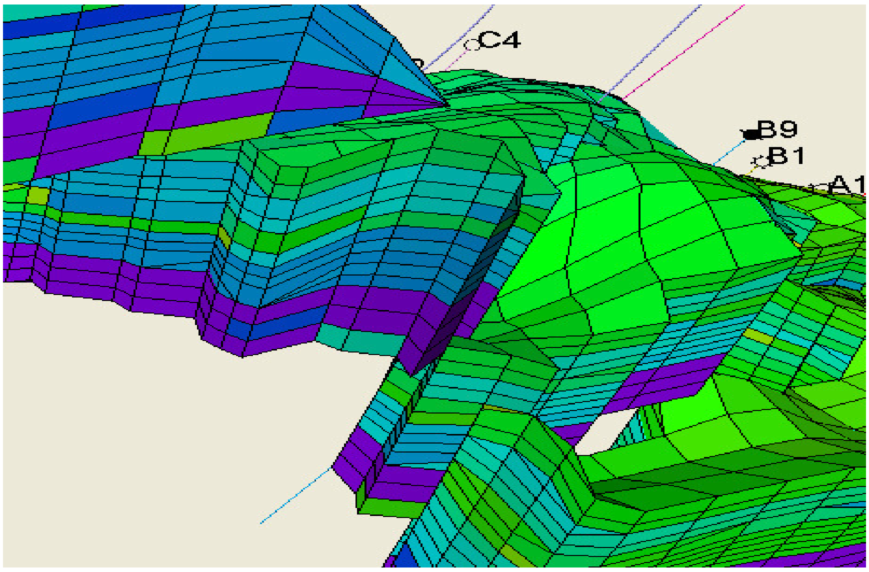


Figure 2.3: Reservoir Cross-section Showing Compartmentalization

2.3.3 MAXIMUM PRODUCTION RATE

Maximum production rate from a well depends upon the reservoir properties, flow area, oil formation volume factor, and pressure gradient. Equation (2) shows the relationship between maximum production rate and reservoir properties.

$$q = \frac{0.001127kA}{\mu B_0}\frac{dp}{dl}$$

q = Production rate (STB / D)

A = Flow area (ft^2)

k = Permeability (millidarcy)

μ = fluid viscosity (cp)

B_0 = oil formation volume factor (reservoir barrels / stock tank barrels, RB/STB)

dp/dl = flow pressure gradient (psi/ft)

As we have discussed above, reservoir properties significantly vary throughout the reservoir and estimates about them are uncertain. As a result, there is significant uncertainty about maximum production rate from different wells in a reservoir. Uncertainty about production rate has a direct impact on project value as it affects production that can be achieved from the field. However, in our study we have assumed a constant production rate of 3000 bopd. We can easily relax this assumption by specifying maximum production rate using a probability distribution, and following similar methodology as used for reserve size to analyze its impact on project value.

2.4 Major Investment Decisions

The main facility planning decisions studied in this study are initial facility capacity, maximum number of well slots, and number of pre-drill wells. These decisions determine the facility architecture and production schedule. Thus, have a large impact on the profitability of the project.

2.4.1 INITIAL FACILITY CAPACITY

Initial facility capacity determines the size of the facility and hence the maximum production capacity. Choosing facility size close to the optimal capacity is important because facility capacity is inflexible, meaning once selected it cannot be increased without expansion. A decision maker can always build a bigger facility than required, but it requires making larger capital investment and affects the profitability of the project. Previous studies have also considered facility capacity choice to be a key decision variable at the facility planning stage (Jablonowski et al., 2008). In this study we vary the optimal choice options from 20 to 80 mbopd, but the methodology developed can be applied for any range of facility choice options.

2.4.2 MAXIMUM WELL SLOT

The total number of dry tree slots determines the maximum number of wells that can be drilled at the facility. The number of wells required and their placement is largely dependent on reserve size and degree of compartmentalization. As estimates about both reserves size and degree of compartmentalization are uncertain choosing the optimal well slots number is not a trivial task. Moreover, deepwater oil wells costs vary in the range of 100-300 million dollars, thus, having more than necessary wells can significantly affect the project economics. Therefore, well slot decision is one of the key decisions we analyze in this study.

2.4.3 Pre-Drilling

In general an oil field development time-line involves, constructing the platform, then drilling and production. Following this sequence of operations means delaying first oil production from the field until the platform is ready. However, another development strategy can be to hire a drill rig and start drilling while the platform is being constructed. The wells that are drilled along with platform construction can be defined as pre-drill wells. This sequence of workflow allows early oil production, but involves a greater capital investment. Thus, the decision maker faces a trade-off between getting early production and investing more capital. Also, deepwater drilling is highly capital intensive and provides lesser margin for errors. Thus, it is essential for the decision maker to identify optimal number of pre-drill wells in order to maximize the value derived from the project.

Figure 2.4 below shows a simple sketch of two projects timelines. The top timeline shows a project without pre-drilling, while the bottom time-line represents a project with pre-drilling. We can see with pre-drilling we can start producing earlier than without pre-drilling.

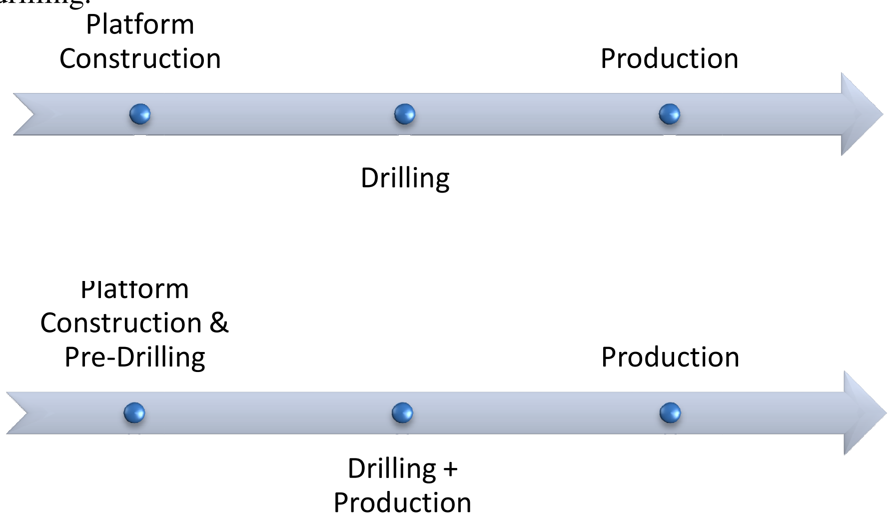


Figure 2.4: Time-Line with and without Pre-drilling

2.4.4 Facility Expansion Option

The initial facility capacity is planned at the appraisal stage. At this stage uncertainty about reserve size, field geology and other reservoir properties is high. Thus making the optimal facility choice is a challenging task. However, as the life of the field progress we know more about the reservoir, and can make better facility capacity choice. Having a facility expansion option, thus, provides the flexibility to increase production from the field after better reservoir estimates are available. Therefore, we included a facility expansion option in the optimization model to better reflect a project's investment decision making process.

CHAPTER 3: BACKGROUND STUDY

3.1 Optimization Problem

An optimization problem involves maximizing or minimizing a variable also known as objective function under certain restrictions called constraints. A common example of an optimization problem is of a firm trying to maximize its profit (objective function) under production, labor, and capital restrictions (constraints). An optimization problem can be mathematically formulated as below –

$$\text{Maximize } f(x)$$
$$\text{Subject to } g_i(x) \leq 0 \text{ for } i = 1, \dots, m$$
$$h_i(x) = 0 \text{ for } j = 1, \dots., k$$

Where $f,\ g_{1,\dots\dots} g_m, h_{1,\dots\dots,} h_k$ are functions defined on R^n, and $x = (x_{1,\dots\dots,} x_n)$ is a vector of variables. The above problem is solved for the vector x , such that x satisfies the constraints while maximizing the objective function. An optimization problem with a minimization function can also be written in a similar fashion.

3.2 Nonlinear Programming

Nonlinear programming is used to solve optimization problems involving nonlinear objective function or/and constraints. We employed a mixed integer nonlinear programming (MINLP) methodology to solve our optimization model. MINLP is a slightly modified version of nonlinear programming and is used when the model involves integer variables. Some of the variables in our model can only take integer values, for this reason we employed a MINLP methodology to find the optimal solution.

3.3 Monte Carlo Technique

Monte Carlo methods rely on repeated random sampling to compute their results. This method is particularly useful in modeling cases with significant uncertainty in inputs. Uncertainty in inputs makes it impossible to obtain a point estimate of the output. However, Monte Carlo method helps us to overcome this problem to a large extent. The actual procedure for applying Monte Carlo method may vary from case to case. However, the general framework can be summarized in the following steps.

1. Inputs are assigned as a random variable to take into account uncertainty in their value. Thus, instead of specifying a deterministic value, inputs are declared in the model using a probability density function.
2. Random sampling is done to obtain a set of realized value for inputs from the specified probability distribution.
3. The realized value of inputs is then used for computation in the model, and a solution is obtained.
4. The procedure is repeated several times and the model is solved for each set of realized inputs.
5. At the end we obtain a probability distribution for the final outcome. Using this probability distribution function, the final outcome can be predicted with a particular probability number associated with it.

In our model reserve size is one of the uncertain inputs and is specified as a random variable. We then employ a Monte Carlo methodology to obtain a distribution of the final outcome, which is the net present value of the project in our case. A step by step illustration is provided in chapter 5 for solving our optimization problem using the Monte Carlo methodology.

3.4 Value of Information (VOI)

Value of information is a tool to distinguish between constructive and wasteful information gathering. VOI can be defined as the maximum amount a decision maker is willing to pay for additional information prior to making a decision. For an optimization model with net present value (NPV) as the objective function, VOI is numerically equal to the extent to which expected NPV can be increased using this information. One important characteristic of VOI is that, it can never be less than zero. As the decision maker can always ignore the additional information and make a decision as if the additional information was not available.

Grayson (1960) was the first to introduce the concept of VOI in the oil and gas industry. Grayson's Harvard Business School dissertation, which was later printed as a book *Decisions under uncertainty: Drilling decisions by oil and gas operators* illustrates how VOI can be used to assist decision on purchase of information. Bratvold et al., (2007) summarized the use of VOI in the oil and gas industry since 1960. There study provides evidence for an upswing in VOI related publications in SPE journals and conferences in the last ten years. This bolsters the fact that VOI is a powerful tool for a decision maker and is finding an increasing interest in the oil and gas industry. However, majority of VOI papers found in SPE publications are focused on valuing seismic information (Bratvold et al., 2007). For example, Stitbolt and Lehman (1993), Aylor (1999) and Waggoner (2000; 2002) apply VOI to value seismic information. Bickel et al., (2006) and Coopersmith et al., (2006) illustrate the use of VOI for valuing 3D land seismic reliability and value. We believe that VOI is a powerful tool and can be similarly employed at other important stages of an Exploration & Production (E&P) project. In our study we apply VOI to the concept selection stage of a project.

During the concept selection stage of an E&P project a decision maker estimates the value of competing development concepts. The concept selection decisions are largely dependent on the estimates of input variables like reserve volume, maximum production rate, initial cost, time of expansion etc. Erroneous estimate have a large impact on the project value (Evan 2005; Walkup and Ligon 2006). Thus, it is important to estimate the loss in project value due to erroneous estimates of input variables. The decision maker can then identify variables that have the largest impact on project value, and how much he can pay for more information on these variables. VOI analysis provides a framework to achieve these twin objectives for the decision maker.

In reality, we do not know if the current estimate (say null hypothesis) is erroneous, but we can estimate the impact of an alternate hypothesis being true. We employ this framework of comparing the impact of null Vs the alternate hypothesis on the project value. A procedure for concept selection decision is defined and a simplified asset development optimization model is used to estimate project values. We then solve the model separately with null and alternate hypothesis and analyze their impact on project value. We assume the alternate hypothesis to be correct in every case. The difference in value can then be interpreted as the maximum willingness to pay to confirm the alternate hypothesis. The difference can also be interpreted as the probable loss in project value if concept selection decisions are based on erroneous estimates (null hypothesis).

CHAPTER 4: MODEL DESCRIPTION

In this section we provide the analytical set up for a simplified asset development model. The model solves a constrained optimization problem, where, a project team is trying to maximize NPV under initial facility and production constraints. The input variables of interest are defined as a random variable to take into account uncertainty in their estimates. The model then estimates project value under different realizations of these inputs. This study focuses on the effect of uncertainty in reserve estimates. Thus, we define reserve estimates as a random variable and solve the model under different realizations of reserve estimates. Other standard input parameters needed to solve the model are assigned values that are typical of a deep water Gulf of Mexico project.

Equations are specified based on prior empirical research by Karlik (1991), and Jablonowski and Kliet (2006). We make the following simplifying assumptions -:

- The asset is comprised of one oil reservoir; associated gas is negligible and is not considered in the optimization.
- The reservoir heterogeneity is neglected and an oil tank model is assumed. Thus, all wells have the same production potential.
- There is no time lag between drilling and production except for pre-drill wells; a maximum of six wells can be drilled in a year.
- Straight line depreciation method is used for depreciating capital costs.
- All cash flows occur at the end of the year.

Objective Function

We consider the decision maker to be risk neutral. Thus, he intends to maximize the net present value of the project, z, defined as below

$$z = \sum_t \left(\left(NI(t) \times (1 - tax) + dep(t) - capex(t) \right) * \frac{1}{(1+r)^t} \right) - platcost \quad (1)$$

$$NI(t) = (P(t) \times q(t) - opex(t) - dep(t)) \times (1 - tax) \quad (2)$$

Where, z = net present value, $

$NI(t)$ = net income at time t, $

$P(t)$ = average oil price at time t, $/bbl, held constant in this model at 60 $/bbl

$q(t)$ = average oil production at time t, bbl

$opex(t)$ = average operating expenditure at time t, $

$capex(t)$ = average capital expenditure at time t, $

$dep(t)$ = depreciation at time t, $

r = discount rate, set at 10% in this study

tax = corporate tax rate, set at 35% in this study

$platcost$ = platform cost, $

Cost Functions

There are three components of capital costs. Initial production facility cost, production facility expansion cost, and drilling cost. There is also a variable operating costs. These four cost components are defined as follows.

Initial Facility Cost. The initial cost of the production facility is computed based on Equation (3). The facility cost equation is adapted from a study of deepwater project costs as reported in Jablonowski and Strachan (2009) in $US2006. The values of the coefficients are b0 = 50 X 10^6, b1 = 4.5 X 10^6, and b2 = 22.5 X 10^6 where the units of platcost are $ and the units of capacity are mbopd. For example, a production facility with 100 mbopd capacity and 24 slots would cost $ 1.04 billion.

$$platcost = b_0 + \ b_1(initial\ capacity) + \ b_2(slots) \tag{2}$$

<u>*Facility Expansion Cost.*</u> We are not aware of any published analysis on the cost of E&P offshore expansion projects. Therefore, the expansion cost is computed using a modified version of Equation (3) with the addition of cost multipliers m and n, and a binary variable E(t) to indicate whether or not an expansion is selected (this is required so that the y-intercept component of the expansion cost equation is only counted in the year of the expansion, and not in every year). Both m and n equal 0.75 in this study. If the example facility above were expanded from 100 mbopd to 150 mbopd (an increase of 18,250 mb/y) the expansion would cost $206 million.

$$\boldsymbol{expansioncost} = \boldsymbol{E}(\boldsymbol{t})\boldsymbol{mb_0} + \ \boldsymbol{nb_1}(\boldsymbol{extracapacity}(\boldsymbol{t})) \tag{3}$$

It is probable that the lead facility engineer could develop simple equations such as these that would be tailored for the specific type of facility under consideration.

<u>*Operating Cost.*</u> A variable operating cost, *vc*, is incurred for each barrel of oil production at a rate of $2/bbl. The operating cost is given by Equation (4).

$$\boldsymbol{opex}(\boldsymbol{t}) = \boldsymbol{vc} \times \boldsymbol{q}(\boldsymbol{t}) \tag{4}$$

Drilling and Completion Cost. The drilling and completion cost for a well, costperwell, is assumed to be constant at $50 million. The total well cost at time t is given by Equation (5).

$$wellcost(t) = costperwell \times \textstyle\sum_h dr(h,t) \tag{5}$$

Production Facility Capacity and Expansion. Defining constraints for production capacity is straightforward in most modeling settings. However, our goal is to allow an option to expand capacity when it is optimal to do so (e.g. when good reservoir outcomes prevail). The value of flexibility has been shown to be important in E&P project valuation and decision-making (Begg et al., 2002; Jafarizadeh and Bratvold, 2009). A project valuation that does not incorporate probable managerial and/or engineering responses to realizations of uncertain variable will result in a systematic undervaluation. To avoid (some of) this effect and to create a more realistic representation of the problem, we endogenize the drilling decision (discussed above) and also include an option to expand production capacity. In the current specification there is one option to expand in year 3, and the level of expansion is determined endogenously.

To accomplish this, several equations are required. The time period t* denotes the fixed option point.

$$currentcapacity(t) = \begin{cases} initialcapacity, for\ t < t^* \\ initialcapacity + extracapacity(t), for\ t = t^* \\ currentcapacity(t-1), for\ t > t^* \end{cases} \tag{6}$$

The maximum ultimate capacity is constrained relative to the initial capacity using a user-defined factor, fm, in Equation (7). In this study, fm = 2.

$$currentcapacity(t) \leq fm(initialcapacity) \tag{7}$$

$$q(t) \leq currentcapacity(t) \tag{8}$$

$$extracapacity(t) \leq M(E(t)) \quad (9$$

Depreciation: We use the straight line depreciation method to depreciate capital expenditure. An analytical expression for depreciation at time t is given by Equation (10) as shown below.

$$dep(t) = dep(t-1) + \frac{capex(t)}{(T-t)} \tag{10}$$

Where, T = life of the project, years

Production Functions

Reservoir Modeling. Deciding how to integrate reservoir phenomena within an optimization framework is important because it determines aspects of the workflow, the level of effort, and the time requirements. As stated above, the modeling approach should be dictated by the decision that the model is being used to support. That is, it is unlikely that the appropriate modeling approach will be the same for decisions during appraisal drilling (e.g. VOI problems), decisions during execution (e.g. well placement), and real-time optimization during the production phase. Recent examples of various decision settings and modeling strategies can be found in the literature (Cullick et al., 2003; Coats et al., 2004; Bilderbeck and Beck 2005; Vasantharajan, Al-Hussainy and Heinemann 2006; Cullick, Cude, and Tarman 2007; Hollund et al., 2007; Litvak et al., 2007; Sarma et al., 2008; Onwunalu et al., 2008; Ettehad, Jablonowski, and Lake 2009; and Purwar, Jablonowski, and Nguyen 2010).

The purpose of this study is to demonstrate a workflow and supporting tools for VOI and uncertainty analysis during appraisal drilling and/or early project planning. Therefore, the reservoir is modeled quite crudely—at this stage of a project, very little may be known about the reservoir and detailed reservoir simulation may not add significant value (see Bratvold and Begg 2008, for a thorough discussion of modeling tradeoffs). Therefore, we define the reservoir as one tank model and assume the reservoir properties are spatially constant. As defined by Equation (10), production from each well is modeled as a function of well productivity and the difference between reservoir pressure and bottom hole pressure.

$$q(t) = \left(j * \left(P(t) - P(wf, t)\right)\right) * 365 \tag{10}$$

Where $q(t)$ = oil production at time t, bbl

j = well productivity index, (bbls/day)/psi

$P(t)$ = reservoir pressure at time t, psi

$P(wf, t)$ = bottom hole pressure at time t, psi

Where, well productivity index, j is given by Equation (11) as shown below

$$j = \frac{0.00708kh}{\mu_o\left(\frac{1}{2}ln\frac{A}{r_w^2 C_A} + 5.75 + s\right)} \tag{11}$$

k = absolute permeability, mD

h = reservoir thickness

μ_o= oil viscosity

A = well drainage area, ft

r_w= well radius, ft

C_A = dietz shape factor

s = skin factor

The reservoir at any time t depends upon the amount of oil that has been produced until that time from the reservoir and is given by Equation (12) as shown below:

$$p(t) = p(0) - \frac{tq(t)}{Vp*Ct} \quad (12)$$

$tq(t) =$ cumulative oil production at time t, bbls

$Vp =$ reservoir volume, bbls

$Ct =$ total compressibility, per psi

The total production from well h is constrained in Equation (13), and there is also a global reservoir constraint on reserves given by Equation (14), where reserves is the total recoverable reserves for the project.

. $$\sum_h qi(h,t) \leq reservesperwell \quad (13)$$

$$\sum_t q(t) \leq reserves \quad (14)$$

Drilling, Completions, and Production. One of the more complex aspects of the model is the treatment for endogenous drilling. Because one cannot drill half of a well, wells must be modeled as binary variables. To accomplish this, we define a 2-dimensional table of binary variables, dr(h,t), where h is the individual well number, and time is indexed by t. This table indicates when a well is drilled, and this enables computation of drilling costs, and also determines when a well is available for production. The structure is explained using the following equations. Equation (15) ensures that each well can be drilled only once.

$$\sum_t dr(h,t) \leq 1 \tag{15}$$

The number of wells that can be drilled per year, maxwells, is constrained by rig availability, drilling and completion times, logistics, and other factors. In this study we set maxwells = 6 wells per year using Equation (16).

$$\sum_h dr(h,t) \leq maxwells \tag{16}$$

A well cannot be used for production until it has been drilled. The available capacity of each well, wellcap(h,t), is determined by the partial sum (i.e. up to the current period only) in Equation (17), where maxrate is the maximum production rate that can be achieved from a well. In our model maxrate is defined as a constant. However, in general maxrate depends upon reserve size, reservoir properties and pressure gradient.

$$wellcap(h,t) = maxrate \times \sum_t dr(h,t) \tag{17}$$

We assume that production engineering considerations warrant the definition of a maximum production rate constraint, maxrate. The production rate of each well must be less than the available capacity as shown in Equation (18), and the total production rate is the sum of the individual well rates per Equation (19).

$$qi(h,t) \leq wellcap(h,t) \tag{18}$$

$$\boldsymbol{q(h,t)} \leq \sum_{\boldsymbol{h}} \boldsymbol{qi\,(h,t)} \tag{19}$$

CHAPTER 5: METHODOLOGY

In this section we describe the procedure for concept selection using the asset development model. After a procedure to take facility planning decisions for an E&P project is established, we explain the methodology to conduct Value of Information analysis.

5.1 Concept Selection

During the concept selection process a decision maker selects facility configurations like facility capacity, maximum well slots, and the number of wells to be predrilled. Before we explain our solution procedure we list key decision variables, input parameters, random variables and assumptions used in the model.

1. Key Decision Variables
    a. Facility capacity
    b. Maximum well slot
    c. Optimal pre-drilling and maximum well slot combination
    d. Time of expansion
2. Main Input Parameters
    a. Reservoir properties (Pressure, area, thickness, porosity, saturation etc)
    b. Capital and Operating costs
    c. Oil price
3. Random Variable
    a. Reserve size

To simplify computations we have fixed the time when facility expansion is considered - year five from the start of the project. We also keep the price of oil constant throughout the life of project. We assume that pre-drilling is done only in year one and two and these wells start producing from year three. We also assume that reserves are uniformly distributed. In addition, we assume the decision maker has limited options for well slot, facility capacity and pre-drilling. These assumptions can be easily relaxed, but they help us here to simplify computations and focus on our main goal, i.e. to estimate the cost of erroneous estimates of inputs.

We now discuss a step by step procedure to solve the optimization problem and identify optimal facility configuration for one of the case in our study.

- Reserve Size = Uniform [250, 350] MMbbls
- Facility capacity options = 20, 30, 40, 50, 60, 70, 80 mbopd
- Maximum well slot options = 8, 12, 16, 20
- Number of wells that can be pre-drilled = 3, 6, 9
- Oil price = $ 60 /bbl

1. The first step simulates a decision maker's choice of optimal facility capacity and maximum well slots for a given reserve distribution and pre-drilling value. We run a Monte Carlo simulation to take into account uncertainty in reserve size. In every run reserve size is sampled from the uniform distribution to get a realized value for reserve size. Then, the optimization model is solved to maximize NPV. We run similar thirty iterations for each facility capacity and obtain a distribution of NPV. A cumulative distribution function (CDF) is then generated for this NPV distribution and expected NPV (sample mean) is computed. Figure 5.1 below shows the CDF obtained after running thirty iterations at a particular facility capacity.

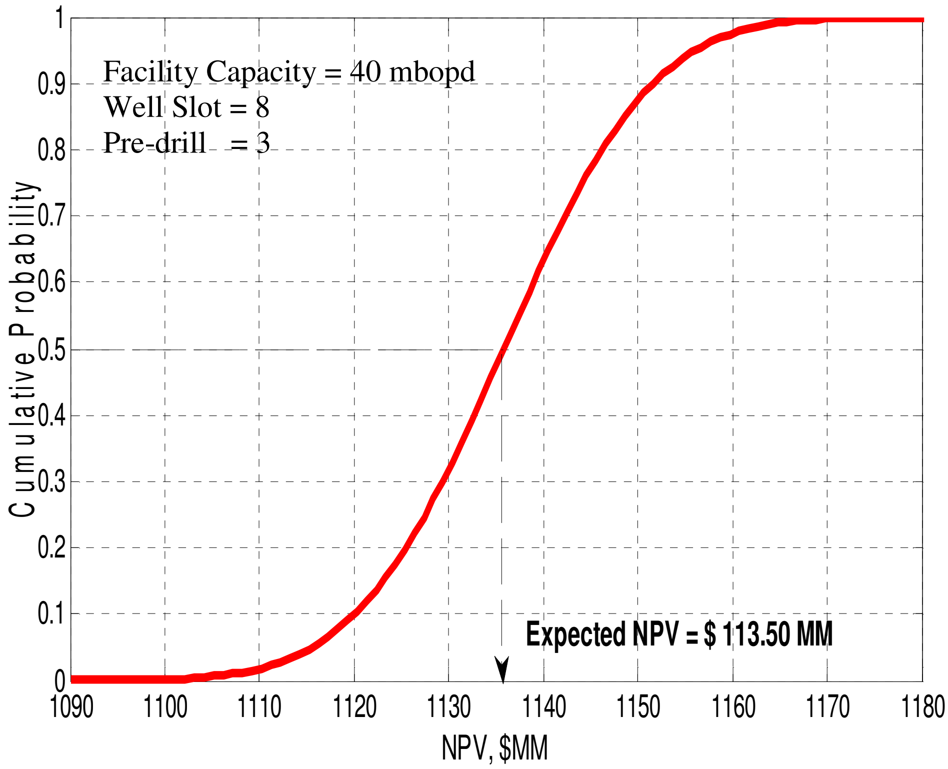


Figure 5.1: NPV CDF for U[250, 350] MMbbls

2. We repeat step 1 for different values of facility capacity and compute expected NPV. Then a plot is generated between expected NPV and facility capacity as shown below. The facility capacity for which this NPV profile is maximized, gives the optimal facility capacity at this well slot.

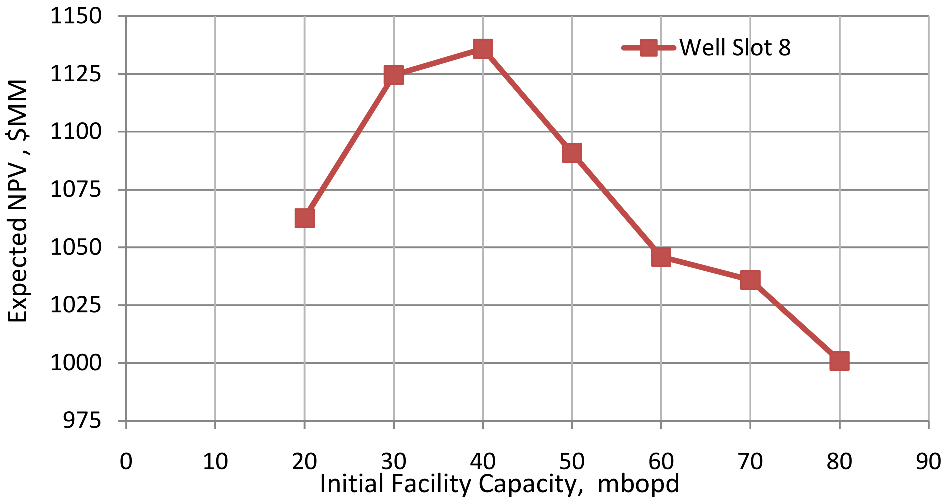


Figure 5.2: NPV Profile for Reserve Size U[150, 250] MMbbls

3. We repeat step 1 and 2 to obtain plots for different values of well slots. This is shown in figure 5.3 below.

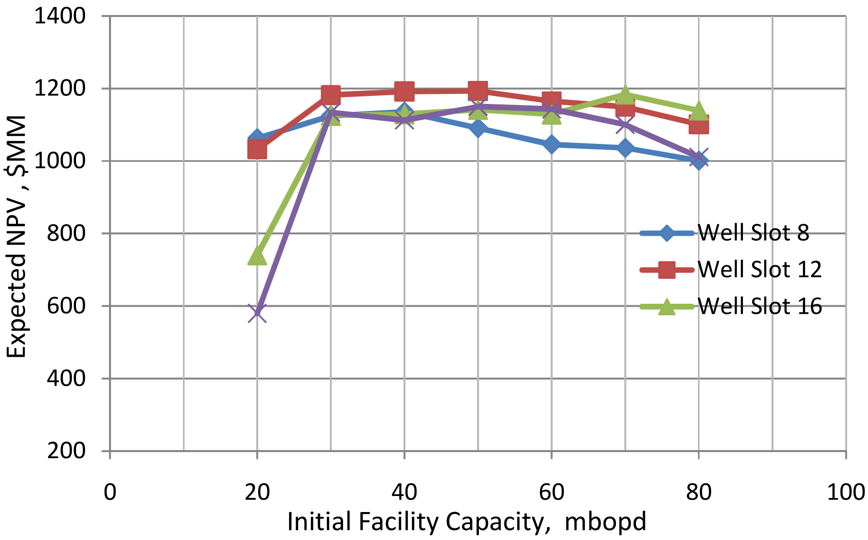


Figure 5.3: NPV Profile with Different Well Slots

4. The optimum facility capacity and well slot combination is selected as the one which offers maximum expected NPV among all possible NPVs. The optimal point is marked with a dotted line in figure 5.4 below.

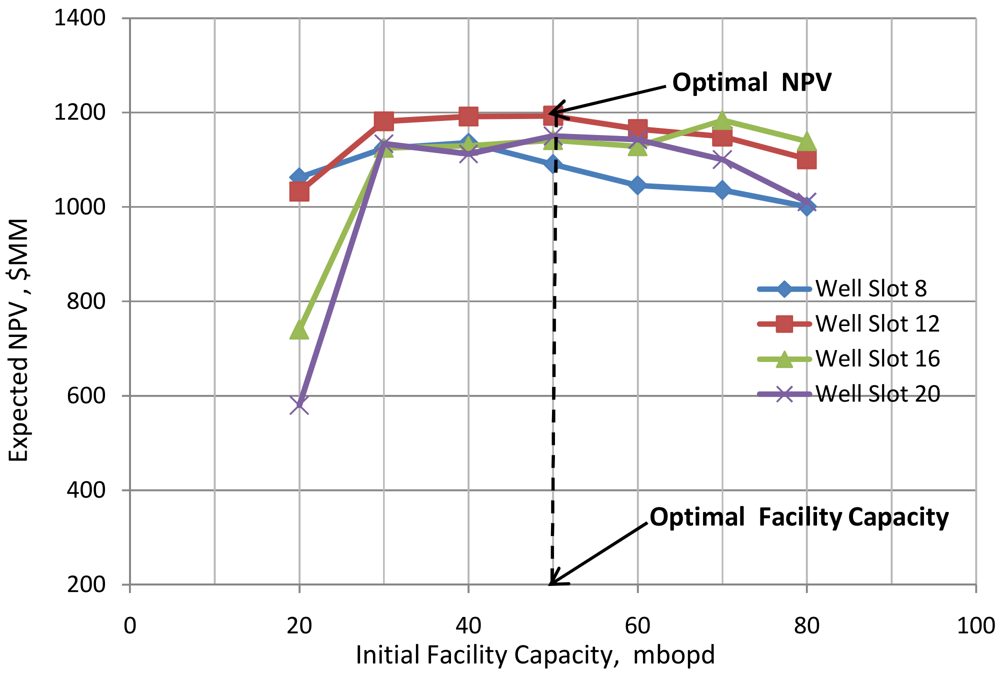


Figure 5.4: Optimal Facility Capacity and Well Slot for U[250, 350] MMbbls

5. Until now we have fixed the number of wells to be pre-drilled, but we can repeat steps 1 through 4 for different values of pre-drilling. This will give us optimal facility and maximum well slot configuration for each pre-drilling value. Although, this does not helps us to identify the optimal number of pre-drill wells, but enables us to identify optimal facility configuration under different scenarios of pre-drilling Table 5.1 shows optimal well slot and facility capacity combination, and optimal expected NPV under different scenarios of pre-drilling for a given reserve distribution. This

analysis can also be used to select pre-drill number with highest expected NPV amongst all different pre-drill options the project team is considering. In this case the number of pre-drill wells with highest expected NPV is six. For the rest of analysis in this study we have fixed the number of total number of pre-drill wells at six.

Facility Configuration	Number of Pre-drill wells		
	3	6	9
Maximum well slot	12	12	12
Initial facility capacity (mbopd)	50	50	40
Expected NPV ($MM)	1,193	1,217	1,125

Table 5.1: Optimal Facility Configuration for U[250, 350] MMbbls

5.2 Value of Information Analysis Procedure

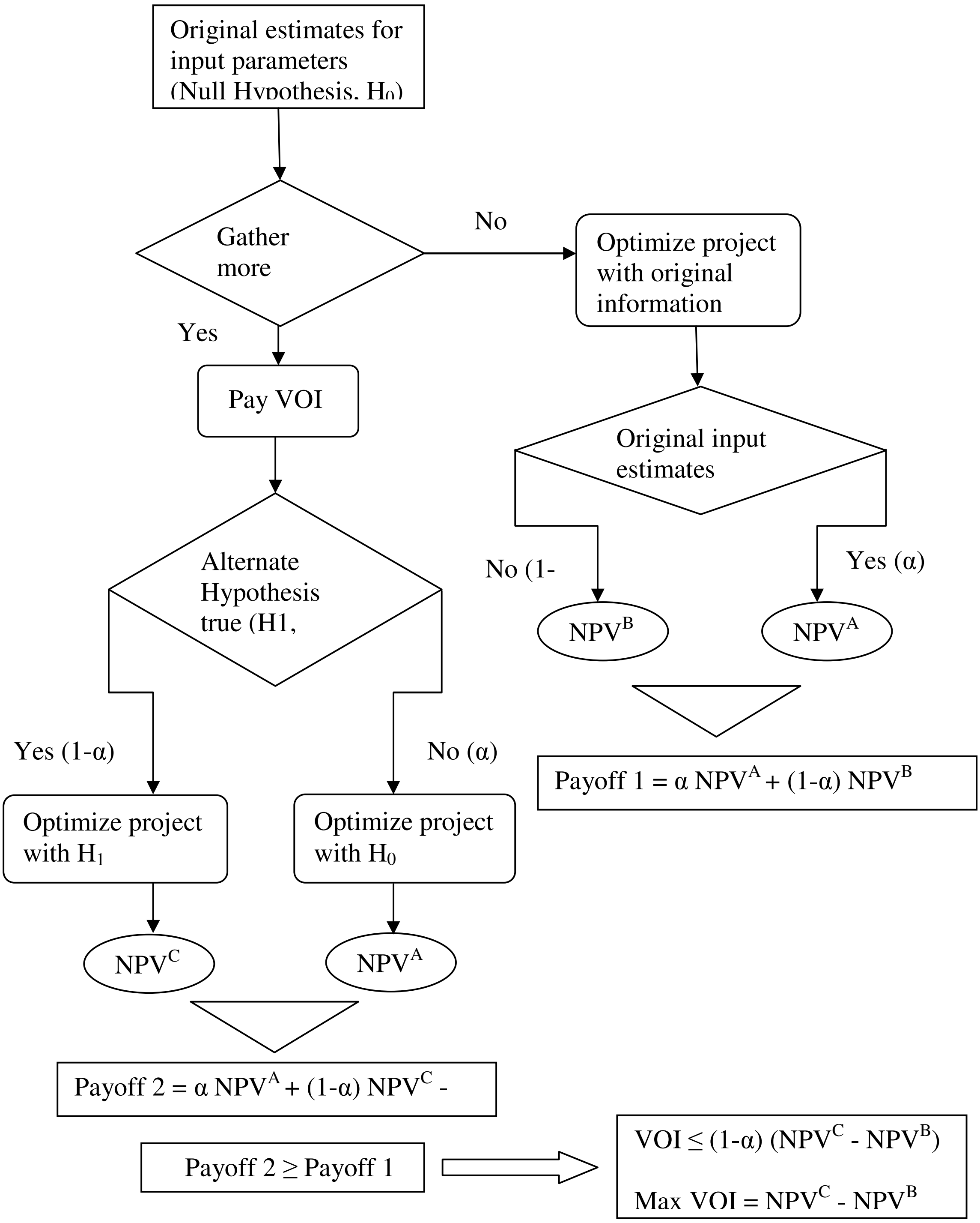
After a decision maker selects a facility configuration based on current estimates of reserve size it is necessary estimate the loss in project value if there are errors in estimates. Although, in reality it is not possible to judge if current estimates are erroneous, but we can always see the effect of realization of an alternate hypothesis. We employ this procedure of comparing the Null Vs Alternate hypothesis to estimate the cost of errors in reserve size. The loss in value can also be interpreted as the maximum amount a person would be willing to pay to verify the alternate hypothesis. Following is a step by step procedure for computing VOI.

1. A decision maker selects the optimal facility configuration based on the Null hypothesis or under the original estimates for reserve size. Let's call the expected NPV obtained under the Null hypothesis NPV^A.
2. The project is operated with the facility configuration obtained in step 1. However, the reserve size is realized according to an alternate hypothesis. Thus, the expected NPV will be different from that obtained in step 1. Let's call NPV obtained here NPV^B.
3. Instead if the decision maker knew beforehand about the alternate hypothesis for reserve size he would have selected optimal facility configuration accordingly. The expected NPV obtained in this case will be different from that obtained in step 2, say NPV^C.
4. The maximum value a decision maker would be willing to pay to verify the alternate hypothesis will be given by the difference of expected NPVs obtained in Step 3 and Step 2 ($NPV^C – NPV^B$).

We provide an analytical proof for VOI estimation procedure using the VOI flow chart shown under figure 5.5. Let's assume α is the probability for the original estimates to be correct. Then, a decision maker should only gather more information if the payoff (Expected NPV) after using new information is greater or at least same as before. We can call this condition, a decision maker's participation constraint. If this condition does not holds he would not participate in gathering more information. Using this participation constraint and VOI flow chart we arrive at Eq(1) for VOI as given below. The maximum value of this expression occurs for $\alpha = 0$ and is given by $NPV^C - NPV^B$. Also, this is the maximum a project team will be willing to spend on collecting more information on subsurface uncertainties.

$$VOI \leq (1-\alpha)\,(NPV^{C} - NPV^{B}) \qquad (1)$$

Figure 5.5: Value of Information Flow Chart



CHAPTER 6: SCENARIOS AND VOI ANALYSIS

In this section we first solve the optimization problem under different scenarios for reserve size. After this we frame each scenario under a null and alternate hypothesis set up and conduct a VOI analysis.

6.1 Problem Set Up With Different Reserve Size

The project team collects several estimates about the subsurface uncertainties. The facility architecture is based on one of these estimates. In general, a project team would do some scenario analysis to estimate the effect of different estimates on the facility design. We mimic a project team decision making process, and solve the optimization model with different estimates for reserve size. We call these estimates as our null hypothesis. The methodology to solve the optimization model is same as described in the previous section.

For each reserve size we consider four different combinations of well slots and number of completions. These combinations of well slots and completions are shown in table 6.1 below.

Well Slots for Dry Trees	Maximum Number of Completions
8	12
12	18
16	24
20	30

Table 6.1: Well Slots and Maximum Number of Well Completions

Other input parameters used in the model are listed in the table 6.2 below -:

Parameters	**Values**
Time (years)	25
Year in which expansion is considered	3
Cost Function Inputs	
Fixed Cost of Well ($ MM)	250
Coefficient for Platform Cost (Constant)	50 X 10^6
Coefficient for Platform Cost (varies with size)	4.5 X 10^6
Coefficient for Expansion Cost (Constant)	50 X 10^6
Coefficient for Expansion Cost (varies with size)	4.5 X 10^6
Variable Cost of Production ($/bbl)	4
Expansion Cost Multiplier	0.75
Expansion Capacity Multiplier	2
Production Inputs	
Reservoir Pressure (Psi)	20000
Well Radius (ft)	0.328
Porosity	0.19
Dietz Shape factor	30.1
Skin factor	-0.91
Absolute Permeability (mD)	700
Oil Viscosity	1.1
Total Compressibility per Psi	9 X 10^(-5)
Initial Oil Saturation	0.85
Maximum Rate Per Well (mbopd)	3
Maximum number of Wells/Year	6
Number of Wells Pre-drilled/Year	3
Other Constants	
Oil price per barrel ($/bbl)	60
Discount rate	10 %
Years in Which Wells are Pre-drilled	1 and 2
Tax Rate	35 %

Table 6.2: Parameters and Their Values as Used in the Model

We set up the model under four different scenarios.

- Small Reserve Size
- Medium Reserve Size
- Large Reserve Size
- Medium Reserve Size with no option to expand the facility capacity.

These scenarios are summarized in table 6.3, 6.4, 6.5 and 6.6 below -:

Reserve Size	**Well Slots**
U[150, 250]	8
U[150, 250]	12
U[150, 250]	16
U[150, 250]	20

Table 6.3: Scenario I: Small Reserve Size

Reserve Size	**Well Slots**
U[250, 350]	8
U[250, 350]	12
U[250, 350]	16
U[250, 350]	20

Table 6.4: Scenario II: Medium Reserve Size

Reserve Size	Well Slots
U[350, 500]	8
U[350, 500]	12
U[350, 500]	16
U[350, 500]	20

Table 6.5: Scenario III: Large Reserve Size

Reserve Size	Well Slots
U[250, 350]	8
U[250, 350]	12
U[250, 350]	16
U[250, 350]	20

Table 6.6: Scenario III: Medium Reserve Size No Facility Expansion Option

These scenarios are then solved, and graphs between expected NPV and facility capacity is generated. Figure 6.1, 6.2, 6.3 and 6.4 show the resulting graphs obtained under different scenarios. The optimal facility capacity and well slot combination for each of the scenarios is obtained by investigating these graphs, and the result is summarized in table 6.7.

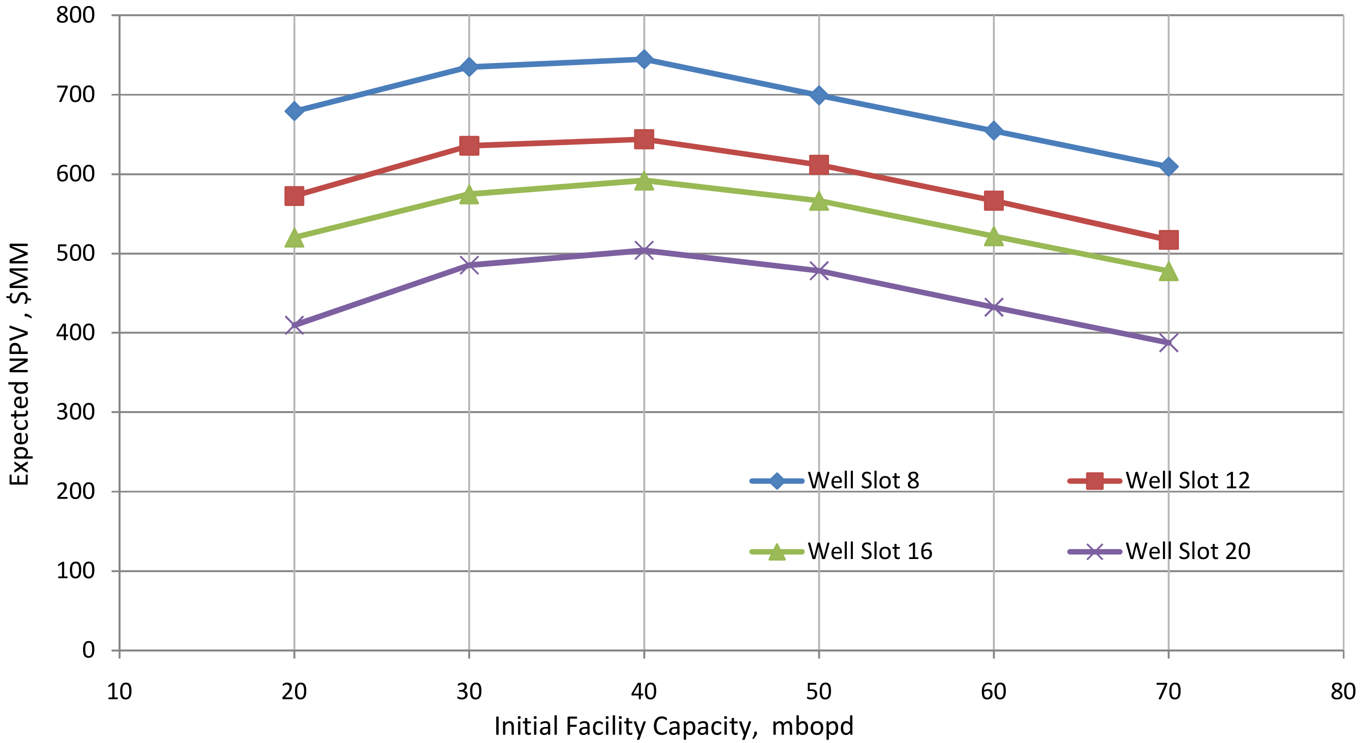


Figure 6.1: SCENARIO I: Small Reserve Size U[150, 250] MMbbls

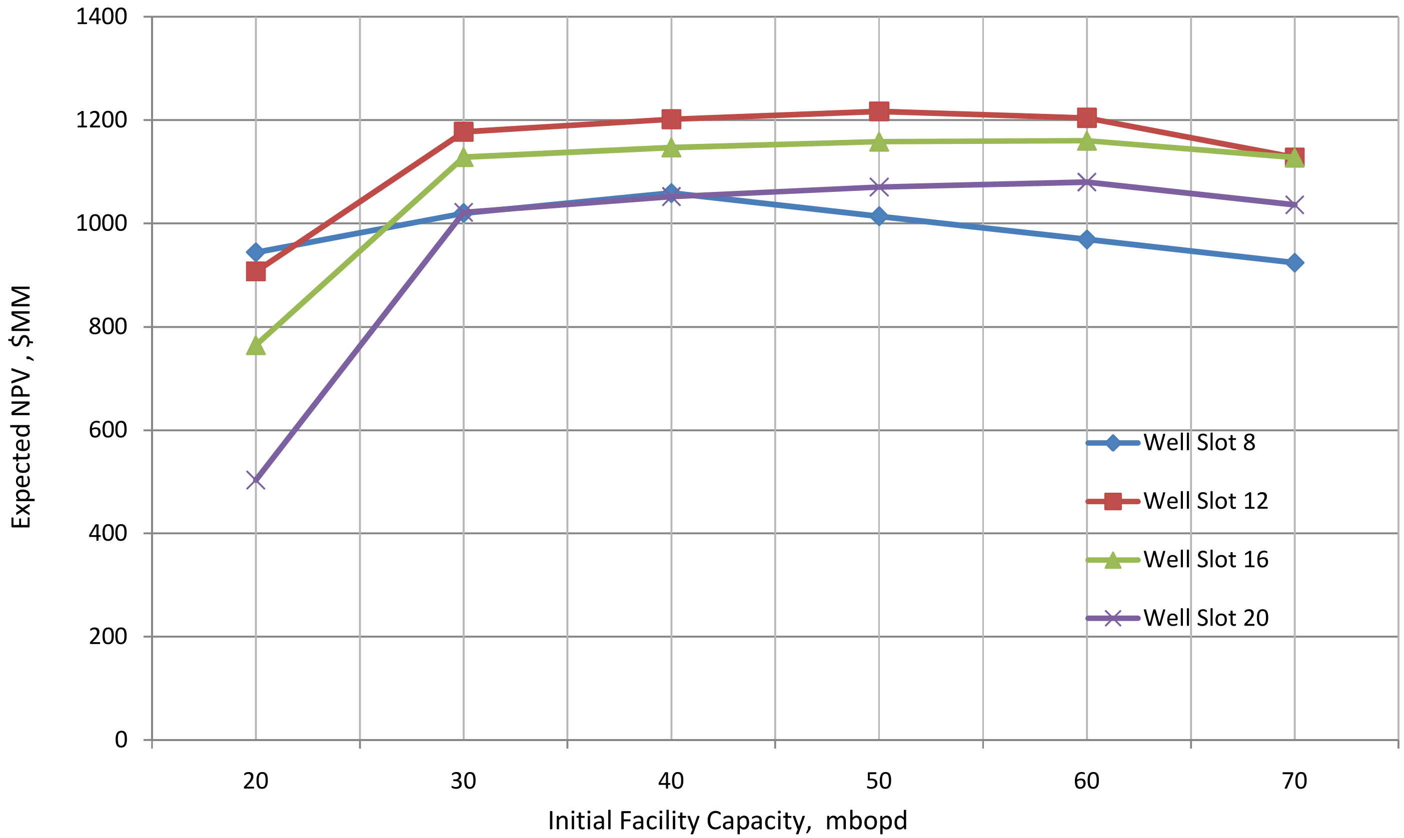


Figure 6.2: SCENARIO II: Medium Reserve Size U[250, 350] MMbbls

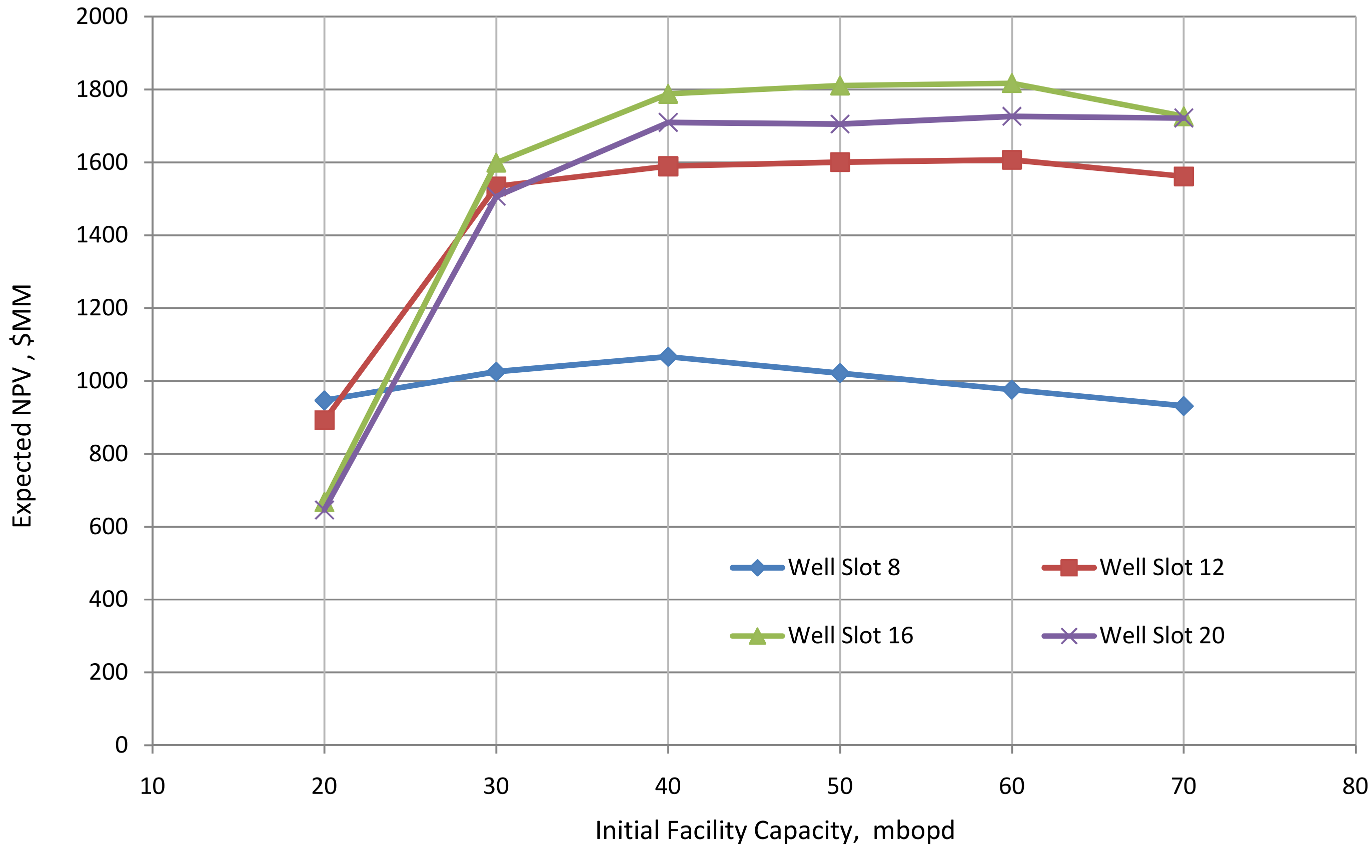


Figure 6.3: SCENARIO III: Large Reserve Size U[350, 500] MMbbls

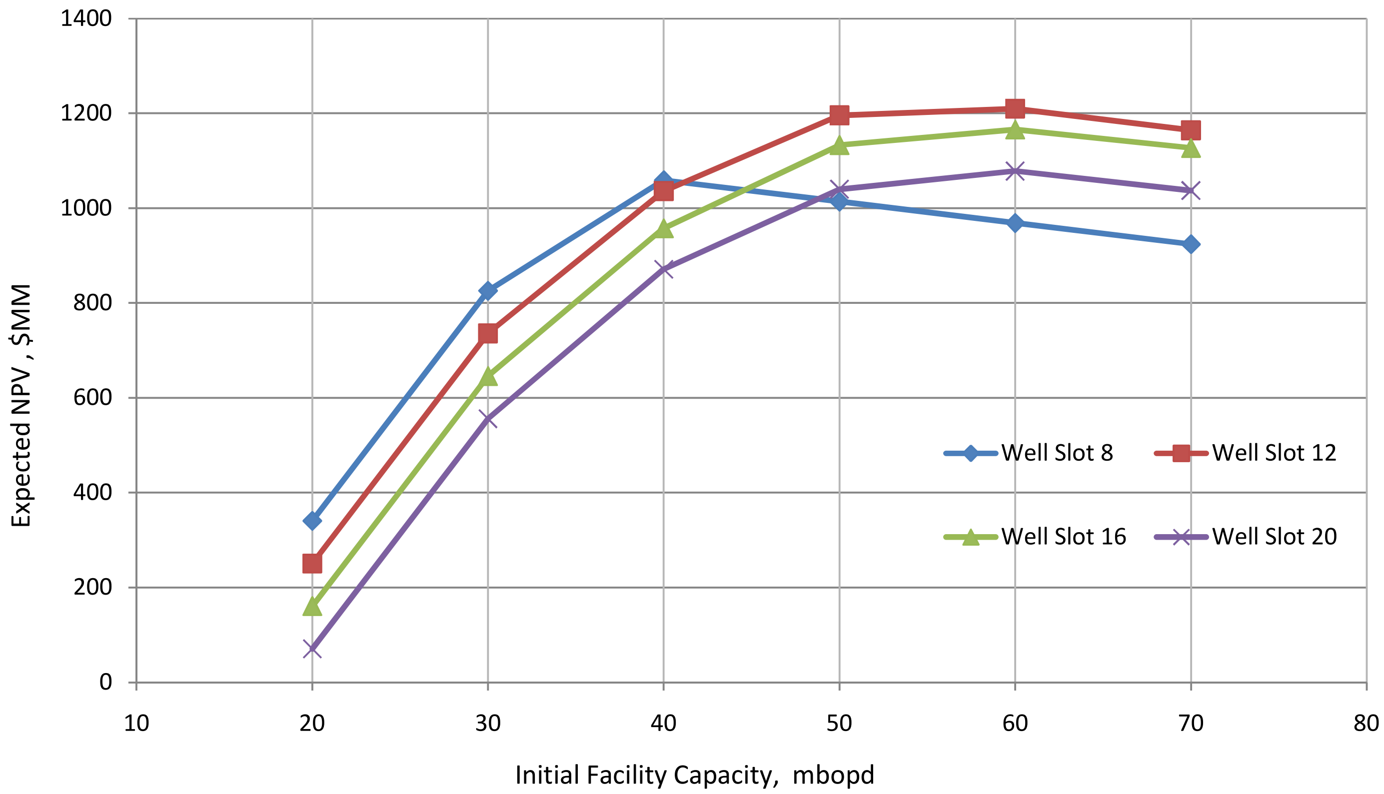


Figure 6.4: SCENARIO IV: Medium Reserve Size No Option to Expand

6.1.1 Optimal Facility Configuration for Null Hypothesis

The optimal facility capacity and well slot combination for each of the scenarios is obtained by investigating the above graphs, and the result is summarized in table 6.7.

Scenario	Reserve Size (MMbbls)	Option to Expand Facility Capacity	Optimal Well Slot	Optimal Initial Facility Capacity(mbopd) FAC_0	Optimal Expected NPV ($ MM)
I	U [150, 250]	Yes	8	40	744.64
II	U [250, 350]	Yes	12	50	1216.83
III	U [350, 500]	Yes	16	60	1817.73
IV	U [250, 350]	No	12	60	1209.93

Table 6.7: Optimal Facility Configuration and Expected NPV

OBSERVATIONS

1. The expected NPV for each case increases with initial facility capacity reaches a maximum and then starts decreasing. The point of maximum gives the optimal facility configuration and optimal expected NPV. All other points on the NPV profile indicate facility sub optimality.
2. The degree of curvature of NPV profiles gives us the rate of change of expected NPV with initial facility capacity. Thus, if the NPV profile is steep it is more sensitive to changes in facility capacity. As a result, making an error in choosing optimal facility capacity will affect expected NPV more on a steep NPV profile than, when the NPV profile has a gradual slope.
3. As the reserve size increases, the optimal number of well slots and optimal initial facility capacity goes up. This behavior supports our intuition that, if the reserve endowment goes up, a bigger facility should be needed to produce more oil and maximize NPV.
4. The optimal expected NPV with the option to expand is greater than without facility expansion option. Thus, having an option to expand is valuable. The option value is given by the difference between NPVs with and without facility expansion option.
5. The approach used to identify the optimal facility configuration is not exact, but at the least it helps us in quickly identify sub-optimal facility configurations.

6.2 VOI ANALYSIS

After analyzing different reserve scenarios we set up the problem in a Null and Alternate hypothesis set up and conduct VOI analysis. We illustrate the VOI estimation procedure for one of the case in our study.

1. Define reserves as U [250, 350] MMbbls for a range of well slots and initial facility capacity and obtain optimal facility configurations (optimal well slots and initial facility capacity). Let's call the expected NPV obtained in this case NPV^A. (See table 6.7 in previous section).
2. Instead if the actual realization is under an alternate hypothesis we will obtain a different NPV. Thus, redefine the well potential to alternate hypothesis as U [150, 250] MMbbls.
3. Solve the optimization model with this redefined reserve distribution. Let's call the expected NPV obtained in this case NPV^B.
4. Had a decision maker known before hand of this alternate hypothesis, he would have planned the facility accordingly. Thus, redefine the reserve size as U [150, 250] MMbbls for a range of well slots and initial facility capacity and obtain the optimal facility configurations. Let's call the expected NPV obtained here as NPV^C. (See table 6.7 in previous section).
5. Value of information (VOI) is computed as $NPV^C – NPV^B$. In this case this value is 605 million. Thus, the decision maker should be willing to pay this money to confirm the alternate hypothesis.
6. Repeat steps 1 to 5 with other reserve sizes and calculate VOI's. Table 6.8 shows the VOI figures (red color represents negative values or loss in project value).

Alternate Hypothesis (Realized), MMbbls / Null Hypothesis (Assumed), MMbbls	U [150, 250]		U [250, 350]		U [350, 500]	
U [150, 250]	VOI ($MM)	0	VOI ($MM)	**158**	VOI ($MM)	**751**
	VOI %	0	VOI %	13 %	VOI %	41 %
	FAC0 (mbopd)	40	FAC0 (mbopd)	40	FAC0 (mbopd)	40
	Well Slot	8	Well Slot	8	Well Slot	8
U [250, 350]	VOI ($MM)	**133**	VOI ($MM)	0	VOI ($MM)	**217**
	VOI %	18 %	VOI %	0	VOI %	12 %
	FAC0 (mbopd)	50	FAC0 (mbopd)	50	FAC0 (mbopd)	50
	Well Slot	12	Well Slot	12	Well Slot	12
U [350, 500]	VOI ($MM)	**223**	VOI ($MM)	**56**	VOI ($MM)	0
	VOI %	30 %	VOI %	5 %	VOI %	0
	FAC0 (mbopd)	60	FAC0 (mbopd)	60	FAC0 (mbopd)	60
	Well Slot	16	Well Slot	16	Well Slot	16

Table 6.8 Value of Information Analysis Results (where the values in red indicate loss)

6.3 GRAPHICAL ANALYSIS

In this section we estimate the value of the expansion option and analyze the relationship between facility capacity and option value. In addition, we estimate the expected expansion size and probability of expansion at different initial facility capacity and wells slots.

6.3.1 VALUING THE OPTION TO EXPAND

An option to expand the facility capacity is built in the asset development model. We take a two step approach to value this option.

6. Solve the optimization model with the option to expand, and obtain expected NPV for different facility capacities. (Say NPV^a)
7. Solve the optimization model without the option to expand, and obtain expected NPV for different facility capacities. (Say NPV^b)

The option value at each facility capacity is then determined by the difference between NPVs obtained from solving the model with and without the option. The following equation gives and analytical representation of the option value.

$$\text{Value of Option} = NPV^a - NPV^b \qquad (1)$$

The value of option to expand may not be necessarily same for different facility capacities. Intuitively, having an expansion option at low facility capacity should be more valuable, as compared to having the same option at a large facility capacity. The option value obtained at different facility capacities from solving the model supports this intuition. In the following section we analyze the effect of facility capacity on the value of the option to expand. Figure 6.5 shows the NPV profile at different facility capacities with and without the option. The difference between the levels of the two NPV profiles in this figure can be seen as the value of the option to expand. This difference can also be interpreted as the maximum amount a person would be willing to pay for having an expansion option at a particular facility capacity.

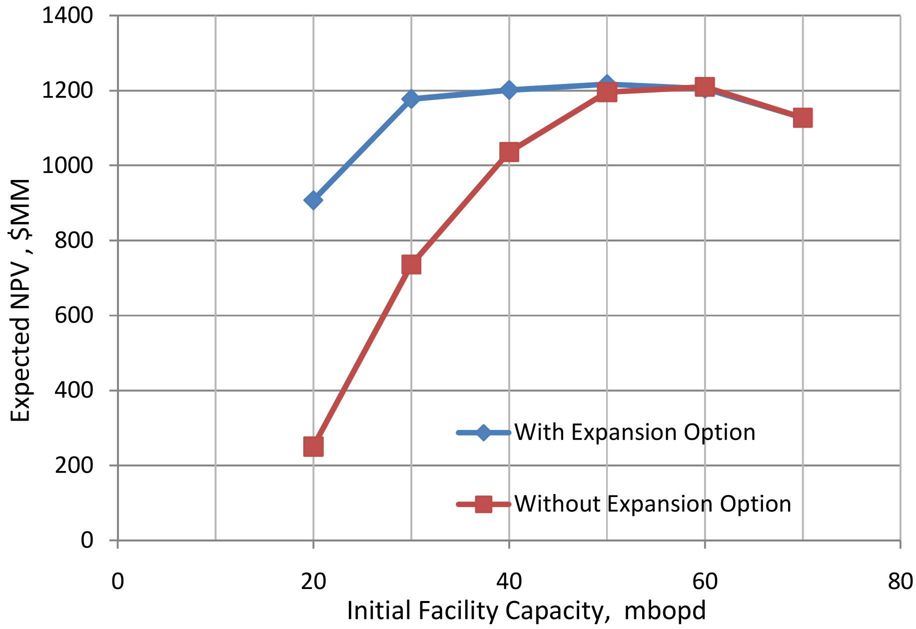


Figure 6.5: NPV with and without Option to Expand, U = [250, 350] MMbbls

OBSERVATIONS

1. The NPV profile for both, with and without the option to expand increases with increase in facility capacity, reaches a maximum and then decreases. However, at each facility capacity the NPV with the option to expand is greater or at least same as the NPV without the option. Thus, having an option to expand is valuable when there is uncertainty in reserves estimations.

2. The value of the option to expand at each facility capacity is given by the difference in levels of the two NPV profiles. This difference between the levels of NPV profiles is more at small facilities than at large facilities. Thus, having an expansion option at low facility capacity is more valuable as compared to the same option at large facility capacity.
3. The option value is significantly greater just below the optimal facility capacity than just above the optimal facility capacity. Thus, if the facility capacity is erroneously selected to be less than the optimal, an expansion option tends to mitigate the effects of this error. However, there are lesser benefits if the initial facility is already more than the optimal facility capacity.
4. The NPV profiles for both with and without the option ultimately converge to the same value. Thus, if the initial facility is too large there is no incentive to have an expansion option.

6.3.2 Effect of Facility Configuration on Expansion Decision

In this section we analyze the effect of initial facility configuration on facility expansion size. Also, we present an analysis between probability of expansion and initial facility capacity.

Figure 6.6 below shows a plot between initial facility capacity and expected expansion size for different well slot configurations.

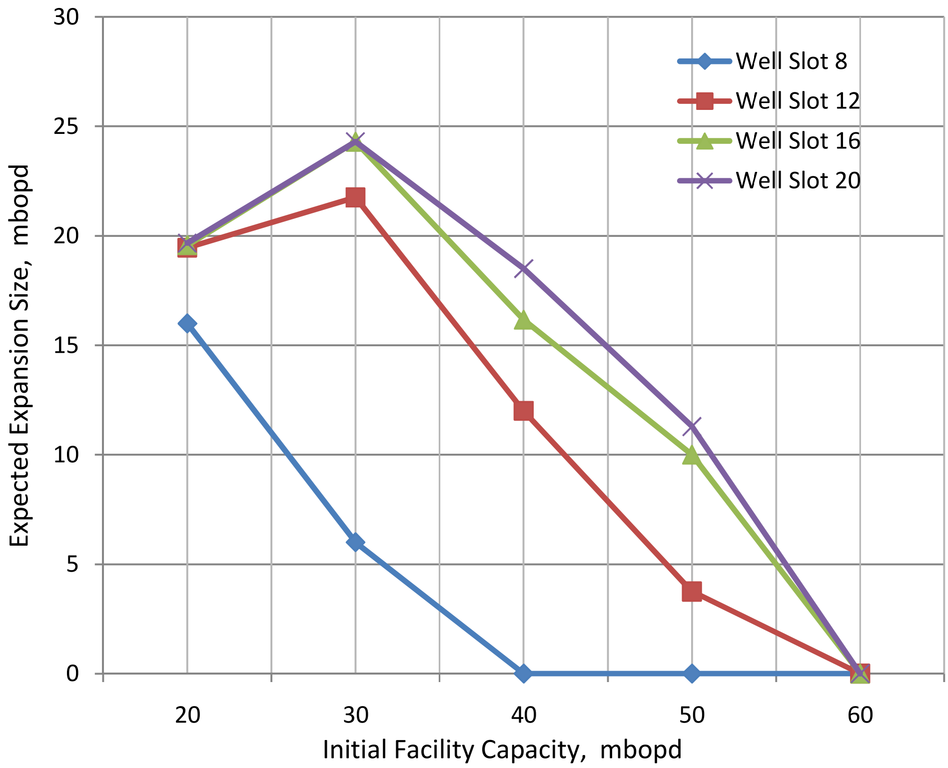


Figure 6.6: Expected Expansion Size and Initial Facility Capacity, U[250, 350]

OBSERVATIONS

1. The expected expansion size decreases with increase in initial facility capacity. This is because as the initial facility size is increased the project requires less expansion in order to achieve the optimum facility capacity.
2. For some well slots there is an initial increase in expected expansion size before a monotonic decrease with increase initial facility capacity. A probable explanation for this can be – The maximum allowable expansion increases with increase in facility capacity. If at a lower facility capacity the maximum expansion is insufficient to achieve the optimal facility capacity, then, at a higher facility capacity, when the allowable expansion is more, the project expands by this greater allowable expansion to achieve optimal facility capacity. Thus, the expansion size increases with initial facility capacity. However, once the optimum is reached we require less expansion to achieve optimal capacity and thus we see a monotonic decrease in expansion size.
3. As we increase the number of well slots the expansion size increases for a given initial facility capacity. This is because decreasing the constraint on the maximum number of wells increases the ability of the facility to produce more oil. In other words we can say it increase the optimal amount of oil the facility should produce. Thus, at a particular facility capacity a greater expansion is optimal for field with more well slots than with less to achieve a higher optimum oil production.

The following figure shows the relationship between probability of expansion and facility configuration (Well slot and Initial facility capacity) choice for reserve size U [250, 350] MMbbls.

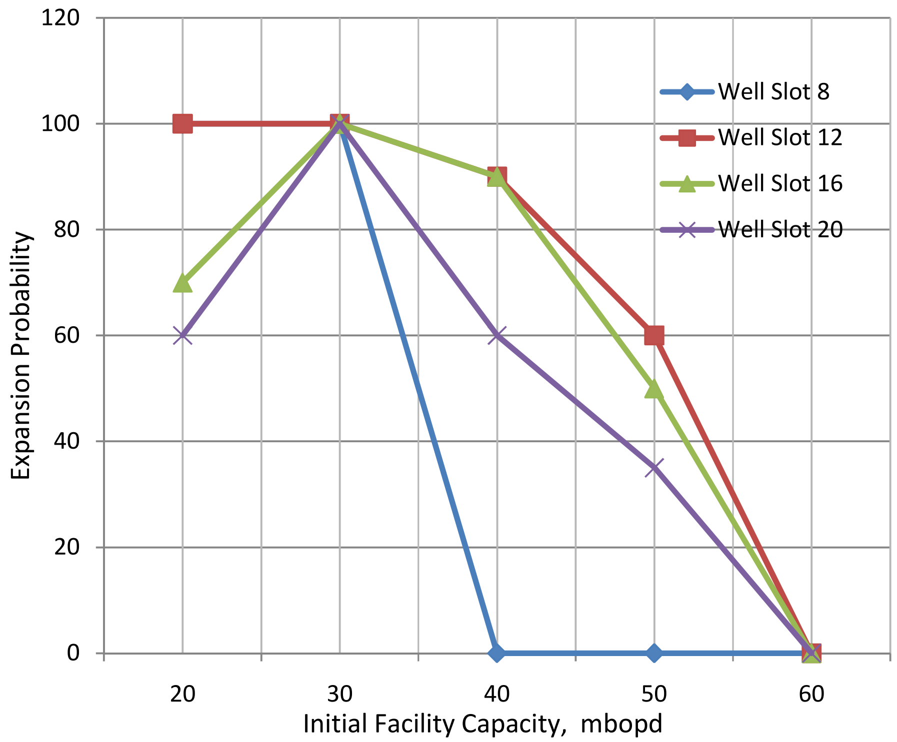


Figure 6.7: Expansion Probability and Initial Facility Capacity

OBSERVATIONS

1. At smaller initial facility capacities there is a higher chance of expansion as the initial facility capacity is too small for the revealed reserve size.
2. The probability of expansion decreases with increase in facility size. This is because the initial facility moves closer to the optimal value for the revealed

reserve size. Thus, reducing the need to expand the facility to achieve the optimal configuration.

3. There seems to be no relationship between the number of well slots and expansion decision.

CHAPTER 7: CONCLUSIONS

The objective of this study is to examine and compare the loss in project value incurred when facility planning decisions are based on erroneous estimates of input variables. The integrated asset development model used along with standard value of information analysis reveals several strategic insights. Errors in estimates of reserves size have a large impact on facility planning and development and the ultimate value derived from the project. In particular, the main results of this study suggest the following -:

- The cost of erroneous reserves estimates is significant and ranges from 5 % to 40% of the total project value.
- Both underestimation and overestimation of reserves estimates result in a loss in project value. Moreover, the cost of error is directly proportional to the magnitude by which realized estimates differ from initial estimates. i.e. a bigger error results in a bigger loss.
- Conservative estimates of reserve size are more destructive to project value than aggressive estimates.
- Facility expansion option is valuable, but more at small facility capacity than at large facility capacity.
- Expansion size decreases with the increase in facility capacity. Thus, if a facility expansion option is built into the facility, the size of this option can be tailored according to the size of the initial facility capacity.

All results in this study are specific to the parameter values used in the analysis. Thus, a different parameter specification may result in different outcomes than obtained in this study. However, the procedure established here can be used as a set up to select optimal facility configuration and conduct VOI analysis.

Appendix

PRODUCTION PROFILE

Figure A.1 shows the production profile from a reservoir, with every colored band representing production from one well, for reserve size U [250, 350] MMbbls, six pre-drill wells, 12 well slots and an initial facility capacity of 30,000 bopd. Production starts from year three as we have assumed that there are no wells ready for production until that time. Main observations are summarized below.

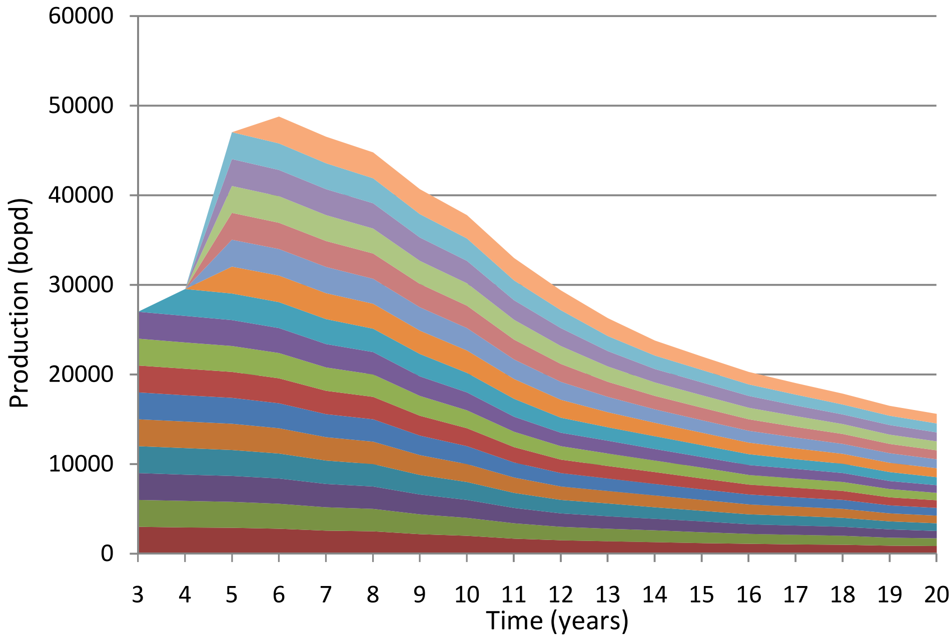


Figure A.1: Production Profile for U [250, 350] and Six Pre-drill Wells

OBSERVATIONS

- The production profile from each well gradually declines with time. This is because production from a well is proportional to the reservoir pressure at that time. As the reservoir starts depleting with time the reservoir pressure falls.

This fall in reservoir pressure with time leads to decline in production from the well. This is the desired production behavior as it is consistent with well production from an actual oil reservoir.

- The tank model successfully incorporates a facility expansion option. In year five when expansion is allowed, additional wells are drilled to attain the optimum production capacity. Again, this is what would be desired on an actual project.

Thus, we see that, although a tank model is a simplified version of the actual oil reservoir, but it closely replicates the behavior of an oil project, and can be successfully used to analyze project development decisions.

Selecting Number of Pre-drill Wells

Figure A.2 and A.3 below show a plot between Expected NPV and Initial facility capacity under two different pre-drilling scenarios for reserve size U [250, 350] MMbbls. One can then compare expected NPV obtained under different pre-drill scenario to choose among a fixed set of pre-drilling options. A detailed methodology to produce these graphs is discussed in Chapter 5.

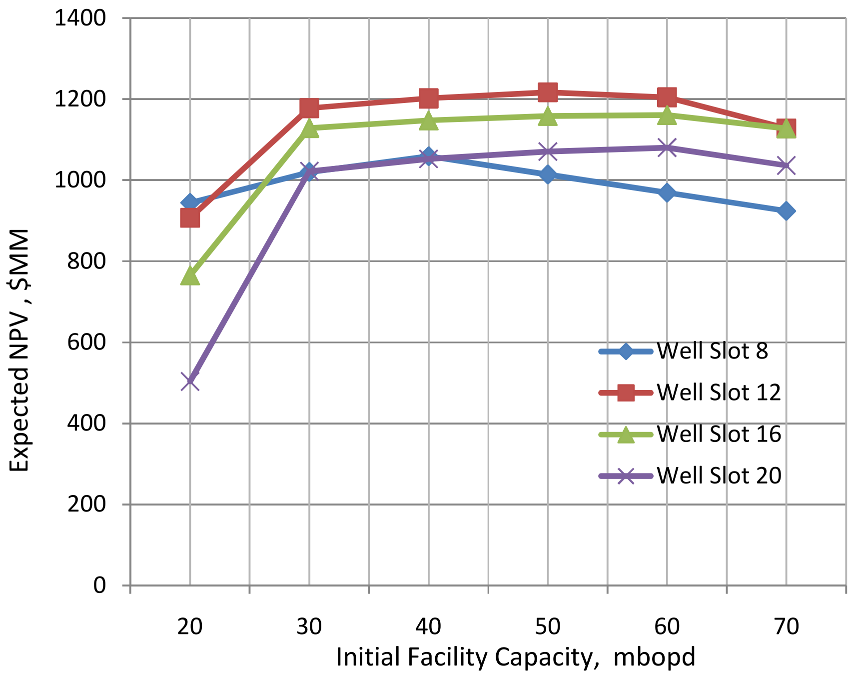


Figure A.2: NPV Profile for U [250, 350] and Six Pre-drill Wells

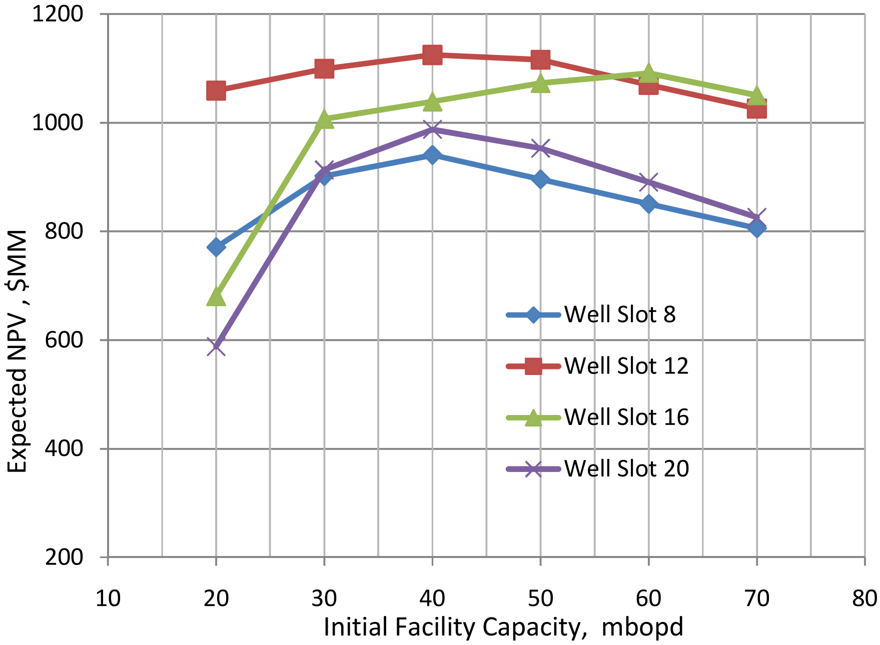


Figure A.3: NPV Profile for U [250, 350] and Nine Pre-drill Wells

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Vita

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