Elsevier Editorial System(tm) for Journal of Petroleum Science and Engineering
Manuscript Draft

Manuscript Number:

Title: Enhancing the Value of Oilfield Developments with Flexible Subsea Tiebacks

Article Type: Research Paper

Keywords: Value of Flexibility; Subsea Tiebacks; Monte Carlo; Uncertainty; Integrated Modeling

Corresponding Author: Dr. Jijun Lin, Ph.D.

Corresponding Author's Institution: BP America Inc.

First Author: Jijun Lin, Ph.D.

Order of Authors: Jijun Lin, Ph.D.; Olivier de Weck, Ph.D.; Richard de Neufville, Ph.D.; Howard K Yue, M.S.

Abstract: Many of the world's largest and most profitable offshore oil and gas basins are reaching maturity and are declining in profitability. Most new discoveries tend to be smaller and present as fragmented and geographically dispersed reservoirs with substantial uncertainty concerning geology and marginal exploitation costs. Many of these discoveries only make sense when considered as a set. This situation is compounded by large oil and gas price volatility and a very large combinatorial size of the design and operational decision space. Subsea tiebacks that connect new fields to existing production facilities are a means of extending the life and profitability of offshore facilities. The challenges of subsea tiebacks are both technical - they require connecting fields and facilities over large distances (>10 km) in deep water (>500 m) - and conceptual. It is not immediately clear where we should place production facilities, how we should size them, and in what sequence and when we should place tiebacks to optimize value. This article presents a methodology that evaluates three kinds of flexibility as a means to mitigate uncertainty in subsea tiebacks: the ability to tie back new fields, the ability to expand the capacity of a central processing facility, and the dynamic allocation of processing capacity to the connected fields. The methodology uses a mid-fidelity model in conjunction with Monte Carlo simulation to identify potential platform design capacities and tieback phasing strategies under uncertainty. We demonstrate the methodology on an offshore multiple-oilfield development patterned after a real case off the West Coast of Africa. The results show that because of the concurrent presence of reservoir, facility, and market uncertainties, implementing flexibility significantly increases, by as much as 76%, the expected net present value of the project compared to a traditional point-optimal inflexible design.

To be submitted to Journal of Petroleum Science and Engineering (JPSE) September 10, 2011

Enhancing the Value of Oilfield Developments with Flexible Subsea Tiebacks

Jijun Lin[a*], Olivier de Weck[b], Richard de Neufville[b], Howard K. Yue[b]

[a] *BP America Inc., 501 Westlake Park Blvd., Houston, TX 77079, USA*

[b] *Engineering Systems Division, Massachusetts Institute of Technology, 77 Massachusetts Ave., Cambridge, MA 02139, USA*

Abstract

Many of the world's largest and most profitable offshore oil and gas basins are reaching maturity and are declining in profitability. Most new discoveries tend to be smaller and present as fragmented and geographically dispersed reservoirs with substantial uncertainty concerning geology and marginal exploitation costs. Many of these discoveries only make sense when considered as a set. This situation is compounded by large oil and gas price volatility and a very large combinatorial size of the design and operational decision space. Subsea tiebacks that connect new fields to existing production facilities are a means of extending the life and profitability of offshore facilities. The challenges of subsea tiebacks are both technical – they require connecting fields and facilities over large distances (>10 km) in deep water (>500 m) – and conceptual. It is not immediately clear where we should place production facilities, how we should size them, and in what sequence and when we should place tiebacks to optimize value. This article presents a methodology that evaluates three kinds of flexibility as a means to mitigate uncertainty in subsea tiebacks: the ability to tie back new fields, the ability to expand the capacity of a central processing facility, and the dynamic allocation of processing capacity to the connected fields. The methodology uses a mid-fidelity model in conjunction with Monte Carlo simulation to identify potential platform design capacities and tieback phasing strategies under uncertainty. We demonstrate the methodology on an offshore multiple-oilfield development patterned after a real case off the West Coast of Africa. The results show that because of the concurrent presence of reservoir, facility, and market uncertainties, implementing flexibility significantly increases, by as much as 76%, the expected net present value of the project compared to a traditional point-optimal inflexible design.

Key words: Value of Flexibility, Subsea Tiebacks, Monte Carlo, Uncertainty, Integrated Modeling

---

*Corresponding author: Jijun Lin: e-mail address: jijun.lin@bp.com, Tel.: 1-281-366-0592

1. Introduction

As the majority of the "low-hanging fruit" in the offshore petroleum production industry (accessible and large monolithic oilfields with reliable reserve estimates) decline in number, the industry is shifting its focus to developing sets of smaller and geographically scattered oilfields. Production facilities for these fields are difficult to design and operate because of the inherent uncertainties involved: one cannot be certain of the reserves available in each of the fields; the more complex reservoir fluid characteristics and associated flow assurance issues make it difficult to predict the performance of subsea wells; the price of oil will fluctuate over the lifetime of the project, and so on.

Flexibility in design is a method of recognizing and embracing the effects of uncertainty (de Neufville and Scholtes (2011)). In the context of deepwater petroleum production, flexibility can take many forms, such as allowing for expansion of the production facility, anticipating the tieback from remote satellite fields, and so forth. While flexibility is philosophically desirable, a comprehensive evaluation framework has not yet been developed that quantifies the value enhancements that flexibility provides in offshore developments. This is relevant since flexibility rarely emerges naturally and it must therefore be "designed in" to offshore production systems. The question is whether the extra effort and cost of building in flexibility will ultimately enhance value. This article presents a methodology for determining the value of flexibility, and more importantly of *interacting types of flexibility* (such as future tie backs and capacity expansion), in deepwater petroleum developments.

2. Literature Review

Abbott et al. (1995) presented a thorough overview of then current deepwater development concepts. Although they did not explicitly address uncertainty and flexibility, they provided a list of the critical issues when evaluating competing deepwater concepts, the most crucial items being the amount of recoverable reserves and projected market price, both of which we know to be uncertain. Following an extensive overview of candidate deepwater production designs, they asserted that “[i]f subsea tiebacks to an existing platform are feasible, the cost will be difficult to beat.” This is an allusion to tieback flexibility.

Stoisits et al. (2010) developed a method of assessing architectural options for developing two offshore satellite fields that are near two existing off-shore production facilities. Using an integrated systems model, they concluded that the assets could be developed most economically by tying them back to existing facilities rather than building a separate, dedicated production facility. This is a prime example of the use of tiebacks to develop new fields with production facilities that have already been deployed. However, it is not clear whether the flexibility to accommodate new satellite fields was originally designed into the existing platforms.

Eriksen and Saucier (2000) explored the difference between subsea dry and wet trees, and their associated costs and benefits. Chitwood et al. (2004) investigated the economic impact of introducing new subsea technologies, providing insights into their possible use in deepwater marginal fields. These are just two examples in the literature of subsea tieback technology and investigations of their economic impact on offshore developments.

Lund (2000) developed a stochastic dynamic programming model for evaluating offshore petroleum projects under uncertainty. The model handles both market risk and reservoir uncertainty. The paper considers different types of flexibility (i.e., capacity expansion flexibility, drilling options). A simulation case study reveals the significant value of flexibility. Particularly, capacity flexibility improves a project’s value significantly when substantial uncertainty surrounds the reservoir properties.

Jablonowski et al. (2010) examined expansion flexibility in a hypothetical deepwater development. They modeled reservoir uncertainty and calculated the value of flexibility for assets of various initial capacities that are expanded in the future for the purpose of maximizing the net present value of the project.

Further discussions of reservoir uncertainty can be found in Chang and Lin (1999), Armstrong et al. (2004), Caumon et al. (2004), Subbey et al. (2004), Zabalza-Mezghani et al. (2004), Maschio et al. (2010), Lin et al. (2010). Dias (2004), Lima and Suslick (2006) Suh et al. (2007), Abid and Kaffel (2009) treat market uncertainty.

A coherent and generic framework for identifying and designing real options "in" deepwater petroleum projects still remains to emerge. For example, uncertainties being considered in the literature are primarily exogenous (i.e., market uncertainty, customer demand). For a complex engineered project, multi-domain uncertainties (i.e., technical, market, and development) can influence the technical or economic success of a project, particularly one involving multiple subsea tiebacks. Furthermore, the literature primarily focuses on particular types of flexibility over a project's lifecycle (i.e., managerial flexibility early stages of a project, operational flexibility after fielding a system). However, we need a holistic view of uncertainty and flexibility to design effective offshore developments under multi-domain uncertainties. This is the subject of this article.

3. Methodology

General Approach

The general approach used to determine the value of flexibility first recognizes and quantifies the multi-domain uncertainties present in the project under consideration. Next, it defines both various flexibilities for responding to the evolution of the uncertain elements of the project, and the triggering conditions governing when we should exercise these flexibilities. Finally, it combines a holistic system model with a Monte Carlo simulation framework to determine the value of the defined flexibilities under the recognized uncertainties. Each component of the methodology is discussed below in detail. Further discussion is available in Lin (2008).

The desired result is a calculation procedure that can explore many development options with embedded flexibility, under uncertainty, and in a tractable amount of time. This serves essentially as a screening model that identifies flexible designs that show promise. These are then taken into the next phase of detailed analysis. This screening methodology by no means replaces careful detailed design; it instead provides a method of efficiently searching the design space for propitious system architectures.

Recognition and Quantification of the Relevant Uncertainties

In order to determine the value of flexibility, we must first identify the uncertainties that can significantly affect the project under evaluation. These uncertainties can be endogenous, which can be actively influenced by projects or field appraisal activities (e.g., drilling and facilities uncertainty, subsurface uncertainty); exogenous uncertainty, which tends to originate from sources beyond the direct influence of projects (e.g., market uncertainty); and hybrid, which jointly result from the previous uncertainties (e.g., well performance and contractual uncertainty). After we identify these uncertainties, we must quantify them appropriately. This may involve using historical data to characterize the evolution of uncertain project parameters such as the market price of crude oil; simplified models that characterize technical processes such as the evolution of the median reservoir volume estimate; or other appropriate means.

Table 1 compares these three types of uncertainties and illustrates them in petroleum projects. In this classification, an important distinction can be made between epistemic uncertainties originating from human perception (or limited knowledge of the system) of a static value, and those that are intrinsically stochastic or aleatoric. For petroleum projects, uncertainty in estimates of reserves is due to limitations in human knowledge of reservoirs since their characteristics (such as Original Oil In Place (OOIP)) have evolved to a (quasi) steady state over millions of years. So, it falls into epistemic uncertainty. In contrast, market uncertainty (such as crude oil and gas prices) is stochastic or aleatoric uncertainty, which is characterized by dynamic and non-stationary processes as crude oil or gas prices evolve over time. Compared to the standard stochastic models for market uncertainty (e.g., Geometric Brownian Motion, binomial tree), the evolution of reserve estimates requires different stochastic models that need to capture the human learning processes of the underlying static values.

Identification of Multi-level Flexibilities

The next step is to identify flexibilities and conditions governing when they are exercised. The flexibilities can be classified into two broad categories: put options and call options. Put options generally provide ways to reduce downside exposure, such as the ability to shut down a facility if its projected profitability is unattractive. Call options are flexibilities that allow the designer to capture potential upside, such as the ability to expand a facility if its expected performance warrants it. Furthermore, we must explicitly define the triggering conditions for each flexibility, so that it can be exercised at the appropriate time during the simulation. Flexibilities can be combined in different combinations to produce flexible strategies. Further development of flexibility in engineering design is found in de Weck et al. (2004), Wang and de Neufville (2006), and de Neufville and Scholtes (2011).

Given the complexity and long lifecycle of capital-intensive projects, it is not easy to identify where to locate flexibility in these systems. Especially in project appraisal and concept selection stages, the search space for sources of flexibility is very large given multi-domain uncertainty. Different types of uncertainties may require different flexible approaches. A system could be flexible in some respects, but rigid in others. Coupling technical and economic systems with feedback loops makes the search for flexibilities even more challenging. It is therefore imperative to have a systematic approach to guide the search for flexibility in the early stages of a project.

Before discussing the flexibility in petroleum projects, let us understand the "problem landscape" for development of a hydrocarbon basin. Different development strategies have unique flexible options in field configurations and system designs. **Figure 1** shows the problem landscape. The horizontal axis represents the numbers of fields (or reservoirs) in a basin, the vertical axis the number of facilities (or platforms). Depending on the combination of fields and facilities, there are four types of field development architectures.

a. **Single field and single facility:** This is the simplest scenario. The development strategy is to build a single production platform (fixed or floating depending on water depth) for the oilfield at moderate size. Much traditional development (e.g., North Sea) falls into this category.
b. **Multiple fields and single facility:** This scenario consists of multiple small fields in a basin. The quantity of hydrocarbons may not be large enough to justify economically a dedicated facility in each field. Therefore, the development concept is to tie back multiple fields to a central production facility. The main decisions are location of the facility, field configuration, number of tieback fields, and timing of tieback. More recent deepwater developments in the Gulf of Mexico and off the West Coast of Africa represent this category. This is the main situation we study in this article.
c. **Single fields and multiple facilities:** Given a giant monolithic oilfield, the development strategy could build multiple facilities to produce the hydrocarbons. These facilities can utilize the same concept and design but come on stream over time. So the main decisions include how to standardize facilities or processes to reduce cost, and how to phase development over time to gain learning benefits or to reduce reservoir uncertainty. An example is the Azeri, Chirag, Gunashli (ACG) project in the Caspian Sea.
d. **Multiple fields and multiple facilities:** This can be treated as a hybrid case based on the previous scenarios. This scenario offers more ways to connect fields with facilities (choice of mapping, one-to-one, one-to-many, many-to-one). Future complex developments may increasingly fall into this category.

This problem landscape of petroleum projects embeds multiple levels of flexibilities in the development or operation phase of an oilfield.

Inter-facility flexibility considers the development configuration of the whole field. It defines the topological relationships between fields and facilities. Typical examples are flexible staged development for a single large oil field or tieback of a new field to an existing platform. At this level of flexibility, entire platforms can be added, moved or decommissioned from the field, or new fields can be tied back to existing facilities over time.

Intra-facility flexibility applies within one facility. It defines the design options of an individual facility (e.g., production, injection, or well platform). Examples include adding extra space on the processing, well head or drilling decks of a platform, allowing later addition of modules such as gas compression or water injection packages, and the flexibility to drill and accommodate more production or injection wells from a single platform.

Operational level flexibility provides different ways to operate the systems but does not change their configurations or designs. For example, to achieve higher oil recovery rates from a reservoir, field operators can actively manage production by increasing water and gas injection rates, or changing the mix of incoming fluids from different wells (e.g., cut back production of wells with higher water-oil-ratio) to maximize oil production and revenues. Exercising operational flexibility will not affect the architecture of a field or the design of facilities.

The importance of identifying multi-level flexibility in a petroleum project is to:

- Enable the search for “sweet spots” in the combinatorial space of which flexibilities to implement to maximize lifecycle value.
- Allow the test of “interaction effects” of different flexibilities, especially for the conditions in which one type of flexibility can add more value if another type of flexibility is also enabled.

- Balance different flexibilities over the lifecycle of an oilfield. Flexibilities during early project phases (e.g., strategic flexibilities), mid-project phase (e.g., tactical flexibility), and production phase (e.g., operational flexibility) are considered under a unified framework.
- Give managerial practitioners a complete view on the hierarchy of flexibilities and their influence on project lifecycle value. More attention (or resource) can thus be paid to specific flexible development strategies during projects' appraisal and concept selection stages.

Development of an Integrated Systems Model and Monte Carlo Simulation

The final step develops a holistic, integrated systems model in conjunction with a Monte Carlo simulation to evaluate the flexible strategies. The purpose of this model is to determine the value of a project, for example its net present value (NPV). Its inputs are the evolution of the uncertain parameters, the data considered to be deterministic, and the flexible strategies with their associated triggering rules. The model simulates the life of the project and exercises the flexibilities when the triggering conditions are satisfied. The primary output of the model is the value of the project. It can also provide other interesting intermediate figures. Examples of integrated systems models include Lund (2000), Goel and Grossman (2004), Bilderbeck and Beck (2005), Hassan et al. (2005), Babajide et al. (2008), Lin (2008), Jablonowski et al. (2010).

The Monte Carlo simulation runs the system model many times, each time with a different evolution of the uncertain parameters. The result is a distribution of the project value under uncertainty. Each flexible strategy, including an inflexible baseline strategy, is subjected to the Monte Carlo simulation. We can then compare the resulting distributions, along with aggregate statistics of interest, to identify the value of flexibility and the preferred design and operations strategy.

Our Monte Carlo simulation uniquely involves two nested loops, shown in **Figure 2**. The outer loop uses traditional Monte Carlo sampling in which each iteration generates a single instance of reservoir, facility, and market uncertainties. The inner loop simulates the lifecycle of an oil field given the uncertainties instantiated in the outer loop and with embedded decision rules for multi-level flexibilities that reconfigure the tiebacks, platform, and its operation in response to the generated uncertainties. By nesting the loops, it is possible to consider not only uncertainty, but also its *evolution* over time.

A crucial element of the integrated systems model is the triggering conditions or decision rules. Essentially, the model must know a priori what actions will be taken for all foreseeable circumstances. These triggering conditions take the form of “if-then” statements – if a certain condition is observed, then a certain action will be taken. They allow the model to simulate the implementation of a flexible option as a response to an uncertainty that has unfolded. There are many ways to represent decision rules, such as decision trees in Wang (2005), decision networks in Silver and de Weck (2007), and logical (Boolean) statements.

4. Case Study: Offshore Multiple-oilfield Development

The proposed analysis methodology is used to evaluate the incorporation of flexibility into the development of an offshore multiple-oilfield project. A description of the case is followed by application of the evaluation methodology. Lin (2008) provides a more detailed discussion.

Scenario Description

Figure 3 depicts an overview of the hydrocarbon basin. Tieback development of multiple oilfields generally involves two steps: 1) developing a hub for the core fields; 2) tieback of remote fields to the existing hub later in field operation when extra processing capacity becomes available. Essentially, a single central processing facility (CPF), in this case a floating production, storage and offloading (FPSO) vessel, will process some or all of the ten reservoirs

R1 through R10. The case assumes that the placement of the CPF has already been determined with possible initial crude processing capacity of 150 or 175 thousand barrels per day (MBD).

The search for higher lifecycle value development options is challenging for several reasons:

- **Existence of multi-domain uncertainty.** These multi-domain uncertainties combine and evolve over time, giving rise to combinatorial growth in the number of unique uncertainty trajectories and in turn, the number of Monte Carlo simulations required to ensure a representative sample.
- **Combinatorial search space for development strategies is large.** The number of combinations of initial, intermediate, and final configurations of a development is very large. For example, one can initially specify a small development and expand later, or begin with a larger development and expand less at a different time, and so on. It is not clear how to choose an optimal development strategy.
- **Potential interactions among different flexibilities.** Certain flexibilities may be more valuable when other flexibilities are also enabled, making it difficult to quantify the value of flexibility using simple approaches.

Without a systematic approach, it is therefore unclear whether or how different flexibilities can enhance the value of the project. The rest of the case study applies the methodology developed previously step-by-step to evaluate this development.

Recognition and Quantification of the Relevant Uncertainties

The case considers three types of uncertainties: Reservoir Uncertainty (RU), Facility Uncertainty (FU), and Market Uncertainty (MU).

<u>Reservoir Uncertainty</u>

RU accounts for the evolution of the understanding of the subsurface properties of the reservoir. The method used to model RU, a Reverse Wiener Jump-Diffusion Process, is discussed in detail in Lin et al. (2010). **Figure 4** shows two possible instantiations of the Estimated Ultimate Recovery (EUR), or the recoverable volume of oil in the reservoir, as it evolves over time. The Reverse Wiener model calculates the EUR, which generally changes in small increments over time, but sometimes shows a discrete jump indicating a surprise finding of subsurface conditions (e.g., the discovery of a fault structure causing a drastic reduction in the EUR). The model can also calculate the 10^{th}, 50^{th}, and 90^{th} percentile values of the EUR (represented by the P10, P50, and P90 lines, respectively). As **Figure 4** shows, the predictions generally approach a steady state EUR and the uncertainty, proximately indicated by the difference between the P10 and P90 lines, tends to decrease over time. For this case study, each of the ten fields has its own independent evolutionary trajectory that is simulated based on the model of Lin et al. (2010).

Facility Uncertainty

FU recognizes that the CPF will not always produce at its designed peak capacity throughout its lifecycle. Generally, it will perform at some percentage of its capacity, defined as the Facility Availability (FA). The FU model implemented to calculate FA in this case study considers three basic features, which can be seen in **Figure 5**. First, there is an Expected Facility Availability (EFA) which is initially low as the CPF is brought into service, increases over the first few years of the project as drilling ramps up and the facility undergoes troubleshooting, and finally settles to a steady-state. The EFA represents the FA that would be observed in the absence of uncertainty. Second, a random walk about the EFA is introduced to account for day-to-day variations in facility throughput, which represents the unplanned production losses due to equipment failures or human errors. Finally, the FU model accounts for random significant events, such as natural disasters (like hurricanes) when the FA temporarily falls to zero. These three features combine to give the overall FA curve.

Market Uncertainty

In this case study, MU is the price of crude oil. Historical data provide the observed behavior of this price. A Geometric Brownian Motion model generated possible future trajectories of the crude price. **Figure 6** shows three possible instantiations of the future oil price over thirty years.

Identification of Flexibilities and Triggering Conditions

Next, the flexibilities to be considered are identified along with their associated triggering conditions, otherwise known as decision rules. The three flexibilities considered in this case study are tieback flexibility, capacity expansion flexibility, and Active Reservoir Management.

Tieback Flexibility

Figure 3 depicts the concept of tieback flexibility. Initially, a core set of reservoirs connects to the CPF. The remaining reservoirs then form a set that can be tied back to the CPF when the decision rule is triggered accordingly. Tieback flexibility is exercised if the following three conditions are satisfied:

a. The total EUR of all the reservoirs connected to the CPF is less than a threshold (e.g., 600 million barrels (MMB)), indicating the CPF may be under-utilized.
b. The reservoir to be tied back contains a threshold EUR (i.e., 30 MMB), indicating that it will contain enough resource to amortize the investment required to tie it back.
c. The market price of oil is above a defined threshold (e.g., $25 per barrel).

The specific thresholds can be chosen at the discretion of the analyst. The analyst can thus examine variations of the thresholds (and associated triggering conditions) to determine an optimal set of decision rules. In the absence of this flexibility, only the initial core set of reservoirs connect to the CPF through the life of the project. From a practical standpoint, tieback flexibility is enabled by provisioning extra space and connection interface (such as larger swivel systems in FPSO) that allows new tieback risers in the future. This case study assumed that the cost of acquiring tieback flexibility was 10% of the initial subsea processing, umbilical, riser, and flow lines (SURF) cost based on analogy to a similar project. The cost of performing a tieback was determined by the scope of the subsea infrastructure (e.g., subsea wells, umbilicals, flowlines, and risers) required to make the tieback.

Capacity Expansion Flexibility

Capacity expansion flexibility complements the tieback flexibility. It provides an increase in the processing throughput of the CPF should conditions be favorable. A capacity increment is applied to the CPF, in this case an expansion from 150 to 200 MBD, when the second and third conditions for tieback flexibility, the existence of large potential reservoirs and exceeding of the minimum oil price, are satisfied but the first condition, the underutilization of the CPF, is not satisfied. This flexibility enables field managers to capitalize on larger EUR predictions than initially anticipated. Without this flexibility, the CPF capacity is static throughout the project lifetime. In other words, it is either infeasible (due to lack of deck space, payload constraints, etc.) or prohibitively expensive to increase CPF capacity through alternative means. In practical terms, extra deck space on the CPF is allotted for additional processing trains in order to enable capacity expansion flexibility. Due to pragmatic considerations, in this case study this flexibility can only be exercised once during the life of the project. The cost of exercising capacity expansion is derived from cost estimation models, once such expansion is triggered in the simulation.

Both capacity expansion and tieback flexibilities are only allowed to be exercised between the third and tenth year of operation. This prevents flexibility from being exercised in the early stages of operation when uncertainties have yet to be resolved and in the late stages when the project nears the end of its lifecycle and additional capital investments may be more difficult to amortize. The earliest and latest time periods for exercising of flexible options can be adjusted in the model.

Active Reservoir Management (ARM)

ARM is a type of operational flexibility that enables managers to allocate the available CPF processing capacity optimally to its reservoirs. The integrated systems model tracks the watercut of each reservoir, chooses to produce preferentially from reservoirs with a low watercut before those with higher watercut. The alternative to ARM is sequential allocation, which processes reservoirs according to the order in which they were connected to the CPF. Sequential allocation does not maximize capacity utilization, whereas the dynamic watercut based scheme prioritizes the processing of higher value fluids (more hydrocarbons and less water). ARM is enabled by designing subsea manifolds and topside separation systems with the ability to manipulate production and injection rates throughout the system, and by having constant human and automatic supervision of the allocation process.

Development of an Integrated Systems Model and Monte Carlo Simulation

Figure 7 shows a flowchart of the integrated systems model for this case study. It involves three major components: reservoir, facility, and project economics. These are integrated into a single model to give a holistic representation of the project. The figure shows the major streams of information between the three components. The one of most interest is the cash flow and NPV as the output of the project economics component and in essence the integrated systems model. This model was developed using reservoir tank model with different types of drive mechanism, facilities cost models, and economic evaluation methods that were calibrated for the West Africa basin that served as a template for this case study.

The final step wraps all the parts developed above into a Monte Carlo simulation. **Figure 2** depicts a flow chart for the calculation algorithm and is the result of applying the proposed analysis methodology to the case study. At the top, the strategies are defined as various combinations of the flexibilities to perform tiebacks, to expand capacity, and implement operational flexibility (ARM). These strategies are inputs into the Monte Carlo simulation. Each simulation instantiates the uncertainties (RU, FU, and MU) according to the models developed to quantify the uncertainties (Fig. 4, 5 and 6). Next, the integrated systems model simulates the future lifecycle of the project in n_2 time steps. At each time step, the decision rules or triggering conditions for each of the enabled flexibilities are evaluated to determine whether a flexible option should be exercised at that time. After the lifecycle simulation is complete, the model calculates the economic output, NPV. This simulation is repeated n_1 times, each with a new instantiation of the uncertainties and consequently a new value of NPV. Once all simulations are completed and the NPV distribution has converged, we examine the set of NPVs to determine the performance of the particular flexible strategy that was enabled.

Results and Conclusions

Table 2 defines the twelve strategies investigated in this case study. Strategies 1 – 8 have a CPF with an initial capacity of 150 MBD with the option to expand to 200 MBD (when capacity expansion flexibility is enabled). Strategies 9 – 12 have a CPF with an initial capacity of 175 MBD but no future expansion capability.

Each of the twelve strategies was run through the algorithm shown in **Figure 2** for n_1=200 times with all uncertainties, RU, FU, and MU, active. We then ordered the resulting 200 NPVs calculated for each strategy and plotted them as a cumulative distribution function, otherwise known as a target curve. For proprietary reasons, the NPVs were normalized to the expected net present value (ENPV) of Strategy 1 evaluated under RU only, which is the inflexible case as it has no flexibilities enabled (see first row in **Table 2**).

Figure 8 shows the target curves for Strategies 1 – 8. Strategies without tieback flexibility (i.e., Strategies 1 – 4) have significantly lower ENPV than those with tieback flexibility. The lower ENPV is partially due to long negative tails in the target curves. When the reserves in the core fields are smaller than the initial estimate, strategies without tieback flexibility cannot bring in new reserves to make the project economically viable. ARM does not make much difference when tieback flexibility is disabled.

Conversely, **Figure 8** shows that tieback flexibility significantly improves ENPV. Strategy 5 is 40% better than Strategies 1-4, Strategy 6 is 51% better, etc. This is because tieback flexibility reduces project downside risks and capitalizes on upside potential. Further, **Figure 9** shows that Strategies 11 and 12 also achieve significant improvement over the inflexible Strategies 1-4. For convenience, **Table 3** compiles summary statistics for the twelve strategies. The improvement in ENPV is significant, up to a value of 76% for Strategy 8 over Strategy 1.

The nonlinear synergy between flexibilities can also be observed by comparing Strategies 1 to 2 and Strategies 5 to 6. There is no difference between the ENPVs of Strategies 1 and 2, even though Strategy 2 has ARM flexibility enabled. However, when tieback flexibility is enabled, as it is in Strategy 5, implementing ARM (Strategy 6) increases the ENPV by 8.3%.

The value of flexibility was further quantified by the main effects and interaction effects. The main effect of a particular type of flexibility is the increase in ENPV it causes when included. Likewise, the interaction effect is the increase due to a combination of enabled flexibilities. **Table 4** shows these effects. Tieback flexibility contributes the most (83%) to improving ENPV. Interestingly, the interaction effects between tieback flexibility and the other two types of flexibilities offer increases (16.5% and 10%) similar to that of operational flexibility and almost double that of capacity flexibility. This highlights the fact that different types of flexibility can interact and enable the value-enhancing capabilities of others.

In an effort to characterize the response surface of the screening model, a regression model was developed using a full-factorial design of experiments (DOE). The result, shown in Equation [1], gives a formal method of defining the value of flexibility. The variables x_1, x_2, and x_3 represent tieback, capacity expansion, and operational flexibility respectively. When a flexibility is not enabled, its variable takes on a value of -1. When it is, the value is 1. Lin (2008) provides more information on the regression model. Equation 1 only applies to strategies 1 to 8 since they all start from same initial capacity 150 MBD. Strategies 9 ~ 12 will have a different regression model with only two variables x_1 and x_3 since they all start with 175 MBD capacity without future expansion.

$$ENPV(x_1, \quad x_2, \quad x_3) = 187.5 + 41.5x_1 + 8.25x_2 + 5x_3 + 8.25x_1x_2 + 5x_1x_3 + 0.75x_2x_3 \qquad \textbf{[1]}$$

It is interesting to note that the strategies with the highest ENPVs (e.g. Strategy 8) also have the highest standard deviations for the NPV. Traditionally, an increase in the standard deviation can be a concern as it indicates greater uncertainty. However, from the perspective of flexibility and maximizing expected value, this increased standard deviation is attractive as it indicates the extension of the upside.

Sensitivity Analysis

To examine the way results depend on assumptions, we performed a sensitivity analysis. Specifically, we perturbed the cost of tieback flexibility, platform expansion flexibility, and time at which flexibilities can be exercised to determine when the flexible strategies became less valuable than the inflexible base case. We also carried out local sensitivity analyses involving small perturbations to parameters to calculate the gradient of ENPV with respect to select input parameters. These analyses were performed under RU only.

Table 5 and **Table 6** show the results of the sensitivity analysis for Strategies 5 and 8. The cost of tieback flexibility is expressed as a percentage of the initial SURF cost of Strategy 1. These two tables show that the ENPV of Strategy 5 becomes less than that of Strategy 1 when the initial cost of tieback flexibility increases to 30% of the initial SURF cost. Similarly, the ENPV of Strategy 8 becomes less than that for Strategy 1 when the cost of tieback flexibility increases to 50% of SURF cost. Strategy 8 remains preferable at a higher cost of tieback flexibility because it enables all three levels of flexibility while Strategy 5 has only tieback flexibility. These results give an indication of the confidence interval the analyst has when comparing and choosing competing strategies. Lin (2008) presents additional global and local sensitivity analyses.

5. Summary

This article presents a methodology for evaluating flexibility in offshore projects operating under multi-domain uncertainty. It involves quantifying the underlying uncertainties, developing flexible strategies to reduce downside exposure and increase upside potential, and evaluating the strategies using an integrated systems model in concert with a Monte Carlo simulation. This approach contrasts with the traditional point-design method, which may allow for rudimentary sensitivity analysis, but does not consider multi-domain uncertainties that were previously not modeled as acting simultaneously. The purpose of this methodology is to maximize the ENPV of a project through the use of various flexibilities, and to identify promising design options that can be taken into the next phase of detailed design. Applying the methodology to a case study which is inspired by a multi-reservoir hydrocarbon basin in West Africa, it was found that the expected net present value of an offshore multiple-oilfield development could be raised by as much as 76% through the use of subsea tiebacks, capacity expansion, and Active Reservoir Management flexibilities. Concurrent consideration of multiple types of uncertainties and flexibility strategies will be essential as the industry begins to explore more complex multi-reservoir multi-facility architectures such as those shown in quadrant D of Fig. 1. Future work includes the expansion of the method to multiple CPFs, including phasing and location decisions of *both* facilities and associated tiebacks under uncertainty.

6. References

Abbott, P. A., D'Souza, R. B., Solberg, I. C., and Eriksen, K. (1995) "Evaluating Deepwater Development Concepts," *Journal of Petroleum Technology*, Vol. 47, No. 4, pp. 314-231.

Abid, F., and Kaffel, B. (2009) "A methodology to evaluate an option to defer an oilfield development," *Journal of Petroleum Science and Engineering,* Vol. 66, pp. 60-68.

Armstrong, M., Galli, A., Bailey, W., Couët, B. (2004) **“**Incorporating technical uncertainty in real option valuation of oil projects,” *Journal of Petroleum Science and Engineering*, Vol. 44, pp. 67-82.

Babajide, A., de Neufville, R., and Cardin, M.-A. (2008) “Integrated Method for Designing Valuable Flexibility in Oil Development Projects,” *Journal of Projects, Facilities and Construction, Society of Petroleum Engineers,* Vol. 4, No. 2, June, pp. 3 – 12, 2009

Bilderbeck, M.G., and Beck, I.V. (2005) “Using Integrated Project Models to Evaluate Field Development Options” *SPE Middle East Oil and Gas Show and Conference*, Kingdom of Bahrain, Mar. 12-15.

Caumon, G., Strebelle, S. B., Caers, J. K., Journel A. G. (2004) “Assessment of global uncertainty for early appraisal of hydrocarbon fields,” *SPE Annual Technical Conference and Exhibition*, Houston, Texas, USA, Sept. 26-29, SPE 89943.
(available at http://pangea.stanford.edu/~jcaers/papers/SPE89943.pdf)

Chang, C. P., Lin, Z. S. (1999) “Stochastic analysis of production decline data for production prediction and reserves estimation,” *Journal of Petroleum Science and Engineering*, Vol. 23, pp. 149-160.

Chitwood, J. E., Wanvik, L. Y., Chin, D., Sheets, B.J. (2004) “Techno-Economic Evaluations of Deepwater Marginal Field Developments,” *Offshore Technology Conference*, Houston, Texas, USA, May 3-6, Paper No. 16722-MS.

de Neufville, R. and Scholtes, S. (2011) *Flexibility in Engineering Design*, MIT Press, Cambridge, MA 2011.

de Weck, O., de Neufville, R. and Chaize, M. (2004) “Staged Deployment of Communications Satellite Constellations in Low Earth Orbit,” *Journal of Aerospace Computing, Information, and Communication*, Vol.1, No.3, pp. 119-136.

Dias, M.A.G. (2004) “Valuation of exploration and production assets: an overview of real options models,” *Journal of Petroleum Science and Engineering*, Vol. 44, pp. 93-114.

Eriksen, R., Saucier, B. “Selecting Cost-Effective and Safe Deepwater Completion Tieback Alternatives,” *Offshore Technology Conference*, Houston, Texas, USA, May 1-4, Paper No. 12167-MS.

Goel, V. and Grossmann, I. E. (2004) “A Stochastic Programming Approach to Planning of Offshore Gas Field Developments Under Uncertainty in Reserves,” *Computers and Chemical Engineering*, Vol. 28, pp. 1409-1429.

Hassan, R., de Neufville, R., de Weck, O., Hastings, D., and McKinnon, D. (2005) “Value-at- Risk Analysis for Real Options in Complex Engineered Systems,” *IEEE International Conference on Large Scale Infrastructures*, Hawaii, 10-12 October, Vol. 4, pp. 3697-3704.

Hayashi, S.H.D., Ligero, E.L., and Schiozer, D.J. (2007) “Decision-Making Process in Development of Offshore Petroleum Fields,” Paper SPE 107737 presented at the *Latin American and Caribbean Petroleum Engineering Conference*, Buenos Aires, 15–18 April. DOI: 10.2118/ 107737-MS.

Ho, S. P. and Liu, L. Y. (2003) “How to Evaluate and Invest in Emerging A/E/C Technologies under uncertainty,” *ASCE Journal of Construction Engineering and Management*, Vol. 129, No. 1, pp. 16-24.

Jablonowski, C., Ramachandran, H., and Lasdon, L. (2010) “Modeling Facility Expansion Options under Uncertainty,” *SPE Annual Technical Conference and Exhibition,* Florence, Italy, Sept. 19-22, SPE 134678.

Lima, G. A. C., and Suslick, S. B. (2006) “Estimation of volatility of selected oil production projects,” *Journal of Petroleum Science and Engineering*, Vol. 44, pp. 129-139.

Lin, J. (2008) “Exploring Flexible Strategies in Engineering Systems Using Screening Models,” *Doctoral Thesis,* Engineering Systems Division, Massachusetts Institute of Technology, Cambridge, MA. http://esd.mit.edu/people/alumni.html#lin

Lin, J., de Weck, O., and MacGowan, D. (2010) “Modeling Epistemic Subsurface Reservoir Uncertainty using a Reverse Wiener Jump-Diffusion Process,” *Journal of Petroleum Science and Engineering*, under review.

Lund, M. (2000) “Valuing Flexibility in Offshore Petroleum Projects,” *Annals of Operations Research*, 99, pp. 325-349.

Maschio, C., de Carvalho, C.P.V., Schiozer, D. J. (2010) “A new methodology to reduce uncertainties in reservoir simulation models using observed data and sampling techniques,” *Journal of Petroleum Science and Engineering,* Vol. 72, pp. 110-119.

Silver, M. and de Weck O. (2007) “Time-Expanded Decision Networks: A Framework for Designing Evolvable Complex Systems,” *Systems Engineering*, Vol. 10, No. 2, pp. 167-186.

Stoisits, R. F., Bashagour, H. M., and Su, C. G. (2010) “Application of Integrated Production and Reservoir Modeling to Deepwater Development,” *Society of Petroleum Engineers International Oil and Gas Conference and Exhibition*, Beijing, China, June 8-10, SPE Paper No. 131621-MS.

Subbey, S., Christie, M., Sambridge, M. (2004) “Prediction under uncertainty in reservoir modeling,” *Journal of Petroleum Science and Engineering*, Vol. 44, pp. 143-153.

Suh, E., de Weck, O. and Chang, D. (2007) "Flexible Product Platforms: Framework and Case Study", *Research in Engineering Design*, Vol.18, No. 2, pp. 67-89.

Wang, T. (2005) "Real Options 'in' Projects and Systems Design – Identification of Options and Solutions for Path Dependency," *Doctoral Thesis,* Engineering Systems Division, Massachusetts Institute of Technology, Cambridge, MA, http://dspace.mit.edu/handle/1721.1/31167.

Wang, T. and de Neufville, R. (2006) "Identification of Real Options "in" Projects," 16th *Annual Symposium, International Council on Systems Engineering*, Orlando, Florida.

Zabalza-Mezghani, I. Manceau, E., Feraille, M., Jourdan, A. (2004) "Uncertainty management: from geological scenarios to production scheme optimization," *Journal of Petroleum Science and Engineering,* Vol. 44, pp. 11- 25.

Figures

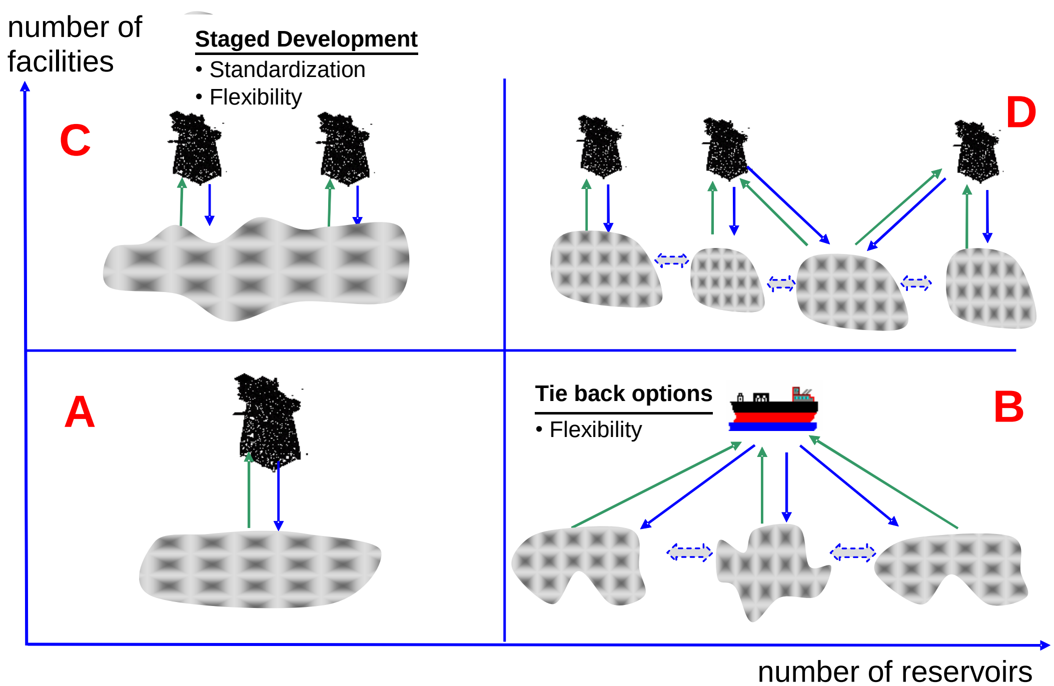

Figure 1: Problem landscape for the development of a hydrocarbon basin

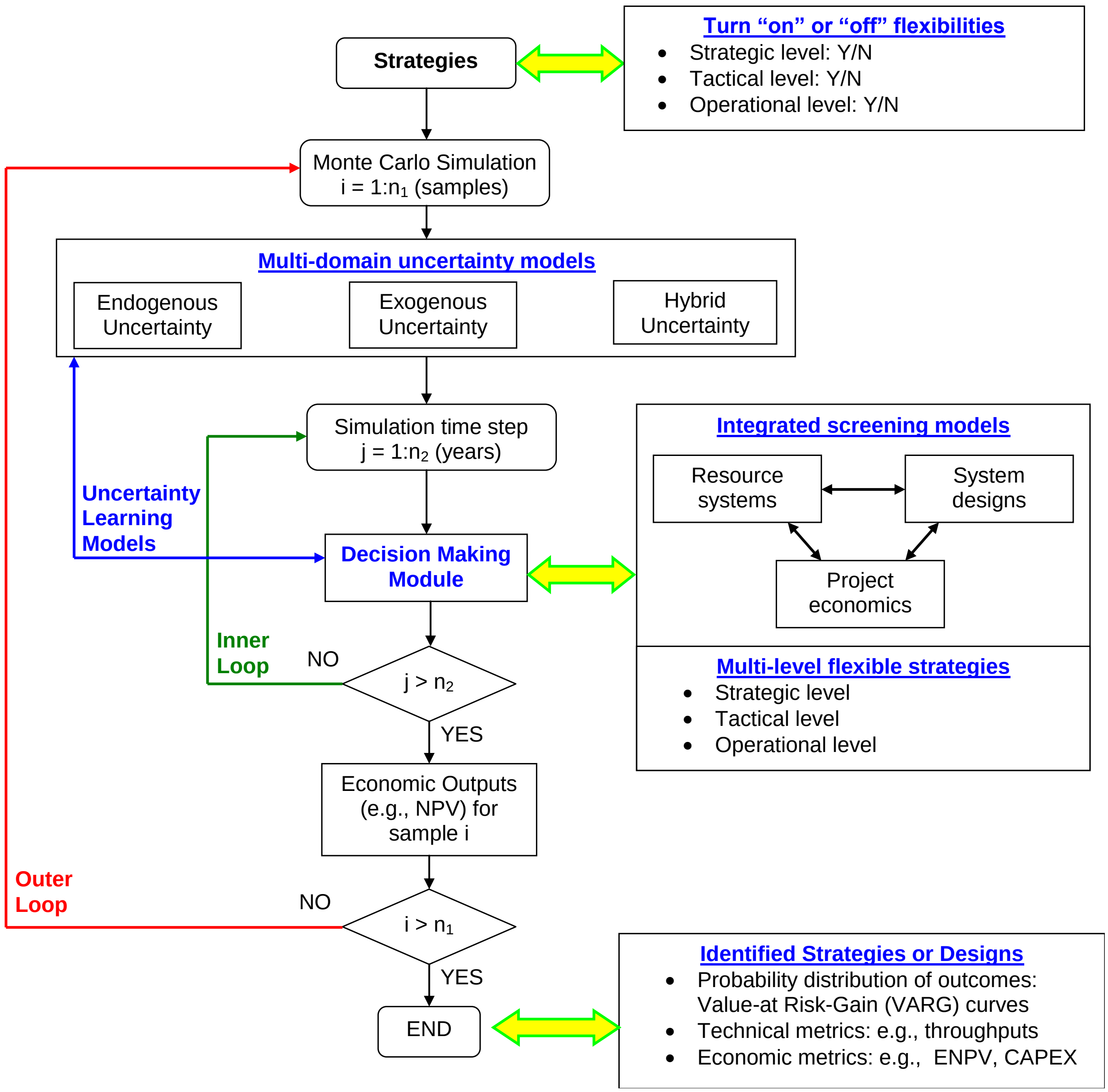

Figure 2: Monte Carlo Simulation Framework. VARG=Value-at-risk-gain, CAPEX = capital expenditures, NPV = net present value

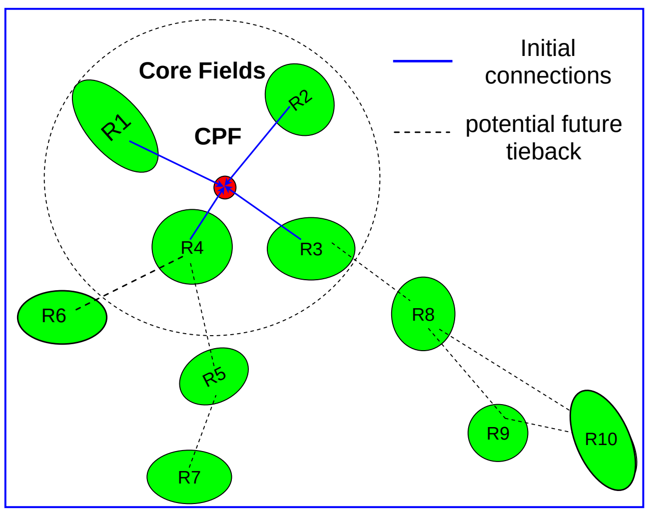

Figure 3: Reservoir Layout for Offshore Multiple-oilfield Case Study

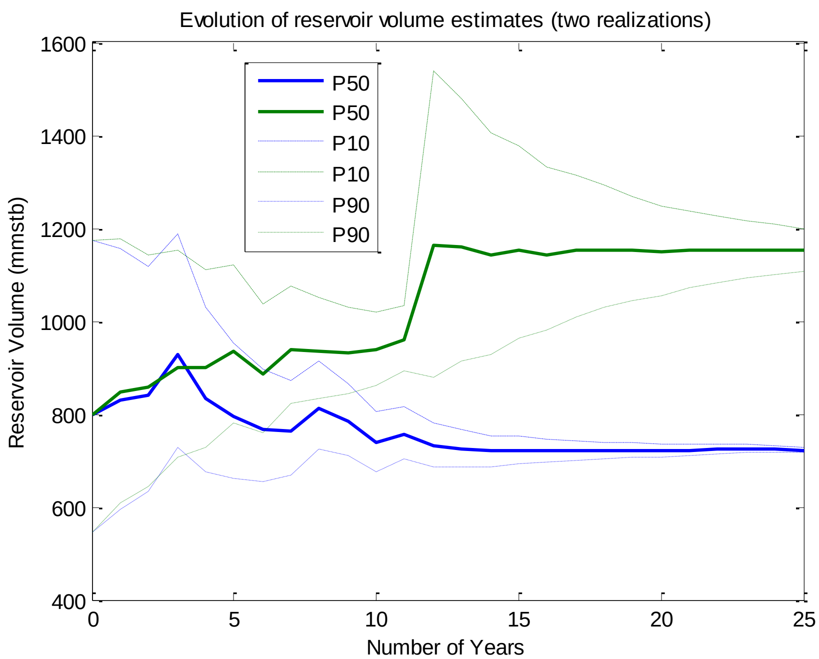

Figure 4: Two Instantiations of Evolution of Estimated Ultimate Recovery (EUR) over Time

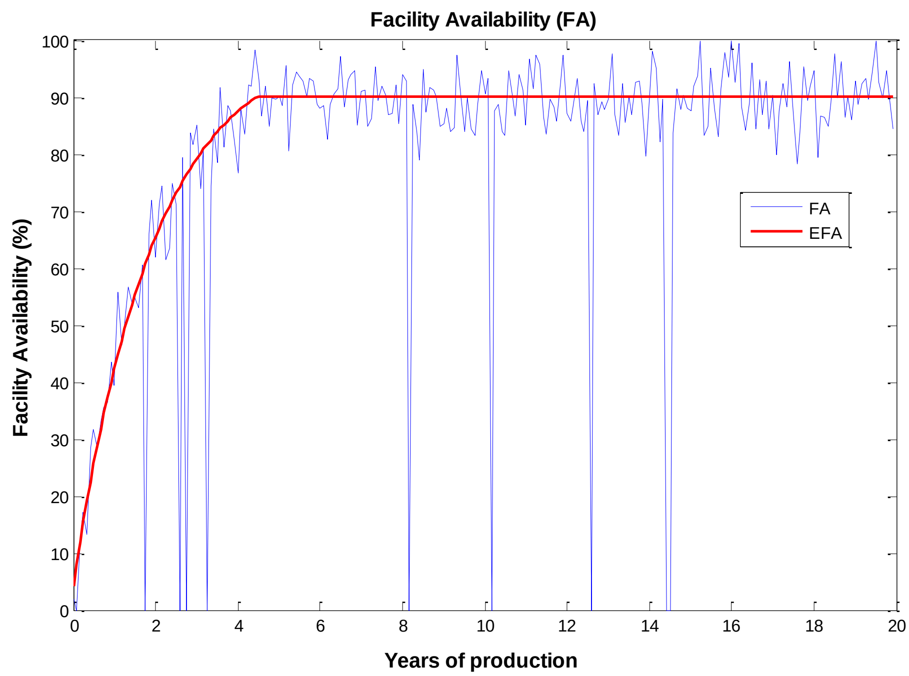

Figure 5: Instantiation of the Facility Availability model over a twenty-year period. The sharp dips represent temporary facility shutdowns

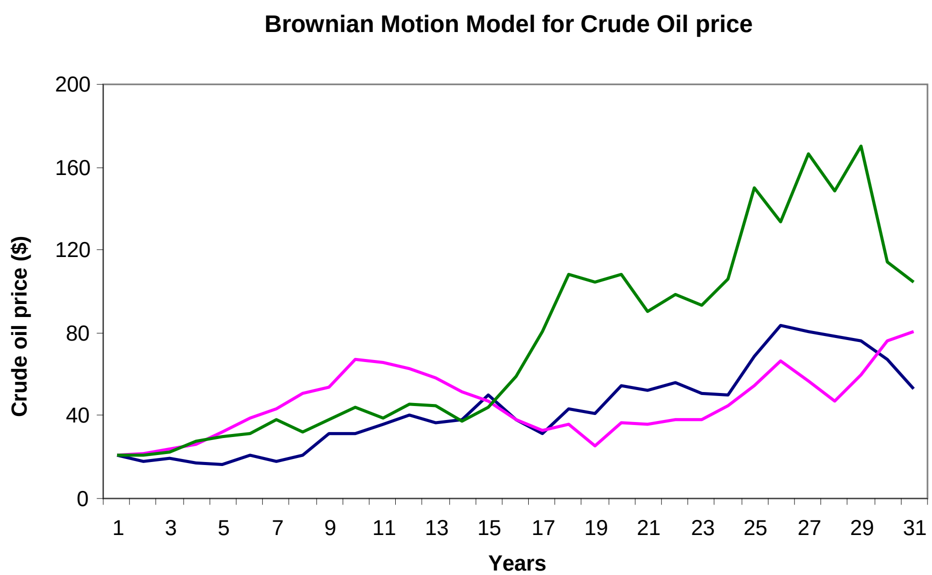

Figure 6: Three Instantiations of the Crude Oil Price over a thirty-year period

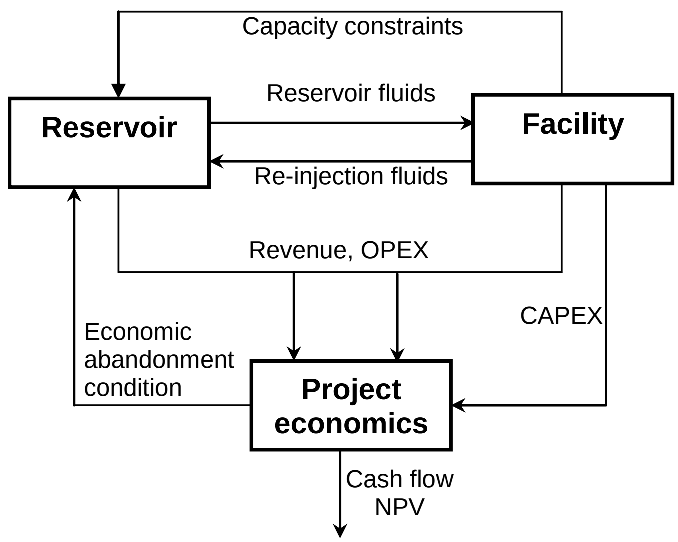

Figure 7: Integrated Systems Model

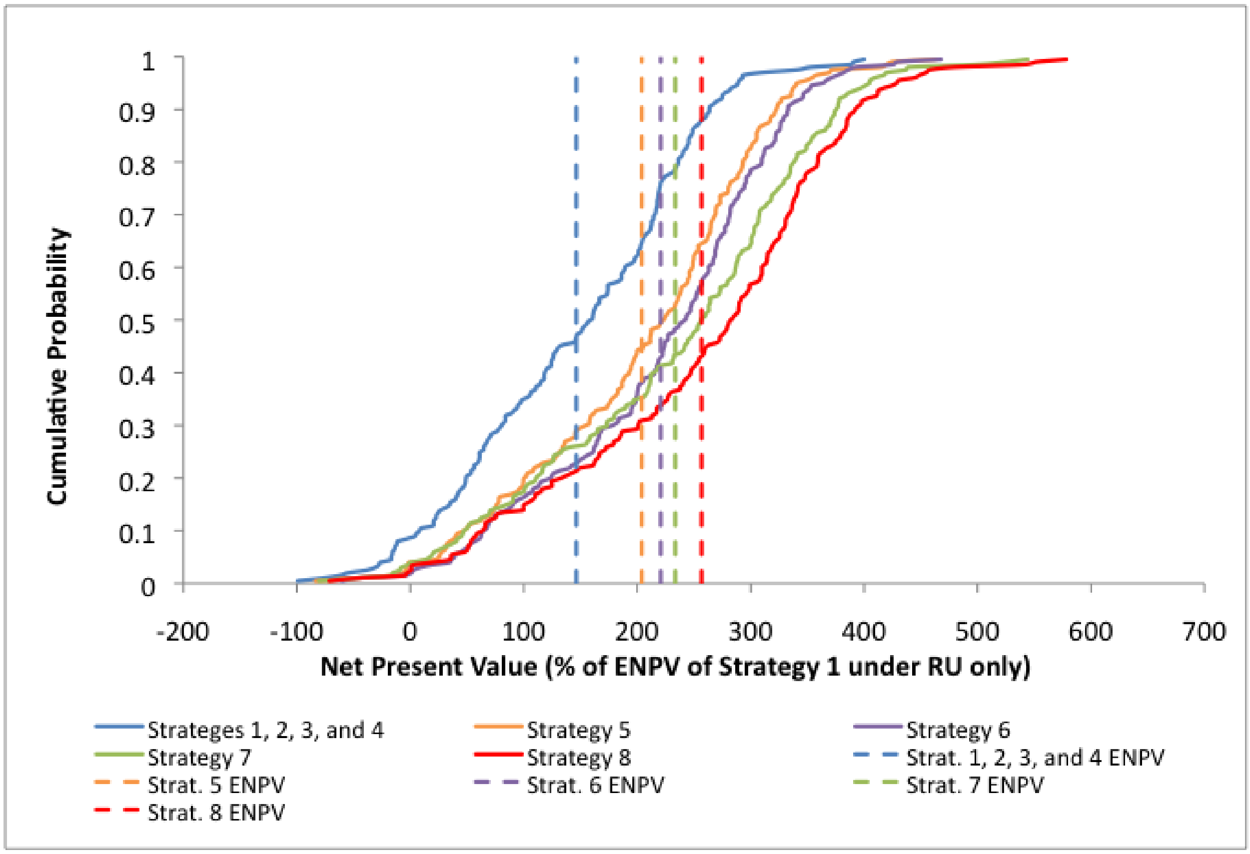

Figure 8: Target Curves for Strategies 1 – 8 under RU, FU, and MU. Vertical dashed lines indicate the expected E(NPV) of the corresponding strategy.

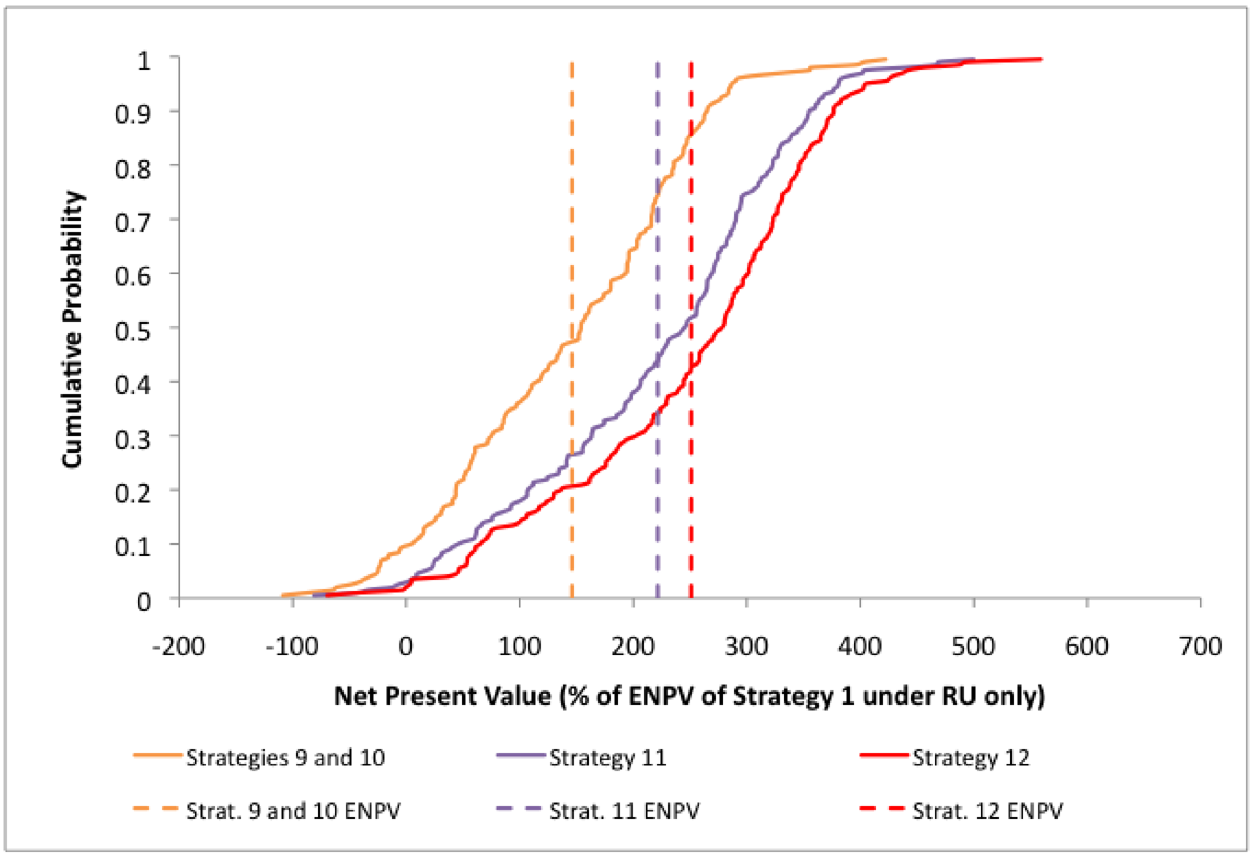

Figure 9: Comparison of Target Curves for Strategies 9 and 10 (identical) and Strategies 11 and 12 under RU, FU, and MU

Tables

Table 1: Three Types of Uncertainty

Type of uncertainty	Evolution of the uncertainty from the perspective of		Examples in petroleum project	Uncertainty modeling and simulation approaches
	Decision makers	**System designers and planners**		
Endogenous	can be actively influenced or managed	depends on system designs and development plan, or is influenced by appraisal activities	Drilling, surface facility uncertainty, subsurface uncertainty (epistemic)	Probability modeling of parameters for technical systems, Bayesian learning model
Exogenous	independent of any project decisions	independent of system designs and development plans	Market uncertainty: i.e., market prices for hydrocarbon products (aleatoric)	Geometric Brownian Motion (GBM), Lattice model, Monte Carlo simulation
Hybrid	can be partially influenced by design choice	partially dependent on system designs and development plans	Development uncertainty: cost, schedule, contract -- jointly influenced by technical and market uncertainties, well performance -- jointly influenced by technical and subsurface uncertainties.	Monte Carlo simulation, discrete event modeling, signal flow graph method, System Dynamics, Design Structure Matrix

Table 2: Definition of Flexible Strategies

	Tieback Flexibility	**Capacity Expansion Flexibility**	**Active Reservoir Management (ARM)**
Strategy 1	not enabled	not enabled	not enabled
Strategy 2	not enabled	not enabled	enabled
Strategy 3	not enabled	enabled	not enabled
Strategy 4	not enabled	enabled	enabled
Strategy 5	enabled	not enabled	not enabled
Strategy 6	enabled	not enabled	enabled
Strategy 7	enabled	enabled	not enabled
Strategy 8	enabled	enabled	enabled
Strategy 9*	not enabled	not enabled	not enabled
Strategy 10	not enabled	not enabled	enabled
Strategy 11	enabled	not enabled	not enabled
Strategy 12	enabled	not enabled	enabled

*Strategies 9 – 12 have an initial CPF capacity of 175 mbpd while strategies 1 – 8 have an initial CPF capacity of 150 mbpd with the flexibility to expand to 200 mbpd.

Table 3: Summary of Statistics for Strategies 1 – 12 under RU, FU, and MU

	NPV (% of ENPV for Strategy 1 with RU only)				Capital Expenditure (% of expected capital expenditure for Strategy 1 with RU only)			Expected total reserve[&]	Expected # of tiebacks
	Exp.*	Min	Max	Std.[#]	Exp.*	Min	Max		
Strategy 1	146	-99	400	100	100	100	100	100	0.0
Strategy 2	146	-99	400	100	100	100	100	100	0.0
Strategy 3	146	-99	400	100	100	100	109	100	0.0
Strategy 4	146	-99	400	100	100	100	109	100	0.0
Strategy 5	204	-83	463	104	131	93	161	146	3.8
Strategy 6	221	-60	468	102	131	93	161	146	3.8
Strategy 7	234	-81	544	123	166	106	193	178	6.3
Strategy 8	257	-71	578	125	166	106	193	178	6.3
Strategy 9	144	-109	422	104	103	103	103	100	0.0
Strategy 10	144	-109	422	104	103	103	103	100	0.0
Strategy 11	222	-81	500	115	155	109	185	172	5.7
Strategy 12	251	-70	559	117	155	109	185	172	5.7

* Expected

[#] Standard Deviation

[&] % of expected reserve for Strategy 1 with RU only

Table 4: Main Effects and Interaction Effects on ENPV

	x_1 (value of tieback flexibility)	x_2 (value of capacity flexibility)	x_3 (value of ARM Flexibility)	x_1x_2	x_1x_3	x_2x_3
Main effects or interaction effects (%)	83	16.5	10	16.5	10	1.5

Table 5: Global Sensitivity on Cost of Tieback Flexibility (Strategy 5, RU only)

	Strategy 5 (% of ENPV or Expected CAPEX of strategy 1)					**Strategy 1**
Cost of tieback flexibility (% of the initial SURF cost of strategy 1)	0%	5%	**10%**	20%	30%	
Cost of tieback flexibility (% of the total CAPEX of strategy 1)	0.0%	2.0%	**4.1%**	8.1%	12.2%	
ENPV	149	140	**132**	115	97	100
Min NPV	28	18	**7**	-14	-36	-66
Max NPV	258	256	**266**	278	267	251
Expected CAPEX	133	136	**138**	144	150	100
Initial CAPEX	64	65	**66**	69	71	64

Table 6: Global Sensitivity on the Cost of Tieback Flexibility (Strategy 8, RU only)

	Strategy 8 (% of ENPV or Expected CAPEX of strategy 1)							**Strategy 1**
Cost of tieback flexibility (% of the initial SURF cost of strategy 1)	0%	5%	**10%**	20%	30%	40%	50%	
Cost of tieback flexibility (% of the total CAPEX of strategy 1)	0.0%	2.0%	**4.1%**	8.1%	12.2%	16.3%	20.4%	
ENPV	198	188	**177**	155	134	112	91	100
Min NPV	43	33	**22**	2	-19	-40	-61	-66
Max NPV	328	327	**335**	315	295	274	253	251
Expected CAPEX	169	173	**177**	185	192	200	207	100
Initial CAPEX	64	65	**66**	69	71	74	76	64

***Highlights**

- An integrated approach to evaluate subsea tieback flexibility under resource, facilities, and market uncertainties.

- Identified and evaluated multi-level flexibility within an offshore development project: strategic level (tieback), tactic level (capacity expansion), and operational level flexibility (production optimization).

- Developed an integrated reservoir, facilities and project economics simulation model and embedded decision making criteria within the simulation engine. Applied Design of Experiment and Monte Carlo simulation techniques to evaluate different development strategies.

- Demonstrated the methodology through an offshore multiple-oilfield development based on a real case off the west coast of Africa. It shows that flexibilities could potentially enhance the project's expected NPV by 76%.