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Optimum Offshore Gas Asset Development Planning with Simultaneous Subsurface and Surface Modeling and Simulation

Abstract

We develop a case study planning process by using a strategy for balancing reservoir uncertainties (rock properties), optimum field development scenario (rate schedule and start time) and associated risks in the capital expenditures (price inflation and discount factor). The objective of this development is to recover dry gas reserves from five recently discovered fields in the most cost-efficient manner.

The methodology has proven to optimize capital investment, by selecting an optimum scenario, namely one that best balances risk and uncertainty, and maximize asset profitability. Faster decision making process is enabled by a series of key digital oilfield components, such as an integrated framework for multi-disciplinary (geology, reservoir and production engineering) and multi-scenario modeling and optimization, and the potential for continuous real-time adaptation of the development plan to prevailing reservoir and market conditions.

Introduction

Operators face typical realities at the time of exploiting oil and gas fields (Saputelli *et al.*, 2000). Well construction and maintenance costs almost always account for at least 50% of the total field exploitation capital and operating expenses. Frequently though, the planned costs and execution times deviate from actual ones because of inadequate project front-end-loading.

Additionally, because of the complexity and ambiguity of such operations, simultaneous modeling and simulation of reservoir, wells and surface facilities plays one of the most important roles in the planning, design, construction and operation of any hydrocarbon producing asset. Project outcomes and operations are affected by a number of market, surface and downhole conditions and uncertainties. Early identification and control of those risk and uncertainties may save time and money for every asset.

An integrated framework for multi-disciplinary and multi-scenario modeling and optimization (Cullick *et al.*, 2003), decision support environment can help decision-making based on fresh information, especially around the drilling and production process, however to create the maximum value from such an environment, it is imperative to spend the time and resources to create solid planning. Planning allows the operator to load, at any time, planned scenarios that correlate to the situation at hand. So, at the moment that a hard decision must be faced by the manager, operator, or team, the pre-planned information is immediately at hand to aid in the decision—increasing the likelihood of making the best decision possible.

The integrated framework presented in this paper will facilitate the decision-making process by continuous update of multiple asset models with real-time acquired information and through permanent adaptation of the development plan (well location and production targets) to prevailing reservoir and market conditions (Escorcia *et al*., 2004).

In this work we present a summary of experience in planning well and facilities construction for developing several recently discovered Tertiary gas assets in Litoral Tabasco business unit, in the SouthWest Marine Divisional Region (RMSO) of PEMEX Exploration and Production (Solis *et al*., 2004).

Several uncertainty-driven development scenarios were analyzed by considering current infrastructure, required pipelines and installations, development drilling and the construction of field infrastructure for Hap-Akpul, Uchak and Chukua-Isiw fields. Initial production is expected by summer 2006.

Project is grouped into three “investment units” (IU’s): (1) Chukua – Isiw field development considers dry gas transport via “Inyeccion de Agua”(IYA) complex; (2) Hap – Akpul field development considers dry gas transport to “Rebombeo” and “Atasta”, and (3) Uchak field development considers dry gas transport to POL-A complex.

Project Description

West-Campeche Tertiary gas project was commissioned for exploring potential non-associated gas in shallow horizons in 2000. Successful activity confirmed new tertiary dry-gas fields (Hap, Akpul, and Uchak). Also in 2002, offshore light-oil reserve replacement project "Litoral Tabasco Marino" permitted the discovery of five additional fields Chukua, Thel, Winak, Kopo and Isiw. Chukua and Isiw are also dry-gas.

Tertiary gas project is located in Gulf of Mexico continental platform, along Tabasco and Campeche states marine coasts, in the Campeche basin, approximately 75 kilometers northeast of Dos Bocas maritime terminal, and between 15 and 90m water depth lines (Figure 1). Tertiary reservoirs exist over traditionally Mesozoic marine producer fields. Therefore, it is possible to use existing infrastructure. The project area Geologically, the project area is within the Marine geological province of Coatzacoalcos Number 44.

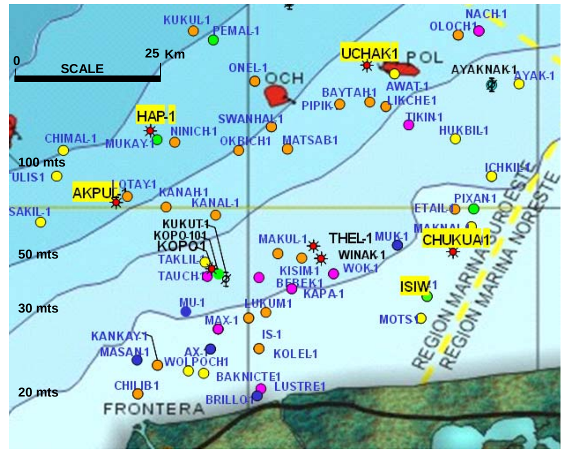

Figure 1 - Project Areas Geographical Region. South limit is the South Region (Pemex Operational Division) and the east limit is given by the Northeast Marine Region (RMNE).

Hap Field

Hap reservoir rock is conformed of sandstones and very fine grain detritus translucent quartz sandstone, sub-rounded and sub-angled, well-sorted, sub-mature, well-consolidated with cementing shaly-calcareous materials (Figure 2). Total depth ranges from 1680 to 2020m; reservoir age is Recent-Pleistocene.

The discovery well, Hap-1, was tested within the 1680-1695m interval, on a ¾" choke, and produced 25 MMSCF/d of dry gas (99.5% CH_4) with 540 psia at the wellhead. Reservoir pressure was calculated to be 2791 psia with a flow capacity of 21,100 md-ft.

Akpul Field

Akpul is conformed by two producing horizons. The first horizon's top is at 2780m, and the second is at 2965 (Figure 3).

The discovery well, Akpul-1, was tested within the 2965-2985m interval, on a ¾" choke, and produced 31.8 MMSCF/d of dry gas (99.8% CH_4) with 3507 psia at the wellhead.

Reservoir pressure was calculated to be 4,430 psia with a flow capacity of 5,800 md-ft.

Chukua Field

Chukua is a NE-SW oriented low-dip structure, limited by a north-west normal fault which bounds the dry gas reservoir. Reservoir rock is fine grain quartz sandstone, lightly calcareous, deep marine turbidite facies (Figure 4). Total depth ranges from 2000 to 2700m, reservoir age is Recent-Pleistocene, and tramp type is structural-stratigraphic.

The discovery well, Chukua-1, was tested within the 2044-2049m and 2539-2547m intervals, on a ¾" and ½" chokes, and produced 20 and 16 MMSCF/d of dry gas (99.65% CH_4).

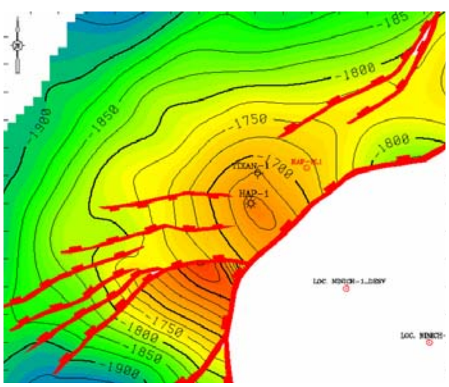

Figure 2 - Hap Field - Shallow Producing Interval Top Structure

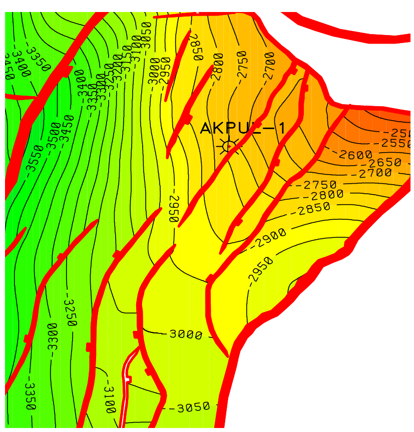

Figure 3 - Akpul Field - Shallow Producing Interval Top Structure

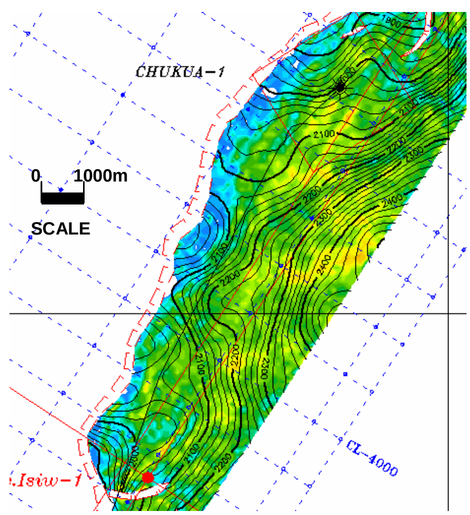

Figure 4 – Chukua Field - Shallow Producing Interval Top Structure

Field Development Strategy Options

The option to re-use existing facilities (pipelines and process facilities) became known from the initial analyses (PEMEX, 2004). In this sense, some existing gathering facilities would be used in the project development options: (1) "Inyección de Agua (IYA)" Complex, (2) Rebombeo Complex and Atasta Terminal and (3) Pol-A Complex. Use of existing infrastructure will allow flexible operation to distribute the produced dry-gas for different needs: pneumatic pump network, fuel gas, external customers, etc.

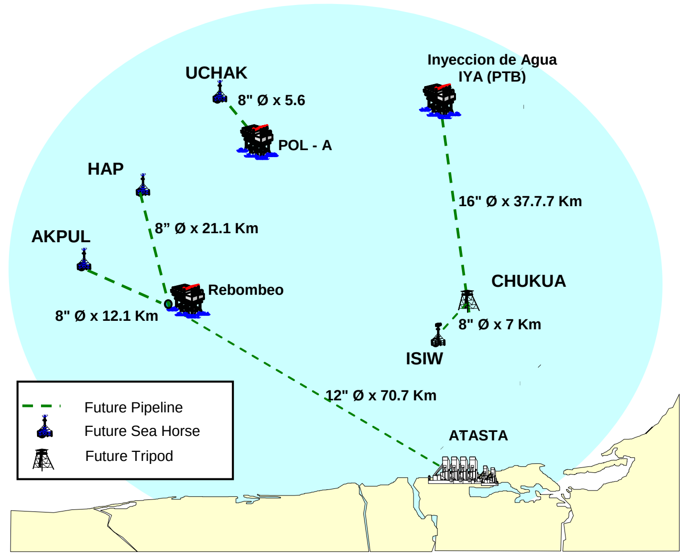

Figure 5 - Project Areas Infrastructure

Investment Units (IU's)

Project is grouped into three "investment units" (IU):

1. Chukua – Isiw field development considers dry gas transport via "Inyeccion de Agua" (IYA) complex.
2. Hap – Akpul field development considers dry gas transport to "Rebombeo" and "Atasta".
3. Uchak field development considers dry gas transport to "POL-A".

Base Case Production Forecasts

A base case scenario was available prior to this multiple scenario modeling study. Figure 6 shows the contribution from four gas production trends, (Isiw production included in Chukua figures). Project horizon was established to be 12 years.

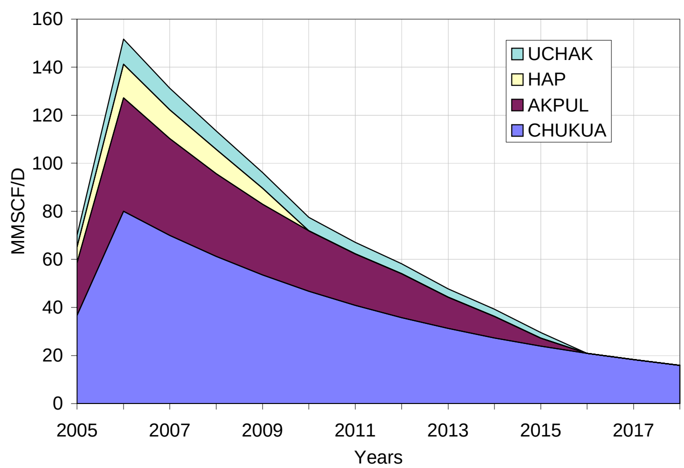

Figure 6 - Production Forecast for the Base Case Scenario and Four Gas Fields (Hap, Akpul, Uchak and Chukua)

Multi-scenario Modeling and Planning

In planning and developing a number of hydrocarbon fields, operators face a number of questions which will influence the decision points. These questions are:

1. How will reservoir property uncertainties affect the gas supply for the period specified?
2. How will those properties affect project economics?
3. Do we know the associated risks of the investments?
4. Which information is more critical for success?
5. What is the optimum development scenario?

Multi-scenario Modeling and Planning Process Overview

A multi-scenario modeling and planning process, based on recently developed Java-based software [Landmark, 2003] was used for uncertainty and scenario analysis in the Tertiary Gas Project field study. The foundation software manages uncertainty and alternatives across multiple disciplines like geological modeling, well planning, surface development alternatives and economics. The process maintains high fidelity to the physics of the flow processes by using a surface and subsurface integrated finite-difference flow simulator [Landmark, 2002] to generate the production profiles.

Workflow used in Offshore Gas Asset Development Planning with Integrated Flow Simulation

The workflow used essentially consisted of the following steps.

1. Supply geologic model, well count, well schedule and surface pipeline network to integrated flow simulator.
2. Determine uncertainties and decision alternatives to be considered (i.e., rock properties, field scheduling, economics)
3. Calculate production profile from base case scenarios using integrated simulation of reservoir, wells and facility.
4. Generate capital investment profile and supply production profile for different scenarios to economic model and calculate economic results (expense profiles, revenue profiles, cash flows, Net Present Value and rates of return).
5. Run the workflow with all combinations of uncertainties and decision alternatives
6. Save workflow inputs and outputs to a database for analysis
7. Analyze results and determine the best way to develop the reservoir.

Table 1 - Summary of Uncertainty, Scenario and Decision Variables

Uncertainty/Decision	Variable Type of Uncertainty	Probability Density Function
Porosity Multiplier	fraction continuous	Uniform (min 0.8, max 1.2)
Horizontal Permeability Multiplier	fraction continuous	Normal (mean 1, stand. dev 0.1)
Net-to-gross Multiplier	fraction continuous	triangular (min 0.6, mean 0.7, max 0.9)
Well Productivity Index Multiplier	continuous (triangular)	triangular (min 0.5, mean 1, max 1.25)
Well Production Start	scenario (discrete)	Scenario1 (yr1); Scenario2 (yr2); Scenario3 (yr3)
Abandnonment Well Bottohome Pressure (psia)	scenario (discrete)	Scenario1 (400); Scenario1 (600); Scenario2 (800); Scenario3 (1000)
GC Production Targets (MMSCF/D)	scenario (discrete)	Scenario1 (20); Scenario2 (40); Scenario3 (80); Scenario3 (120)
Gas Transport Pipeline Size	scenario (discrete)	Scenario1 (6"); Scenario2 (8"); Scenario3 (12")
Terminal Receiving Pressure (psia)	scenario (discrete)	Scenario1 (200); Scenario2 (400); Scenario3 (600)
Gas Price ($/MSCF)	scenario (discrete)	Scenario1 (2); Scenario2 (3.4); Scenario3 (5)
Discount Factor (%)	scenario (discrete)	Scenario1 (8); Scenario2 (12); Scenario3 (15)
Price Inflation Multiplier	scenario (discrete)	Scenario1 (0.9); Scenario2 (1); Scenario3 (1.1)

The multi-scenario modeling and planning software selects a value for the uncertainty or the decision alternative from its possible values. Possible decision values can be continuous or discrete alternatives. There are multiple ways to select a value from all the possible values. In a Monte Carlo simulation, values are obtained by random sampling from the probability distribution. In this study, all possible combinations of the values were used (i.e. a full factorial design). Each combination of the possible values is referred to as iteration in the subsequent discussions.

A number of reservoir uncertainties were considered for the multiple scenario models. Simple reservoir grid multipliers were used for horizontal permeability, porosity and net-to-gross (Table 1).

Based on the values chosen for the different uncertainties or the decision alternatives for any iteration, the integrated subsurface and surface simulation input files are built by the multi-scenario modeling and planning software by including the correct files for the uncertainties and scenarios. Constraints honoring physical restrictions were used on the wells and surface facilities in all the iterations.

Figure 7 shows a schematic of the coarse grid containing the five numerical gas reservoir models. The grid shows the relative position of the local refinements and pipeline layout. Figure 8 shows the 3D simulation model grid.

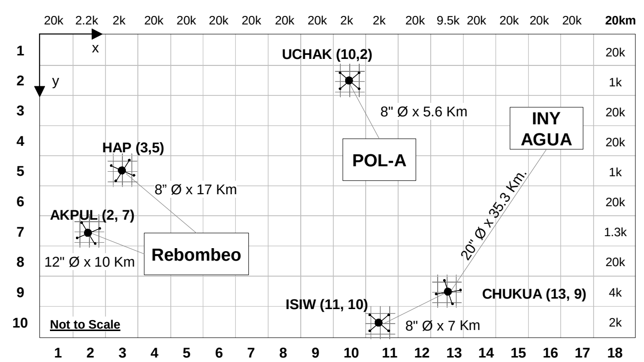

Figure 7 – Simulation Grid Schematic Containing 5 Local Grid Refinements and Surface Pipeline Network Model in 2D views

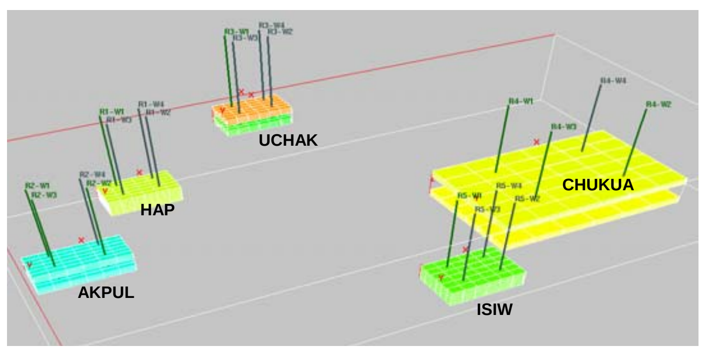

Figure 8 – Numerical Grid Containing Local Grid Refinements for each of the five Gas Fields and possible well locations

A commercial simulator (Landmark, 2003) was used to model, simultaneously, flow both in the subsurface and in surface facilities. Production forecasts were consistent with behaviors reported from nearby gas fields as well as with material balance calculations (Figure 6). Figure 7 shows a schematic of the surface pipeline network model for the base case. Each well has been modeled from the reservoir connection to the well head and the surface gathering centers.

Figure 9 shows the total gas production rate for all the fields (Hap, Akpul, Uchak, Chukua, and Isiw) as results of multiple scenario modeling in the variables described in Table 1, following the procedure described above. Notice the variability in the plateau rate duration period. For favorable reservoir condition cases plateau rate could extend up to 10 years. Notice also the different production yearly decline rates; they can vary from 20% and up to 60% per year. The time to recover all the possible reserves and still be economic can vary from 12 to 18 years. For favorable reservoir condition cases recovery of more tan 90% of the reserves can occur in less than 6 years.

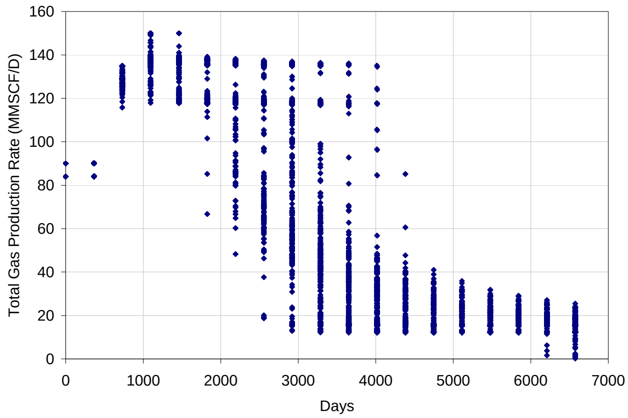

Figure 9 - Gas Production Rate for All Uncertainty Scenarios

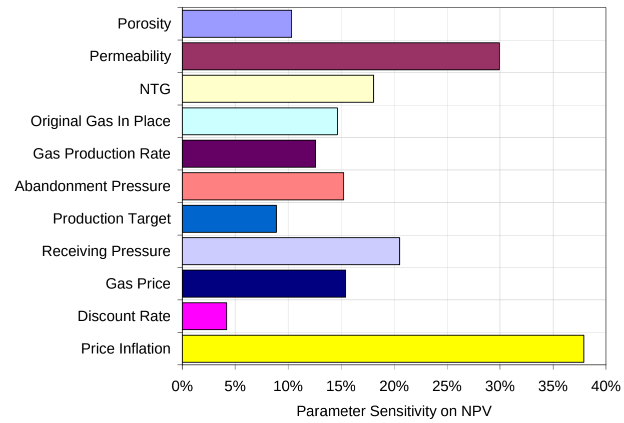

Figure 10 - NPV Sensitivity for all Decision Variables

With all possible scenarios honoring the variability in reservoir properties, exploitation options and market scenarios, there are many opportunities to optimize project outcome. The most technically attractive cases (fastest recovery or long plateau period) do not necessarily correspond to the best economic cases. Parameters sensitivity analysis is paramount for understanding the variability of all modeling parameters and the economic outcome. An autocorrelation of input parameters to project outcomes shows the relative importance of each parameter. Figure 10 shows the parameter sensitivity analysis for all variables described previously. Notice the highest variability in price inflation and permeability models.

Optimum Field Development Planning Process

In all situations the maximum number of possible decision combinations for rate scheduling and the number of wells is practically impossible to simulate. In our case, the number of possible wells to be drilled in each of the 5 units was restricted from 0 to 4, i.e. $5^5 = 3125$. Let's say that any of those wells could be drilled at any time (days or month) from year 1 to year 12, i.e. 365 x 12 = 4380 possible dates. Therefore, the number of required iterations to span the whole solution space would be approximately 13.7 million iterations. Even with a very simple model that takes 1 minute to run, we would require about 5.2 months of continuous computing intensive calculations. Our method took only 4 hours to find the optimum.

Figure 11 describes the workflow of adding a metaheuristic-optimizer (Narayanan *et al.*, 2003) as the engine that selects the best field development options that maximizes an economic value objective function, such as Net Present Value (NPV). The objective function details have been included in Appendix A.

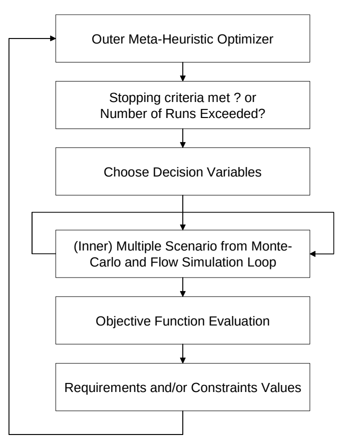

Figure 11 –Optimizer Flow Simulation Loop (Narayanan et al., 2003)

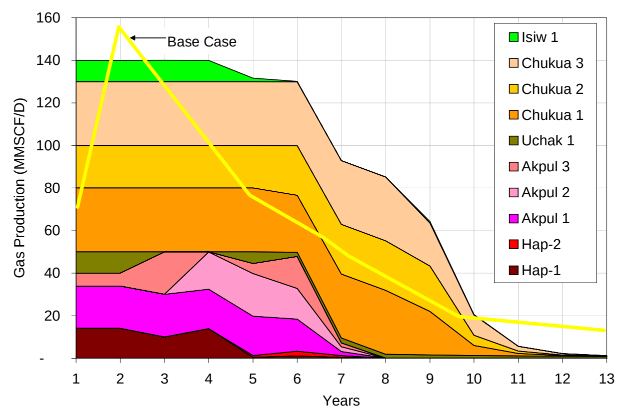

Figure 12 - Gas Production Rate for Optimum NPV Scenario

Figure 12 shows the total gas production rate for all the fields (Hap, Akpul, Uchak, Chukua, and Isiw) as a result of optimized scenario modeling, without considering uncertainty in the variables described in Table 1, following the procedure described in Figure 11; we can see the rate scheduling and the number of wells (number of series is 10) selected by the optimizer. The optimum solution was achieved after 170 iterations. This solution maximizes the net present value of the project and also minimizes the maximum cash exposure, by selecting every well rate and start date. Notice that the variability in the plateau rate duration period has been reduced and is about 4 years. In this case, the objective was to maximize NPV.

Figure 13 shows comparative results on the net present value frequency distribution (FD) and cumulative frequency distribution (CFD) for both the uncertainty and optimized without uncertainty case scenarios. While FD and CFD for the uncertainty scenario are completely scattered and do not show any particular mode or trend, FD and CFD for the optimized scenario shows very little variance and point to a very high NPV value around US$ 360 MM.

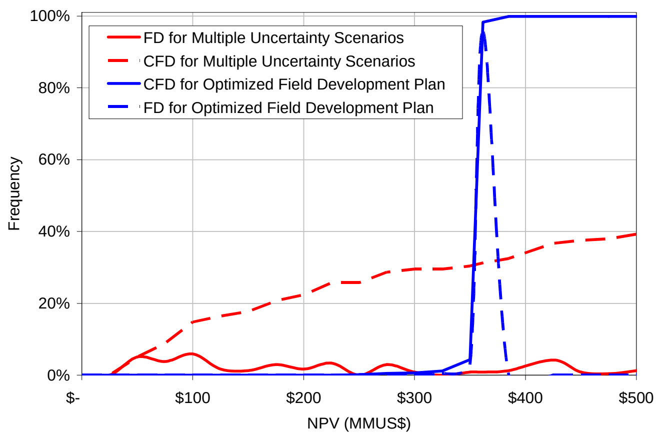

Figure 13 – NPV FD for Uncertainty and Optimized Scenarios

Conclusions and Next Steps

The methodology described in this paper presents a framework for fast and intensive analyses leading to the optimum plan for field development of the Litoral Tabasco gas fields. We have modeled five gas reservoirs and integrated with surface pipeline network models.

We have proven the value that multiple scenario modeling and optimization could bring to the field development planning process of Offshore Gas Asset planning in Litoral Tabasco by: (a) selecting the optimum number of well and rate schedules while (b) understanding physical and economical risk and uncertainties. The next steps are to include detailed reservoir characterization models in to the Monte Carlo loops and incorporate the uncertainty models in the outer optimization loop. Alternative well architecture could also enhance project economics.

The framework presented in this paper will facilitate the decision-making process by continuous update of multiple asset models with real-time acquired information and through permanent adaptation of the development plan (well location and production targets) to prevailing reservoir and market conditions.

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Appendix A - Objective Function and Constraints

Objective function. Maximize mean NPV where

$$\text{NPV}=\sum_t\left[\text{revenue}_t-\text{cost}_t\right]\left[(1-\tau)(1-\rho)\right]$$

$$\text{cost}_t=\left[(1/(1+i)^t\right]\times\left[\sum_r^R\{W_r\times C_{w,r}+C_{f,r}\}+\sum_p^3 C_p\times Q_p\right]\text{and}$$

$$\text{revenue}_t=\left[(1/(1+i)^t\right]\times\left[\sum_p^3 P_r\times Q_p\right]$$

Decision variables. Production start time for each reservoir unit $y_{t,r}\in\{0,T\} \quad \forall \quad r\in\{1,R\}$, and number of wells for each reservoir unit, W_r are the decision variables in the optimization scenario case.

Constraints. Logical and production constraints are present.

- Reservoir or well can only start at one time
- The maximum gas production rate for each IU
- The maximum gas rate for every gathering center
- Gas limit on each well
- Max number of wells for each reservoir unit
- Minimum outlet pressure at Processing Center
- Minimum reservoir abandonment pressure

Where t = time period (year); T = time horizon in years; r = reservoir unit identifier; y = time at which reservoir unit starts; W = number of wells in reservoir unit coming on-stream; i = discount rate; R = number of reservoir units; w = well identifier; p = fluid phase identifier (oil o, gas g, water w); C = cost – Opex and capex (capital adjusted for depreciation); f = facility identifier; P = price of sales fluid; τ = tax rate; ρ = royalty rate