A NEW GENERATION OF MULTILATERAL WELL ENHANCES SMALL GAS FIELD ECONOMICS

A Thesis

by

JEAN-PHILIPPE ATSE

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2003

Major Subject: Petroleum Engineering

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Approved as to style and content by:

Richard A. Startzman (Chair of Committee)	Peter P. Valkó (Member)
John Leggett (Member)	Hans C. Juvkam-Wold (Head of Department)

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ABSTRACT

A New Generation of Multilateral Well
Enhances Small Gas Field Economics. (December 2003)
Jean-Philippe Atse, B.S., INP-HB/ESMG;
Chair of Advisory Committee: Dr. Richard A. Startzman

The main objective of this study is to investigate the applicability of a new multilateral well architecture in the domain of small size and offshore gas fields.

The new architecture completely reverses the current multilateral technology. The innovative concept suggests that laterals can be achieved like any conventional wells. They could be drilled from the surface and tied back to a common wellbore referred to as the mother well. Production would go through the toe of laterals into the mother well. The mother well could be as simple as a large diameter casing equipped with prepared connections to tie in feeder wells.

This study looked past the mechanical challenge of achieving the new architecture. I demonstrated important benefits in terms of cost reduction, well completion and operations, and reservoir drainage.

I looked at a typical field case, Phoenix, located in West Africa. Its actual development plan targets an ultimate recovery of 600 BCF with a total of four sub-vertical wells. I implemented a new development scenario with the innovative multilateral architecture. For comparison purposes, I achieved a reservoir simulation and a production forecast with both scenarios. The only simulation variable was the well architecture definition.

As a main result, the new multilateral structure could produce as many as four vertical wells with three slim-hole laterals.

I achieved a quantitative risk analysis on both development plans. I assessed the development cost of each scenario and performed a Monte Carlo simulation to account for cost uncertainties.

In addition to the actual 70 MMSCFD gas contract, I simulated a progressive gas demand increase of 20 MMSCFD every five years and a 150 MMSCFD gas market.

The study demonstrates the economic benefits of the new technology in the domain of offshore and small gas fields. This work also shows that this new generation of multilaterals brings new option values to the domain of multilateral technology.

DEDICATION

This thesis is dedicated

to my father ***Pierre Katou****, and my mother* ***Nicole Thouron****, whose love, and support made my studies a success;*

to my sister, ***Géraldine****, whose love and encouragement made this effort easy;*

and to my brother, ***Alexandre*** *for his love.*

ACKNOWLEDGEMENTS

I would like to express my sincere appreciation and gratefulness to Dr. Richard A. Startzman, chair of my advisory committee, for his permanent involvement and guidance through the completion of my studies and research.

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I am also very thankful to James R. Longbottom, for his special help and support of this research.

Moreover, I would like to express my sincere gratefulness to Gérard Hautavoine, Gourenne Zadi S. Levi, Allangba Faustin, Kodjo Arthur, Ahipo Albertine, and Soro Sekou for authorizing a data confidentiality agreement between Texas A&M University and their respective companies. This project would have not been possible without their support.

Finally, I would like to express my deep gratitude to the Ministry of Mines and Energy of Côte d'Ivoire and Vanco Energy Company for sponsoring me. Especially, I would like to thank the Minister of Mines an Energy of Ivory Coast, and his main collaborators: the Office Manager, the Hydrocarbon Manager, and the Formation and Education Manager. A very special thank also to Steve Thornton, Phil Dimmock and Nguyen Thu at Vanco Energy Company for their continuous support.

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CHAPTER I

INTRODUCTION

1.1 Overview of Multilateral Wells (ML)

1.1.1 Historical Review

Russian engineers implemented the first multilateral well (ML) in the 1950's as a development of drilling practices. Since then, the technology has advanced quickly and spread worldwide. In 1995, Phillips Petroleum completed the first trilateral in the North Sea. In 1996, Norsk Hydro completed the first successful Level 5 ML in the Oseberg Field, North Sea. In 1998, Shell successfully completed the first Level 6 (see **Table 1.1**) ML in California [24].

ML technology continues to be improved and is expected to lead to tremendous changes in oil and gas operations for the next 5 to 10 years [2].

1.1.2 General Definition

The TAML [23] group (Technical Advancements of Multi-Laterals) defines multilaterals or multilateral wells as:

> Wells having one or more branches (laterals) tied back to a mother wellbore, which conveys fluids to or from surface. The branch or lateral may be vertical or any inclination up to or greater than horizontal. (**Fig. 1.1**)

This thesis follows the style of *SPE Journal.*

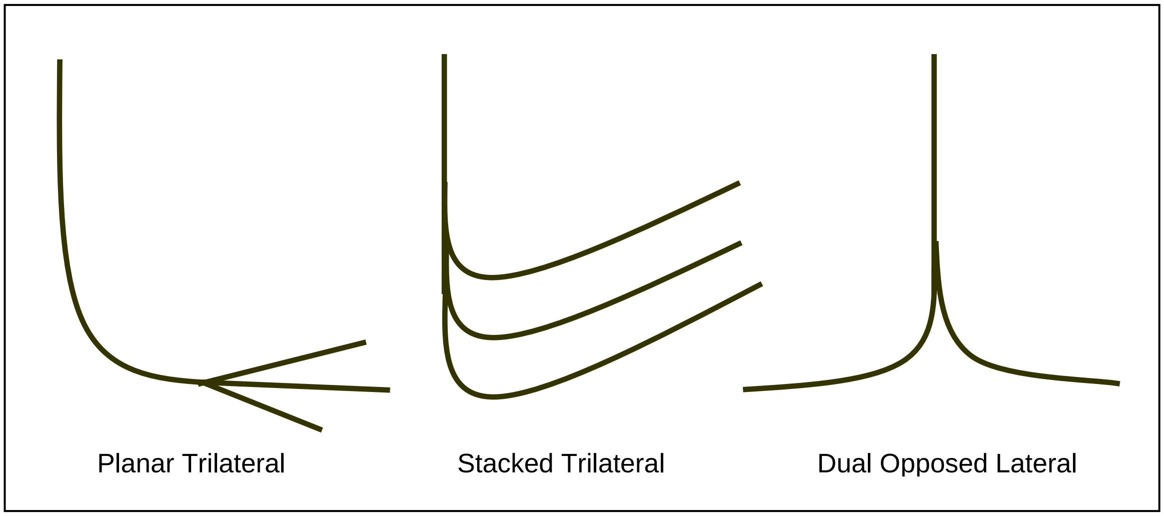


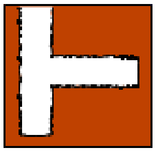
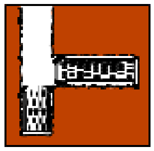
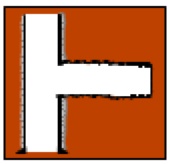
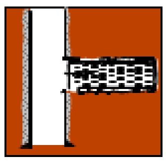
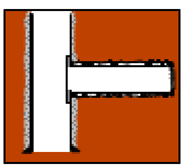
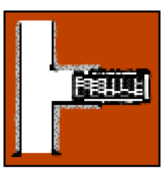
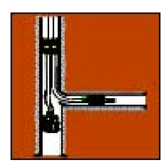
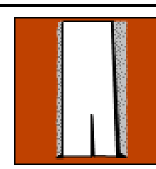
Fig. 1.1 - Examples of multilateral wells currently used – after 24

The number of laterals is described as dual lateral, trilateral, quadrilateral, etc. ‘Stacked’, ‘Planar’, ‘Opposed’, ‘Y-Well’, etc generally describe the geometry of multilaterals.

1.1.3 TAML Classification System

The level of a multilateral refers to the complexity of the junction and its properties. TAML classification [23] reports six levels of multilateral junction.
In general, cost, complexity and risk increase as the level increases. The highest level of junction defines the level of a multiple junctions well (**Table 1.1**).

Table 1.1 - TAML Classification System [23]

1	**Open / Unsupported Junction** Barefoot main bore & lateral or slotted liner hung off in either bore  or 	
2	**Main bore Cased & Cemented, Lateral Open** Lateral either barefoot or with slotted liner hung off in open hole  or 	
3	**Main bore Cased & Cemented, Lateral Cased but Not Cemented** Lateral liner anchored to main bore but not cemented at junction  or 	
4	**Main bore & Lateral Cased & Cemented** Both bores cemented at the junction  or 	
5	**Pressure Integrity at the Junction** Achieved with the completion, i.e. straddle packers (may or may not be cemented)	
6	**Pressure Integrity at the Junction** Achieved with sealed casing (cement alone is not sufficient). Includes reformable junctions and non-reformable, full diameter splitters that require larger diameter wellbores	

1.1.4 Drivers for Multilateral Technology

Primary drivers for considering ML technology are business drivers [2], [3]. All multilateral projects will have a combination of drivers specific to the field application.

Business drivers for ML are [2], [3]:

- Cost Reduction

  One key driver of ML technology is CAPEX reduction. Drilling cost, i.e. cost of drilling, casing and cementing to top of zone and mobilization/demobilization costs, are substantially reduced considering the fact that one ML well may be equivalent to several conventional wells (monobore completions). For instance, a ML well can contribute up to twice the production but only 1.5 times the cost of a monobore completion.

- Increased Reserves

  ML may allow recovery of substantial reserves in isolated lenses of pay or compartmentalized reservoir. These marginal reserves would be non economic on a separate basis.

- Accelerated Recovery

  Drainage optimization is especially important when price per barrel or OPEX is high. ML drilled in the same horizontal plane or vertical plane when Kv/Kh is low accelerate production.

- Platform Slot Conservation

  The value of a slot can range from thousands of dollars to the value of unrealized projects due to slot limitation. ML technology allows a maximum number of reservoir penetrations with a minimum number of wells, increasing production per slot thus reducing capital cost per barrel.

1.1.5 Potential Disadvantages and Limitations of Today's ML

- System mother well – lateral highly interdependent

  This is one of the key issues when dealing with multilaterals. The fact that today's technology allows laterals drilling only from the main bore has a tremendous limitation on ML use:

  - Risk of drilling operations and well control issues: one lateral puts the overall structure at risk.
  - Diameter limitation: the main bore diameter does limit not only the lateral diameter but the tools and completion system that production through laterals may require.
  - Well intervention limitation: they require reentry capability through the main bore and a minimum Level 4 junction. Intervention on one lateral stops the overall production thus delaying incomes.
  - Rigid, heavy and costly drilling program: heavy duty rigs are required to drill big monobore and laterals in deep offshore. The drilling program is not flexible as far as the drilling sequence of laterals is concerned.
  - Concentrated investment and economic risk: as a result, huge investment up to 1.5 times the cost of a simple monobore completion may be required at a time.

Other factors do not play in favor of ML use. Among these, there are:

- High complexity of lateral completion and junction: needs special design consideration
- Additional Risk due to additional risk operations
- Logistically (design, engineering, equipment, qualified more demanding than , especially offshore
- ML still considered as a new technology [23, 24]
  Lack of experience tends to increase operational risks and reduce thereafter the use of the technology.

In response to some of the limitations of today's ML wells and driven by cost reduction and new option values, a new concept of ML well was invented[1]. This concept attacks the Achilles heel of current ML: it allows the laterals to become independent of the main wellbore.

[1] Invented by Jim Longbottom, US Patent 6199633, [28]

1.2 Introduction to a New Generation of Multilateral Wells

1.2.1 Well Scheme and Main Design

In any ML operation, laterals are branches drilled from the main producing wellbore. The new idea[1] completely reverses this concept and proposes to drill laterals from the surface, like any other wells, and ties them back to the main bore. In that case, we can view the main bore as a collector pipe buried underground at reservoir level (**Fig. 1.2**)

In the following, mother well or main bore refers to such a collector well with the following features:

- **Horizontal well**
  In this study, the proposed architecture perceives the mother well as horizontal. Nothing however prevents a design in which the main bore would be vertical or deviated.

- **Drilled at reservoir depth and most likely through the formation of interest**
  The mother well could be the result of an exploratory well.

- **A large diameter well, most likely greater than 6" to handle high flow rates**.
  Depending on the target rate, one key parameter for optimization will be the mother well diameter. A small radius may result in poor production capabilities while drilling and casing costs will limit the actual well diameter.

- **Cased and cemented with prepared connection to safely tie back the laterals**.
  These prepared connections are enabled by current Level 6 ML technologies: the junctions basically are specialized casing joints with two casing legs extending below the manufactured junction assembly. They ensure hydraulic

isolation at low cost and less operational risks [21]. To date, we don't know if such system has been tested on any horizontal wells.

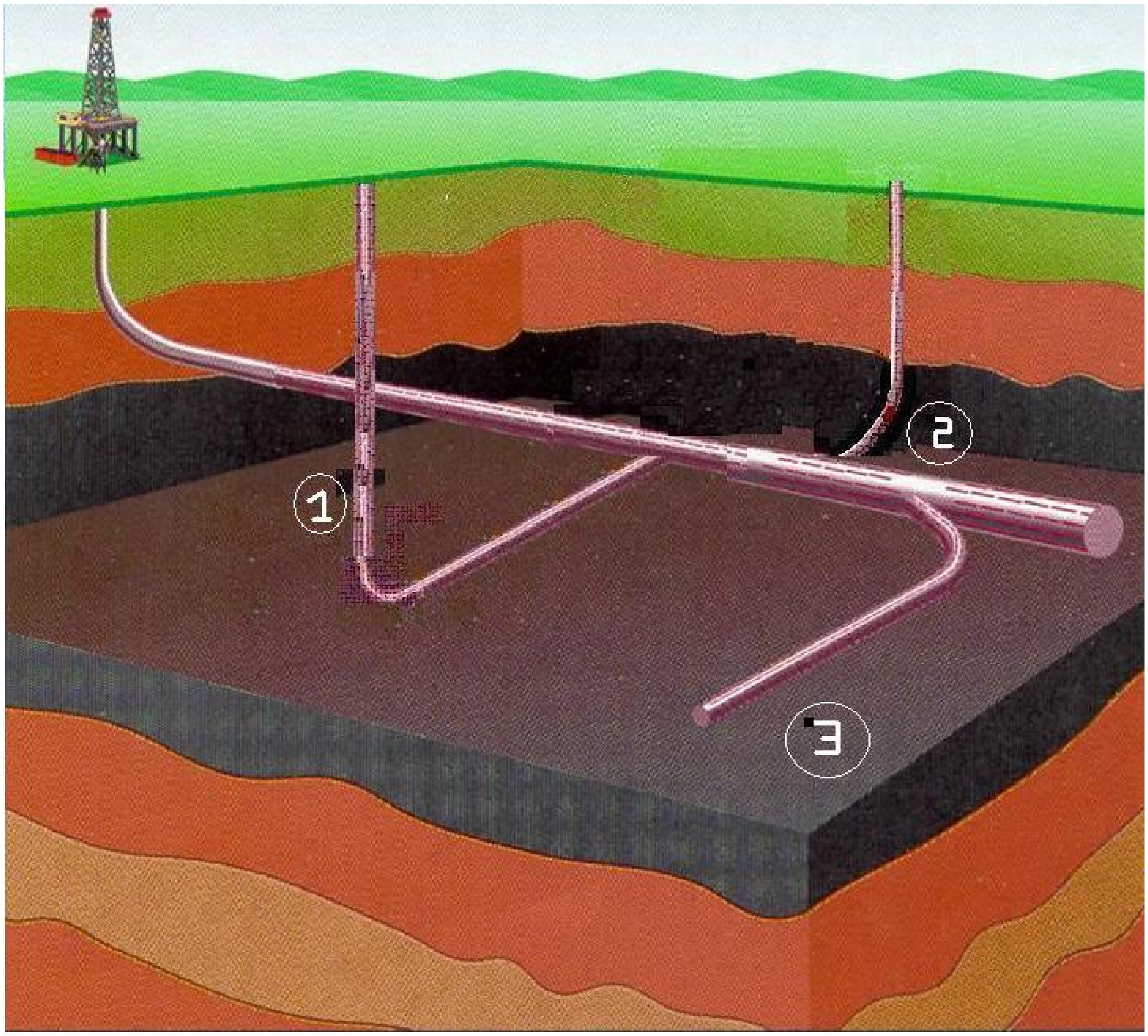


Fig. 1.2 - The new well architecture introduces feeders (1 &2) drilled from surface as opposed to a conventional lateral (3) achieved from the main bore

- **May not be perforated.**

  Without perforation, the mother well is no more than a collector pipe buried underground, instead of lying on the sea floor.

  Nothing however prevents the perforation of the main bore as any conventional horizontal well.

Once tied back to the mother well, the laterals or feeders achieve production through their toes into the main bore. That is as if they were standard well branches.

The fact that production from laterals flows directly into the mother well, even though they are drilled from the surface, presents interesting features. In doing so, laterals can have the following features:

- **Slim-hole well if economical and desired**

  A low pressure drop is expected if production goes through the toes only. Therefore, as the well design aims at the lowest cost, a 2” to 3” final hole might be desired. However, slim-hole tools tend to be more expensive than conventional tools. This will result in an optimum economic design for feeders.

- **No need for tubing and trees since no surface production is expected**

  Obviously, this feature results in a very low cost feeder well.

As introduced, the new well architecture presents very attractive features. Yet, we perceive a lot of other advantages over conventional architectures, including horizontal and current ML.

In the following, new well architecture refers to a ML structure such as I described above (**Fig. 1.2**), that is feeders drilled from surface and tied back to a horizontal main bore. On the contrary, conventional wells refer to current ML wells, vertical or horizontal wells.

1.2.2 New Well Architecture Advantages

The new architecture takes advantage of both current ML technology and standard drilling and completion operations.

- In terms of reservoir drainage, the new concept can be compared to any other ML technology. It is a reservoir technology first. Besides, it is also motivated by the same business drivers as current ML architectures:

    - Cost Reduction
    - Platform Slot Conservation
    - Increased Reserves
    - Accelerated Recovery

- Laterals are drilled separately from the main bore like any standard well. This fact attacks the Achilles heel of current ML technology:

    - Drilling and operations on any lateral puts almost no risks on the overall structure. The junction occurs in a well known zone. Any well control issue is contained to the lateral only.

    - Feeders require standard completions and standard drilling operations (up to the connection).
      As a result, laterals can be equipped with cheaper completions than what current ML would require. If needed, current smart completions can be easily run.

    - Well intervention and treatments on lateral become standard.
      This should lower operating cost of ML wells.
      Intervention on feeders does not interrupt production. Laterals can be stimulated, treated, and then plugged back to the mother well before

production actually starts. If needed, laterals can be accessed trough their own bore, such access does not interfere with production.

    - The new structure enables a flexible drilling program for laterals, as required by a proper reservoir management. Additional feeder drilling does not interfere with existing production. We expect important benefits on projects economics since this allows investments to be delayed, thus reducing economic risks and increasing project present values.

- Production goes through the toes directly into the mother well.
  This has significant advantages:

    - The new well architecture enables slim-hole technology and can take advantage of its low cost. In deep offshore for instance, coiled tubing seafloor drilling might become a tremendous source of saving

    - Laterals need neither tubing nor tree.
      As a result, we expect between 30% and 40% reduction of drilling costs compare to a conventional well with surface production.

We also foresee other significant advantages of the proposed architecture with fluid collection occurring at reservoir depth.

- Reduction of the number of surface or seafloor flowlines and equipments.

- Reduced environmental footprint, with feeder well collected into a common production well.

- Flow assurance issue partly solved.
  Since fluid transportation occurs at reservoir temperature and pressure, risks of hydrate formation or wax deposit have less impact on project economics.

All of these considerations have an impact on the evaluation of such architecture. A significant portion comes from new option values the new ML design offers. Reduced and delayed investments are part of its tremendous value.

1.2.3 Limitations of the proposed ML architecture

- Drilling and operational challenges

Huge technical challenges remain. Even tough this study does not focus on the mechanical and drilling issues, we are aware that they tend to increase the operational risks. However, such new technology if well implemented will beneficiate from quick learning process, which in turn will gradually minimize implementation risks.

- Practical length of the mother well

This limits the number of possible connections to laterals. As a result, optimum well spacing might not be achievable.

- Cost of mother well

This will drastically increase with increases in wellbore diameter

- Mother well might limit production capacity with feeder wells deliverability exceeding its outtake capacity.

1.3 Research Objectives

It is expected that the applicability of the proposed ML architecture ranges from deepwater, to artic, to heavy oil, to general EOR applications for both oil and gas reservoirs.

The main objective of this study is to investigate the applicability of the proposed new well architecture as an alternative to the development of a small size offshore gas field. In that exercise, I will look at a typical field case, Phoenix, for which our research group has signed a confidentiality agreement with cooperating operators.

The project looks past the mechanical challenge of achieving the new structure (Appendix C).
In doing so, the research focuses on two main sub-objectives:

- Investigate the potential reservoir benefits of the new ML well
- Investigate cost reductions impacts as the main economic driver of the new well architecture.

1.4 Research Methodology

To reach these objectives, I first choose to evaluate and compare production performances of both development scenarios. That is the actual development plan with four vertical wells versus the new ML well scheme.
In doing so, I followed the following steps:

1. Build an accurate reservoir model of Phoenix Field, i.e. calibrate its reservoir properties by history matching. For this purpose, I used the Computer Modeling Group (CMG) black oil simulator IMEX.
   Once calibrated, the reservoir properties and production constraints remain fixed in the study. The only simulation variable is therefore the well architecture definition.

2. Forecast Phoenix production performances with its actual development plan.
   The forecast includes new well location and production schedule, and recommends tubing size for optimum gas deliverability.

3. Implement and recommend a design for the new ML well architecture. This includes number of laterals, location, length and radius of feeder wells and mother well.

4. Forecast Phoenix production performances with various design options of the new well architecture.

Phoenix Field is subject to a “take or pay” type of gas contract. As a result, I evaluate the performances of the two well schemes by focusing on the maximum period of time during which the contract is respected.

After I have selected a design for each development options and forecasted their production performance by simulation, I need to evaluate each plan through an economic analysis.
Since there are a number of unknowns in terms of cost, I choose to perform a quantitative risk analysis on both actual and new plans. Not only, this allows consistency when comparing the various development schemes, it also capture large uncertainties associated with the implementation of the new structure.
In doing so, I followed the following steps:

- First, I assessed the development cost of each scenario.
  I based my estimation on a West Africa cost database available through FieldPlan. FieldPlan is an early economic assessment tool that provides real time economic assessment through a worldwide web database.

- Second, I performed a Monte Carlo simulation to account for investments and new well cost uncertainties.
  Basically, I ran a cash flow model with probabilistic distribution as input for the initial investment and the cost of additional well/feeder. As a main output, I generated NPV and IRR probabilistic distributions for each development scenario.

- Finally, I ranked the selected well schemes.
  As main criteria, I used the NPV and IRR probabilistic distributions.

In addition to the actual 70 MMSCFD gas contract, I simulated a progressive gas demand increase of 20 MMSCFD every 5 years and a 150 MMSCFD gas market.
In doing so, I tested the benefits of the new ML well scheme under various constraints of production.

CHAPTER II

PHOENIX FIELD RESERVOIR SIMULATION

2.1 Overview of Phoenix Field

Phoenix Field is a small offshore gas field located in West Africa at about 650 ft water depth. Phoenix sands are thick and reach up to 300 ft. Average reservoir depth is about 7500 ft TVDSS.

The structure is a closed anticline (**Fig. 2.1 and Fig. 2.2**). Two major faults (NW-SW) compartmentalize the reservoir into three main blocks.
Two wells - P1 and P2 - were drilled in 1999 and target a gas rate of 70 MMSCFD.

Table 2.1 summarizes the main reservoir characteristics of Phoenix.

Table 2.2 - Phoenix Reservoir Average Properties

Porosity Ø	**Net Thickness h (ft)**	**Water Saturation S_w**	**Area A (acres)**	**Gas Volume Factor B_g (rescf/scf)**	**Gas Viscosity μ_g (cP)**	**Rock Permeability K (md)**	**Initial Pressure Pi (psia)**
19%	300	41%	2480	0.0045	0.02	6.5 – 10.2	3820

To estimate gas in place, I use the following equation:

$$\textbf{GIP (MSCF)} = .04356 \times (A)\,(h)\,Ø\,(1 - S_w)\,(1/B_g) \quad \textbf{- Equation 2.1}$$

A volumetric estimation of the gas in place for Phoenix is:

$$\text{GIP (BSCF)} = .04356 \times 1E\text{-}6 \times (2480)\,(300)\,0.19\,(1 - 0.41)\,(1/0.0045)$$
$$= 850 \text{ BSCF}$$

2.2 Reservoir Simulation

The objective of this simulation is to calibrate our model for forecasting purposes. The resulting calibrated reservoir model will be used as a standard model upon which I can implement various well architectures.

2.2.1 Grid Model

The grid block number and dimensions I used in the model are:

Total Number of Blocks: 345
Fundamental Grid Dimensions: **NI= 15 NJ= 23 NK=1**
Number of Grids (Fundamental and Refined):1
Number of Active Blocks: 211
Number of NULL Blocks: 134

I choose to model major faults by zero transmissibility cells. Although this model is simple, it allows us to model non-completely sealed faults and permeability barriers that characterized Phoenix Field.

Fig. 2.1 shows the 2D grid model.
Fig. 2.2 shows the corresponding 3D model that reveals the anticline structure.

At the edges of the grid model, I used null blocks and volume modifier to better represent the shape of the reservoir such as depicted by the contour map. In absence of sufficient data, I input a constant 300 ft thickness.

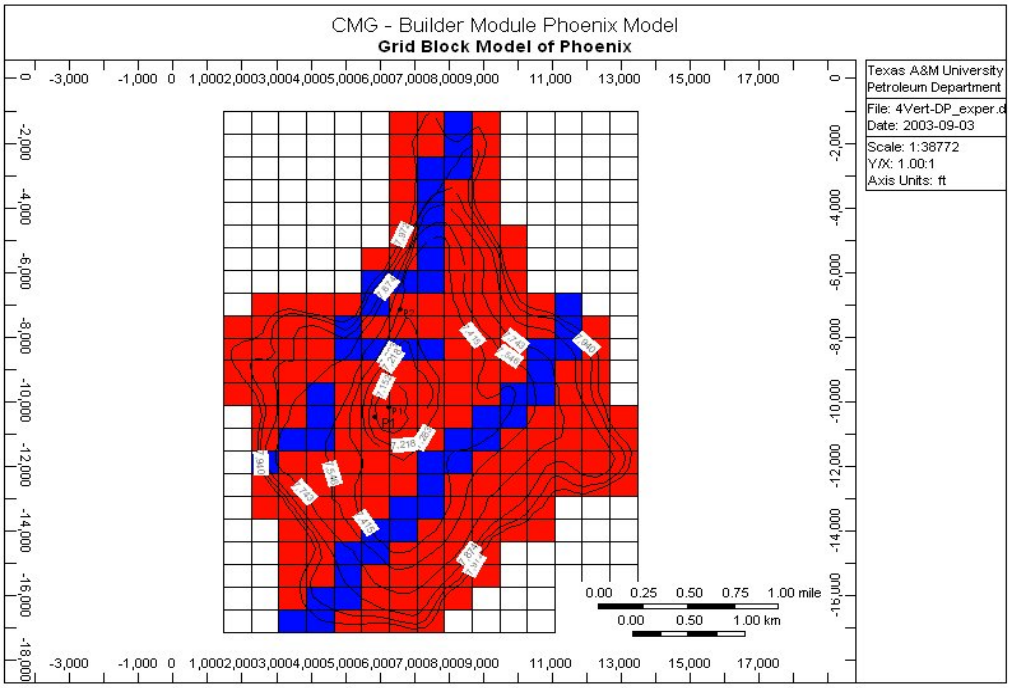


Fig. 2.1 - 15 x 23 x 1 grid model with 211 active grid blocks

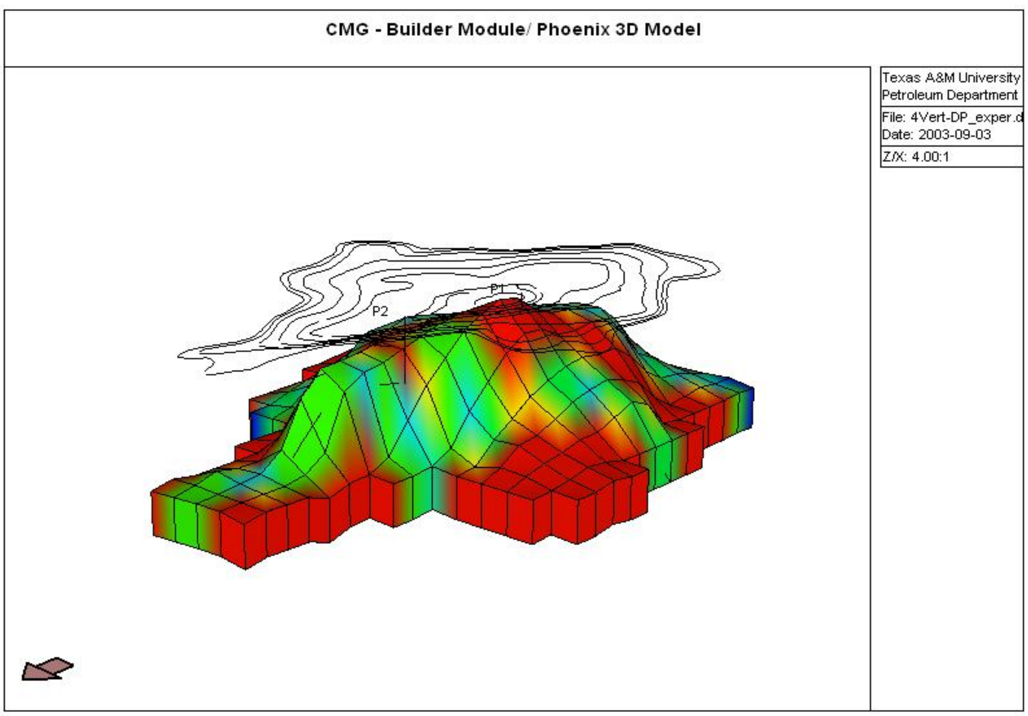


Fig. 2.2 - 3D model of Phoenix Field – constant thickness @ 300 ft

2.2.2 History Matching

2.2.2.1 Data

Available data are:

- Average reservoir properties (**Table 2.1**)
- Contour map (**Fig. 2.1**)
- Cumulative production at specific points in time (Table **2.2** and **2.3**)
- Bottom Hole Pressure (BHP) at specific times (Table **2.2** and **2.3**)

With the available data, only the following parameters are to be matched:

- Estimated Gas in Place – 850 BCF
- BHP (**Table 2.2 and 2.3**)
  - Point 1 : Initial pressure
  - Point 2 : BHP taken with bottom hole gauges, the same day and after a buildup of 24 hours

Tables 2.2 and 2.3 summarize the cumulative production for well P1 and P2 along with static BHP.

Table 2.2 - Cumulative Production & Static BHP for well P1

Date	Cum Prod (BSCF)	Pws (psia)
01/27/1999	0	3820
09/11/2000	13.82	3554

I observe a difference of almost 50 psi between well shut-in pressure of P1 and P2. This further comforts the hypothesis of a barrier between the two wells.

Table 2.3 - Cumulative Production & Static BHP for well P2

Date	Cum Prod (BSCF)	Pws (psia)
02/24/1999	0	3820
09/11/2000	9.28	3509

2.2.2.2 Procedure

The initial reservoir model includes basic reservoir properties displayed in **Table 2.1**. As a result, the initial model is a reservoir with uniform properties.
I tuned those properties so that I can match the gas in place, production and pressure histories.

As a general procedure, I entered gas production rate in the simulator and tuned reservoir properties so that gas in place and pressure are matched.
I computed gas rate so that cumulative production matches available data.

- Gas in place is matched first. In doing so I tuned porosity, null blocks and volume modifiers properties. I maintained a constant 300 ft thickness (no net thickness data available).
- I then matched static BHP for each well.
  To achieve pressure history, I tuned permeability and transmissibilities that control reservoir fluid movements and therefore pressure with time.
  I also assumed a zero skin factor.

2.2.2.3 Calibrated Reservoir Properties

I successfully matched the gas in place (850 BCF) after tuning the porosity and volume modifier (at the edge of reservoir). Further porosity tuning was also required to achieve pressure matching.

Figs. 2.3, 2.4, 2.5 and **2.6** show the calibrated reservoir properties.

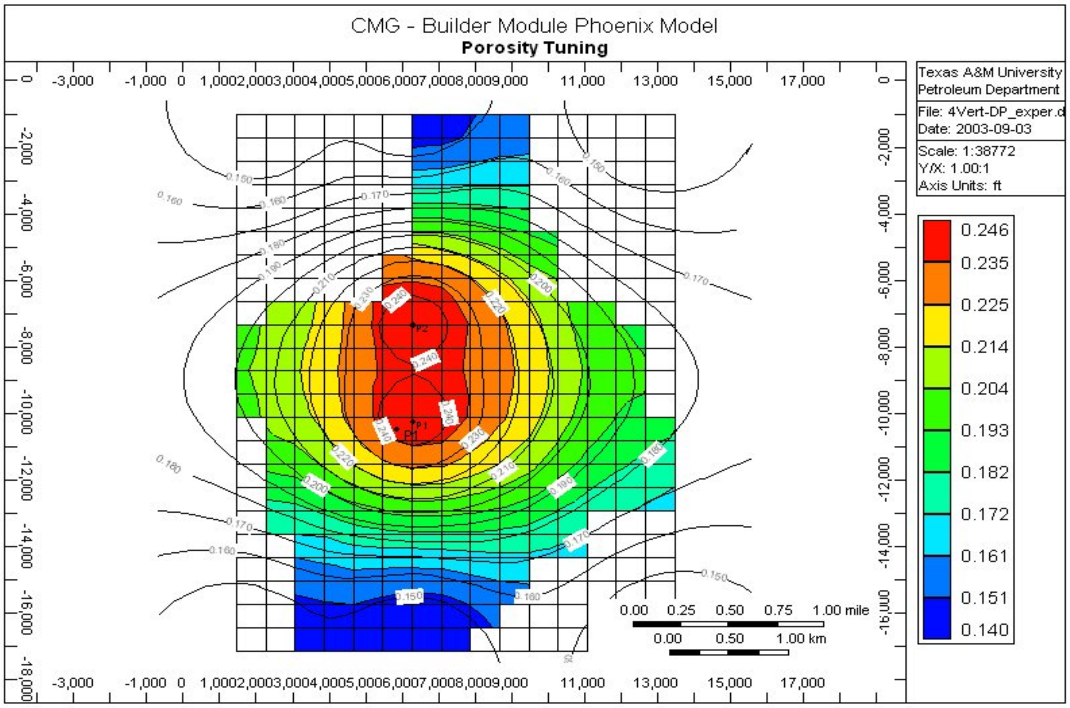


Fig. 2.3 - Calibrated porosity after gas in place and pressure matching

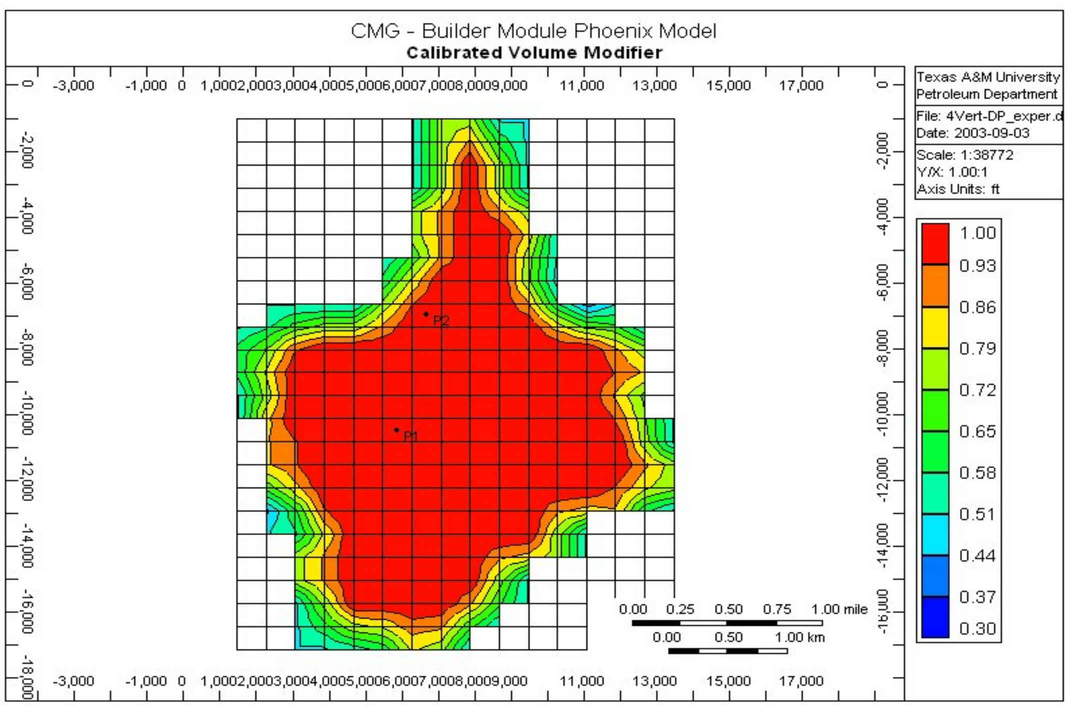


Fig. 2.4 - Calibrated volume modifiers

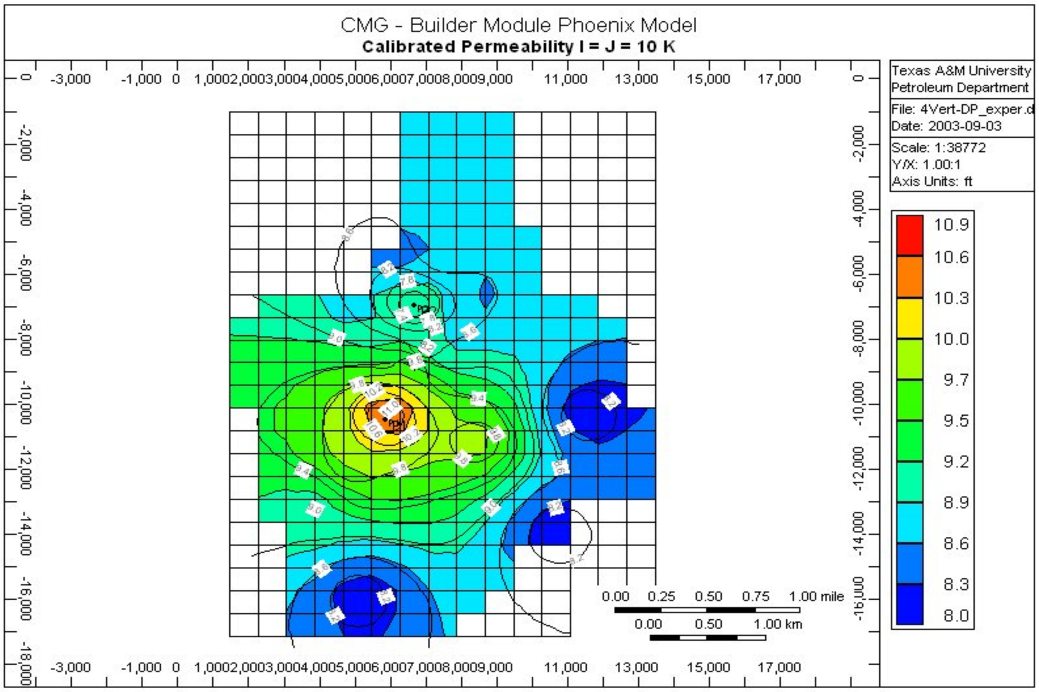


Fig. 2.5 - Calibrated permeability reveals a decrease from the center to the edge of the reservoir

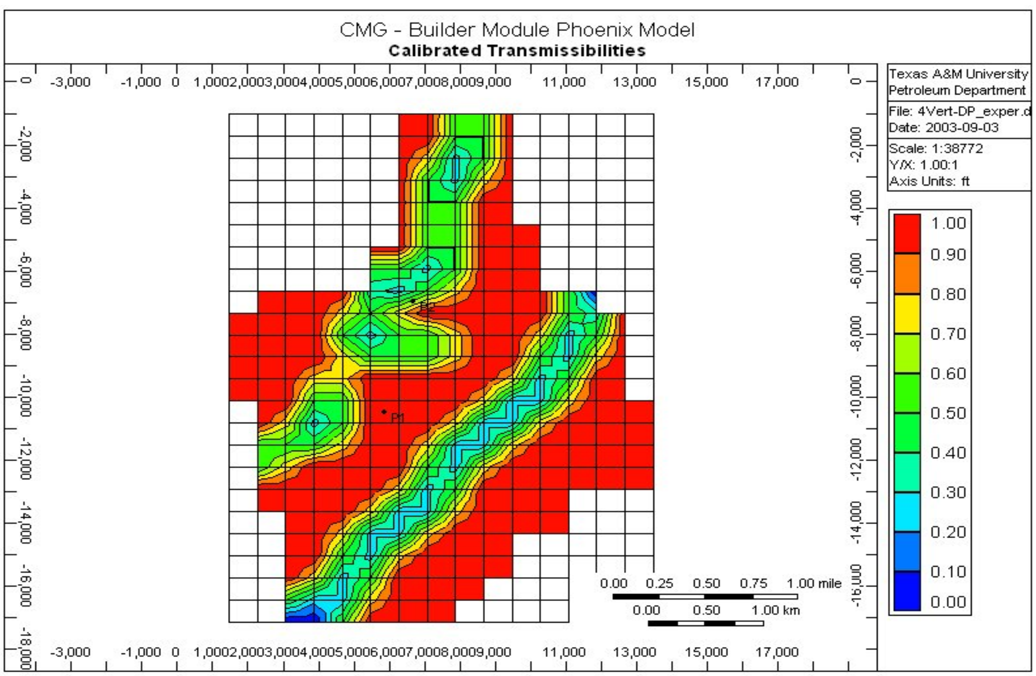


Fig. 2.6 - Calibrated transmissibility allows for fluid movements through the barrier

2.2.2.4 Rates and Pressure Matching

With the above calibrated reservoir properties, our model successfully predicts a gas in place of 850 BCF. I also achieved a good pressure match.

Rates are given. **Fig. 2.7** verifies the matching with production data.
Fig. 2.8 is the result of a long series of reservoir properties tuning.

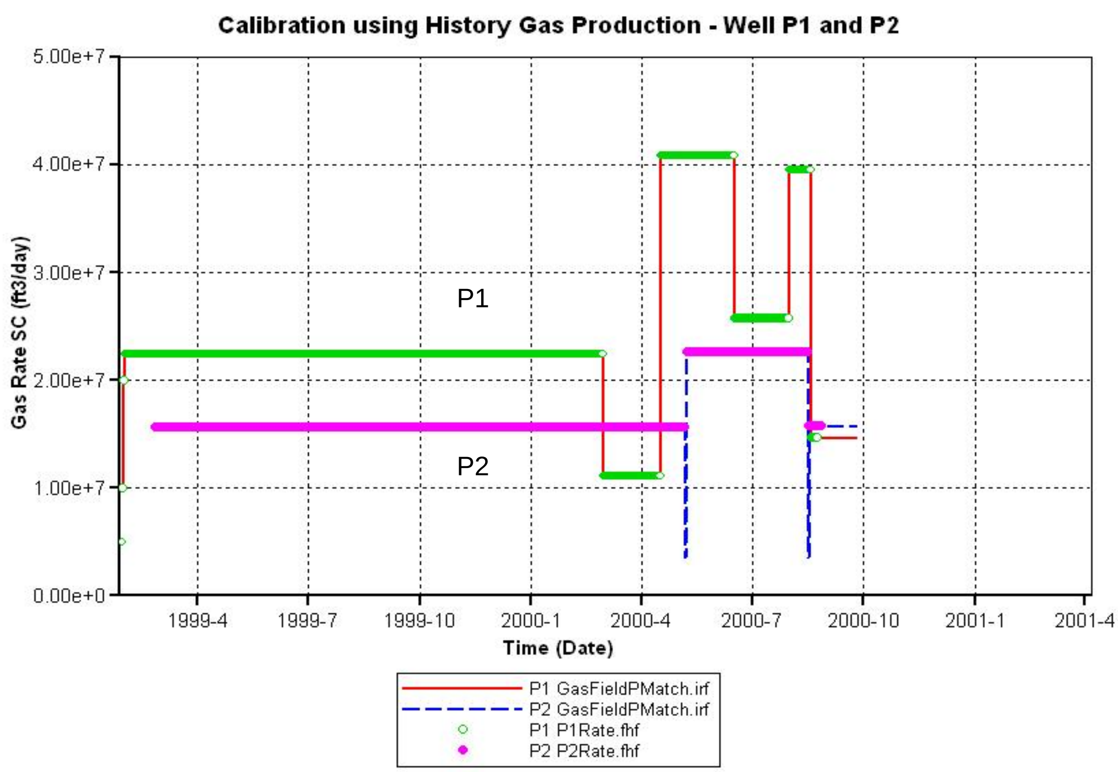


Fig. 2.7 - Rate calibration for wells P1 and P2

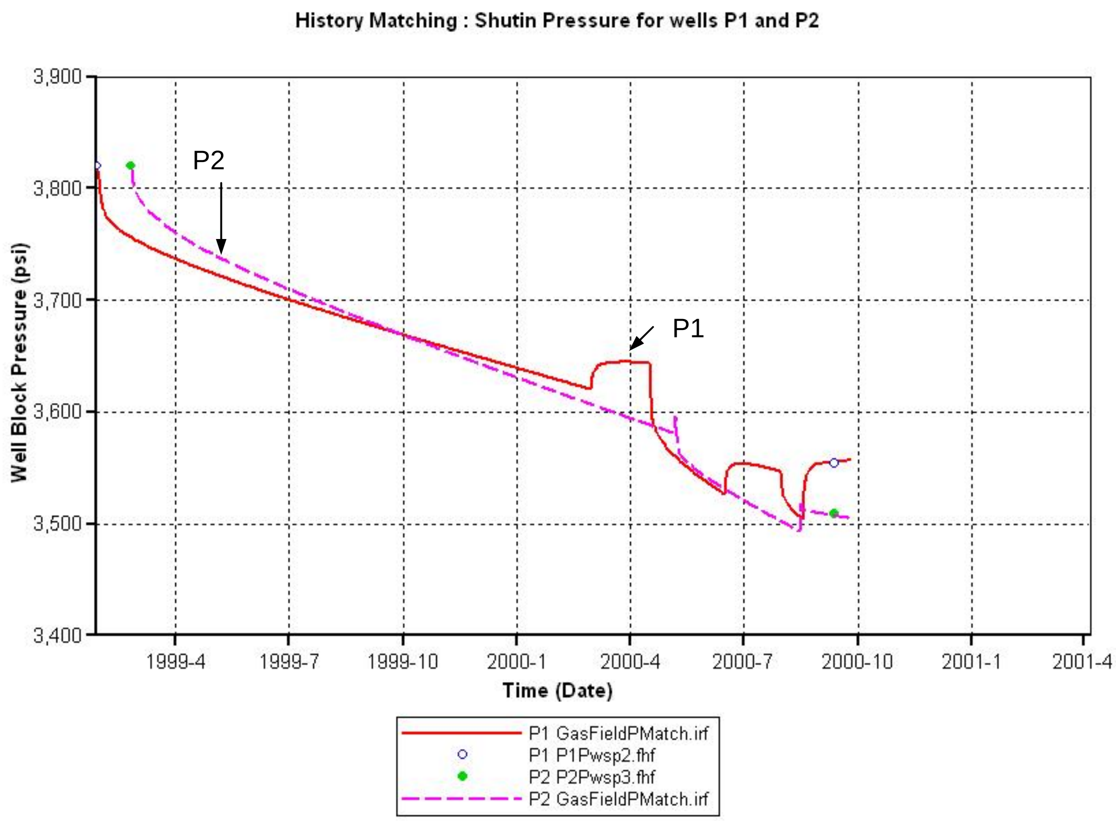


Fig. 2.8 - Pressure history match for wells P1 and P2

Once I have tuned our reservoir properties, I can use our model for forecasting purposes.

With the few data available, I am aware of the non-uniqueness of the match parameters. However, I will model both the actual development and new plan with the same reservoir model. This allows consistency in the evaluation and comparison of the two well plans.

2.2.3 Production Forecasting

2.2.3.1 Well P1 – P2 – P3 – P4 Simulation Parameters

This development scenario is the actual one. It includes wells P1 and P2 that presently produce and I forecasted two additional wells (P3 and P4) and their drilling schedule.

I modeled wells (actual development scenario) with the following parameters:

- **Tubing diameter**

Wells P1 and P2 were first completed with a dual completion: a short string of 2”7/8 for gas production and a long string of 3”1/2 ID for oil production. Both of them are now used to produce gas. I calculated an equivalent 3.553 inch ID tubing. In 2002, both of the wells were recompleted with a 5” tubing. Future wells completion also include a 5” ID tubing.

- **Average depth = 7600 ft**
- **Sub-vertical wells. These are supposed vertical in the simulator.**
- **Perforation and well index effect**

Our simplified reservoir model accounts only for one layer of 300 ft. In reality, this represents a gross thickness. In fact, Phoenix Field is made of a succession of sands and thin clay layers. As a result, not all the 300 feet are perforated and produce such as handled by IMEX[1]. Besides, I do not have detailed information regarding the perforation intervals.
Therefore I choose to modify the well index parameter to account for the “true” producing and perforation interval. I estimated that a 50% reduction was reasonable.

- **Simulation control parameters**

  - Minimum well head pressure @ 700 psia (contract requirements)
  - Maximum gas rate of 70 MMSCFD (Take or Pay)
  - Minimum gas production estimated @ 10 MMSCFD (confirmed by economic analysis)
  - Maximum individual well production: 40 MMSCFD except P2 @ 35 MMSCFD (from production allocation)

[1] CMG Black Oil Simulator

2.2.3.2 Well P1 and P2 Production Forecasting

Based on the overall production history and well performances, I choose the following rate constraints:

- **P1 : Max rate of 40 MMSCFD**
- **P2 : Max rate of 30 MMSCFD**
- **Total Rate = 70 MMSCFD in agreement with the gas contract**

Fig. 2.9 shows the production forecast for well P1 and P2.

The overall gas recovery is 55% i.e. ~450 BCF. The production plateau and thus target gas rate of 70 MMSCFD is maintained until August 2012. After this date, well P2 can no longer produce 30 MMSCFD. Well P1 can achieve its plateau until August 2014.

A third well is then required in August 2012 in order to achieve the gas market requirement.

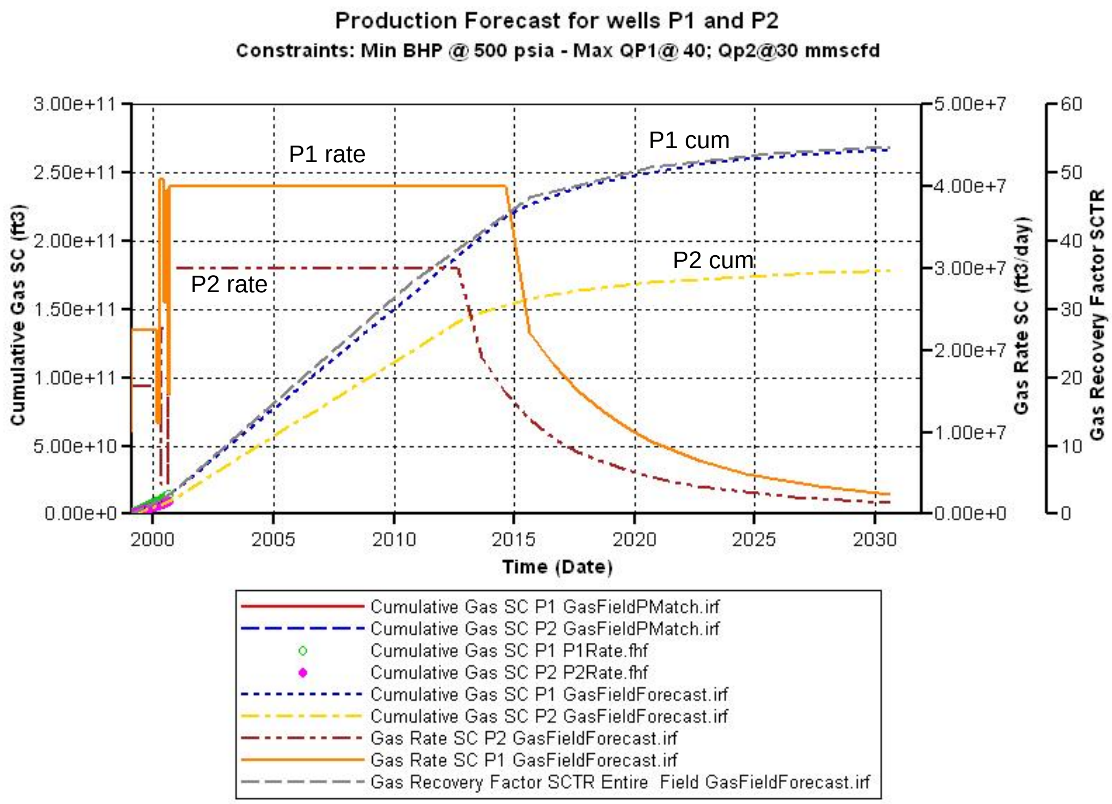


Fig. 2.9 Production forecast for wells P1 and P2 shows a better performance for P1 and a field recovery factor of 55%

2.2.3.3 Field Production Forecasting

Constraints for P3 and P4:

I arbitrarily choose the following rate constraints:

- **P3 : Max rate of 45 MMSCFD**
- **P4 : Max rate of 35 MMSCFD**

These constraints allow the well to maintain the target gas rate of 70 MMSCF even if P1 and P2 stop producing.

Fig. 2.10 shows the well location.

Fig. 2.11 presents the overall field and individual well (P1, P2, P3 and P4) production forecast. It also shows the recovery factor curve.

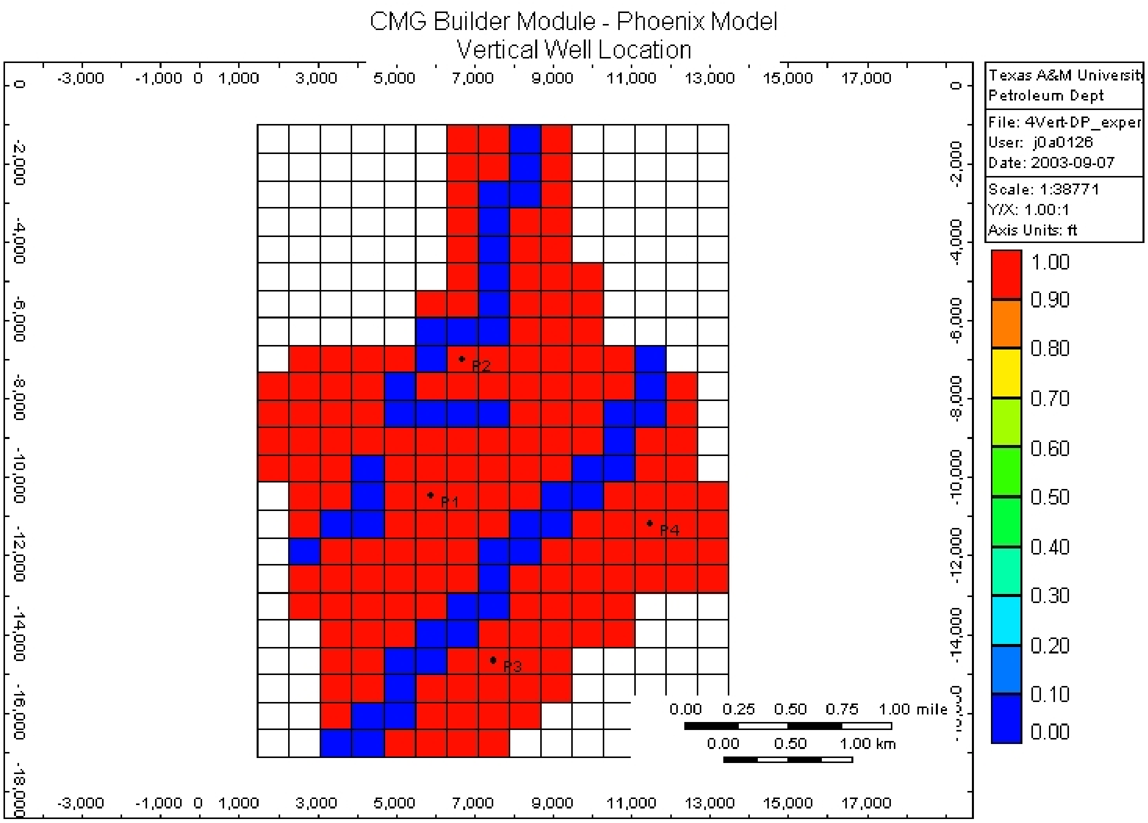


Fig. 2.10 - Phoenix Field actual development plan: 4 vertical wells

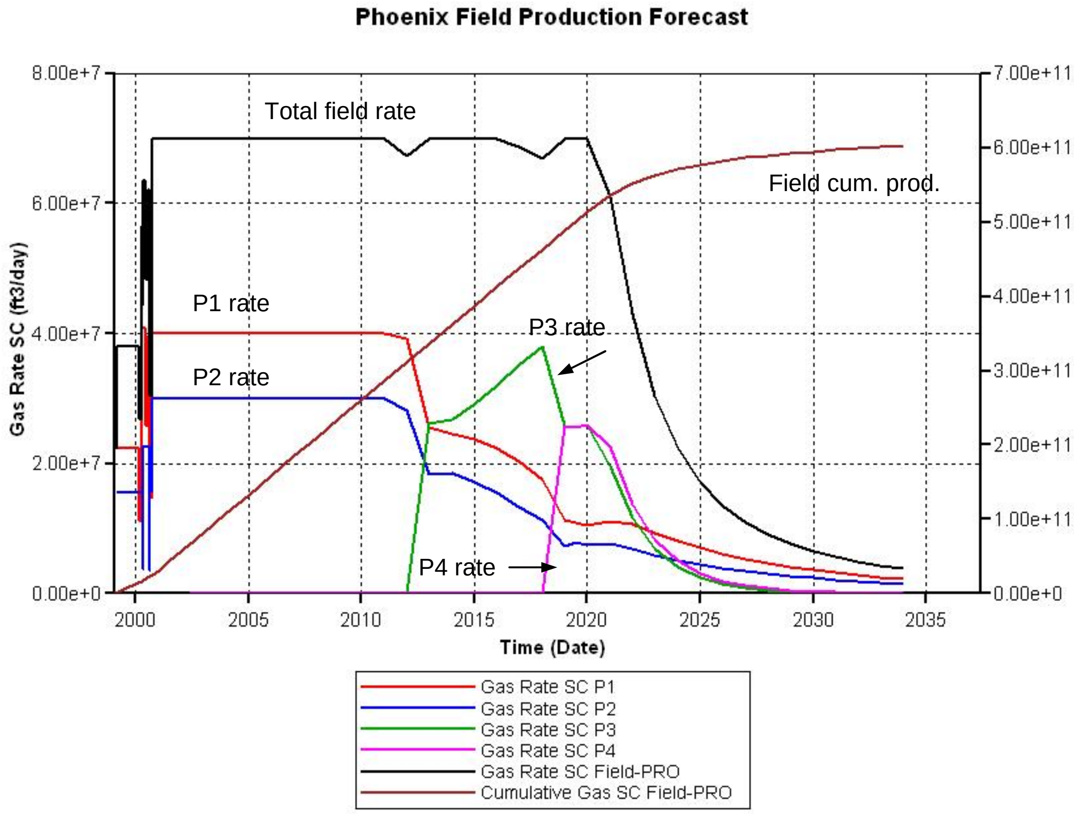


Fig. 2.11 - Production forecast: The 70 MMSCFD take or pay plateau is achieved until August 2020 with an ultimate recovery of 600 BCF

The 70 MMSCFD plateau is achieved until 2020. ~76% of the reserves are recovered. Well P3 must enter production in 2012. Well P4 must start production in 2017.

I believe these predictions to be accurate enough for the purpose of this comparative study.

2.3 New Well Architecture Implementation and Design

Assumptions and simplification

- Straight horizontal and lateral sections
- Pressure drop neglected (see justifications as follows)

Design parameters:

- Horizontal section @ 7" ID casing
- Lateral section from 3" to 5" ID

2.3.1 Implementation in IMEX (CMG Black Oil Simulator)

IMEX does not provide the required flexibility to model such architecture. The main limitations are:

- A single well can only handle one hole diameter.
- A single well can only handle one tubing diameter.
- Two different wells can not be connected

As a result, IMEX handle laterals as simple extension of the mother well. In doing so, there are no means to indicate a different hole and tubing diameter for the mother well and the laterals.

The well hole diameter dictates the well productivity index while the tubing diameter strongly influences the pressure drop in the well. Because our design includes an important difference in the mother well (7") and lateral well hole and tubing/liner diameter (2.5" to 5"), I had to overcome these limitations.

A solution was to conduct a sensitivity analysis on the well hole diameter and tubing diameter.

2.3.1.1 Handling Well Hole Diameter Issue

I run the final simulations with a 7" hole diameter, ie mother well diameter.
I modified the well indices (WI) in order to account for the lateral diameter reduction.

A sensitivity analysis on hole diameters varying from 7” to 2” was performed and corrected WI calculated after simulation.
I provide details in appendix A.

A 2” hole diameter has an equivalent WI of 80% the 7” WI: **WI (2”) = 80% WI (7”)**

Fig. 2.12 shows the WI effect on the production of a two lateral structure. The reference is a 7” hole diameter. I applied various factors on the well index that model a well with a smaller diameter. For instance, 60% WI(7”) shows the production curve of a well equivalent to 60% the 7” ID well. 5% WI(7”) shows the production curve of a well equivalent to 5% the 7” ID well. This sensitivity analysis tells whether a well index factor of 80% result in a significant change in production capabilities of the well.

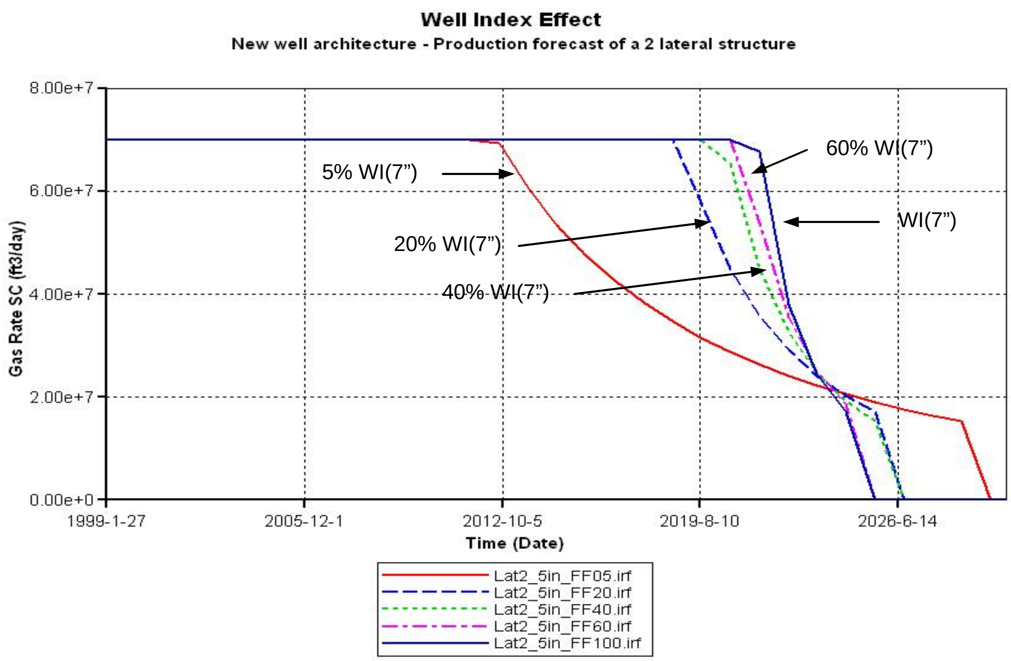


Fig. 2.12 - Well index factors above 60% have no effect on production

Fig. 2.12 demonstrates that I can in fact neglect the effect of the diameter difference between the mother well and laterals if the well index factor is above 60%. I therefore concluded on the small effect of a factor of 80% on the overall production performances.

2.3.1.2 Handling tubing diameter issue

Since I cannot adequately model the pressure drop effects of the well architecture in IMEX, our aim is to propose a design for which I can safely ignore pressure drop calculation. Furthermore, getting a feeling for the pressure drop amplitude, I will consider Bottom Hole Pressure constraints more severe than the vertical well case.

The tubing diameter strongly influences the pressure drop. This is especially true at high gas flow rate such as 70 MMSCFD.
In order to quantify the effects of frictional pressure drop on the production performances, I performed a sensitivity analysis on both the tubing diameter and the flow rate.

- **Mother well (7" ID)**

Using Weymouth Equation (Single phase gas - see details in appendix B), I calculated a 60 psia pressure drop over 10,000 ft, for a tubing of 7" ID and a 70MMSCFD.
Such flow rates occur in the mother well. 10,000 ft is an upper limit I arbitrarily chose.

- **Laterals**

Fig. 2.13 shows an example of a one lateral structure such as implemented in our model.
I arbitrarily chose an upper limit of 1000 ft for the lateral length.

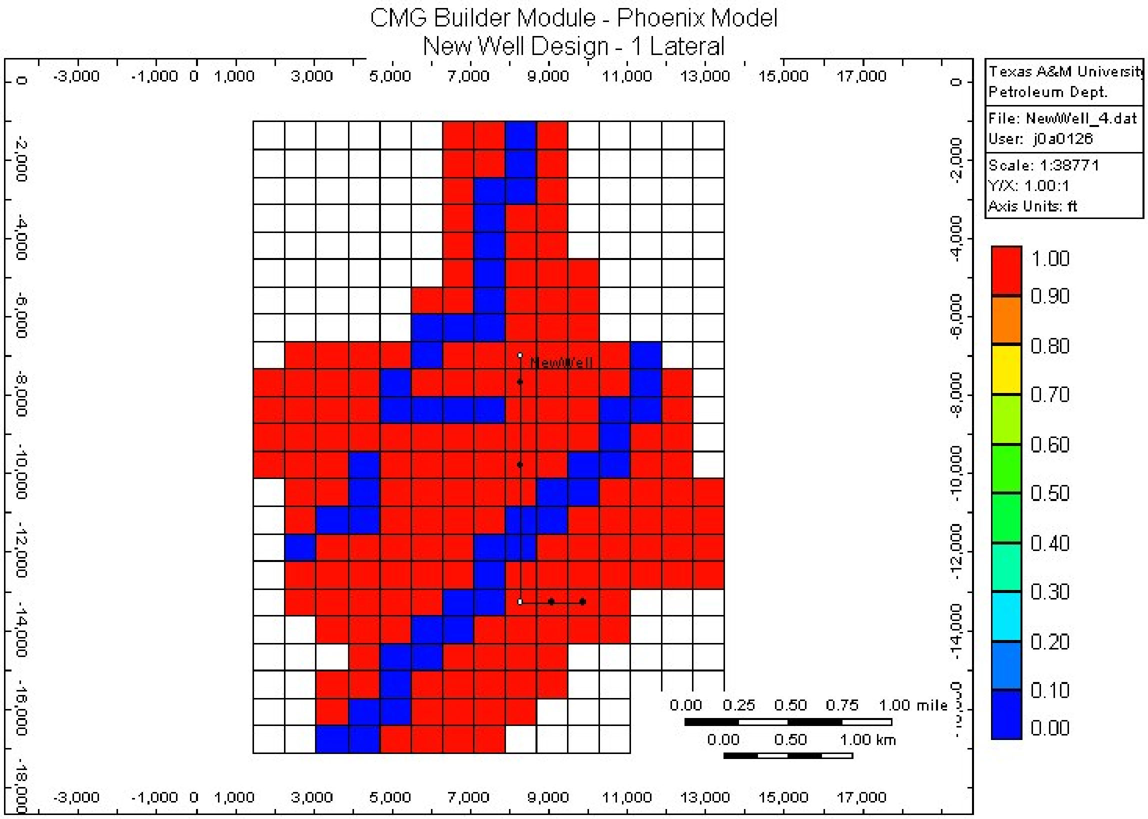


Fig. 2.13 - One lateral architecture

To isolate the effect of the pressure drop only in the lateral, I ignore the mother well length section. That is, I consider only the lateral length (1000 ft) in the simulator.

Besides, as I increase the number of lateral, I equally allocate the production per feeder. Therefore, the flow rate and associated pressure drop decreases in each lateral. As a result, the more the laterals, the less pressure drop constraints and the smaller the lateral tubing/liner.

These results are especially important since they will help us to propose a design such that pressure drop can be ignored. Also, it has important repercussions in the overall development strategy once I balance cost (well diameter - tubing/liner cost) and production.

2.3.2 Cases and Results

I run the following cases:

- o Depth @ 7700 ft – Length @ 1000 ft
- o Well head pressure @ 700 psia
- o Tubing diameter @ 2.5” – 3” – 3.5” – 4” – 4.5” - 5” – 5.5”
  - Gas rate @ 70 MMSCFD (1 lateral case)
  - Gas Rate @ 35 MMSCFD (2 laterals case)
  - Gas Rate @ 25 MMSCFD (3 laterals case)

Figs. 2.14, 2.15 and 2.16 show the effect of the tubing diameter at a fixed rate of 70, 35 and 25 MMSCFD respectively. In these figures, the file names correspond to each case: **LatXXin_YY.irf** means a **XX** in tubing diameter and a gas rate of **YY** MMSCFD.
I also compared each of these cases to a no-pressure drop case.

The results are:

- Ignoring pressure drop in the horizontal section (7” ID – 10,000 ft overall length): DP = ~ 60 psia (Weymouth)
  - ✓ BHP = PWH + 60 = 700 + 60 = 760 psia minimum

- Ignoring pressure drop in the lateral (1000 ft):

  - o 1 lateral – 70 MMSCFD
    - ✓ Minimum ID @ 5”
    - ✓ Minimum BHP @ 760 + 100 safety margin = ~ 850 psia
  - o 2 laterals – 35 MMSCFD/lateral
    - ✓ Minimum ID @ 4”
    - ✓ Minimum BHP @ 760 + 50 safety margin = ~ 800 psia
  - o 3 laterals - ~25 MMSCFD/lateral
    - ✓ Minimum ID @ 3”
    - ✓ Minimum BHP @ 760 + 50 safety margin = ~ 800 psia

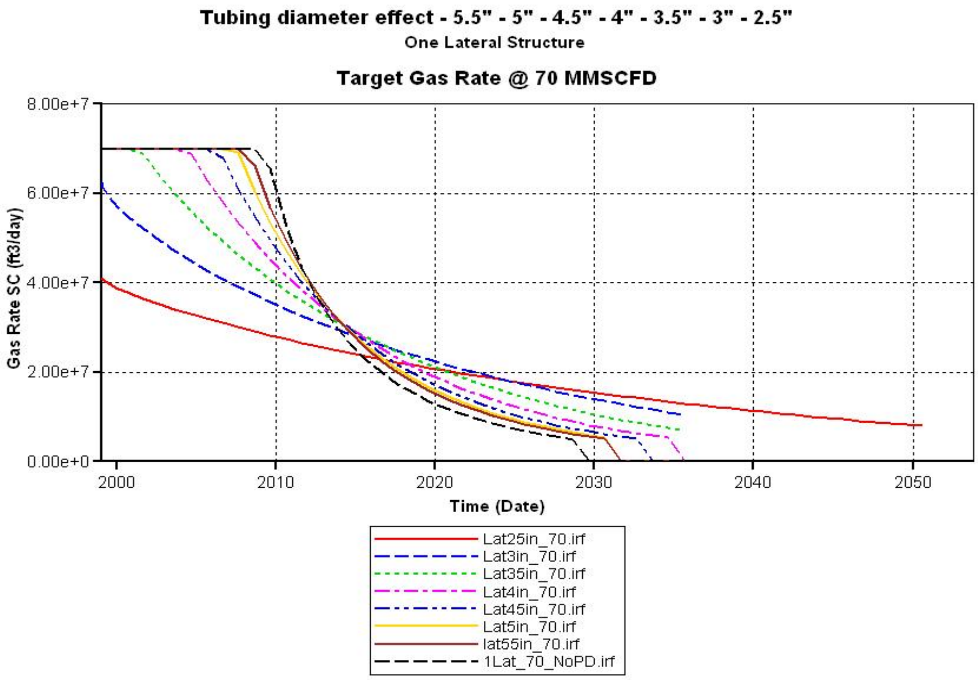


Fig. 2.14 - One feeder case: a 5" diameter yields almost no pressure drop

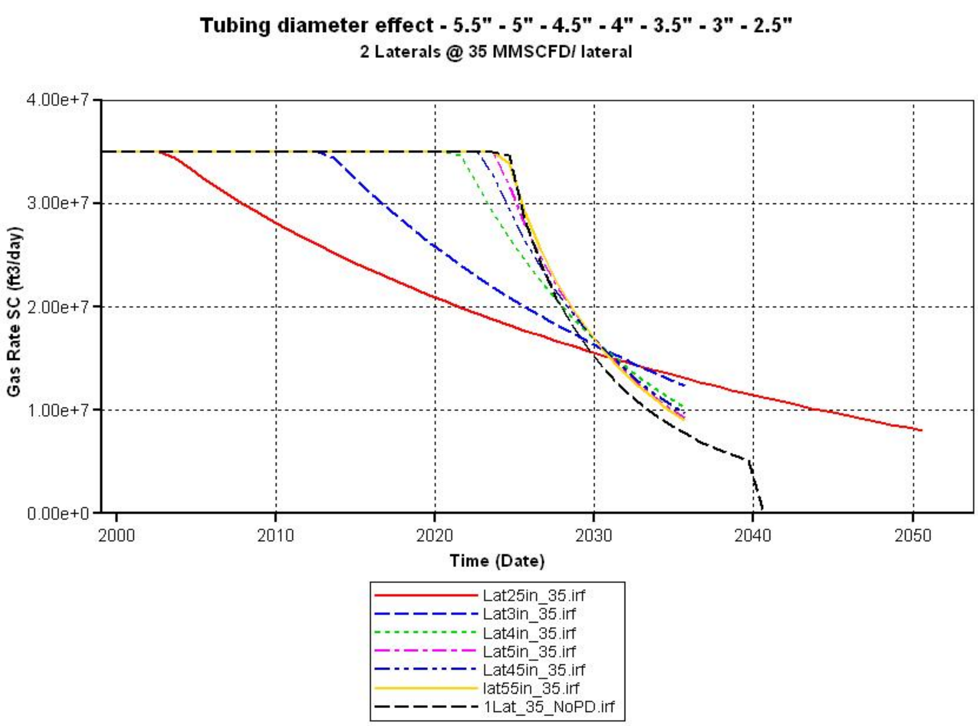


Fig. 2.15 - Two feeder case: a 4" ID yields almost no pressure drop

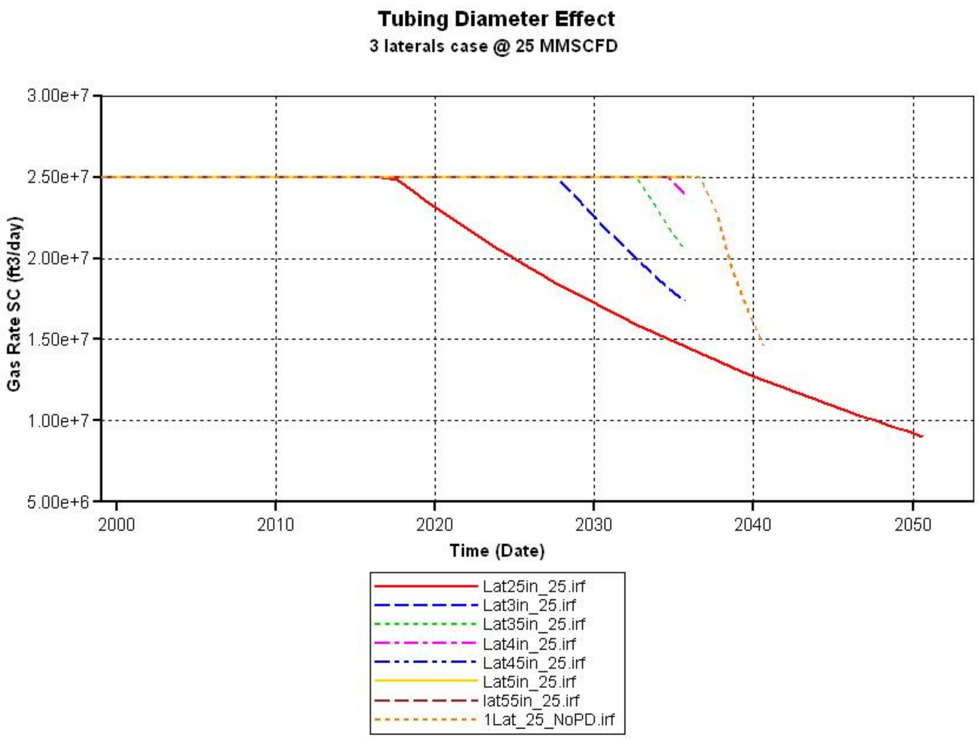


Fig. 2.16 - Three feeder case: 3" ID considerably reduces pressure drop effects

2.3.3 New Well Architecture Production Forecast

Forecasting for the new well architecture does assume no-pressure drop effect. I took into account the overall loss in the horizontal section (mother well) and in the laterals by imposing severe bottom hole pressure constraint in the simulator.

Fig. 2.17 shows the effect of adding feeders to the production performances.
Fig. 2.18 shows the lateral implementation in our model. F# represents the feeder number in the chronological order I included them in the model.

The 70 MMSCFD take or pay is maintained until:

- 2010 with one feeder
- 2018 with two feeders

- 2021 with three feeders
- 2022 with five feeders

The above dates are also an indication of a possible drilling schedule in order to maintain the 70 MMSCFD plateau.

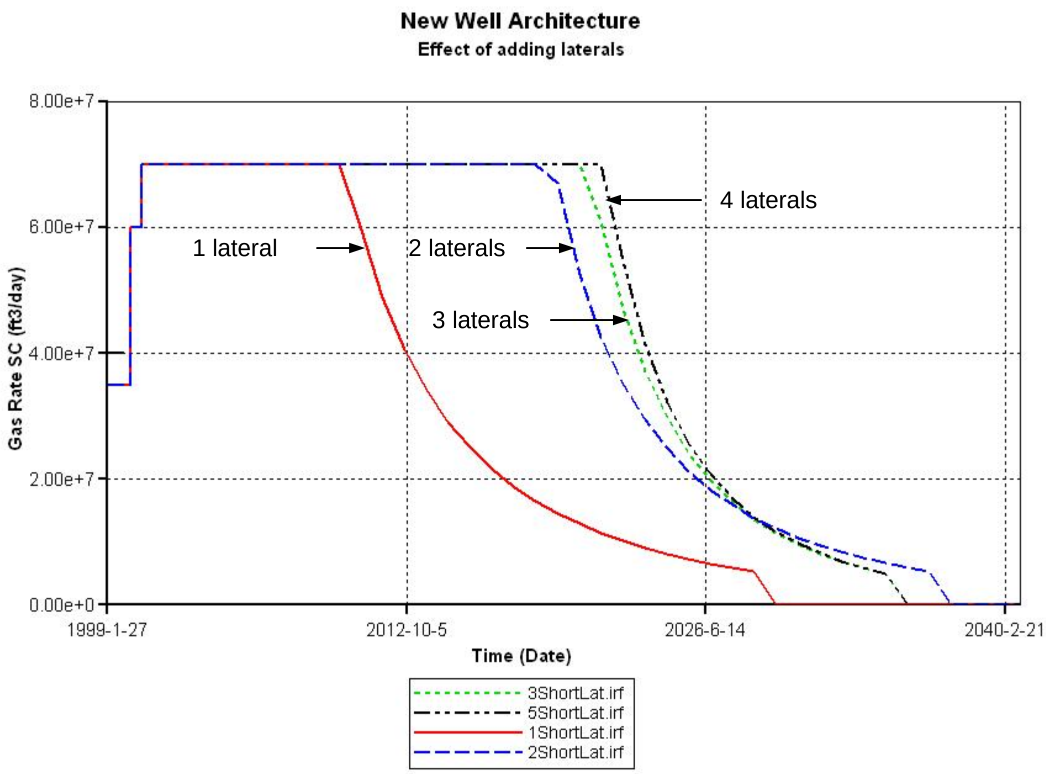


Fig. 2.17 - Good production performances require a minimum of two feeders

Fig. 2.17 also shows that the production gain becomes small above two laterals.

As mentioned earlier, balances between cost and production performances will drive the development options.

I recommend drilling no more than three laterals since the production gain does not seam to justify other feeder drilling.

Based on the above results and assumptions I built the following development options table. (**Table 2.4**). I also extended our result to others possible designs that would lead to cost savings. I judged the production performance estimates reasonable. However they are not fully supported.

Table 2.4 - Development options and design parameter

	Simulation design and parameters		**Other possible design and estimation of production time**	
Drilling schedule	**Minimum ID**	**Plateau until**	**ID**	**Plateau until**
1999: Lateral1 **2009: Lateral 2** **2017: Lateral 3**	5” 3.5” 2.5”	August 2009 August 2017 August 2020	4” 3” 2.5”	~ 2005 ~ 2012 ~ 2017
1999: Laterals1 and 2 **2009: Lateral 3**	4” 2.5”	~ 2017 ~ 2020	3” 2.5”	~ 2012 ~ 2017
1999: Lateral 1 – 2 and 3	3”	~2020	2.5”	~2015

Suggested length: Lateral 1 and 2 @ 1000 ft – Lateral 3 @ 500 ft

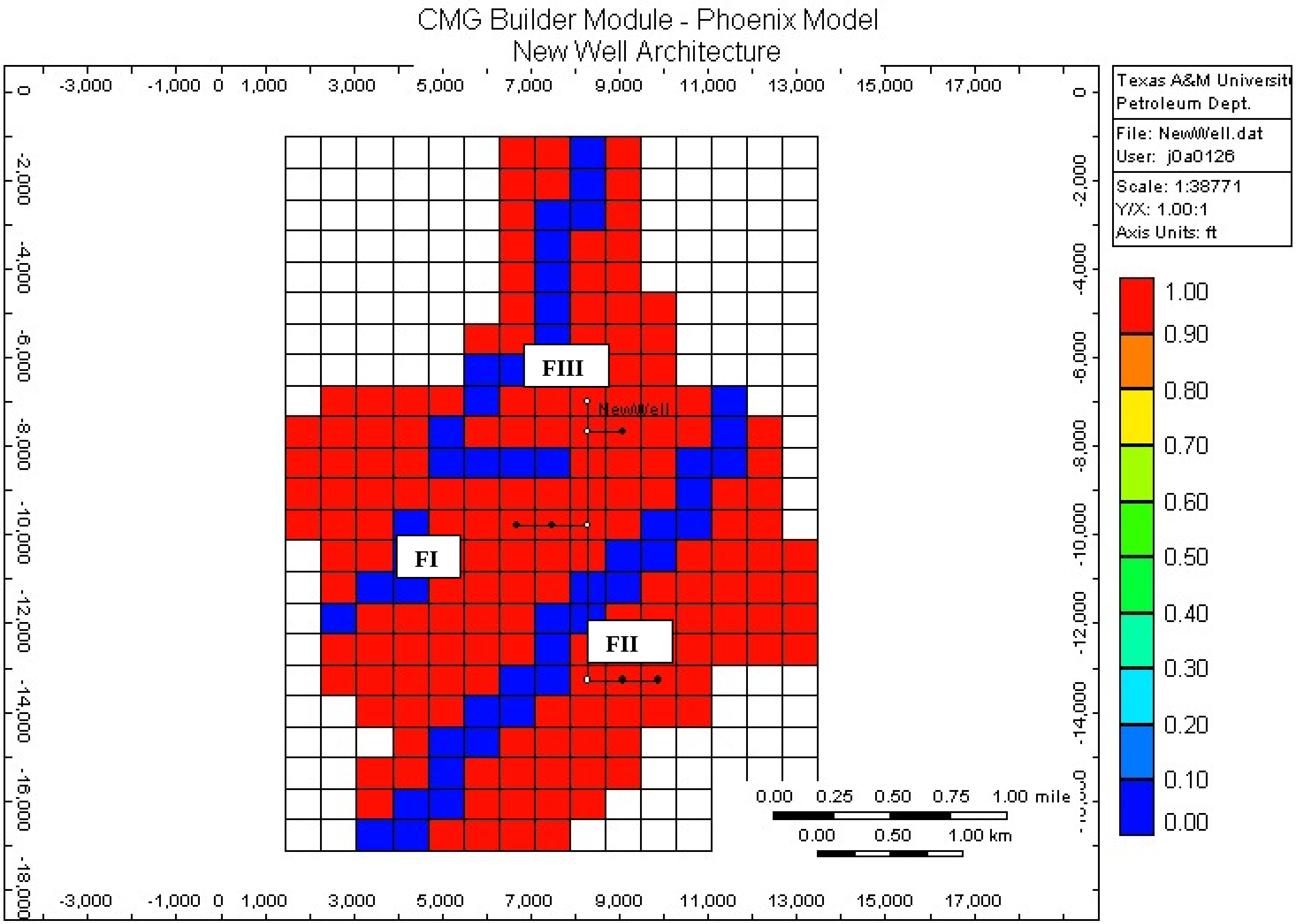


Fig. 2.18 - New well architecture implementation

2.4 New Well Architecture versus Conventional Architecture

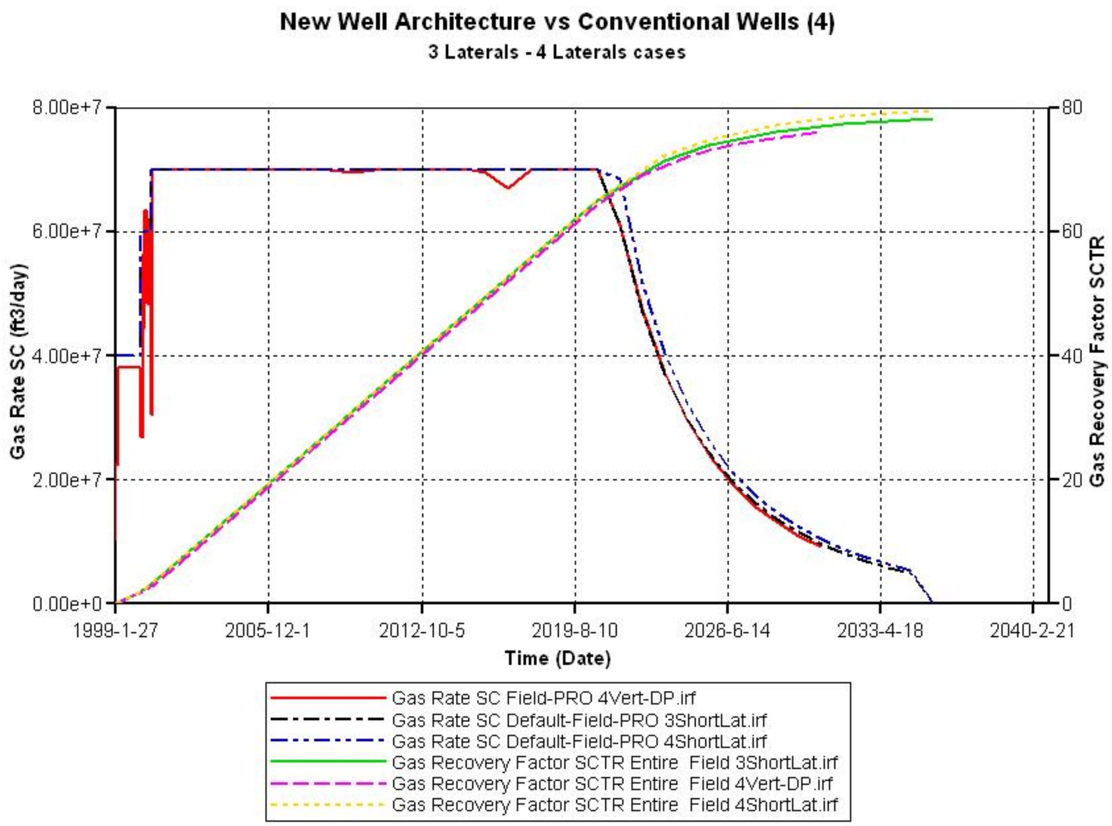


Fig. 2.19 - New well architecture versus conventional structure : a three feeder structure is equivalent to four vertical wells – no more sensitive gains over three feeders

Fig. 2.19 shows that a three feeder wells structure produces as much as the four vertical wells.

The recovery factor is a little bit higher for the three laterals: 78% against 76% (vertical wells).

2.5 Reservoir Simulation Main Results

The actual development plan of Phoenix includes four sub-vertical wells. The two producing wells P1 and P2 will deliver the contracted 70 MMSCFD until august 2011. Two additional wells, P3 and P4, can sustain this production until 2020. Well P3 must enter production in 2012. Well P4 must start production in 2017.

The new well architecture scenario should include at least two feeders, each of them located in the two main reservoir compartments. A three-feeder structure can produce as much as four vertical wells. In that case, a 70 MMSCFD production plateau is achieved until 2020 with a recovery factor of 78% against 76% with four vertical wells. More than three laterals do not result in a significant production gain.

The tubing/liner diameter and production rates strongly influence the production performances of each lateral. The more the feeders the less the flow rate per feeder and the smaller the tubing diameter in each lateral.

I proposed several development options including drilling schedule and design parameters. I recommend a 7” ID mother well in all cases since high flow rates such as 70 MMSCFD occur in that section.

The main purpose of reservoir simulation was to forecast production performances of both actual and proposed new well architectures.
The model also yielded to important results in terms of design parameters.

I can now use these important results to generate a cash flow model and evaluate the cost of each development scenario.

CHAPTER III

QUANTITATIVE RISK ANALYSIS USING MONTE CARLO SIMULATION

3.1 Objectives and Methodology

In the following I evaluate and compare economic yardsticks of both the actual development plan and the new well architecture scenario.

The objective is to investigate cost reductions impacts as the main economic driver of the new well architecture.

As a result, I expect that it will yield better economic performances for the project than the actual development plan.

I achieved a quantitative risk analysis on both development plans. I first analyzed the development cost of each scenario. I relied my estimation on a West Africa cost database available through FieldPlan software.

I then performed a Monte Carlo simulation to account for investments and cost uncertainties. I ran a cash flow model with probabilistic distribution as input for the initial investment and the cost of any additional well/feeder. As a main output, I generated NPV and IRR probabilistic distributions for each development scenario.

In addition to the actual 70 MMSCFD gas contract, I simulated a progressive gas demand increase of 20 MMSCFD every 5 years and a 150 MMSCFD gas market.

Since there are a number of unknowns in terms of cost, I performed a quantitative risk analysis on both conventional and new plans. To better represent risks and uncertainties, I implemented a Monte Carlo simulation on both models. This allowed me to compare economic yardsticks such as NPV and IRR in a consistent way.

Before I can implement such an analysis, I need a cost basis. I used **FieldPlan Computerized Field Development Planning System** developed by Halliburton. This software integrates a geographic cost database that is yearly updated. I believe this provides us with valuable and reliable cost estimate for our cases. I generated an overall cost analysis for the conventional plan. I then used it as base case from which I derived a cost estimate for the new well architecture. I further detail and explain those derivations.

I can then assume a probabilistic distribution using the cost basis for each plan as a mean of the distribution. This allows us to remain consistent with our first estimation while including cost uncertainties in our evaluation.

3.2 Conventional Development Plan – 70 MMSCFD Case

The conventional development plan aims a total of 4 sub-vertical wells. Two of them are already in production: P1 and P2. Based on the gas market, I forecasted the drilling date and location of the two other wells P3 and P4.

3.2.1 Simulation with FieldPlan

Fig. 3.1 is a development plan schema generated by FieldPlan.

Tables 3.1 and **3.2** detail the cost analysis for the investment and the cost of each additional well (p3 and P4).
Those costs are extracted from the West Africa cost database within FieldPlan.

In summary, I estimate the initial investment at 122 million dollars. This includes the platform construction, installation and the drilling of wells P1 and P2.
The cost of each additional well is estimated at 25 million dollars. It includes the flowlines that link each well to the main platform.

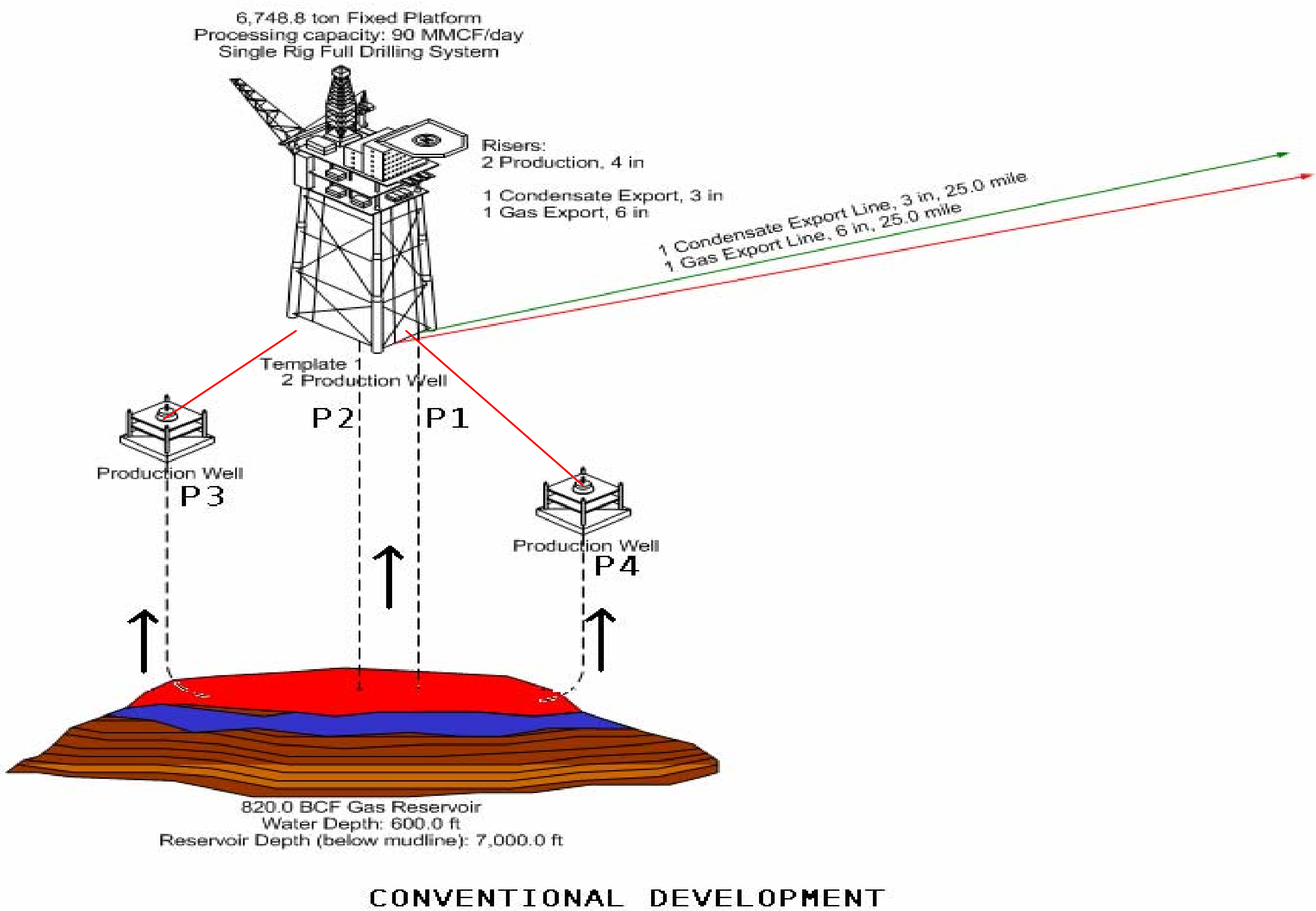


Fig. 3.1 - The conventional plan includes 4 vertical wells linked to a main platform

Table 3.1 - Initial Investment for the Conventional Development

Plan: Conventional / 2 wells and No Intrafield Flowlines at year ZERO

	Equipment $ mil	Installation $ mil
Platform Fabrication/Conversion (4 slots)	27.391	15.981
Process Facilities on Platform	15.281	
Auxilliary&Marine Systems	0.988	
Accommodations	1.74	
Drilling Equipment & Completion Tools	19.072	
Production/Export Riser	0.026	
Trees	1.6455	
Wellheads	0.43	
Intrafield flowlines	0	0
Control System	0	
Export Pipelines	4.468	16.148
Sub-Total	**71.0415**	**32.129**
Engineering/Design	7.734	
Project Management/Services	3.867	
Total Cost	**82.6425**	**32.129**
Total Cost Excluding Drilling Operations	114.7715	
Drilling/Completion Cost		
Consumables	3.302	
Drilling Rig Cost	3.985	
Sub-Total	**7.287**	
Total Project Cost at Year ZERO	**122.0585**	

Table 3.2 - Cost Estimate for Additional Wells in Conventional Development

Plan: Conventional / Satellite well and Intrafield Flowline		
	Equipment $ mil	**Installation $ mil**
Platform Fabrication/Conversion (4 slots)	0	0
Process Facilities on Platform	0	
Auxilliary&Marine Systems	0	
Accommodations	0	
Drilling Equipment & Completion Tools	9.536	
Production/Export Riser	0	
Trees	0.82275	
Wellheads	0.215	
Intrafield flowlines	0.112	0
Control System	0.866	
Export Pipelines	0	0
Sub-Total	**11.55175**	**0**
Engineering/Design	2.578	
Project Management/Services	1.289	
Total Cost	**15.41875**	**0**
Total Cost Excluding Drilling Operations	15.41875	
Drilling/Completion Cost		
Consumables	1.341	
Drilling Rig Cost	7.9925	
Sub-Total	**9.3335**	
Total per satellite well	**24.75225**	

3.2.2 Monte Carlo Simulation of the Cash Flow Model

Monte Carlo Simulation refers to the use of random numbers to generate values for the varying and uncertain parameters of a stochastic model.
The idea is then to associate those random numbers with a probabilistic distribution which I think represent the best the variable.

Our stochastic model is a common cash flow model. Its main parameters are:

- CAPEX (Capital Expenses or Investment)
- OPEX (Operating Expenses)
- Gas price
- Interest rate

The aim of this study is to investigate the effects of any cost reduction related to the use of a new technology: a new well architecture. Since, this well architecture has never been tried before, its cost bear the most uncertainties.

In a cash flow model, investment is per definition the sum of all costs.
As a result, I chose the investment parameter, including the cost of any additional well or feeder as the varying and uncertain parameters.

I assume OPEX will remain fairly constant around 5 million $/year. However I do include an increase of 1 million $/year each time a well is drilled.

I assume a fixed interest rate of 15%.

I assume a fairly constant gas price. I account for an increase of 0.5$/MSCF every 10 years starting at 2.5$/MSCF in 1999:

- o 1999 – 2009: 2.5 $/MSCF

- o 2010 – 2019: 3.0 $/MSCF
- o 2020 – end of project: 3.5 $/MSCF

As an effective way of comparison, I will keep the same assumptions for both development scenarios.

3.2.2.1 Investment and Additional Well Cost Probabilistic Distribution

Since investments and additional well cost are the result of a summation, a normal distribution would represent them the best.

A Normal or Gaussian distribution is defined as:

$$P(x) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{1}{2}\left[\frac{x-m}{\sigma}\right]}$$

Equation 3.2

where sigma is the standard deviation and m the mean of the distribution.

P(x) is the probability that the event x occurs. In our case, an event is any possible investment or cost.

In the Monte Carlo approach, each generated random numbers is assumed to be a cumulative probability (between 0 and 1) of the chosen distribution.
In other words I solve the following equation for x:

$$U(0,1) = \int_{-\infty}^{x} P(x)dx$$

Equation 3.3

where U(0,1) is a generated random number.

I use EXCEL built in functions to solve for x (investment or cost) each time a random number is generated.

The more the random numbers I generate, the more accurate (smooth shape) is the resulting distribution.
I chose to generate 5000 random numbers for each distribution.

The initial investment was estimated at 122 MM$. Any additional well is estimated at 25 MM$. Taking these as cost references, I assume the following distributions:

1. **Initial Investment = Normal (122, 20)** (**Figs. 3.2** and **3.3**)
   I.e. I model the initial investment as a normal distribution with a mean of 122 million $ and a standard deviation of 20 million $.
   Fig. 3.2 shows the normal distribution (after solving equation 3.2) while **Fig. 3.3** presents the corresponding cumulative distribution.

2. **Additional Well Cost = N (25, 3)** – (**Fig. 3.4 and 3.5**)
   I.e. I model the cost of a new vertical well as a normal distribution with a mean of 25 million $ and a standard deviation of 3 million $.

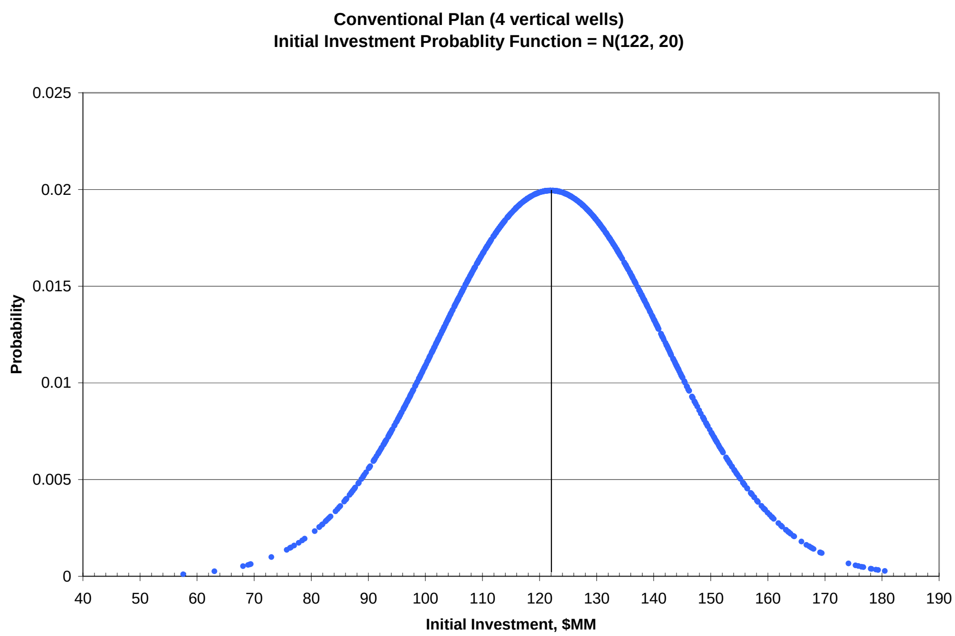


Fig. 3.2 - The initial investment might take any values within the normal distribution with the most probable values around 122 MM$

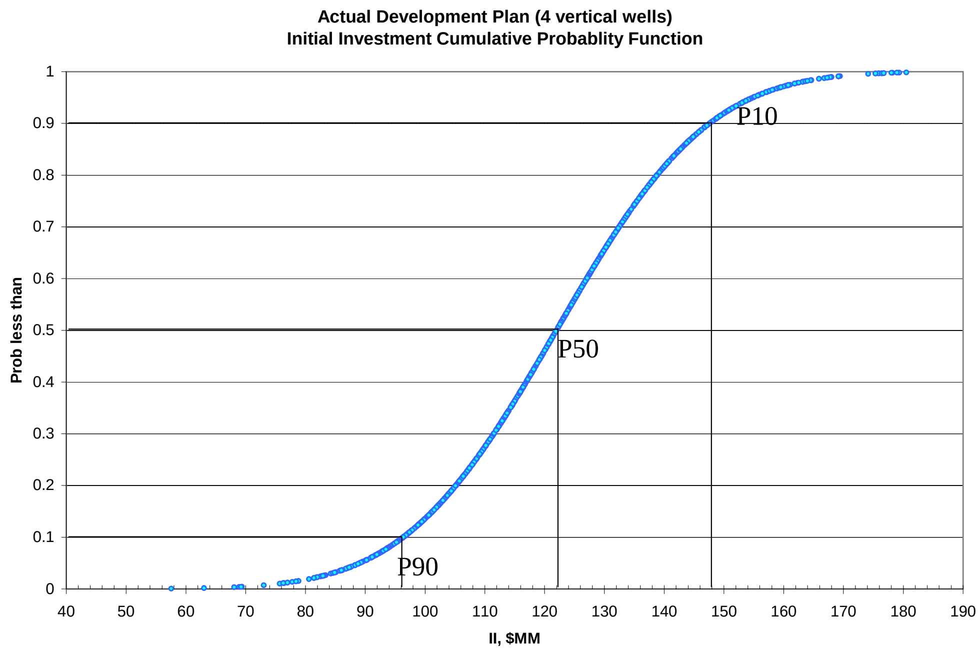


Fig. 3.3 - The investment is greater or equal to 122 MM$ in 50% of the cases

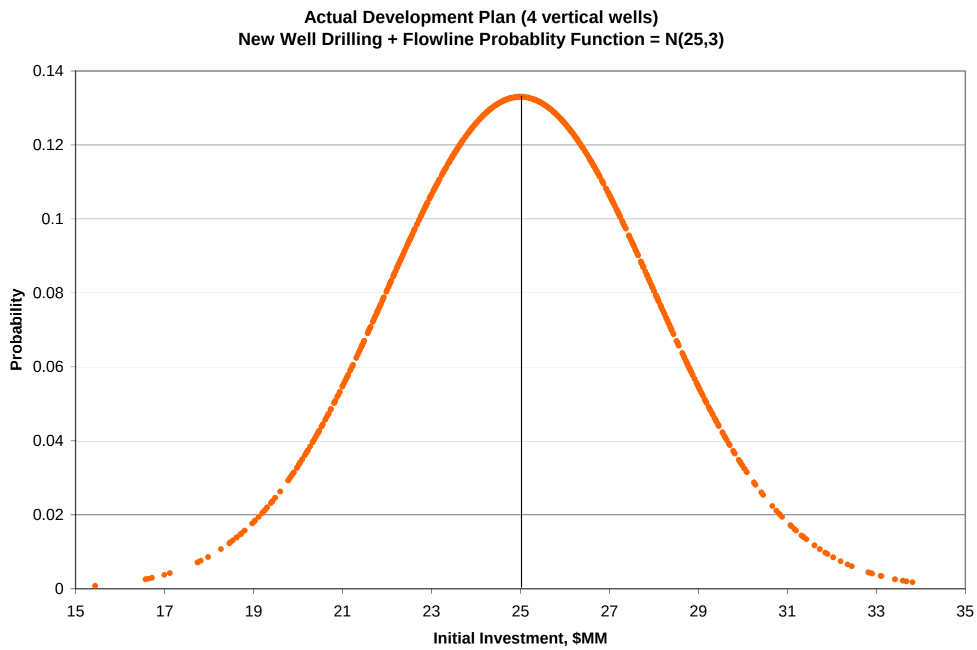


Fig. 3.4 - The cost of any additional well might be any value within the normal distribution with the most probable values around 25 MM$

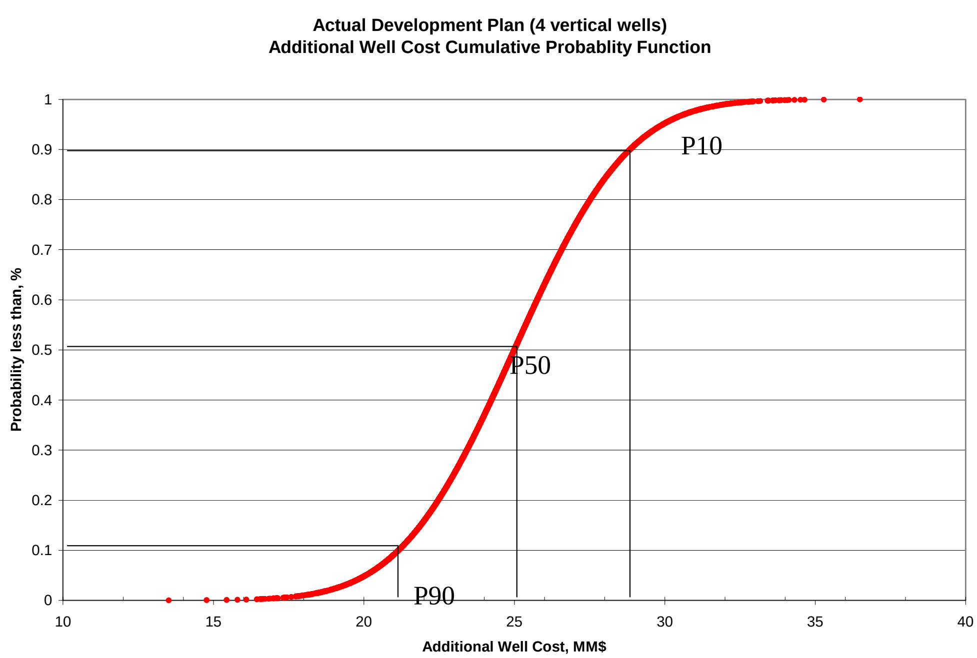


Fig. 3.5 - The additional well costs is greater or equal to 20.5 MM$ in 90% of the cases

Table 3.3 - Standard Cash Flow Model run with the P50 Values of All Distributions

Actual Development Plan - Economic Evaluation

70 MMSCFD Gas Market

Interest Rate =	15%

Gas Price =	**2.5**	**$/MSCF**
2010- 2019	**3.0**	**$/MSCF**
2020 - 20XX	**3.5**	**$/MSCF**

									drilling P3		**drilling P4**				
			1999	2000	2001	2002	2003	...	**2012**	...	**2018**	...	2029		
Années		0	1	2	3	4	5	13	**14**	15	**20**		Abandonment	**Total**	
Gas Production	MMSCF/Y		1.24E+04	1.84E+04	2.56E+04	2.56E+04	2.56E+04	2.45E+04	**2.56E+04**	2.56E+04	**2.56E+04**	2.40E+03		**594992.0**	**MMSCF**
Gross Revenue	$MM		31.05	46.04	63.88	63.88	63.88	73.64	76.65	76.65	**76.65**	8.39		**1695.07**	**$K**
CAPEX	$MM	122							**25.00**		**25.00**			**172.00**	**CAPEX**
Development Cost	$MM		4	2	5	0.5	0.5	0.0		0.0					
Operating Cost	$MM/Y		5	5	5	5	5	5	**6**	6	**7**	6		**181.00**	**OPEX**
Abandonment Cost													20		
Total Expenses/Y		122	9	7	10	5.5	5.5	5	**31.00**	6	**32.00**	6.00	20	**385.00**	**TotExp**
Cashflow		-122.00	22.05	39.04	53.88	58.38	58.38	68.64	**45.65**	70.65	**44.65**	**2.39**	-20.00		
NPV Project @ 15%	**213.70**														
IRR	**36.50%**														
Cashflow Projet Cum		-122.00	-99.95	-60.91	**-7.04**	**51.34**	109.72	603.64	**649.29**	719.94	**1042.55**	1330.07	1310.07		
Pay Out Projet	**3.9**														

Table 3.4 - Generation of NPV and IRR probabilistic distribution for a 30-point Monte Carlo Simulation of the Cash Flow Model

Monte Carlo Simulation of the Cash Flow Model - Actual Development Scenario

					drilling P3		drilling P4						
		1999	2004	...	2012	...	2018	...	2029				
Simulation Number	Initial Investment Probabilistic Values	Cash Flows			Probabilistic cost values of well subtracted from cash flow	Cash Flows	Probabilistic cost values of well subtracted from cash flow	Cash Flows	Abandonment	NPV	Probability less than	IRR	Probability less than
1	-157.21	22.05	58.88	68.64	19.07	67.22	26.11	3.83	-20.00	$168.20	5.00%	29.17%	4.00%
2	-135.20	22.05	58.88	68.64	15.74	67.22	20.09	3.83	-20.00	$186.57	22.00%	33.07%	24.00%
3	-144.38	22.05	58.88	68.64	26.63	67.22	21.31	3.83	-20.00	$181.83	16.00%	31.45%	13.00%
4	-106.49	22.05	58.88	68.64	19.90	67.22	22.03	3.83	-20.00	$217.23	77.00%	40.50%	76.00%
5	-152.89	22.05	58.88	68.64	25.49	67.22	21.29	3.83	-20.00	$172.87	7.00%	29.93%	6.00%
6	-104.46	22.05	58.88	68.64	21.20	67.22	18.12	3.83	-20.00	$219.10	80.00%	41.16%	80.00%
7	-75.69	22.05	58.88	68.64	21.89	67.22	18.46	3.83	-20.00	$248.19	99.00%	53.62%	99.00%
8	-108.07	22.05	58.88	68.64	16.85	67.22	20.58	3.83	-20.00	$214.21	72.00%	39.96%	74.00%
9	-110.11	22.05	58.88	68.64	20.73	67.22	17.49	3.83	-20.00	$213.16	70.00%	39.38%	71.00%
10	-116.01	22.05	58.88	68.64	16.78	67.22	19.68	3.83	-20.00	$206.10	57.00%	37.66%	60.00%
11	-99.13	22.05	58.88	68.64	23.16	67.22	20.32	3.83	-20.00	$225.55	88.00%	43.01%	87.00%
12	-149.43	22.05	58.88	68.64	24.03	67.22	14.13	3.83	-20.00	$174.56	9.00%	30.48%	8.00%
13	-154.69	22.05	58.88	68.64	19.07	67.22	22.27	3.83	-20.00	$168.74	5.00%	29.53%	5.00%
14	-111.31	22.05	58.88	68.64	24.02	67.22	16.36	3.83	-20.00	$213.05	70.00%	39.07%	69.00%
15	-144.28	22.05	58.88	68.64	16.10	67.22	14.82	3.83	-20.00	$176.74	10.00%	31.28%	12.00%
16	-93.49	22.05	58.88	68.64	22.54	67.22	17.80	3.83	-20.00	$230.54	93.00%	45.12%	92.00%
17	-99.08	22.05	58.88	68.64	20.44	67.22	15.66	3.83	-20.00	$223.77	86.00%	42.99%	87.00%
18	-92.96	22.05	58.88	68.64	21.34	67.22	17.00	3.83	-20.00	$230.47	93.00%	45.32%	93.00%
19	-114.89	22.05	58.88	68.64	25.32	67.22	21.09	3.83	-20.00	$210.77	66.00%	38.09%	63.00%
20	-147.98	22.05	58.88	68.64	15.73	67.22	21.12	3.83	-20.00	$173.96	8.00%	30.62%	9.00%
21	-141.50	22.05	58.88	68.64	20.90	67.22	18.75	3.83	-20.00	$182.05	16.00%	31.89%	16.00%
22	-132.35	22.05	58.88	68.64	19.49	67.22	22.66	3.83	-20.00	$191.31	30.00%	33.74%	30.00%
23	-110.90	22.05	58.88	68.64	20.14	67.22	20.63	3.83	-20.00	$212.67	69.00%	39.15%	69.00%
24	-135.14	22.05	58.88	68.64	18.68	67.22	17.24	3.83	-20.00	$187.29	23.00%	33.13%	25.00%
25	-125.32	22.05	58.88	68.64	21.49	67.22	19.94	3.83	-20.00	$198.66	44.00%	35.36%	43.00%
26	-114.59	22.05	58.88	68.64	17.89	67.22	18.49	3.83	-20.00	$207.75	61.00%	38.06%	63.00%
27	-127.05	22.05	58.88	68.64	24.57	67.22	23.97	3.83	-20.00	$198.80	44.00%	35.01%	40.00%
28	-141.56	22.05	58.88	68.64	17.67	67.22	19.67	3.83	-20.00	$180.89	15.00%	31.83%	16.00%
29	-92.31	22.05	58.88	68.64	22.89	67.22	20.55	3.83	-20.00	$232.31	94.00%	45.60%	93.00%
30	-112.97	22.05	58.88	68.64	22.54	67.22	18.08	3.83	-20.00	$211.11	66.00%	38.58%	65.00%

3.2.2.2 Cash Flow Model

Table 3.3 shows the standard cash flow model ran with the most likely values of all distributions. **Table 3.4** is a "30 points" Monte Carlo Simulation example ran for the cash flow model. In fact I ran a 5000 points model.

In doing so, I generated the following NPV (**Fig. 3.6)** and IRR (**Fig. 3.7)** - distribution curves for the actual development plan.

3.2.3 Simulation Results

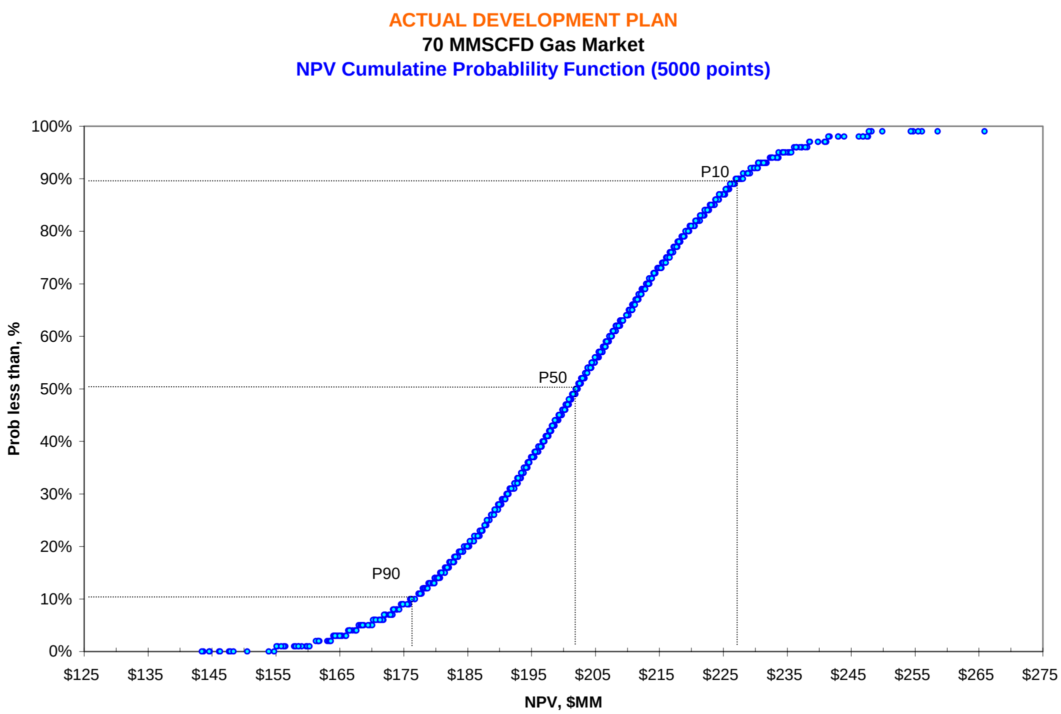


Fig. 3.6 - Resulting NPV probabilistic distribution for the actual development: the most likely NPV@15% is ~200 MM$

The following example shows how to read and interpret such a distribution (**Fig. 3.6**).

The Monte Carlo simulation reveals that the actual development scenario NPV has less than 10% chance to be under ~ 177 $MM. In other words, we have a 90% confidence (P90) that it will be at least 177 $MM.
The most likely NPV value would be ~202 $MM (P50). I.e. there are 50% chance that the NPV will be less or greater than 202 $MM.

There are 90% chances that the NPV will be less than 228 $MM. That is we have a 10% confidence that its value will be greater than 228 $MM (P10).

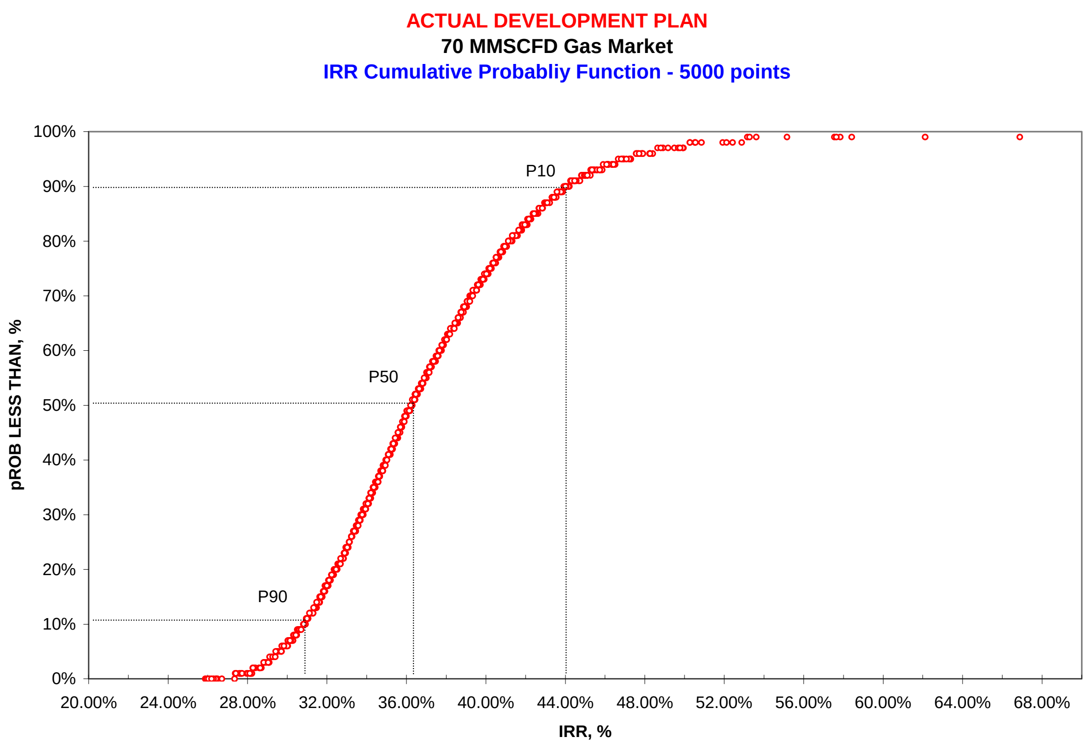


Fig. 3.7 - Resulting IRR probabilistic distribution for the actual development: the most likely IRR value is ~ 36%

Table **3.5** summarizes the main characteristics of the resulting NPV and IRR distributions.

Table 3.3 - P90 – P50 – P10 of the NPV and IRR Distribution

	P90 (90% confidence)	**P50 (Most Likely Value)**	**P10 (10 % confidence)**
NPV@15% ($MM)	177	202	228
IRR (%)	31	36	44

The actual development scenario with 4 vertical wells and intra-field flowlines is our base case. The Monte Carlo simulation allowed us to account for cost and investment uncertainties in the cash flow model. In the same time, I included sensitive variations of gas price and operating expenses.

The simulation shows that the actual development option presents good economic yardsticks. With a lowest NPV of 177 $MM at 15% interest and a rate of return of 31% at least the project is ensured to be successful.

3.3 New Well Architecture Scenario – 70 MMSCFD Case

The new well architecture proposes a completely different approach as far as well design is concerned.

A large diameter and extended horizontal well is drilled through the reservoir. It might be perforated or not. Slim-hole feeders are drilled from the surface and connected to the main horizontal well (mother well). The feeders produce directly in the mother well. All gas production comes to a main platform via the horizontal well – see **Fig. 3.8**.

Yet the reservoir model shows some advantages to use such architecture. Indeed, in most of the cases, the resulting production plateau is further extended – see chapter II.

3.3.1 Mother Well Cost Estimate

Fig. 3.9 shows a typical mother well casing design.
Table 3.6 presents a cost estimate for the mother well.
I derived an estimation from the West Africa cost database (FieldPlan). I used some rules of thumbs to estimate for instance how long it might take to drill the 8000' / 7" horizontal section. It is relevant to precise that no cost data are available as far as horizontal well drilling in this region are concerned. Therefore I accounted for uncertainties by varying the drilling time, which in turns impacts the possible cost of the well.
I finally estimated that the mother well cost would lie between 5.5 $MM (65 drilling days) and 6.3 $MM (80 days).

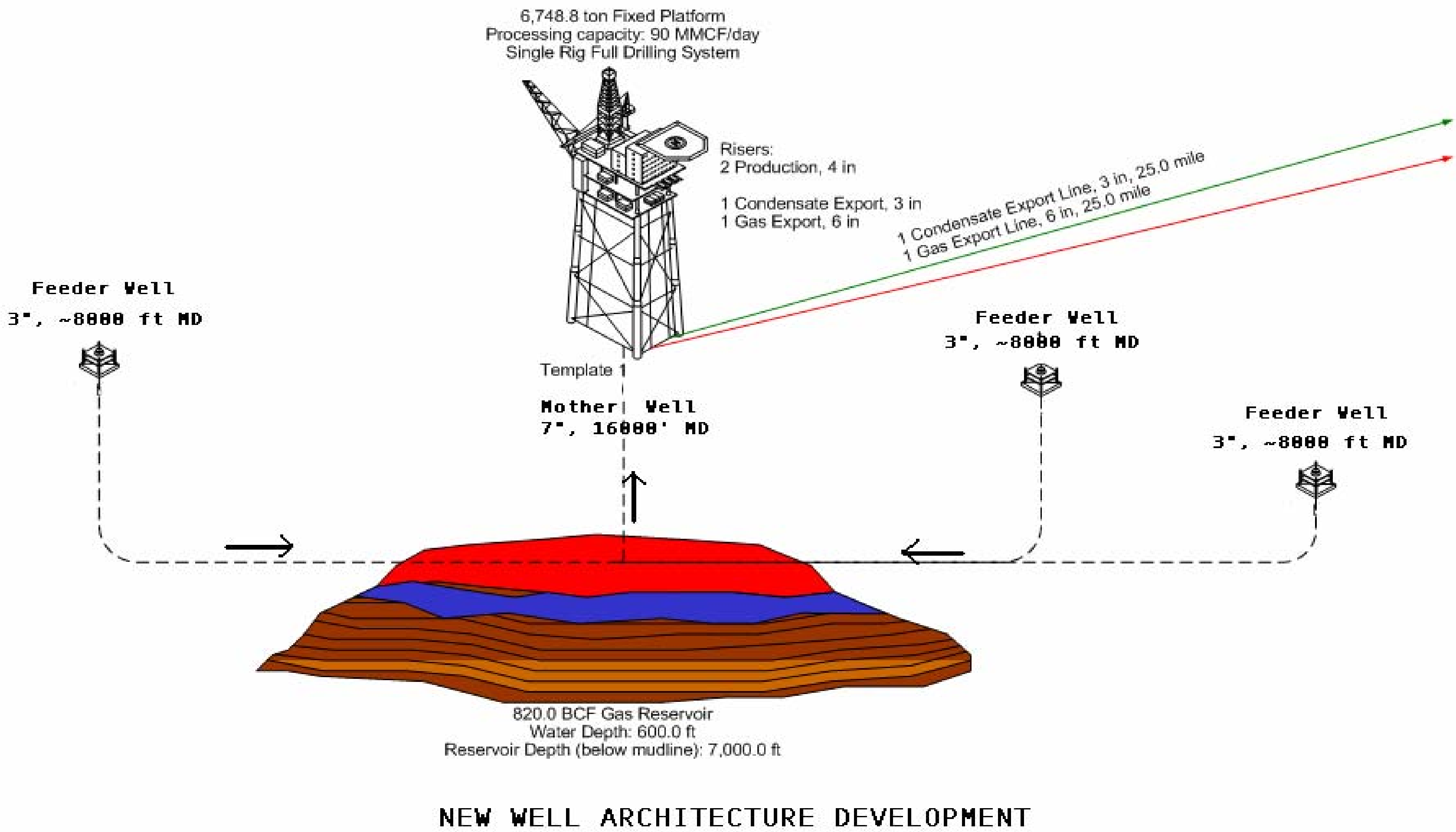


Fig. 3.8 - New well architecture scheme

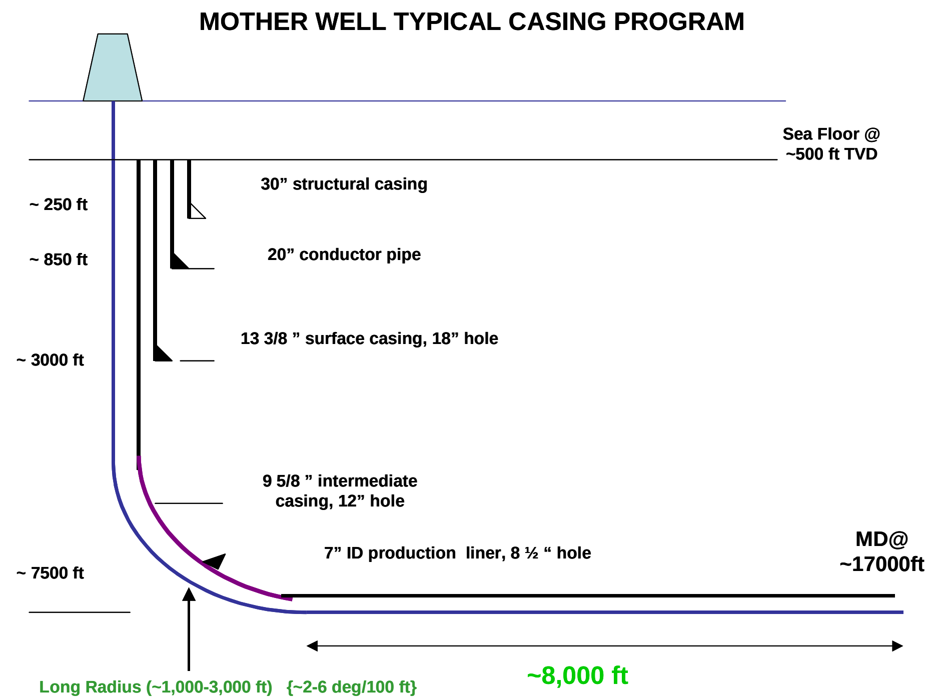


Fig. 3.9 - Example of a casing design for the mother well

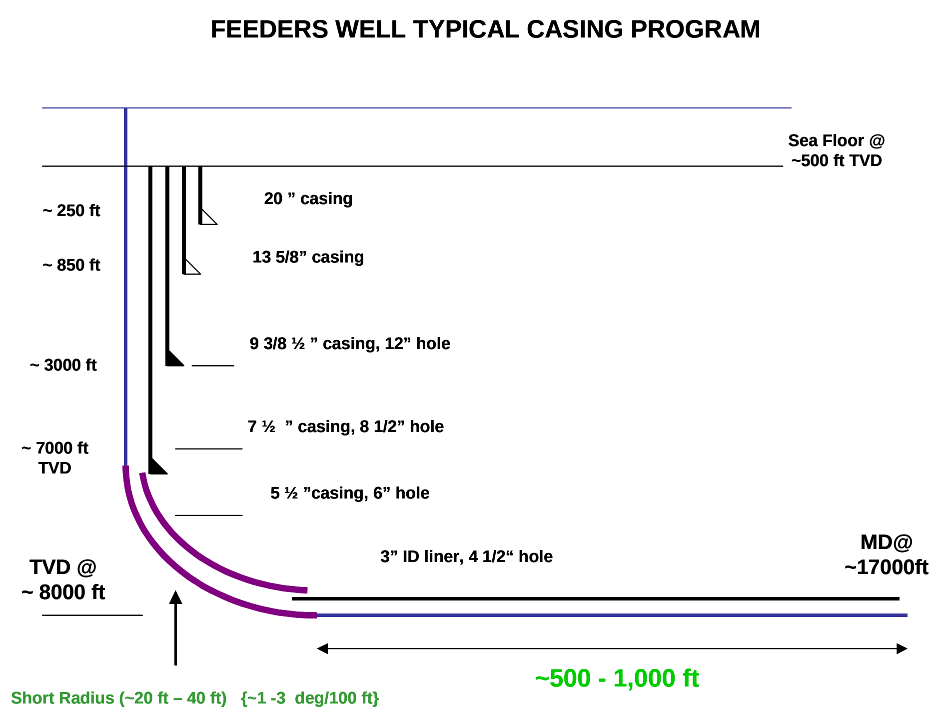


Fig. 3.10 - Example of a casing design for the feeder wells

Table 3.6 - Mother Well Cost Estimate

New Well Architecture Cost Estimation

Well Architectute Components

Mother Well (drilled from platform)

The mother well is a 7" ID cased bore.

Vertical (include deviated part) Component

TVD@8000 ft; MD @9000 tf

West Africa Cost Estimate for vertical wells @ 8000 ft				
Basic Rig Rate	$22,500	/day		
Operating Rig rate	$32,100	/day		
Total Rig Rate	**$54,600**	**/day**		
	Material Cost		Time	
Drilling Operation	$1,426,500		27	days

We assume a maximum of 30 days to complete the vertical and buid section with approximatly the same material cost

	Material Cost	**Time**	
Drilling Operation (MW)	$1,426,500	30	days

Total Cost Vertical (include deviated part) Component

$54,600	/day	x	$30	+	$1,426,500

$3,064,500

Horizontal Component

7" ID Liner run and set - 8000 ft long

Based on West Africa Cost Estimate Database

Material Cost 7" ID liner 8000 ft
$250,000
Mud & Chemical Cost
$350,000
Cement Cost
$200,000

Drilling Time Estimate	30	days
	45	days

Total Horizontal Section Cost Estimate

30 days:	**$2,438,000**
45 days:	**$3,257,000**

TOTAL MOTHER WELL COST ESTIMATE
Vertical + Horizontal Sections

$5,502,500	**(65 days)**
$6,321,500	**(80 days)**

3.3.2 Feeder Well Cost Estimate

Fig. 3.10 shows a typical feeder well casing design.
Table 3.7 & **3.8** present a cost estimate for a feeder well.

- Vertical component – **Table 3.7**

  Basically, I expect 15% to 20% cost reduction in drilling operations for the feeder compared to the actual development design. Such reduction is justified by the slim-hole characteristic of the feeder well. This design indeed requires less heavy and costly casings.

- Horizontal component – **Table 3.7**
  Again, I used some rules of thumb and time fluctuation to estimate drilling cost of this section.
- The feeder-mother well connection design would be a conventional level 6 multilateral junction. I bounded its cost between $100,000 and $500,000.
- New technology additional cost – **Table 3.8**
- Additional directional equipment will be needed to achieve the junction feeder-mother well at the required connection point. Achievement of this junction might also require additional time. I estimated that a total additional cost would lie between $50,000 and $150,000 and 2 to 5 days more.

In resume, I estimated that a possible feeder cost would range between 6.5 $MM (32 days) and 7.9 $MM (42 days). This does not account for the drilling and completion tools cost.

I estimated total investments and total feeders cost based on the actual development cost assessment.
Table 3.9 details the initial investment estimate that includes a mother well and one feeder. It is a coincidence that it also ranges (as the actual development scenario) between 121 $MM and 123$MM.
Table 3.10 presents a total investment estimate for any additional feeder well. It lies between 18 $MM and 20$MM.

Table 3.7 - Feeder Well Cost Estimate (Drilling Cost)

Feeders

Feeders are slim-hole (3" final hole) drilled from a leased rig
We estimate their costs from the West Africa Cost Estimate Database:
Satellite wells drilled from a leased rig
No tubing is needed

Vertical (include deviated part) Component

Drilling Operations	**Length**	**Cost ($1000)**	**Days**
Rig Move			1.6
Run and set 30' casing	252	93.3	1.5
Run and set 20" casing	848	91.4	5.2
Run and set 13 3/8" casing	3312	182.5	5.9
Run and set 9 5/8 " casing	7500	258.3	13.4
Mud and Chemical		345.8	
Cement		210.9	
Log&Test			2.6
		1182.2	**30.2**

Drilling Operations	**Length**	**Cost ($1000)**	**Days**
Rig Move			1.6
Run and set 20" casing	250	27	1.5
Run and set 13 5/8" casing	850	47	5.2
Run and set 9 3/8" casing	3000	103	5.9
Run and set 7 1/2 " casing	7000	241	13.4
Run and set 5 1/2 " liner	1000	32	2
Mud and Chemical		346	
Cement		211	
Log&Test			2.6
	8000	**1007**	**32.2**

Horizontal Component

	Length (ft)	**Cost ($1000)**	**Length (ft)**	**Cost ($1000)**
Run and set 3 " liner	500	16	1000	32
Mud and Chemical		22		43
Cement		13		26
		51		**102**
Time:	**2.5**	days	**5**	days
	Junction Type	**Min Cost**	**Max Cost**	
Junction Cost	**Level 6**	**100000**	**500000**	

Table 3.8 - Feeder Well Cost Estimate: Drilling Cost of New Technology

New Technology Additional Cost

This section includes both additional time and equipment needed to achieve
the connection feeder - mother well

Type	**Min Cost**	**Max Cost**
Orientation Equipment	**50000**	**150000**

Additional Time

	Min	**Max**
Per Feeder	**2**	**5**

Leased Rig rate

West Africa Database		
Basic Rig Rate	$99,700	/day
Operating Rig rate	$65,300	/day
Total Rig Rate	**$165,000**	**/day**

We predict some cost reduction mainly on the operating rig rate
which includes fuels and others consumables. The amount of those are somehow
linked to the hole size.
We predict the following reduction

Basic Rig Rate	$99,700	/day
Operating Rig rate	$45,710	/day
Total Rig Rate	**$145,410**	**/day**

Estimation summary

Time

Min	Max
37	42

Cost

Min	Max
1208108	1759046

TOTAL FEEDERS WELL COST ESTIMATE

Min	Max
$6,544,655	**$7,895,348**
(32 DAYS)	(42 DAYS)

Table 3.9 - Initial Investment Estimate: Mother Well + 1 Feeder Well

Plan: New Well Architecture		
	Equipment $ mil	**Installation $ mil**
Platform Fabrication/Conversion (1 slot)	16.4346	12.7848
Process Facilities on Platform	15.281	
Auxilliary&Marine Systems	0.988	
Accomadations	1.74	
Drilling Equipment & Completion Tools	22.8864	
Production/Export Riser	0.026	
Trees (1)	1.097	
Wellheads (1)	0.287	
Intrafield flowlines	0	0
Control System (for feeder wells)	2	
Export Pipelines (Gas&Condensate)	4.468	16.148
Sub-Total	**65.208**	**28.933**
Engineering/Design	10.312	
Project Management/Services	5.156	
Total Cost	**80.676**	**28.933**
TOTAL excluding drilling operations	109.608	
Drilling/Competion Cost		
	Min	Max
Mother Well	5.503	6.322
Feeder (1)	6.545	7.895
Sub-Total	**12.047**	**14.217**
Total Project Cost at Year ZERO - 1 feeder case	**121.656**	**123.825**

Table 3.10 - Total Feeder Cost Estimate

Plan: Feeder Cost		
	Equipment	**Installation**
	$ mil	**$ mil**
Platform Fabrication/Conversion (1 slot)	0	0
Process Facilities on Platform	0	
Auxilliary&Marine Systems	0	
Accomadations	0	
Drilling Equipment & Completion Tools	7.6288	
Production/Export Riser	0	
Trees (1)	0	
Wellheads (1)	0.000	
Intrafield flowlines	0	0
Control System (for feeder wells)	0	
Export Pipelines (Gas&Condensate)	0	0
Sub-Total	**7.629**	**0.000**
Engineering/Design	3.0936	
Project Management/Services	1.5468	
Total Cost	**12.269**	**0.000**
TOTAL excluding drilling operations	12.269	
Drilling/Competion Cost		
	Min	Max
Mother Well	0.000	0.000
Feeder (1)	6.545	7.895
Sub-Total	**6.545**	**7.895**
Total Feeder Cost	**18.814**	**20.165**

3.3.3 Simulation Results

As I did for the actual development option, I ran a Monte Carlo simulation on the cash flow model of the new well scenario.

I analyzed two options for the new well implementation. In all cases, the initial architecture includes one feeder well at least.

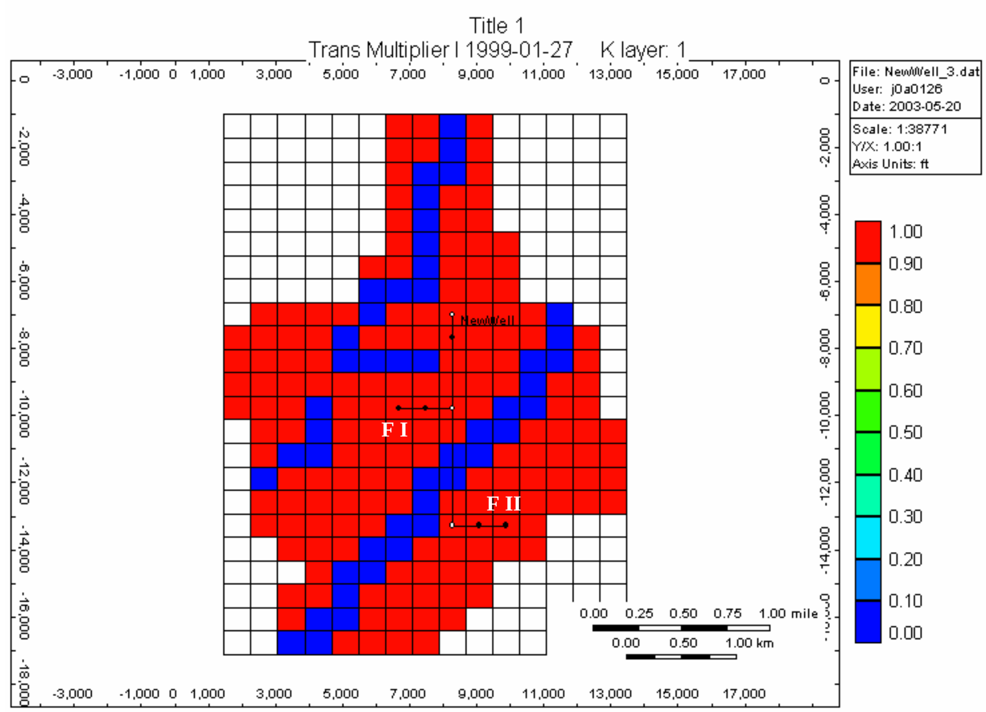


Fig. 3.11 - Two feeders well architecture: the mother well is perforated in the upper north part of the reservoir

The two options are:

- **2 feeders development option** – (Fig. **3.11)**
  The mother well is perforated in the upper north compartment.
  Two feeders produce in the mother well. The second feeder is scheduled in time. I determined the suitable time after a reservoir simulation.

- **3 feeders development option**
  Instead of two, three feeders drain the reservoir – (Fig. **3.12)**. An additional feeder drains the small isolated north area.

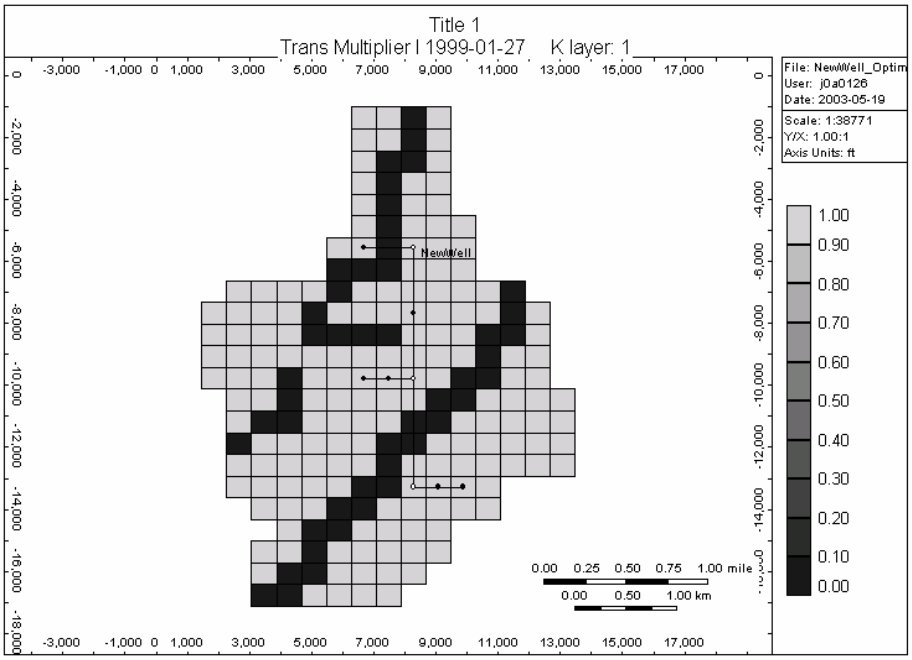


Fig. 3.12 - Three feeders development option

Fig. **3.13** shows the production forecasting with 1, 2 and 3 feeders. This allows us to schedule their drilling in time.

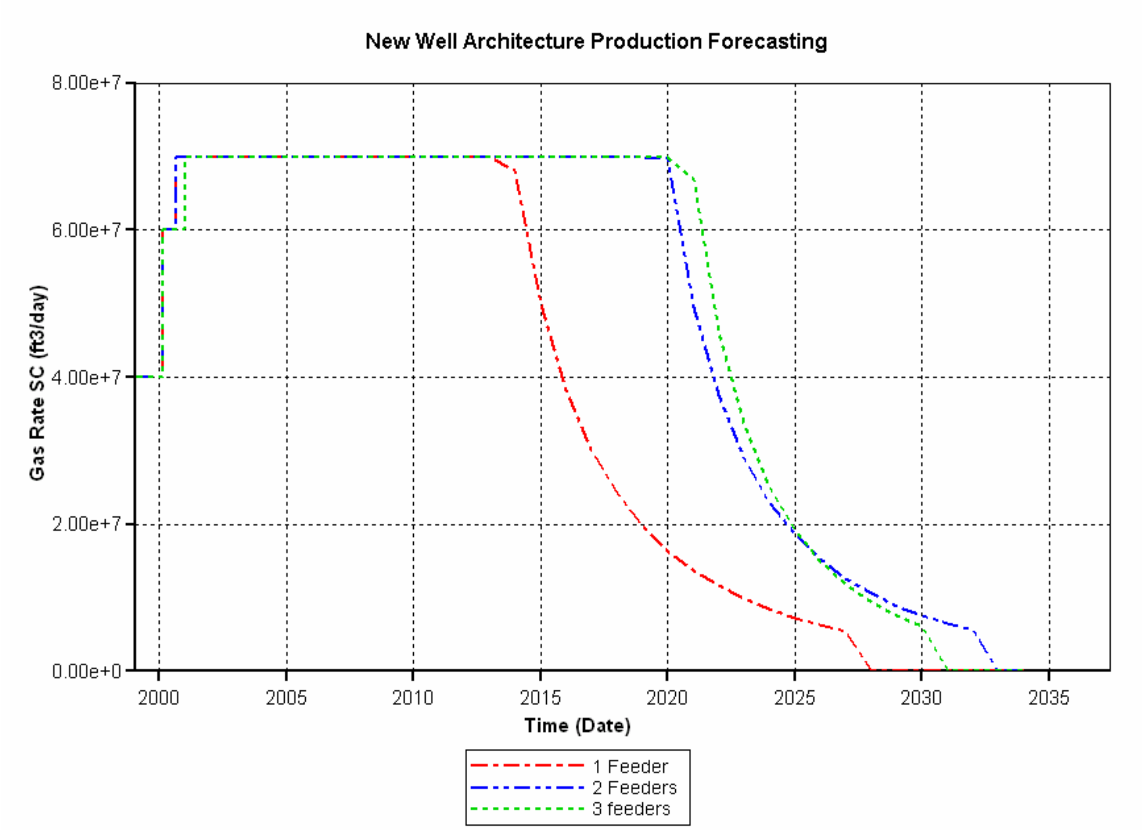


Fig. 3.13 - Feeder 2 is scheduled in ~ 2012 while feeder three can be drilled late 2019

Having, the production forecasting, the well schedule and the base cost I generated the NPV and IRR probabilistic distribution.

I assumed the following distributions:

- **Initial Investment = Normal (122, 20)** – ie the same as the actual development I.e. we model the initial investment as a normal distribution with a mean of 122 million $ and a standard deviation of 20 million $ (**Figs. 3.2** and **3.3**).

- **Additional Well Cost = N (19, 3)** – see **Figs. 3.4** and **3.5** I.e. we model the cost of a new vertical well as a normal distribution with a mean of 19 million $ and a standard deviation of 3 million $.

Fig. **3.14** compares both additional vertical well and feeder well cost distribution. Both distributions are normal. In most of the cases, the new well cost is less than a vertical well. This will not however always the case in the simulation.

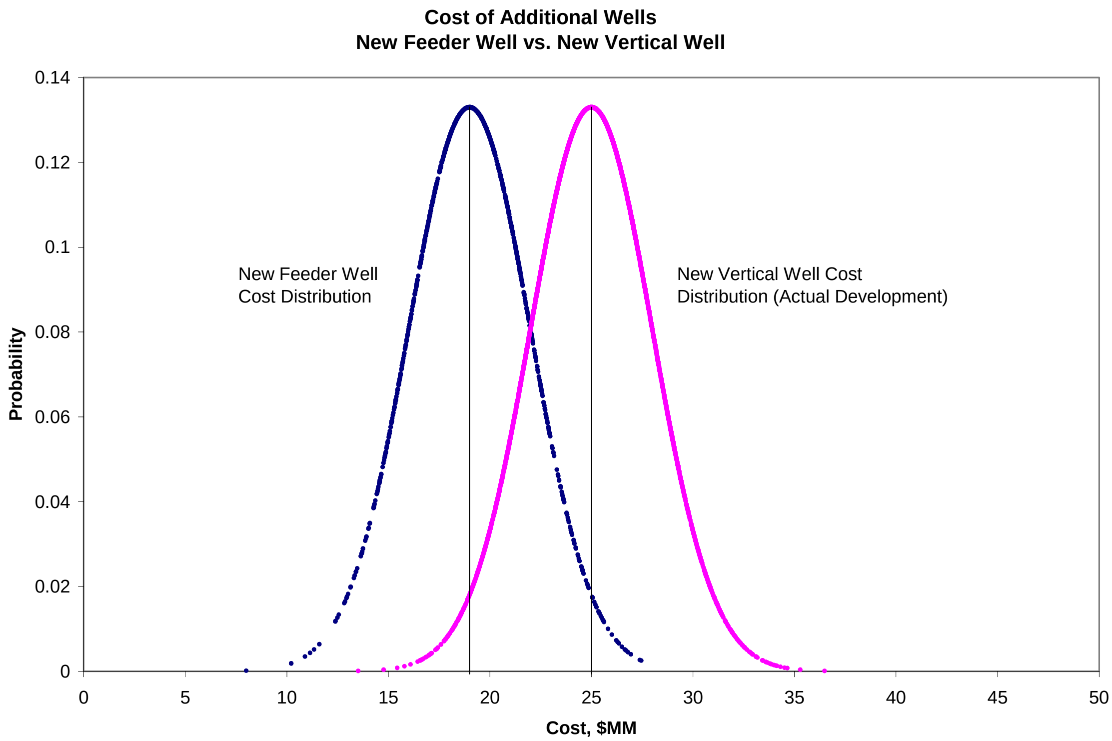


Fig. 3.14 - On average, the new feeder well will cost less than a conventional vertical well

3.4 New Well Development Scenario vs. Actual Development Scenario

I compare here the NPV@15% – **Fig. 3.15** and IRR distributions – **Fig. 3.16** of all the cases, that is: actual development vs. new architecture development with 2 and 3 feeders.

All of them are for a 70 MMSCFD Gas Market Case.

Tables 3.11 and **3.12** summarize the main characteristics of the resulting NPV and IRR distributions.

Table 3.11- P90 – P50 – P10 of the NPV Distributions – 70 MMSCFD

NPV@15% ($MM)	P90 (90% confidence)	P50 (Most Likely Value)	P10 (10 % confidence)
Actual Development Scenario	175	202	228
New Well Scenario @ 2 Feeders	202	228	252
New Well Scenario @ 3 Feeders	202	228	252

Table 3.12 - P90 – P50 – P10 of the IRR Distributions - 70 MMSCFD

IRR (%)	P90 (90% confidence)	P50 (Most Likely Value)	P10 (10 % confidence)
Actual Development Scenario	30.7	36	44
New Well Scenario @ 2 Feeders	33.5	39.5	48.7
New Well Scenario @ 3 Feeders	33.5	39.5	48.7

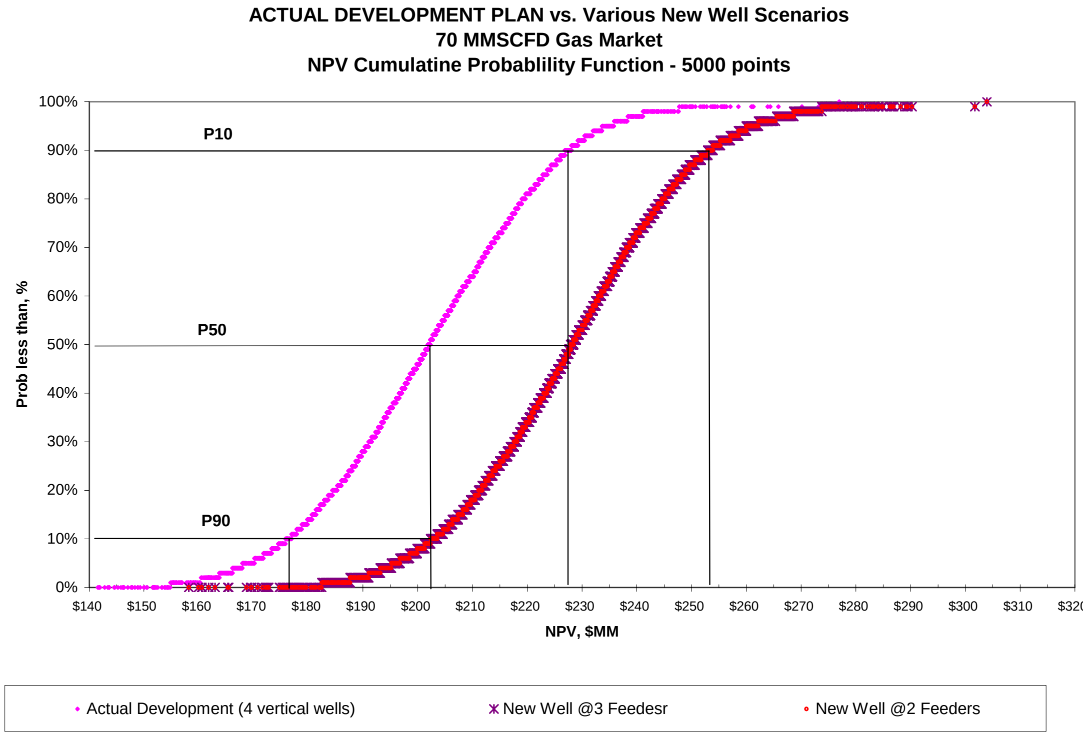


Fig. 3.15 - The new well development scenario presents a P50 NPV advantage of ~ 30 $MM

I first observe that the new well architecture scenario generates a greater net present value than the actual scenario. With one or two feeders, the new scenario offers a net advantage of nearly 25 $MM over the all distribution.

There is 90% chance that the new development would generate an additional 27 $MM compared to the actual development.
There is only a 50% chance that the actual development would yield 202 $MM while the new well scenario ensures it at 90%.

This tendency is confirmed by the internal rate of return of both project scenarios. Overall, the new well option generates revenues at a faster rate, over 3% compared to the actual development.

I also notice that both 2 feeders and 3 feeder wells options yield the same distribution for both IRR and NPV.

This can be explained by two factors:

1. The feeder # 2 does not significantly impact the production. As **Fig. 3.15** shows, its impact is small and occurs at the very end of the project.
2. As a result, the additional cash flow occurs also at the very end of the project, i.e. 20 years from now. When discounted over such a long period, this has no effect on the NPV and the IRR

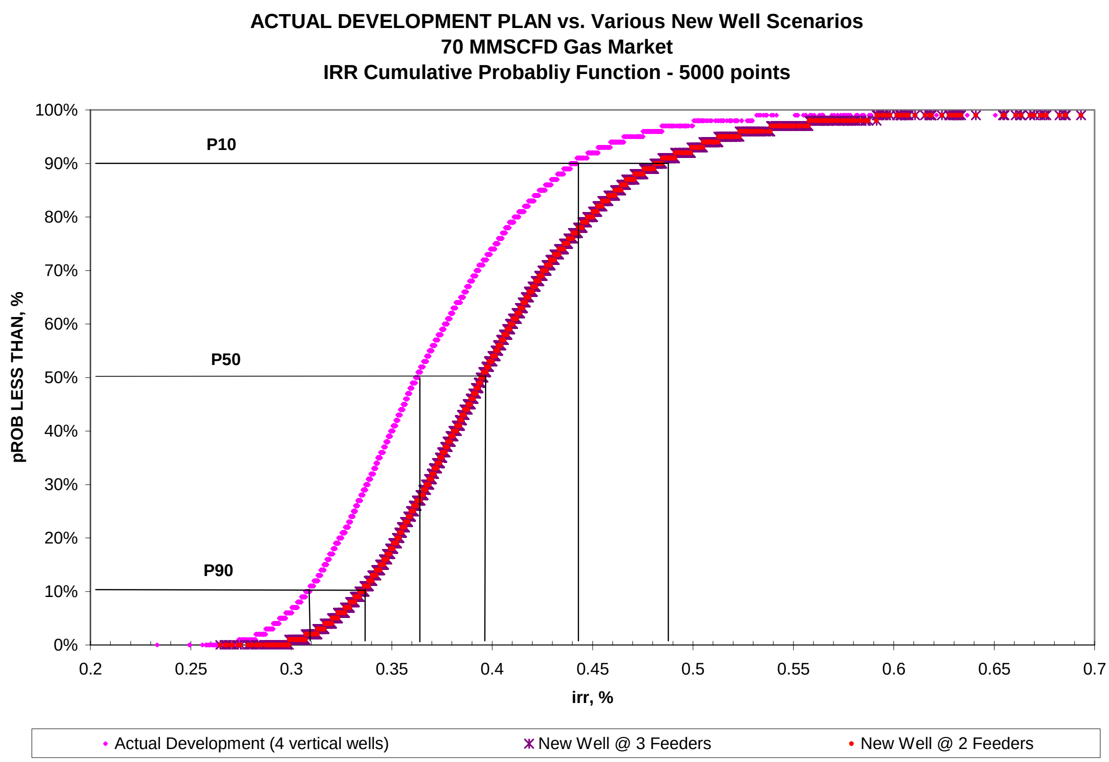


Fig. 3.16 - The P50 IRR is going from 36% for the actual development to nearly 40% for new well options

From the contractor side, both options are economically equivalent. It this case the decision to drill a second feeder is not worthy. Moreover, the contractor would probably account for drilling and other technical risks.

From the client side, government or market, the additional gas supply would be certainly welcome. Beside, a government will definitely recommend a second feeder in order to maximize its resource development.

3.5 Gas Market Variation

In additional to the actual gas market of 70 MMSCFD, I investigated other possible variations of the demand:

1. The gas demand progressively increases
2. The gas demand doubles to 150 MMSCFD

Such variations allow us to test and compare the potentialities of both architectures in terms of production capacity and flexibility.
I achieved reservoir and Monte Carlo simulations to compare both development scenarios.

The initial investments and design were made for a 70 MMSCFD target rate.
As a consequence, I had to review the project cost assumption to fit this new demand.
Only the initial investment changes, the additional well costs remain the same in both scenarios. **Table 3.14** summarizes the new evaluation.

I changed two items compared to the 70 MMSCFD gas target initial investment:

- **Process Facilities on Platform**: 50% equipment cost increase i.e. from 15.28 $MM to 22.92 $MM.
  Larger separators and tanks are required to process 110 MMSCFD

- **Export Pipelines (Gas & Condensate):** 50% increase in equipment cost and 25% increase in installation cost i.e. from 20.62 $MM to 26.88 $MM.

The total investment for both cases is now around 136 $MM.

3.5.1 Gas Market Progressively Increases

I simulated a progressive increase of the gas market. I arbitrarily chose a 20 MMSCFD increase in demand every five years – see **Fig. 3.17**.
The market requirements become:

- 2001 – 2005: 70 MMSCFD
- 2006 – 2010: 90 MMSCFD
- 2011 – 20XX: 110 MMSCFD

3.5.1.1 Production Forecasting and Cost Estimate

Overall, the actual development will be able to reach the required gas target as long as the new well architecture.
However, at such rate, the drilling schedule is more at the advantage of the new well option – see **Table 3.13**

Table 3.13 - Drilling Schedule - Progressive Gas Market Increase

	Start Production with	**Additional Well**	**Additional Well**
New Well Architecture	1 Feeder	Feeder #2 in 2012	Feeder #3 in 2013
Actual Development	2 vertical wells (P1 and P2)	Well P3 in 2009	Well P4 in 2011

Fig. 3.18 describes individual well production in the actual development scenario.

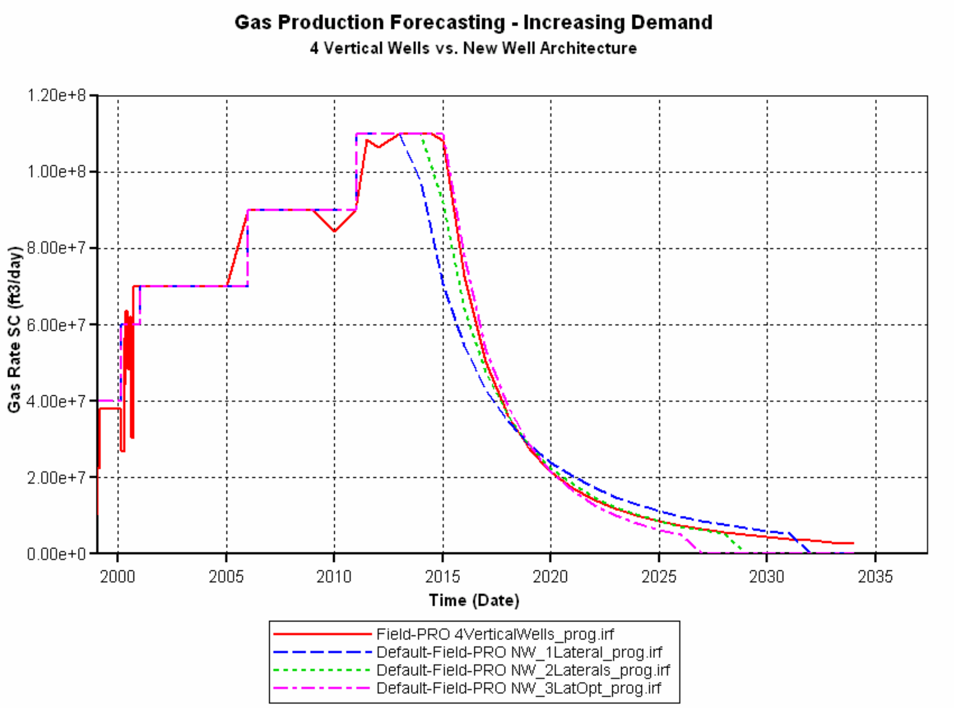


Fig. 3.17 - Production forecasting - progressive increase of gas demand

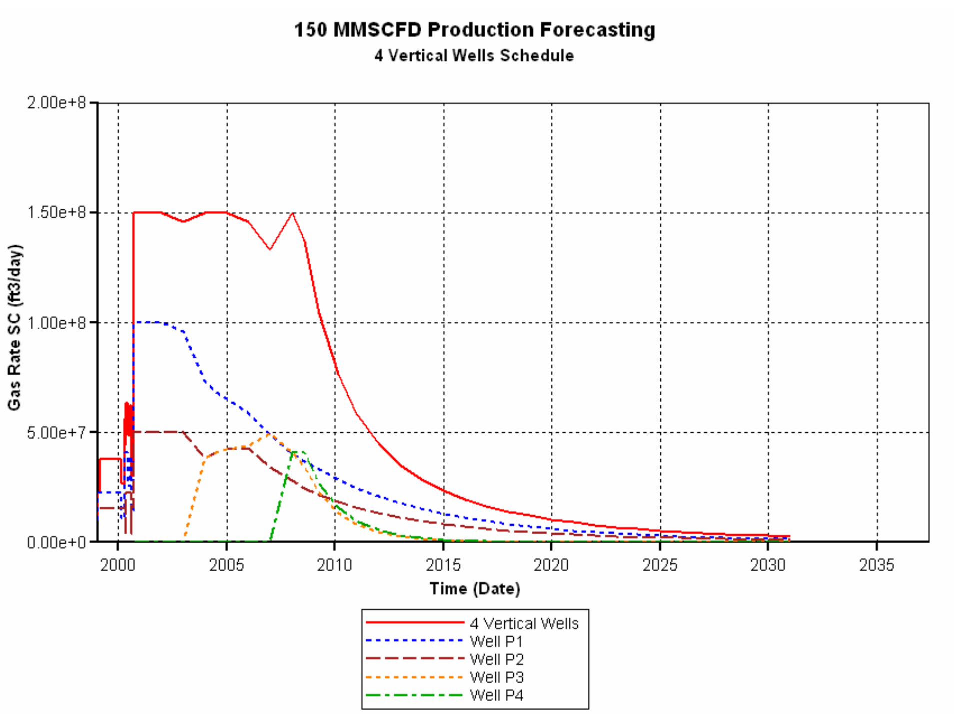


Fig. 3.18 - Actual development scenario – 150 MMSCFD gas market

Table 3.14 - Investment Evaluations for Actual and New Development – Gas Market Increase

Plan: Conventional / 2 wells and No Intrafield Flowlines at year ZERO		
	Equipment $ mil	Installation $ mil
Platform Fabrication/Conversion (4 slots)	27.391	15.981
Process Facilities on Platform	22.9215	
Auxilliary&Marine Systems	0.988	
Accomadations	1.74	
Drilling Equipment & Completion Tools	19.072	
Production/Export Riser	0.026	
Trees	1.6455	
Wellheads	0.43	
Intrafield flowlines	0	0
Control System	0	
Export Pipelines	6.702	20.185
Sub-Total	80.916	36.166
Engineering/Design	7.734	
Project Management/Services	3.867	
Total Cost	92.517	36.166
Total Cost Excluding Drilling Operations	128.683	
Drilling/Competion Cost		
Consumables	3.302	
Drilling Rig Cost	3.985	
Sub-Total	7.287	
Total Project Cost at Year ZERO	135.97	

Plan: New Well Architecture		
	Equipment $ mil	Installation $ mil
Platform Fabrication/Conversion (1 slot)	16.4346	12.7848
Process Facilities on Platform	22.9215	
Auxilliary&Marine Systems	0.988	
Accomadations	1.74	
Drilling Equipment & Completion Tools	22.8864	
Production/Export Riser	0.026	
Trees (1)	1.097	
Wellheads (1)	0.287	
Intrafield flowlines	0	0
Control System (for feeder wells)	2	
Export Pipelines (Gas&Condensate)	6.702	20.185
Sub-Total	75.082	32.970
Engineering/Design	10.312	
Project Management/Services	5.156	
Total Cost	90.550	32.970
TOTAL excluding drilling operations	123.520	
Drilling/Competion Cost		
	Min	Max
Mother Well	5.503	6.322
Feeder (1)	6.545	7.895
Sub-Total	12.047	14.217
Total Project Cost at Year ZERO - 1 feeder case	135.567	137.737

3.5.1.2 Monte Carlo Simulation Results: NPV and IRR

I chose to represent costs and investments with the same distributions as the 70 MMSCFD case. However, the mean of the investment distribution reflects the new evaluation that is 136 $MM (instead of 122 $MM).

- **Initial Investment = Normal (136, 20)** - see **Figs**. **3.2** and **3.3**
  I.e. we model the initial investment as a normal distribution with a mean of 136 million $ and a standard deviation of 20 million $.
- **Additional Well Cost = N (25, 3)** – see **Figs. 3.4** and **3.6**

The others assumptions remain identical for OPEX, interest rate @ 15% and gas price.

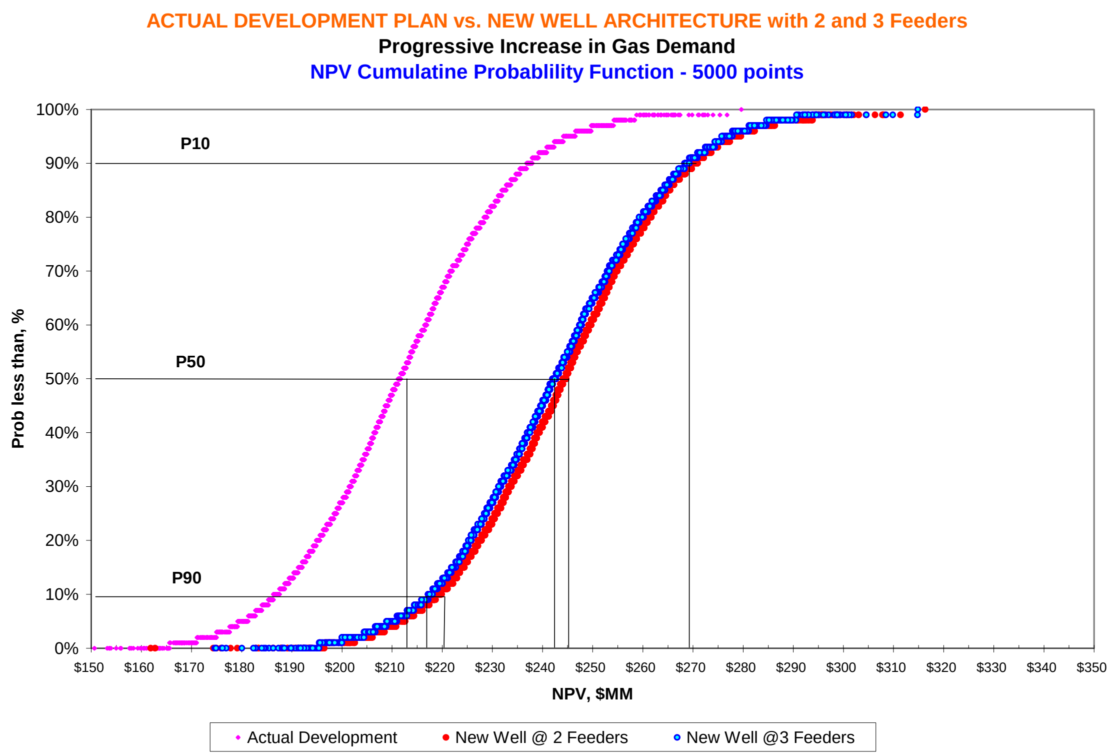


Fig. 3.19 - The new well with 2 feeders generates the highest NPV

Table 3.15 - P90 – P50 – P10 of the NPV Distributions – Progressive Gas Market

NPV@15% ($MM)	P90 (90% confidence)	P50 (Most Likely Value)	P10 (10 % confidence)
Actual Development Scenario	186.3	210.2	236.7
New Well Scenario @ 2 Feeders	218	244.2	270
New Well Scenario @ 3 Feeders	215.9	242.7	269

Again, I observe that the new well architecture scenario generates a greater net present value than the actual scenario (**Fig. 3.19** and **Table 3.15**). With one or two feeders, the new scenario offers a net advantage of nearly 32 $MM over the all distribution.

There is 90% chance that the new development would generate an additional 30 $MM compared to the actual development.
There is only a 50% chance that the actual development would yield 210.2 $MM while the new well scenario ensures 218 $MM NPV at 90% (2 feeders).

This tendency is confirmed by the internal rate of return of both project scenarios – see **Fig. 3.20** and **Table 3.16**. Overall, the new well option generates revenues at a faster rate, over 3% compared to the actual development.

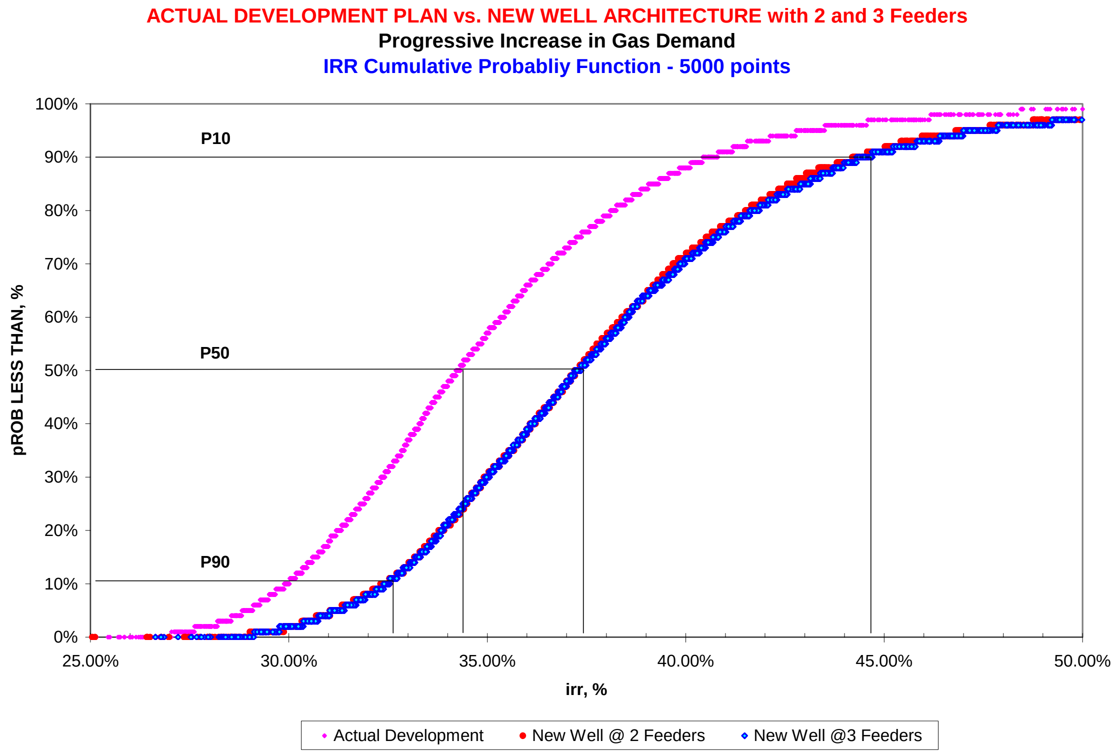


Fig. 3.20 - The P50 IRR is going from 34% for the actual development to nearly 37.5% for new well options

Table 3.16 - P90 – P50 – P10 of the IRR Distributions – Progressive Gas Market

IRR (%)	**P90 (90% confidence)**	**P50 (Most Likely Value)**	**P10 (10 % confidence)**
Actual Development Scenario	30	34.2	40.5
New Well Scenario @ 2 Feeders	32.8	37.5	44.5
New Well Scenario @ 3 Feeders	32.8	37.5	44.5

I also notice that both two feeder wells and three feeder wells options yield nearly the same distribution for the IRR. The NPV distributions show a little advantage for the two feeder wells option.

The operator should choose not to drill more than two laterals.

3.5.2 Gas Market at 150 MMSCFD

I kept the same cost and investment evaluation as the progressive demand case. The distribution assumptions remain the same.

3.5.2.1 Production Forecasting

The reservoir simulation yields the following production forecast for both new well and actual development – **Fig. 3.21**. **Fig. 3.22** shows the drilling schedule in the actual development case.

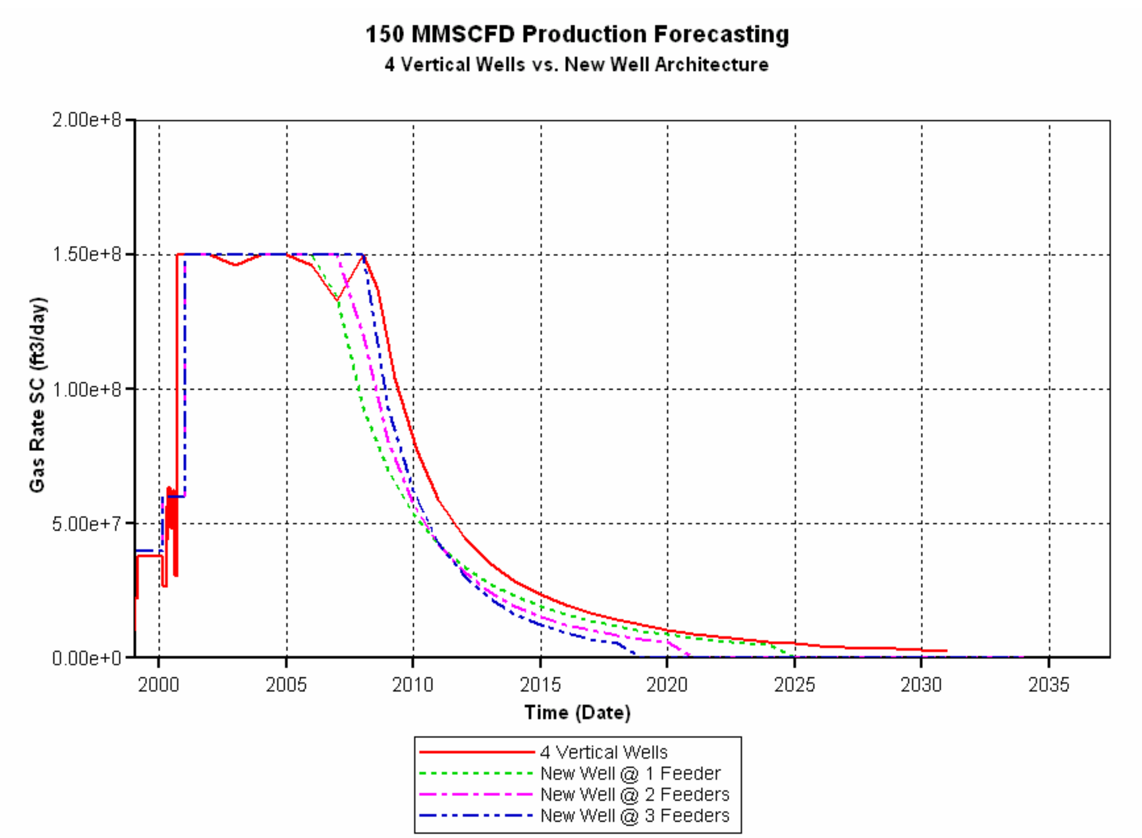


Fig. 3.21 - Production forecasting – 150 MMSCFD gas demand: the plateau is maintained until 2008

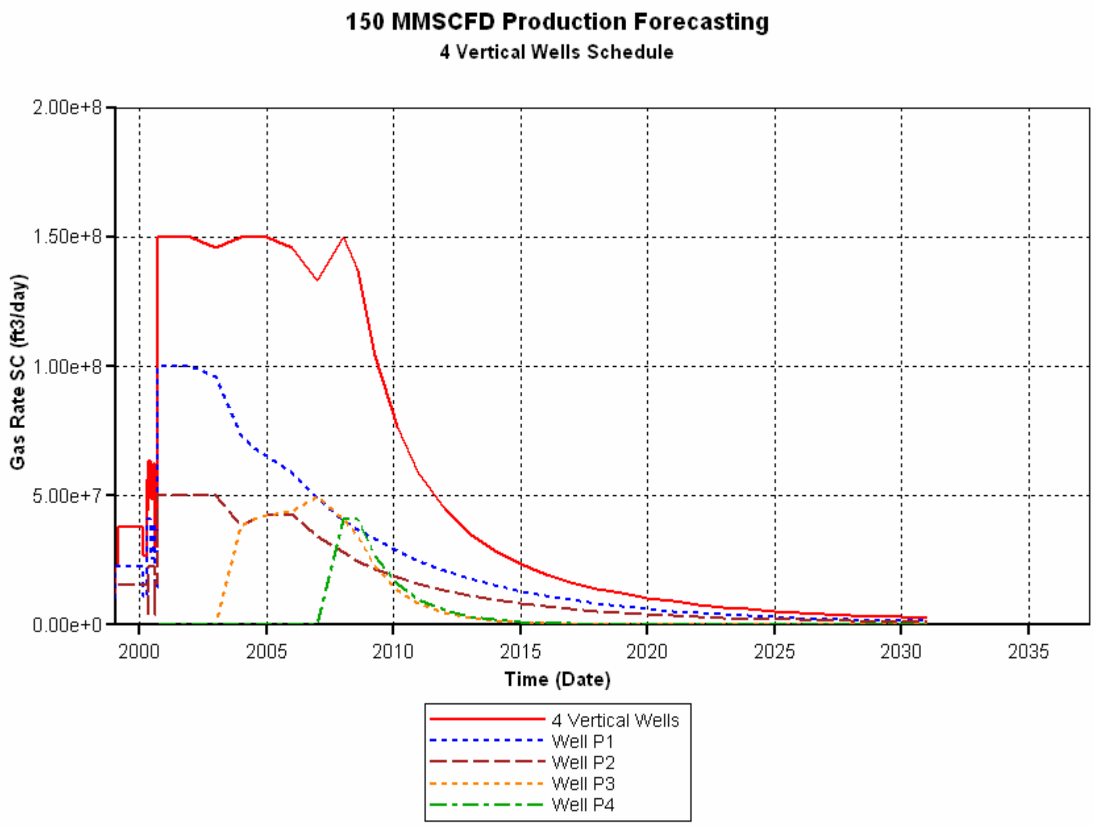


Fig.3.22 - Actual development drilling schedule – 150 MMSCFD gas market

3.5.2.2 Monte Carlo Simulation Results: NPV and IRR

Table 3.17 - P90 – P50 – P10 of the NPV Distributions –Gas Market at 150 MMSCFD

NPV@15% ($MM)	P90 (90% confidence)	P50 (Most Likely Value)	P10 (10 % confidence)
Actual Development Scenario	309.7	335.7	361.3
New Well Scenario @ 2 Feeders	349.6	375.9	401.1
New Well Scenario @ 3 Feeders	348	375	399

Table 3.18- P90 – P50 – P10 of the IRR Distributions – Gas Market at 150 MMSCFD

IRR (%)	P90 (90% confidence)	P50 (Most Likely Value)	P10 (10 % confidence)
Actual Development Scenario	44	50.5	59.7
New Well Scenario @ 2 Feeders	47.3	54.3	63.5
New Well Scenario @ 3 Feeders	47.5	54.3	63.5

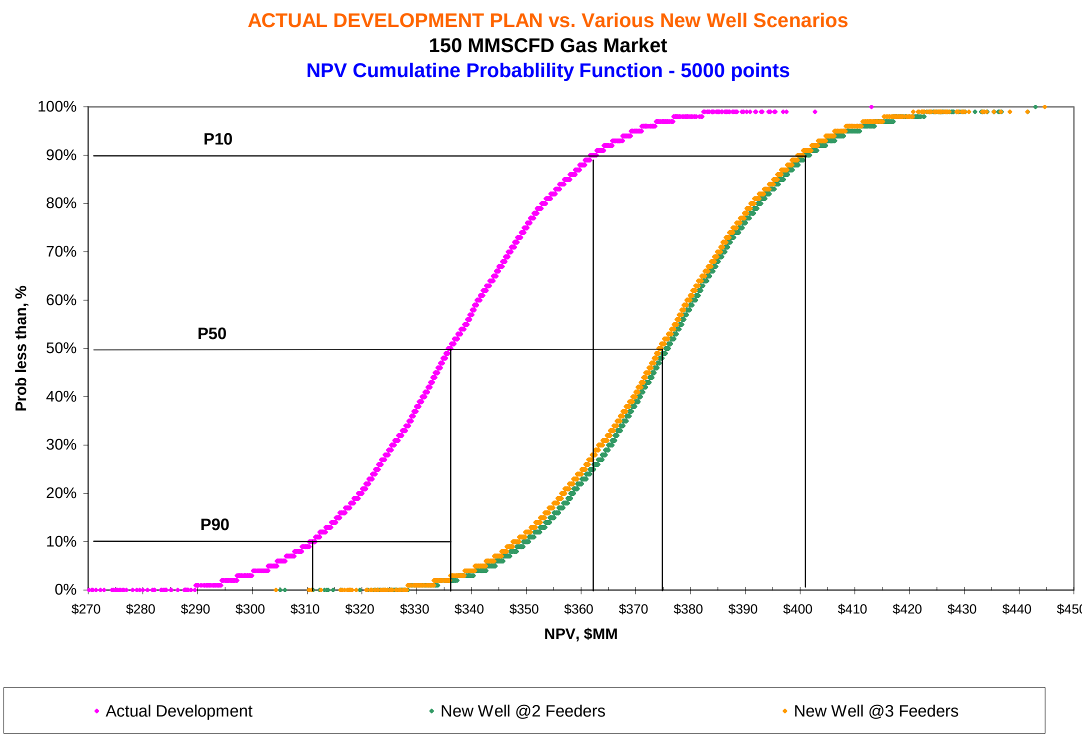


Fig.3. 23 - The new well architecture generates the highest NPV

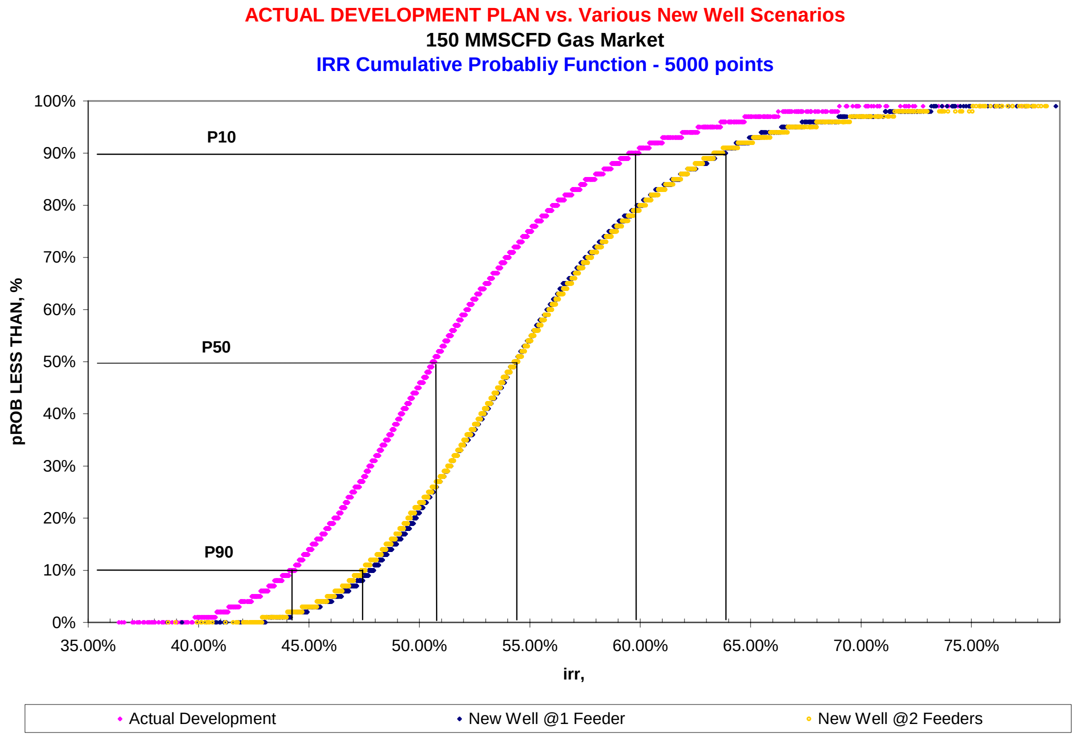


Fig.3.24 - The P50 IRR is going from 51% for the actual development to nearly 56% for new well options

Again, I observe that the new well architecture scenario generates a greater net present value than the actual scenario. With one or two feeders, the new scenario offers a net advantage of nearly 40 $MM over the all distribution (**Fig. 3.23** and **Table 3.17**).

There is 90% chance that the new development would generate an additional 40 $MM compared to the actual development.
There is only a 50% chance that the actual development would yield 337.5 $MM while the new well scenario ensures 348 $MM NPV at 90%.

This tendency is confirmed by the internal rate of return of both project scenarios – see **Figs. 3.24** and **Table 3.18**. Overall, the new well option generates revenues at a faster rate, over 5% compared to the actual development.

3.6 Quantitative Risk Analysis Summary and Main Results

I performed a quantitative risk analysis using Monte Carlo simulation technique on both the actual development plan and the new well architecture scenario.

I investigated 3 gas markets:

- 70 MMSCFD actual gas contract
- Progressive gas market increase of 20 MMSCFD after every 5 years
- 150 MMSCFD gas contract

Based on FieldPlan West Africa cost database, I estimated that the two developments would require an initial investment of:

- 122$MM for the 70 MMSCFD gas contract case
- 136 $MM for the others gas markets contract.

In each case, this accounts for the two existing wells P1 and P2 in the actual development case. In the new well scenario, the initial investment includes an 8000' long and 7" diameter horizontal mother well with one feeder @ 5" and 1000' long.

I also estimated the base cost of additional wells in each scenario:

- 25 $MM for any vertical wells including intrafield flowlines (actual development)
- and 19 $MM for any additional feeder (new well architecture).

Applying Monte Carlo technique I generated probabilistic distribution for the initial investment and additional well cost as input in a cash flow model. As a main output, I generated NPV@15% and IRR probabilistic distributions for each development scenario.

In all cases, the new well architecture presents the most favorable NPV and IRR distributions. This demonstrates that the new well scenario offers better economic performances than the actual development plan.

For the **70 MMSCFD actual gas contract** the most likely values (P50) are:

- NPV@15% / IRR
  - 202 $MM / 36% – actual development: P3 in 2012, P4 in 2018.
  - 228 $MM / 39.5% – new well development with 2 feeders: feeder #2 scheduled in 2012 or 3 feeders: third in 2013.

For the **progressive gas demand increase**, the most likely values (P50) are:

- NPV@15% / IRR
  - 210.2 $MM / 34.2% – actual development: P3 in 2009, P4 in 2011.
  - 244.2 $MM / 37.5% – new well development with 2 feeders: feeder #2 scheduled in 2012.
  - 242.7 $MM / 37.5% – new well development with 3 feeders: feeder #2 scheduled in 2012, feeder #3 in 2013.

For the **150 MMSCFD gas contract**, the most likely values (P50) are:

- NPV@15% / IRR
  - 335.7 $MM / 50.5% – actual development: P3 in 2003, P4 in 2006.
  - 375.9 $MM / 54.3% – new well development with 2 feeders: feeder #2 scheduled in 2005.
  - 375 $MM / 54.3% – new well development with 3 feeders: feeder #2 scheduled in 2012, feeder #3 in 2013.

Between the two feeders and the three feeders options in the new well architecture schema, none of the distributions reflect a significant difference. In most cases, the IRR is less sensitive than the NPV and shows identical results.

However, the reservoir simulation forecasts a better recovery for the three feeders options.

Based on these yardsticks, the choice of whether to drill a third feeder or not strongly depends on the contractor's willingness to take more risks and sustain the gas supply.

CHAPTER IV

CONCLUSIONS

4.1 Conclusions

- To demonstrate the applicability of the innovative multilateral architecture in the domain of small offshore gas field, the research focused on a field case, Phoenix, located in West Africa.

- A reservoir model of Phoenix was built. Its reservoir properties were calibrated after history matching. The calibrated reservoir model was further used for forecasting purposes.

- Simulations showed that under the current development plan, four sub-vertical wells would be necessary to sustain the 70 MMSCFD gas contract as long as possible. The two existing wells P1 and P2 can supply the required gas production until 2012. Therefore, a new well (P3) must start production in 2012, while the fourth well (P4) should begin production in 2017. All these wells should be equipped with a 5" ID tubing to ensure good well performance.

- The current development scenario performs well with 600 BCF gas recovery (75% recovery factor). The gas contract will be maintained until 2020.

- The new multilateral architecture was implemented as part of a new development scenario of Phoenix Field. For comparison purposes, the same reservoir model and gas contract requirements were used. Only, the well definition was changed.

- The new well architecture should start production with at least two laterals. This reduces the overall well cost by reducing the lateral well diameter requirement.

- The reservoir study concludes that three laterals would yield the best production performance, both in terms of gas supply and gas recovery.

- The simulations also show that a three-feeder well structure can produce as much as four vertical wells. In that case, the gas contract (70 MMSCFD) is achieved until 2020 with a recovery factor of 78%. More than three laterals do not result in a significant production gain.

- The tubing/liner diameter and production rates strongly influence the production performance of each lateral. The more the feeder wells the less the flow rate per lateral and the smaller the tubing diameter can be in each lateral. Slim-hole technology is enabled with lateral diameter up to 2.5" ID for the third lateral and 4" to 3.5" ID for first and second laterals.

- The mother well should be equipped with a 7" ID casing to attenuate pressure drop effects due to high flow rates (70 MMSCFD) occurring in that section. Its length should not exceed 8000 feet.

- The potential economic benefits of the new multilateral structure were investigated. A quantitative risk analysis on both development scenarios was performed. The development cost of each scenario was assessed. A Monte Carlo simulation was performed to account for cost uncertainties.

- Three gas market scenarios were investigated :
    - 70 MMSCFD actual gas contract
    - Progressive gas market increase of 20 MMSCFD after every 5 years
    - 150 MMSCFD gas contract

- Based on FieldPlan West Africa cost database[29] , the two developments would require an initial investment of:
    - 122$MM for the 70 MMSCFD gas contract case
    - 136 $MM for the others gas markets contract.

- The base cost of additional wells in each scenario was estimated at:
    - 25 $MM for any vertical wells including intra-field flowlines (actual development)
    - and 19 $MM for any additional lateral (new well architecture).

- Applying Monte Carlo technique, probabilistic distributions were generated for the initial investment and additional well cost as input in a cash flow model. As a main output, NPV@15% and IRR probabilistic distributions were produced for each development scenario.

- For every gas market profile investigated, the new well architecture presents the most favorable NPV and IRR distributions. The more severe the gas demand, the more advantageous is the new multilateral design.

- The NPV yardstick shows more significant results in terms of economic improvement than the IRR criterion does. When comparing current development design and new well development, the gain in terms of P50 - NPV@15% values is:
    - 70 MMSCFD: +24 million $, +3%
    - Demand increase: +34 millions $ (2 laterals), +32 million $ (3 laterals)
    - 150 MMSCFD: +41 million $ (2laterals), +40 million $ (3 laterals)

- This demonstrates that the new well scenario offers better economic performances than the actual development plan.

- The study demonstrates the economic benefits of such new multilateral technology in the domain of offshore and small gas field.

4.2 Discussion of Results and Recommendations

The main objective of this study was to investigate the applicability of a new multilateral well architecture in the domain of small size and offshore gas field.

The study looks past the mechanical challenge of achieving the structure itself, especially the junction between the lateral and the mother well. A key assumption is that it is feasible with current technology. I would refer to the works of James R. Longbottom[28] for further information on the technical details of the design. I would also recommend that future studies thoroughly assess operational risks associated with the suggested design.

My works rigorously demonstrate the applicability of the proposed well architecture to Phoenix Field, a West Africa small and offshore gas field. From the success of this case study, I also suggest that the new multilateral design has a great potential of development in the domain of small offshore gas field. One justification for such a conclusion is the specificity of the West Africa region where supply, equipment, level of services and various risks do not play in favor of project economics. In other words, if it is applicable in West Africa, there are great chances it might be applicable in most of the region of the world.

In terms of reservoir simulations, I had some difficulties to accurately model pressure drop effects of the new multilateral design. Most of these difficulties come from the poor simulator options (CMG) when it comes to multilateral wells. I bypassed these issues by performing a sensitivity analysis that allows me to recommend the most suitable design, in terms of diameter and length. However, I would recommend that future works implement a pressure drop table that can be used as an input to CMG IMEX simulator. Such tables can be generated with PIPESIM 2002.

The quantitative risk analysis using Monte Carlo technique permitted to capture most of the uncertainties linked the new well development. Those uncertainties exist at the level of the design, the use of new technology and associated cost. I choose a normal distribution to model the possible costs. One logical reason for that choice is the nature of the variables modeled: investments and costs result from the addition of every single cost.

The NPV and IRR are among the very common and effective yardstick when it comes to rank and screen projects. However, neither NPV nor IRR can reflect with enough significance late expenses. For instance, Phoenix has a total life of nearly twenty years (70 MMSCFD gas contract). The drilling cost impact and revenues from additional production fifteen years from now are much less significant than early investments. This is why both IRR and NPV distributions are almost identical for two or three lateral schemes. The reservoir simulation however shows an additional year of gas supply at 70 MMSCFD with three compared to two laterals.
Based on these yardsticks, the choice of whether to drill a third feeder or not strongly depends on the contractor's willingness to sustain the gas supply. This decision in this case is at least delayed in the future. It would not affect current production. This is a good example of an important option value current multilateral technology cannot offer.

It is also important to notice the difficulty when it comes to translate into numbers the option values of the new multilateral architecture. The all concept of risk reduction, standard well maintenance and treatments, reduction in flow assurance issues could not be modeled in the Phoenix case for instance. It would be valuable to this study to investigate various cases for example with well stimulation or wax deposit issues. Quantification of new option enabled by the suggested architecture could bring tremendous vales to the project.

Like any technology, the suggested multilateral architecture has some limitations and disadvantages:

- It is a new technology. Therefore more risks are associated with is implementation.

- Drilling and achievement of the structure are technically challenging and demanding.

- The mother well has a maximum length that will limit the number of connections.

- The cost of mother well might be prohibitive.

- The mother well might limit production capacity with feeder wells deliverability exceeding its outtake capacity.

NOMENCLATURE

BCF:	Billion Cubic Feet
BHP:	Bottom Hole Pressure
BSCF:	Billion Standard Cubic Feet
CAPEX:	Capital Expenditures
ft:	feet unit
IRR:	Internal Rate of Return
Kv/Kh:	Vertical Permeability over Horizontal Permeability
ML:	Multi Lateral
MSCF :	Thousand Cubic Feet
NI, NJ, NK:	Number of Grid Blocks in I, J, K direction
NPV:	Net Present Value
NW-SW:	North West - South West
OPEX:	Operating Expenses
psi:	Unit Measure, Pound Sqauare Inches
psia:	Unit Measure, Pound Sqauare Inches Absolute (= psi + 14.7)
TAML:	Technical Advancement for Multilaterals
TVDSS:	True vertical Depth Subsea

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APPENDIX A

WELL INDEX MODIFICATION

CMG IMEX simulator uses a well segmentation approach [1, 26]. Basically, each perforation is modeled a segment i. IMEX computes a well index (WI) and productivity index (PI) on a segment basis. The total WI and PI is a summation.

Equation 4

$$Qg = \sum_i \left[PI_i \times \lambda_g \times \left(Pwf + head - Pblocki \right) Bg \right]$$

$$PI = \sum_i PI_i = \sum \lambda_i \times WI_i$$

IMEX introduces a flow factor (**0 < alpha < 1**) coefficient that models the perforation penetration.

We modified alpha to account for well diameter differences within WI:

$$\alpha_{x/7} = \frac{WI\ @\ xinches}{WI\ @\ 7inches}$$

We simulated a well with a 7” ID (mother well) and another well with the desired X” ID. At the level of each lateral perforation, we replaced the flow factor coefficient such as :

$$WI\ @\ Xinches = \alpha_{X/7} \times WI\ @\ 7inches$$

Table A1 shows the computations for the 2” and 2.5” cases. In the table ffX/7 represents alpha.

Table A1 - Well Index Modification

Gas PI scf/d/psi (5 in)	WELL INDEX (2.5 in)	Gas PI scf/d/ps (2.5 in)	WELL INDEX (2 in)	Gas PI scf/d/psi (2 in)	|WELL | INDEX (7 in)	Gas PI scf/d/ps (7in)	ff 2,5/5 = WI2/WI5	ff 2/7 = WI2/WI7
------------	----------	----------	----------	-----------	-----------	----------		
0	2.55E+03	0	2.46E+03	0	3.03E+03	0	0.893	0.814
0	1.11E+03	0	1.07E+03	0	1.31E+03	0	0.893	0.814
0	1.73E+03	0	1.68E+03	0	2.06E+03	0	0.893	0.814
0	1.72E+03	0	1.66E+03	0	2.04E+03	0	0.893	0.814
1.25E+05	1.71E+03	1.11E+05	1.65E+03	1.08E+05	2.02E+03	1.32E+05	0.894	0.815
1.24E+05	1.70E+03	1.11E+05	1.64E+03	1.07E+05	2.02E+03	1.32E+05	0.894	0.815
1.24E+05	1.69E+03	1.11E+05	1.64E+03	1.07E+05	2.01E+03	1.31E+05	0.894	0.814
1.23E+05	1.69E+03	1.10E+05	1.63E+03	1.07E+05	2.00E+03	1.31E+05	0.894	0.815
1.23E+05	1.68E+03	1.10E+05	1.63E+03	1.06E+05	2.00E+03	1.30E+05	0.894	0.815
4.98E+05	6.92E+03	4.53E+05	6.73E+03	4.40E+05	8.00E+03	5.23E+05	0.910	0.842
8.11E+04	1.11E+03	7.24E+04	1.07E+03	7.00E+04	1.32E+03	8.60E+04	0.894	0.813
8.13E+04	1.11E+03	7.26E+04	1.08E+03	7.02E+04	1.32E+03	8.63E+04	0.893	0.814
8.15E+04	1.12E+03	7.28E+04	1.08E+03	7.04E+04	1.33E+03	8.65E+04	0.893	0.814
8.14E+04	1.11E+03	7.27E+04	1.08E+03	7.03E+04	1.32E+03	8.64E+04	0.893	0.814
8.13E+04	1.11E+03	7.27E+04	1.08E+03	7.03E+04	1.32E+03	8.63E+04	0.893	0.814
3.46E+05	4.83E+03	3.16E+05	4.70E+03	3.07E+05	5.56E+03	3.63E+05	0.912	0.845
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1.87E+06		1.68E+06		1.63E+06		1.97E+06		

APPENDIX B

WEYMOUTH EQUATION FOR PRESSURE DROP CALCULATION

HORIZONTAL WELL – SINGLE GAS PHASE

$$p_2 = \left[p_1^2 - \frac{\gamma_g ZLT}{d^{\frac{16}{3}}} \left(\frac{q_g}{15320} \right)^2 \right]^{1/2}$$

Flow from 1 to 2
P1, P2 : psia
d: ID, inch
T: deg R
L: miles
Qg: scf/d

Table B1. Pressure Drop Calculation using Weymouth equation and an iterative process

Gas Gravity =		0.6			
Reservoir Temp =		655R			
P1 =		3820 psia			
Length =		**1.893939** miles		10000ft	
Diamter =		**7** in			
Gas Flow rate =		**70000000** scf/d			
Pass	**DP**	**P2**	**Pav**	**Z**	**P2 cal**
1	100	3720	3770	0.955	3759.098
2	**60.90227**	3759.098	3789.549	0.95	3759.419

APPENDIX C

METHOD AND APPARATUS FOR INTERSECTING DOWNHOLE WELLBORE CASING

US patent 6199633, reprinted with the permission of James R. Longbottom

(see following pages)

(12) **United States Patent**
Longbottom

(10) **Patent No.: US 6,199,633 B1**
(45) **Date of Patent: Mar. 13, 2001**

(54) **METHOD AND APPARATUS FOR INTERSECTING DOWNHOLE WELLBORE CASINGS**

(76) Inventor: **James R. Longbottom**, P.O. Box 1115, 25311 Winding Creek Ct., Magnolia, TX (US) 77353

(*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 0 days

(21) Appl. No.: **09/384,619**

(22) Filed: **Aug. 27, 1999**

(51) **Int. Cl.**[7] **E21B 17/10**

(52) **U.S. Cl.** **166/242.6**; 166/117.6; 166/50; 175/45; 175/171

(58) **Field of Search** 166/268, 50, 117.5, 166/117.6, 242.6; 175/45, 61, 171; 403/328, 327

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Primary Examiner—Lanna Mai
(74) *Attorney, Agent, or Firm*—Marvin J. Marnock

(57) **ABSTRACT**

The present invention provides a method and apparatus for mechanically interconnecting a lateral wellbore liner to a main, or parent, wellbore casing. The present invention further provides a method of wellbore construction for the construction of multiple wellbores which are interconnected downhole to form a manifold of pipelines in a reservoirs of interest. Provision is made for flow controls, sensors, data transmission, power generation, and other operations positioned in the lateral wellbores during the drilling, completion and production phases of such wellbores.

9 Claims, 8 Drawing Sheets

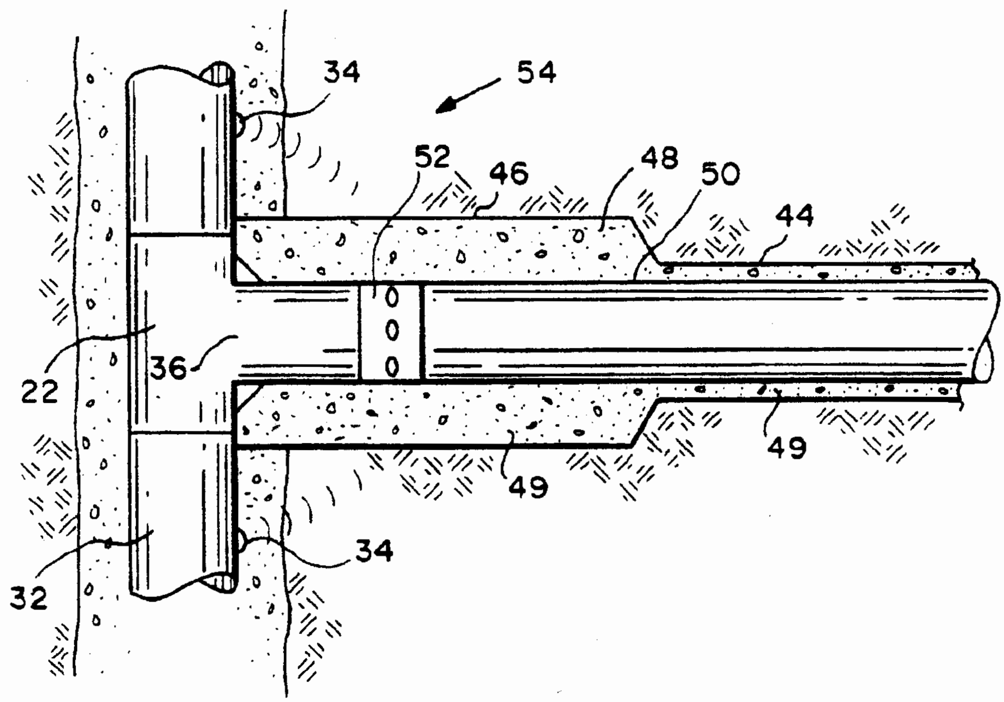


FIG. 1A
PRIOR ART

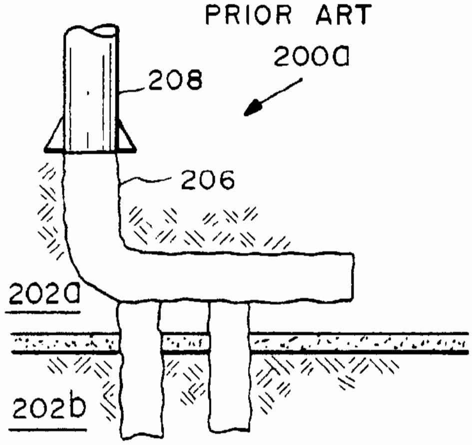


FIG. 1B
PRIOR ART

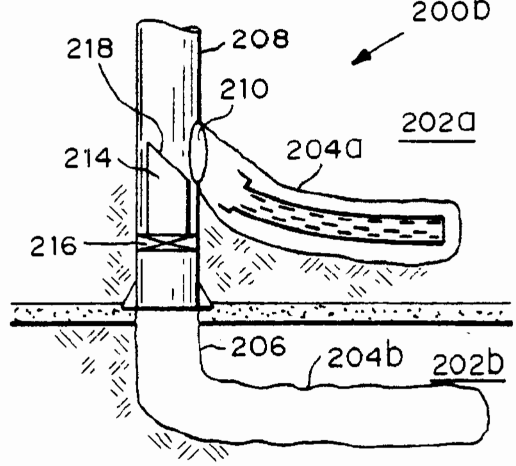


FIG. 1C
PRIOR ART

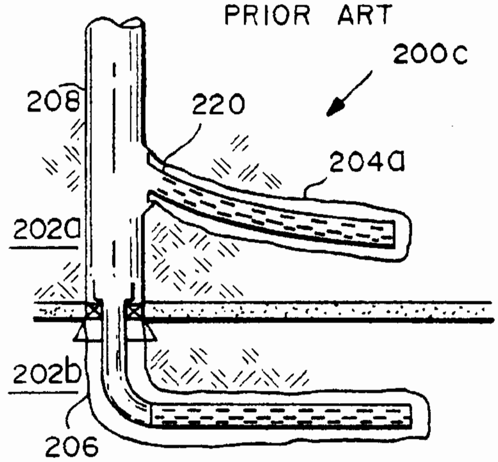


FIG. 1D
PRIOR ART

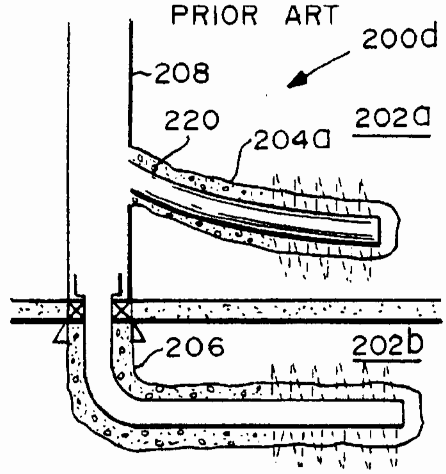


FIG. 1E
PRIOR ART

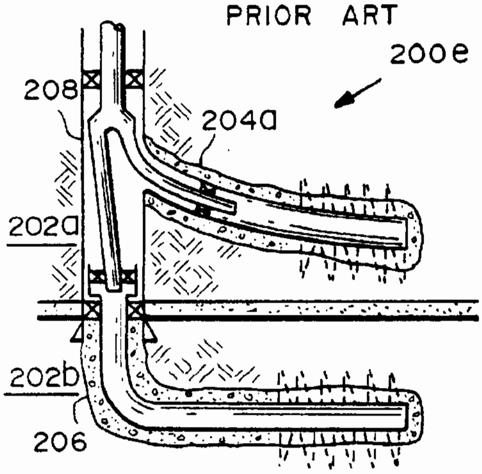


FIG. 1F
PRIOR ART

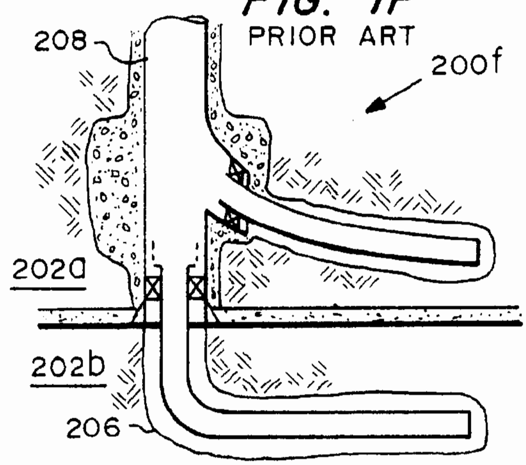
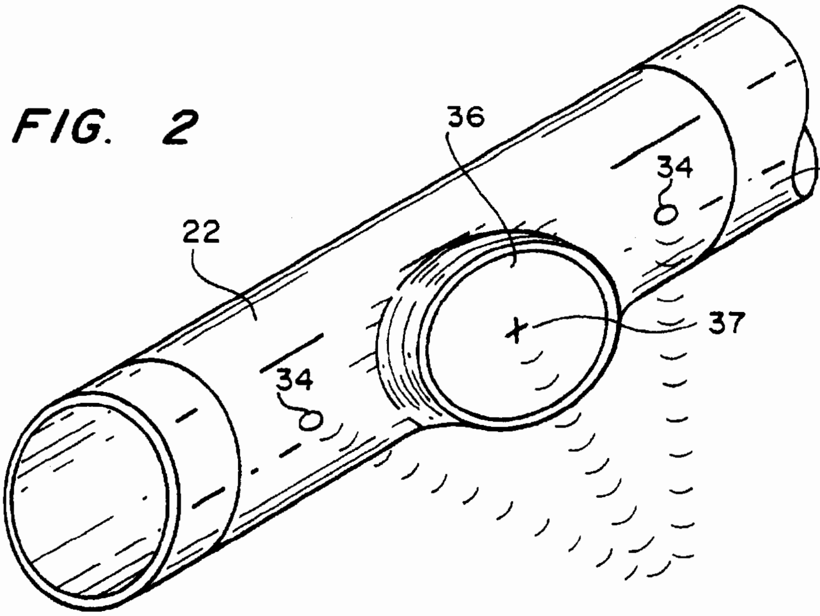


FIG. 2



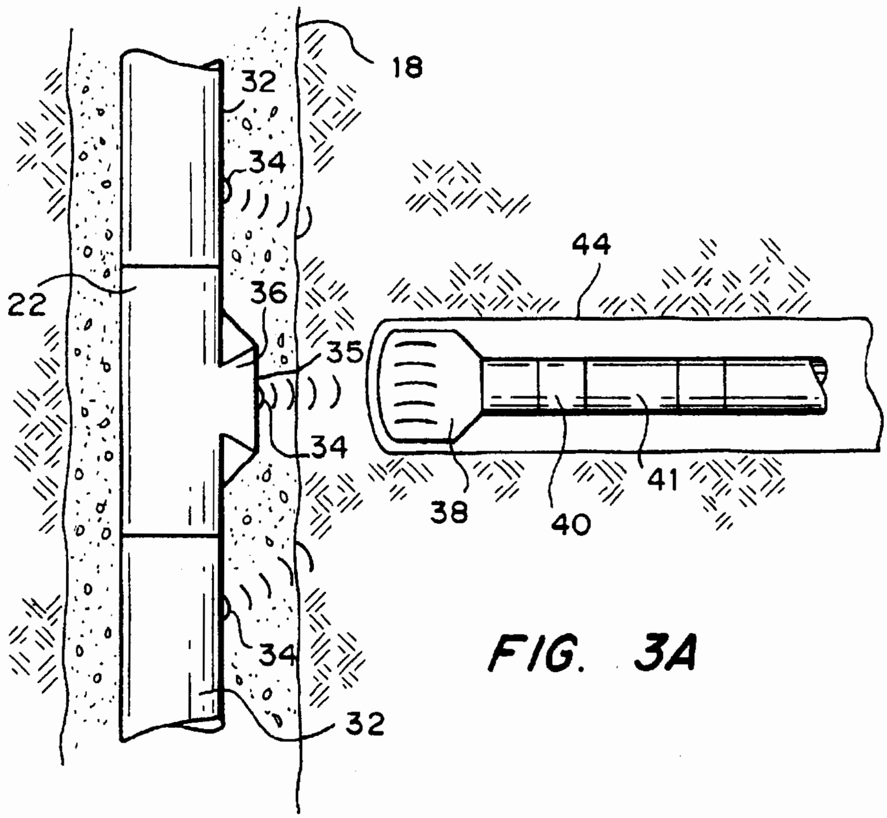


FIG. 3A

FIG. 3B

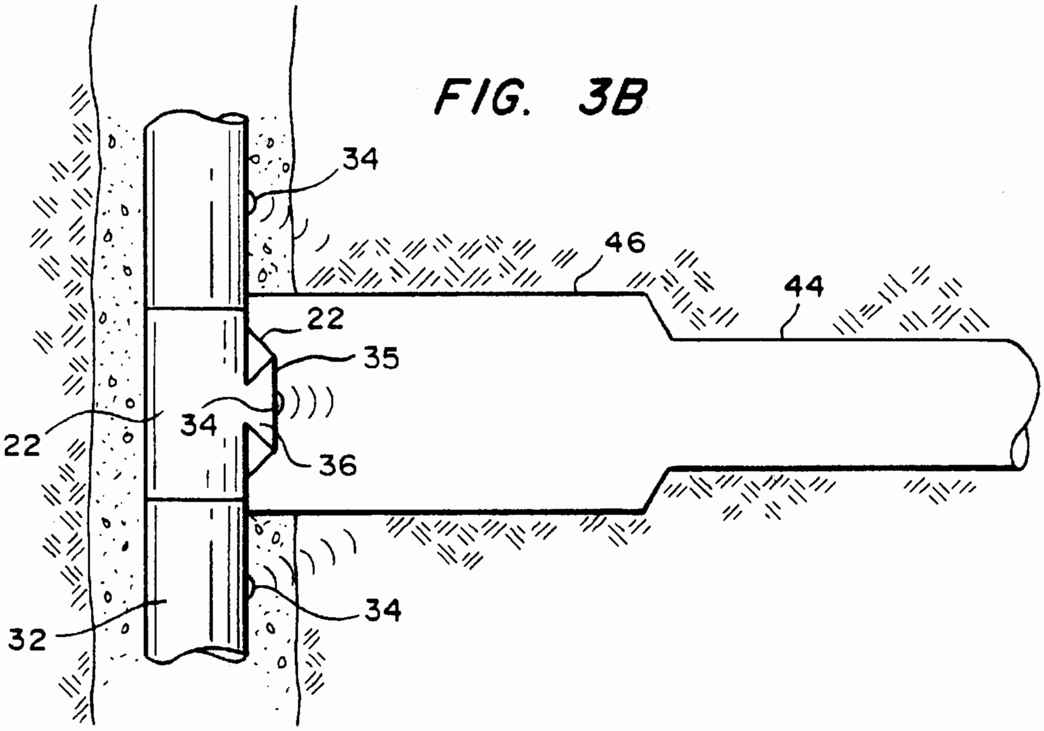


FIG. 3C

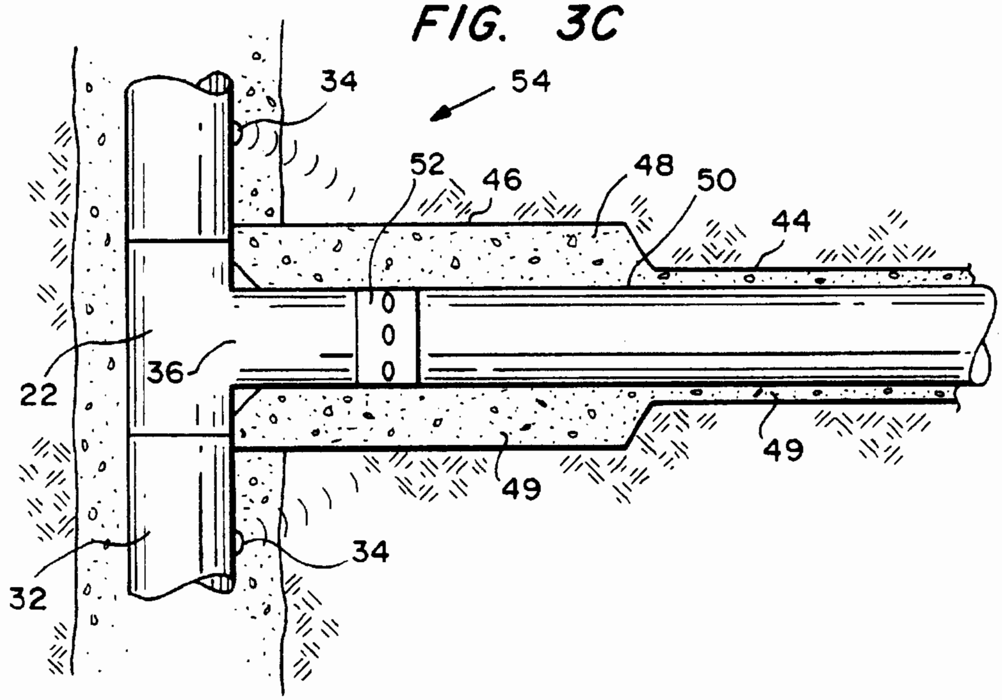
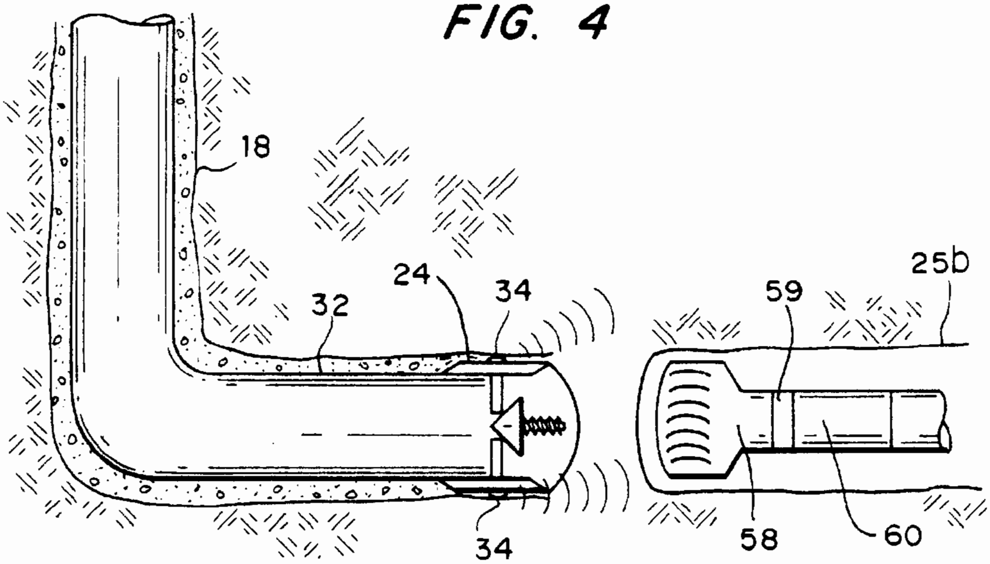


FIG. 4



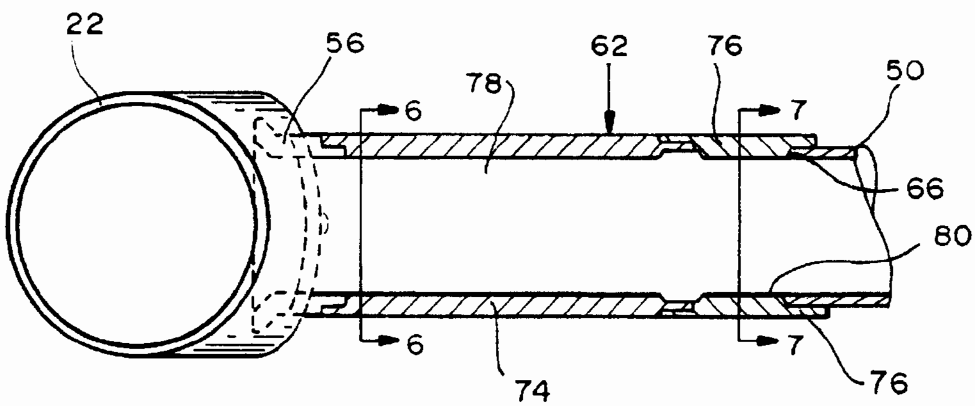


FIG. 5

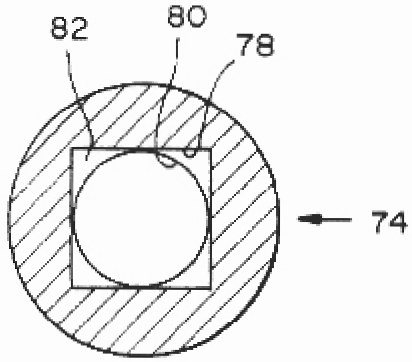


FIG. 6

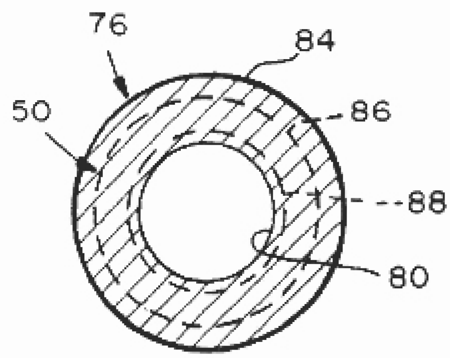


FIG. 7

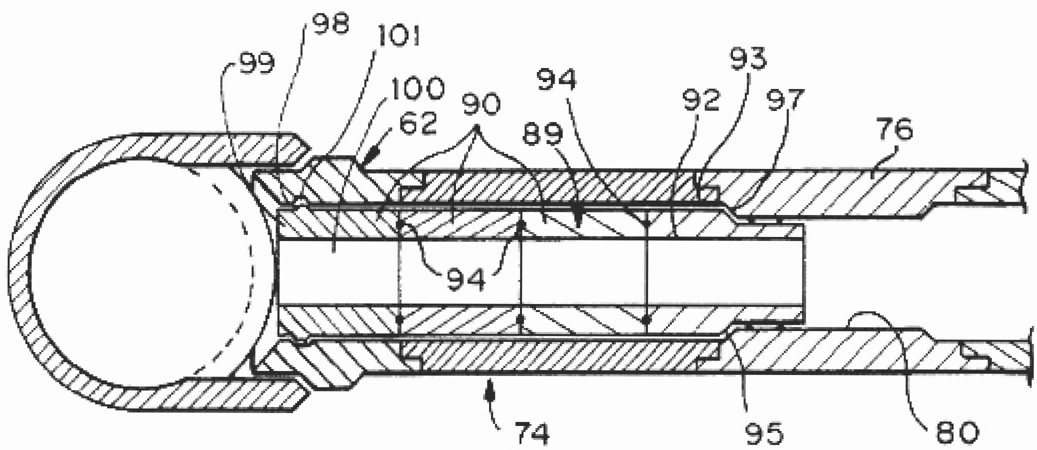


FIG. 8

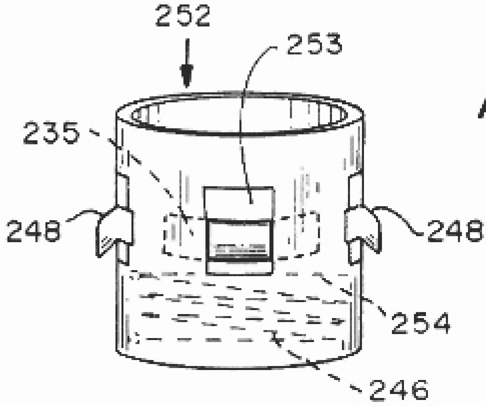


FIG. 9C

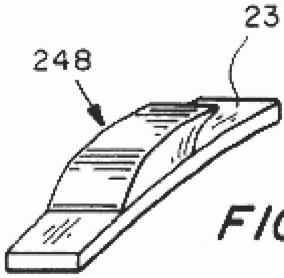


FIG. 9B

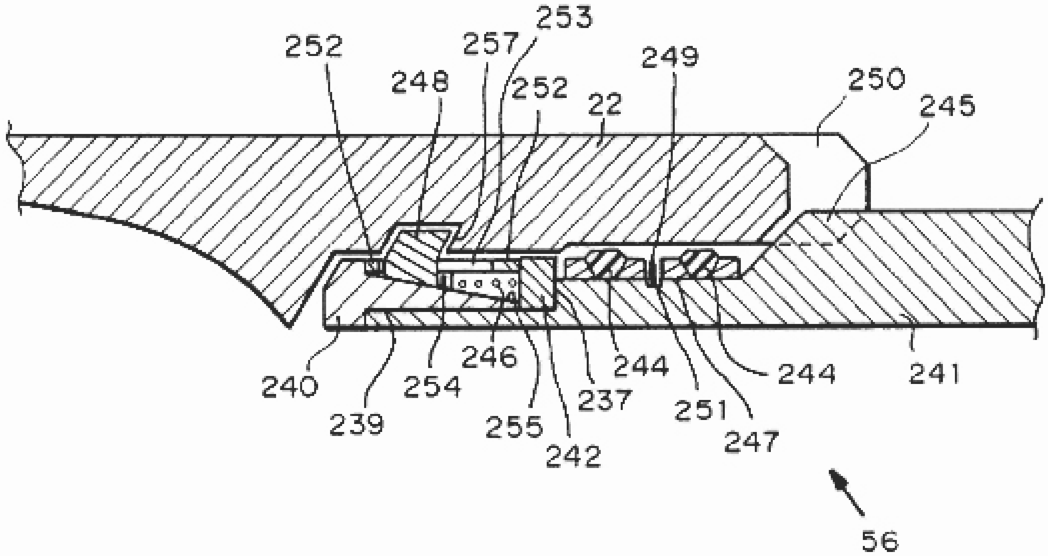
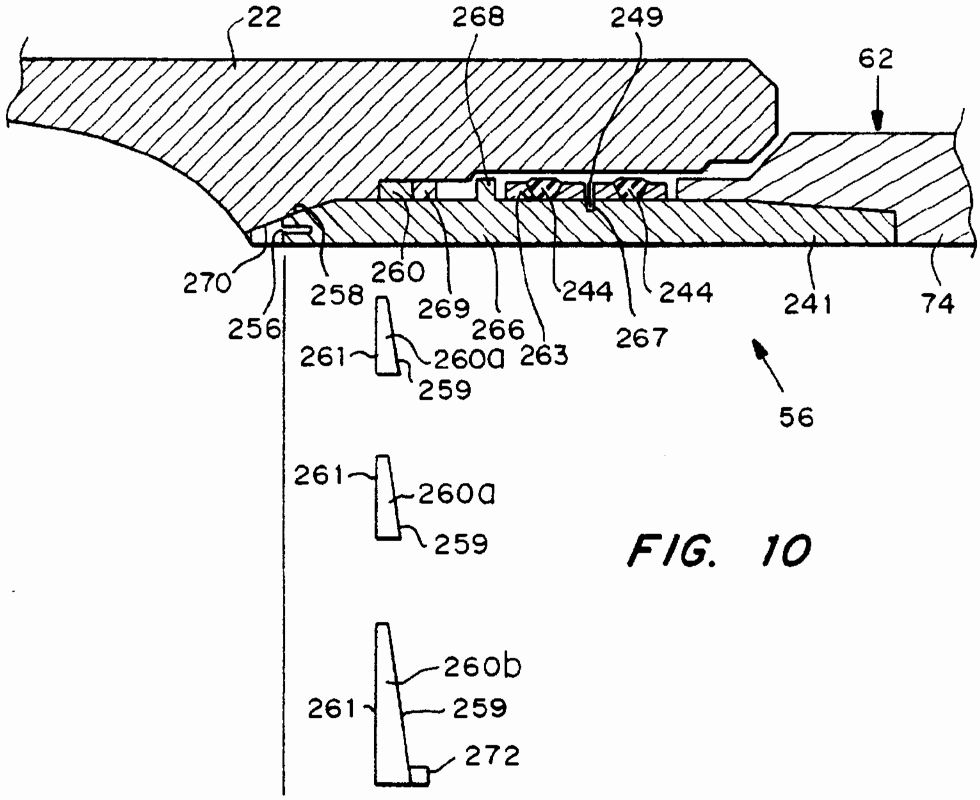


FIG. 9A


22
268
249
62
270
258
260
269
266
263
244
267
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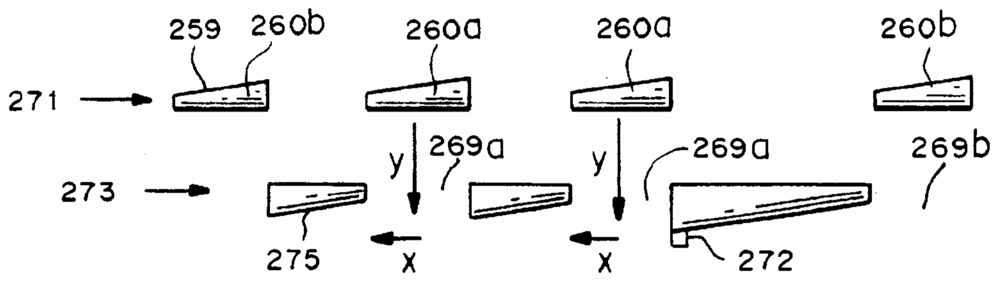
241
74
256
261
260a
259
56
261
260a
259
260b
261
259
272

FIG. 10

FIG. 11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269a
269b
273
275
x
x
272

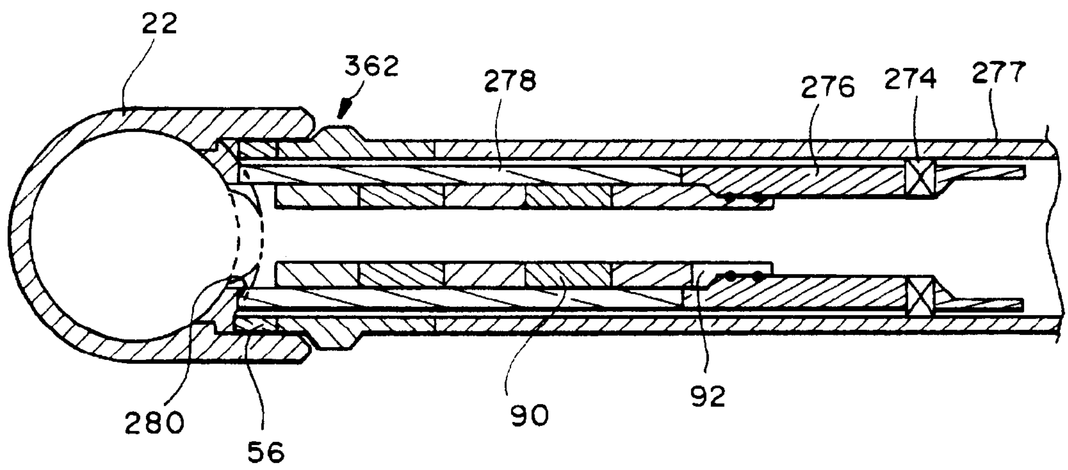

FIG. 12

METHOD AND APPARATUS FOR INTERSECTING DOWNHOLE WELLBORE CASINGS

BACKGROUND OF THE INVENTION

1. Field of the Invention

The present invention relates generally to wellbore construction and more particularly to the construction of multiple wellbores which are interconnected downhole to form a manifold of pipelines in the reservoirs of interest. Provision is made for flow controls, sensors, data transmission, power generation, and other operations positioned in the lateral wellbores during the drilling, completion and production phases of such wellbores.

2. Background of the Related Art

To obtain hydrocarbons such as oil and gas, wellbores or boreholes are drilled from one or more surface locations into hydrocarbon-bearing subterranean geological strata or formations (also referred to herein as reservoirs). A large proportion of the current drilling activity involves drilling deviated and/or substantially horizontal wellbores extending through such reservoirs. To develop an oil and gas field, especially offshore, multiple wellbores are drilled from an offshore rig or platform stationed at a fixed location. A template is placed on the sea bed, defining the location and size of each of the multiple wellbores to be drilled. The various wellbores are then drilled from the template along their respective pre-determined wellpaths (or drilling course) to their respective reservoir targets. Frequently, ten to thirty offshore wells are drilled from an offshore rig stationed at a single location. In some regions such as the North Sea, as many as sixty separate wellbores have been drilled from an offshore platform stationed at a single location. The initial drilling direction of several thousand feet of each such wellbore is generally vertical and typically lies in a non-producing (non-hydrocarbon bearing) formation.

Each wellbore is then completed to produce hydrocarbons from its associated subsurface formations. Completion of a wellbore typically includes placing casings through the entire length of the wellbore, perforating production zones, and installing safety devices, flow control devices, zone isolation devices, and other devices within the wellbore. Additionally each wellbore has associated wellhead equipment, generally referred to as a "tree" and includes closure valves, connections to flowlines, connections for risers and blowout preventors, and other devices.

As an example, ten wellbores may be drilled from a single offshore platform, each wellbore having a nine-inch internal diameter. Assuming that there is no production zone for the initial five thousand feet for any of the wellbores, there would be a total of fifty thousand feet (five thousand for each of ten wellbores) of non-producing wellbore that must be drilled and completed, serving little useful purpose. It may, therefore, be desirable to drill as few upper portions as necessary from a single location or site, especially as the cost of the drilling and completing offshore wellbores can range from $100 to $300 per foot of wellbore drilled and completed.

Multilateral well schemes have been proposed since the 1920's. Various methods of constructing these well geometry's have been disclosed showing methods of creating the wellbores, methods of mechanically connecting casings in the various wellbores drilled, methods of sealing the casing junctions, and various methods of providing re-entry access to the lateral wellbores for remedial treatments.

Multilateral wellbore junction construction is currently thought of as fitting into one of six levels of complexity. Level 1 is generally thought of as open hole sidetracks where lateral wellbores are drilled from an open hole (uncased) section of the main well. No casing is present in the main well or lateral well at the junction of the two wellbores. This method is generally the least expensive but does not ensure wellbore stability, does not provide a method of easy lateral re-entry, and it does not seal the junction in a manner to allow future flow control of the lateral versus the main wellbore.

Level 2 multilateral junctions are those where the lateral exits from a cased main well using section miling or whipstock methods to create the exit. The lateral wellbore may be left as open hole or a liner may be run and "dropped off" outside the main well casing exit such that the lateral liner and main casing are not connected and an openhole junction results. This method is currently a little more costly than Level 1; it provides some more assurance of re-entry access to laterals, and it can provide some flow control of the various wellbores. It does not however protect or reinforce the junction area against potential collapse of the open hole wellbore wall.

Level 3 junctions provide laterals exiting from a cased main well and a lateral liner is run in the lateral wellbore and mechanically connected to the main casing but no seal of the junction is achieved. This method supports the borehole created and provides access to laterals but the lack of a seal at the junction can lead to sand production or fluid inflow or outflow into the junction rock strata. In many applications this inflow or outflow of fluids at junction depth is not desirable as the laterals may penetrate strata of different pressures and the unsealed junction could result in an underground blow out.

Level 4 junctions also provide a lateral wellbore exiting from a cased main well and a lateral liner is run into the lateral wellbore with the top end of the lateral casing extending back to the main casing with the junction of the lateral liner and main casing sealed with cement or some other hardening liquid material that can be pumped in place around the junction. This method achieves isolation of the junction from adjoining strata providing a sufficient length annular seal can be placed around the lateral liner and provided the main casing has an annular seal between the casing and the main wellbore wall. Various methods of reentry access to the laterals is provided using deflectors or other devices. The pressure seal integrity achieved in this type of wellbore junction is generally dependent on rock properties of the junction strata and cannot exceed the junction strata fracture pressure by more than a few hundred pounds per square inch. In addition the guaranteed placement and strength of liquid cementatious hardening materials in a downhole environment is extremely difficult with washouts causing slow fluid velocities, debris causing contamination of sealing materials, fluid mixing causing dilution, gelled drilling muds resisting displacement, etc. The junction may be isolated from adjoining zones but seal reliability specifically at the junction is difficult.

Level 5 systems generally provide lateral wellbores exiting from a cased main well. Liners are run in the lateral wellbore and may be "dropped off" outside the window in the main casing or a Level 4 type cemented intersection may be created. The Level 5 systems however use production tubulars and mechanical packer devices to mechanically connect and seal the main casing and lateral liners to each other. Level 5 systems can achieve a junction seal exceeding the junction strata capability by five to ten thousand psi.

These systems do however restrict the diameter of access to the lateral and main casings below the junctions due to the relatively small tubular diameters compared to casing sizes. Well designs must also generally consider the possibility of a leak in the junction tubulars. This limits the application of Level 5 systems to generally those applications where the junction pressures are abnormal for the junction rock only due to surface applied pressures such as may be encountered in injection wells or during well stimulations. Flow rates achievable through such junctions are also restricted to the rates possible through the smaller diameter tubulars.

Level 6 junctions create a mechanically sealed junction between the main casing and lateral liner without using the restricting bores of production tubulars to achieve the seal. The methods devised to date generally are of two categories. One category uses prefabricated junctions in which one or both bores are deformed. This prefabricated piece is lowered into the well bore on a casing string and located in an enlarged or underreamed section of hole such that it can be expanded or unfolded into its original shape/size. The casing string with the prefabricated junction is then cemented in the wellbore. The lateral borehole is then drilled from the lateral stub outlet and a lateral liner is hung/sealed in the lateral stub outlet. A second category of Level 6 junction currently used creates an oversized main well borehole and full size underformed junctions are run into the main wellbore on the main casing. Laterals can then be drilled from a lateral stub outlet as described from the previous category.

FIGS. **1***a* to **1***f* illustrate several conventional methods **200***a* to **200***f* for forming multiple lateral wellbores into reservoirs **202***a* and **202***b*. Multiple lateral wellbores or drainholes **204** are conventionally drilled from the cased main wellbore **208** or from the openhole section **206** of the main wellbore. When constructing the laterals **204***a* from a cased hole **208**, a whipstock **214** is usually anchored in main well casing **208** by means of a packer or anchoring mechanism **216**. A milling tool (not shown) is deflected by the whipstock face **218** to cut a window **210** in the casing **208**. The lateral wellbore **204***a* is then directionally drilled to intersect its targeted reservoir **202***a*. The whipstock face **218** is typically 1 to 6 degrees out of alignment with the longitudinal axis of the whipstock **214** and the lateral wellbore **204***a* is directed away from the main wellbore casing **208** at a substantially equal angle. The intersection or junction between the lateral liner **220** and the main well casing **208** thus created is elliptical in its side view, curved in its cross section, and lengthy due to the shallow angle of departure from the main well casing **208**. This conventional prior art method **200***a–d* creates a geometry that is difficult to seal with appreciable mechanical strength or differential pressure resistance. Method **200***e* of FIG. **1***e* uses tubulars and packers to mechanically seal the junction but restricts the final production flow area and access diameters to the two production bores. Method **200***f* of FIG. **1***f* uses a prefabricated junction which is deployed in place in an underreamed or enlarged section of the wellbore. This method requires an enlarged wellbore to the surface or an underreamed portion. If the underreamed wellbore approach is used then current technology deforms the junction piece in the underreamed section and by nature of design uses a low yield strength material which causes low pressure ratings. Alternatively this method may use an oversized diameter main wellbore to allow a prefabricated junction to be placed at the desired depth.

In the conventional multilateral wellbore construction methods described above, the lateral borehole is typically drilled from the main casing and departs the main casing at a shallow angle of 1 to 6 degrees relative to the longitudinal axis of the main casing. Recently, however, multilateral wellbores have been constructed by drilling separate lateral wellbores towards the main well casing, from the outside of the main casing so that the downhole end of the lateral wellbore is located proximate perforations in the main wellbore or even intersecting with the main wellbore if possible. Production fluids such as hydrocarbons can, therefore, be flowed between the main wellbore and the lateral wellbores.

However, such prior methods of constructing multilateral wellbores do not provide a mechanical connection or other suitable seal against downhole pressures between the main wellbore and the lateral wellbores. Accordingly, in a particular application such conventional techniques may only be desirable in situations in which the lateral wellbore intersects a production zone co-extensive with a production zone of the main wellbore. The present invention provides a method of mechanically connecting the lateral liner to the main casing and sealing the junction, which may be beneficial for multilateral wellbore construction where it is desirable to intersect a main wellbore with lateral wellbores drilled from outside the main wellbore in a direction generally towards the main wellbore.

In operations in which high pressure connections are desired, the less desirable conventional drilling techniques described above may heretofore have been employed which require deviating the lateral wellbores from within the main, or parent, wellbore. However, these conventional multilateral wellbore construction techniques may also cause undue casing wear in the parent wellbore when many lateral wellbores are drilled from a common parent well. In such a case, the parent well casing may be exposed to thousands of drillpipe rotations and reciprocations executed in the drilling. This drilling process wears away the metal walls of the casing internal diameter. Drill pipe is also used over and over and is therefore commonly treated with a hard coating on the tool joints to minimize the wear on the drill pipe itself. This wear resistant coating on the drill pipe can increase the wear on the casing. Since the production of the wellbore typically flows through the parent wellbore to the surface, the parent casing typically must have sufficient strength after drilling wear to contain wellbore pressures while also accounting for corrosion and erosion expected during the production phase of the well. Accordingly, a need has arisen to provide mechanical connection methods and apparatus between lateral wellbores and parent wellbores for operations in which it may be beneficial to drill the lateral wellbores from outside the parent wellbore in a direction towards the parent wellbore.

Further, during the completion of a wellbore, a number of devices are utilized in the wellbore to perform specific functions or operations. Such devices may include packers, sliding sleeves, perforating guns, fluid flow control devices, and a number of sensors. To efficiently produce hydrocarbons from wellbores drilled from a single location or from multilateral wellbores, various remotely actuated devices can be installed to control fluid flow from various subterranean zones. Some operators are now permanently installing a variety of devices and sensors in the wellbores. Some of these devices, such as sleeves, can be remotely controlled to control the fluid flow from the producing zones into the wellbore. The sensors are used to periodically provide information about formation parameters, condition of the wellbore, fluid properties, etc. Until now the flow control devices and sensors have been installed in the main well production tubing necessitating a reduction in the production flow area for a given main casing size. For example devices are now available matching 5½ inch nominal tubing to fit in 9⅝ inch nominal casing. 7 inch nominal tubing could be used in 9⅝ inch casing but the remotely operated production control devices are restricted to 5½. The present invention provides a method of placing the production control devices out of the main casing and into the lateral wellbore so they do not restrict the main casing tubular design or size and yet production of each lateral wellbore is controlled independently.

In deepwater fields (generally oil and gas fields lying below ocean water depths greater than 1000 ft), the costs of field development are even more extreme than the costs previously mentioned. In these environments satellite wells might be used with seafloor flowlines connected back to a central seafloor manifold for processing and a flowline extends from the central manifold to the sea surface where it is connected to a floating vessel or from the central manifold along the seafloor to a nearby existing platform or pipeline infrastructure. In these deepwater applications the reservoir fluids are subjected to cold ocean floor temperatures (which are generally 40 degrees Fahrenheit or less). These cold temperatures can cause problems in flow assurance since many hydrocarbons contain waxes which will crystallize when the fluid is cooled and can plug pipelines or flowlines especially if flow is stopped for any reason. The typical solution is to insulate individual wellbore risers from the seafloor to the sea surface and/or to insulate flowlines on the seafloor or even make provisions for flowline heating. These solutions have an associated high cost. The present invention provides for connecting wellbores at reservoir depth such that the wellbore fluids remain at substantially reservoir temperatures and pressures until they reach a common outflow wellbore to the surface thus addressing a portion of the well flow assurance concerns.

Accordingly, there is a need for a method and apparatus for providing mechanical connections between a main wellbore and a lateral wellbore, in which the lateral wellbore has been drilled from outside the main wellbore in a direction generally towards the main wellbore. The present invention provides a method and apparatus for providing mechanical connections between a main wellbore and a lateral wellbore, in which the lateral wellbore has been drilled from outside the main wellbore in a direction generally towards the main wellbore

In addition, there is a need for measurement and control apparatus in the lateral wellbores so that production through the lateral wellbores can be controlled independent of the production through the main wellbore. The present invention provides measurement and control apparatus in the lateral wellbores so that production through the lateral wellbores can be controlled independent of the production through the main wellbore.

SUMMARY OF THE INVENTION

In a particular aspect, the present invention is directed to downhole well system including a main wellbore and a lateral wellbore, wherein the lateral wellbore is drilled from outside the main wellbore in a direction generally towards the main wellbore, a wellbore junction, comprising: a mechanical seal between the lateral wellbore and the main wellbore.

A feature of this aspect of the invention is that the main wellbore may include a lateral receiver coupling, and wherein a fluid sealant such as cement has been pumped through the lateral wellbore and hardened to mechanically seal the lateral wellbore within the lateral receiver coupling.

Another feature of this aspect of the invention is that the fluid sealant may be pumped through a cementing port collar disposed within the lateral wellbore. The main wellbore may include a lateral receiver coupling, wherein the lateral wellbore includes a mechanical latching mechanism adapted to engage with the lateral receiver coupling of the main wellbore. The mechanical latching mechanism may be spring-actuated; and the spring-actuated latching mechanism may include at least one locking dog adapted to mate with a latch profile within the lateral receiver coupling.

Yet another feature of this aspect of the invention is that the mechanical latching mechanism may comprises: a plurality of tapered keys spaced apart and disposed about an outer surface of the lateral liner; and a plurality of tapered keys spaced apart and disposed about an inside surface of the lateral receiver coupling, whereby a keyway is provided between each of the plurality of tapered keys, and whereby rotation of the lateral liner causes the keys of the lateral liner to engage with the keys of the lateral receiver coupling to urge the lateral liner against a sealing surface associated with the lateral receiver coupling.

In another aspect, the present invention is directed to a latching system for mechanically interconnecting a lateral wellbore with a main wellbore, comprising: a lateral receiver coupling associated with the main wellbore; and a mechanical latching mechanism associated with the lateral wellbore. A feature of this aspect of the present invention is that the lateral receiver coupling may be adapted to receive a portion of the lateral wellbore therein. The lateral wellbore liner may also include the mechanical latching mechanism on its distal end proximate the main wellbore; and the lateral receiver coupling may also be an axial receiver coupling for joining two axially oriented wellbores.

Another feature of this aspect of the invention is that the lateral receiver coupling may include a receiving bore for receiving a lateral liner of the lateral wellbore. The receiving bore may extend from the main wellbore at an angle substantially 90 degrees from the long axis of the main wellbore, the receiving bore may extend from the main wellbore at an angle generally towards the wellhead, or the receiving bore may extend from the main wellbore at an angle generally away from the wellhead.

In yet another aspect, the present invention is directed to a method of forming a plurality of interconnected wellbores for producing hydrocarbons from or injecting fluids into earth formations comprising the steps of: forming a parent wellbore with a parent wellbore casing with one or more lateral wellbore receiver couplings placed in its casing; forming a lateral wellbore with a lateral wellbore liner to intersect the parent wellbore casing proximate the lateral wellbore receiver coupling; and mechanically connecting the lateral wellbore liner to the parent wellbore casing.

A feature of this aspect of the invention is that the step of forming the lateral wellbore to intersect the parent wellbore casing proximate the lateral wellbore receiver coupling may further compirse the steps of: providing a beacon within proximate the receiver coupling to emit signals adapted to be received by a sensor in a lateral wellbore drilling assembly; and steering the drilling assembly towards the lateral wellbore receiver coupling in response to the signals emitted by the beacon and received by the sensor in the drilling assembly.

Another feature of this aspect of the invention is that the signal emitted by the beacon may be of a type selected from the group consisting of acoustic, electromagnetic, or thermographic signals. The main wellbore may be formed in an oilfield having at least one existing wellbore and the method may further comprise the steps of establishing fluid communication between one or more of the existing wellbores and the main wellbore.

Yet another feature of this aspect of the invention is that the method may further comprise a step of underreaming the end of the lateral wellbore adjacent the receiver coupling to allow lateral movement and flexibility of the lateral liner for minor alignment adjustments in the mating of the lateral liner to the receiver coupling.

BRIEF DESCRIPTION OF THE DRAWINGS

So that the manner in which the above recited features, advantages and objects of the present invention are attained and can be understood in detail, a more particular description of the invention, briefly summarized above, may be had by reference to the embodiments thereof which are illustrated in the appended drawings.

It is to be noted, however, that the appended drawings illustrate only typical embodiments of this invention and are therefore not to be considered limiting of its scope, for the invention may admit to other equally effective embodiments.

FIGS. 1*a*–1*f* illustrate conventional methods of constructing multilateral wellbore junctions.

FIG. **2** is a perspective view of a main wellbore according to a first embodiment of the present invention wherein the intersection to be formed is perpendicular.

FIG. **3***a* is a cross-sectional view of the main wellbore of FIG. 2 showing a drilling assembly being guided by guidance beacons to intersect with a lateral receiver coupling according to an embodiment of the present invention.

FIG. **3***b* is a cross-sectional view of the main wellbore of FIG. 2 showing the lateral wellbore drilled according to the embodiment of FIG. 3*a*, and also showing an under-reamed portion of the wellbore proximate the lateral receiver coupling according to an embodiment of the present invention.

FIG. **3***c* is a cross-sectional view of the main wellbore of FIG. 2 showing a lateral liner run into the lateral borehole of FIG. 3*b* and coupled to the lateral receiver coupling of the main wellbore of FIG. 2.

FIG. **4** is a cross-sectional view of an embodiment of a wellbore intersection according to the present invention wherein the intersection of the two wellbores is axial.

FIG. **5** is a cross-sectional view of the intersected and connected liners of the main wellbore and lateral wellbore according to the embodiment shown in FIG. 2.

FIG. **6** is a cross-sectional view of a portion of the lateral liner of FIG. 5, taken along section 6—6.

FIG. **7** is a cross-sectional view of a portion of the lateral liner of FIG. 5, taken along section 7—7.

FIG. **8** is a cross-sectional view of the intersected and connected liners of a main wellbore and a lateral wellbore according to the embodiment of FIG. 2 with flow controls and other equipment installed.

FIG. **9***a* is a cross-sectional view of a latching mechanism according to a first embodiment of the present invention.

FIG. **9***b* is a perspective view of a locking dog of the latching mechanism of FIG. 9*a* according to an embodiment of the present invention.

FIG. **9***c* is a side view of the locking dog within the sleeve of the latching mechanism of FIG. 9*a* and also showing the spring and push ring thereof.

FIG. **10** is a cross-sectional view of a latching mechanism according to a second embodiment of the present invention.

FIG. **11** is a projected plan view of the keys and keyways of the latching mechanism of FIG. 10.

FIG. **12** is a cross-sectional view of the intersected and connected liners of a main wellbore and a lateral wellbore according to a third embodiment of the present invention.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENT

The present invention generally provides a method and apparatus for interconnecting multilateral wellbores with a main, or parent, wellbore whereby the lateral wellbores are drilled from outside the main wellbore in a direction generally towards the main wellbore. A wellbore junction according to the present invention is generally provided by a lateral receiver coupling **22** engaged by mechanical connection with a lateral liner **50**, as described further hereinbelow.

Referring to FIG. **2**, a perspective view of a main wellbore casing **32** is shown having lateral receiver coupling **22** connected to or otherwise disposed in connection with the outer surface thereof. The main wellbore casing **32** is adapted to be lowered or otherwise provided in a main, or parent wellbore using conventional casing methods known in the art. A plurality of guidance beacons **34** are placed at multiple positions along the lateral receiver coupling **22** or on the adjoining main well casing **32** and are known distances from the centerline **37** of the connecting lateral bore opening **36** formed by the walls of lateral receiver coupling **22**.

Referring now to FIG. **3***a*, main wellbore casing **32** is shown in partial cross-section lowered in place within a main, or parent, wellbore **18**. It should be noted that the main wellbore may be vertical, horizontal, or have any other orientation in a particular application. In addition, the main wellbore may have separate sections which may be independently vertical, horizontal, or some other orientation relative to the surface. The main, or parent, wellbore may typically be a primary production wellbore; however, to the extent consistent herewith, the terms "main wellbore" or "parent wellbore" herein refer to any wellbore to which it may be desired to remotely couple a separate wellbore drilled from a location outside the main wellbore towards the main wellbore after the main wellbore is already in place. To the extent the context herein does not indicate anything to the contrary, the term "wellbore" herein refers to a conduit drilled through a particular geological formation and may also refer to the drilled conduit including well casing, tubing, or other members therein. The term "lateral wellbore" refers generally to the separate wellbore being drilled towards and intended to connect with the main wellbore.

Still with reference to FIG. **3***a*, wellbore casing **32** includes lateral receiver coupling **22** disposed in connection therewith. A conventional guidance system known in the art such as guidance beacons **34** are shown in connection with the casing **32** and preferably send signals into the surrounding strata. Preferably, a plurality of guidance beacons **34** are provided on the well casing **32** and are spaced-apart from centerline **37**, which passes through the center of receiving bore **36**. A separate guidance beacon **34** may also be preferably provided on a receiving bore cap **35** initially connected to the lateral receiving coupling **22**. It should be noted that the guidance system described herein is illustrative only and that other guidance systems as may be known in the art may also be employed.

Still with reference to FIG. **3***a*, lateral borehole **44** is shown being drilled by bit **38** provided at the end of a drilling string. Bit **38** is steered by conventional directional steering tools known in the art such as directional steering tool **41**. In the directional steering tool **41** shown, the path of the drilling bit **38** is adjusted as conventional guidance sensors **40** detect and interpret the current borehole location relative to the centerline **37** of receiving bore **36**. Receiving bore **36** is in a known spatial relationship relative to the guidance beacons **34**. Preferably, a rotary steerable drilling assembly such as the "Autotrak" drilling assembly available from Baker Oil Tools or other suitable steering drill assembly may be modified to have an added guidance sensor **40** to detect the source location of guidance beacons **34**.

Referring now to FIG. **3b**, the lateral borehole **44** has preferably been drilled so that the centerline of the lateral receiver coupling **22** and the centerline of the lateral borehole **44** are generally co-extensive. An under-reamed section **46** of borehole **44** is created as shown proximate lateral receiver coupling **22** using conventional drilling techniques. Although not shown, a conventional running tool may be run through the lateral borehole **44** and used to remove the cover **35** from the lateral receiver coupling **22** so that a lateral liner may be inserted within the receiving bore **36** of the lateral receiver coupling **22** as described further below.

Hardenable Fluid Sealant Embodiment

Referring now to FIG. **3c**, lateral liner **50**, which may be wellbore casing or some other suitable tubular assembly, has been run into the lateral borehole **44** using conventional techniques and is inserted into the receiving bore **36** of lateral receiver coupling **22**. A stage tool or cementing port collar **52** may be provided within lateral liner **50** proximate the end of the lateral liner **50** inserted into the receiving bore **36** of lateral receiver coupling **22**. A hardenable liquid sealant or cement **48** may then be pumped through the lateral liner **50**, through cementing port collar or stage tool **52**, and into annulus **49** formed defined by the under-reamed section **46**. The stage tool or port collar **52** may then be closed, thus creating in one embodiment a mechanical seal between the lateral liner **50** and the lateral receiver coupling **22** and, accordingly, the main wellbore casing **32** to which the lateral receiver coupling **22** is connected. It should be noted that, in this embodiment, essentially no sealing mechanism or sealing substance is provided within the production bore of either the lateral liner **50** or the main wellbore casing **32** so that flow therethrough is not significantly impeded. It should further be noted that this embodiment may be used as a primary mechanical seal or it may be used in connection with the latching mechanism embodiments described below.

Referring to FIGS. **2–3**, **5**, and **12**, the lateral receiver coupling **22** is shown having a receiving bore **36** extending generally 90 degrees to direction of the main wellbore casing **32** to form a "T" intersection. However, the receiving bore **36** of lateral receiver coupling **22** may also extend at any desired angle relative to the main wellbore casing **32**. Referring to FIG. **4**, it will be readily apparent that receiver coupling **24** may also be an axial receiver coupling **24** provided axially at a distal end of the main wellbore casing **32** to form an "end-to-end" intersection. In this embodiment, guidance beacons **34** may preferably be spaced apart and on opposing sidewalls of axial lateral receiver coupling **24**.

Lateral Connector

Referring now to FIG. **5**, lateral liner **50** is shown intersecting with and connected to lateral receiving coupling **22**. Lateral liner **50** may include lateral connector **62**, which may be attached to the distal end **66** of the lateral liner **50** to be connected to the lateral receiver coupling **22** of the main wellbore casing **32**. The lateral connector **62** generally comprises: seal bore receptacle **76**, equipment receptacle **74**, and latch mechanism **56**. Seal bore receptacle **76** is preferably threadedly attached to the distal end **66** of the lateral liner **50** and receptacle **76** preferably has a polished seal bore surface **80** suitable for mating with a sealing member (not shown). Equipment receptacle **74** is preferably threadedly attached to the opposite end of the seal bore receptacle **76**.

A cylindrical wall of equipment receptacle **74** preferably defines bore **78** therewithin. Referring now to FIG. **6**, equipment receptacle **74** is shown in a cross-section taken along section **6—6** of FIG. **5**. As shown in FIG. **6**, the cross-section of bore **78** of equipment receptacle **74** may preferably be square (shown in FIG. **6**). It should be noted, however, that the cross-section of bore **78** of equipment receptacle **74** may also be cylindrical (not shown) or have some other suitable cross-section. In the preferred embodiment, the cross-section of bore **78** is rectangular.

In the event that the cross-section of bore **78** is rectangular, transitional cross-sectional areas may be required to suitably mate with the preferably cylindrical cross-sectional area of seal bore **80** of seal bore receptacle **76**. Accordingly, surface **82** may preferably be spherical or conical to provide the transition from the preferably square equipment receptacle bore **78** to the preferably cylindrical seal bore **80**.

Referring now to FIG. **7**, seal bore receptacle **76** is shown in a cross-sectional view taken along section **7—7** of FIG. **5**. The preferred diameter of seal bore receptacle **76** defining seal bore surface **80** is shown relative to the internal diameter of the bore **88** of the lateral liner **50** and also relative to the outer diameter of the outside surface **86** of lateral liner **50**. Referring again to FIG. **5**, latch mechanism **56** is shown threadedly attached to the end of the equipment receptacle **74**.

Latch mechanism **56** will be described in more detail below with reference to FIGS. **9**, **10** and **11**.

Equipment Assembly

Referring now to FIG. **8**, lateral connector **62** is shown having equipment assembly **89** disposed within equipment receptacle **74**. Equipment assembly **89** comprises seal assembly **92**, which has a proximal end adapted to sealingly engage seal bore surface **80** to create a hydraulic pressure retaining seal between the outside diameter of the seal assembly **92** and the inside diameter of the seal bore receptacle **76**. A portion of seal assembly **92** preferably has an enlarged outside diameter **93** defining shoulder **95**. Shoulder **95** is adapted to bear on landing **97** associated with equipment receptacle **74** to limit the movement of the seal assembly **92** beyond a given point in the seal bore **76**.

A face seal **94** is preferably located on the distal end of the seal assembly **92**. A sealing force may be applied to an adjoining equipment module **90** against seal assembly **92**, whereby the face seal **94** will create a pressure seal between the equipment module **90** and the seal assembly **92**. A plurality of equipment modules **90** may be similarly joined with face seals **94** provided between each set of adjoining module **90**. Each of the equipment modules **90**, the seal assembly **92**, and the latch module **99** include a flow through bore **100**. Equipment modules **90** may preferably include conventional monitoring or control modules, providing, for example: a) well flow control devices (having choked positions or full open or full closed positions); b) monitoring devices for sensing wellbore parameters such as water cut, gas/oil ratios, fluid composition, temperature, pressure, solids content, clay content, or tracer/marker identification; c) a fuel cell, battery, or power generation device; or d) a pumping device.

The last module **90** to be inserted into the equipment receptacle **74** proximate the distal end of the lateral liner **50** is preferably latch module 99. Latch module 99 preferably includes a face seal 94 to seal it to the adjoining equipment module 90, and also preferably includes a conventional latch mechanism 98 adapted to retain the latch module 99 within the equipment receptacle 74 by engaging a recessed profile 101 within the lateral liner 50.

First Latching Mechanism Embodiment

Referring now to FIG. 9*a*, a first embodiment of latching mechanism 56 is shown in detail. Main mandrel 241 of latch mechanism 56 is preferably threadedly attached to the equipment receptacle 76 (shown in FIG. 5) as previously described. A plurality of seals 244 may be mounted on an outer seal surface 247 of main mandrel 241. A snap ring 249 is preferably installed in groove 251 to hold the seals in place about the main mandrel 241. Stop nut 242 preferably has a threaded inner surface and is preferably screwed onto a threaded portion of mandrel 241 until it reaches stop shoulder 237. Sleeve 252 is preferably provided about the main mandrel 241 proximate the distal end of main mandrel 241. End cap 240, is threadedly attached to the main mandrel to provide a tapered, conical, surface 255 between the main mandrel 241 and the sleeve 252.

A plurality of locking dogs 248, preferably having wings 235 extending therefrom (as shown in FIG. 9*b*), are provided within sleeve 252 and have a portion thereof which are adapted to selectively extend through slots 253 provided in sleeve 252 (as shown in FIG. 9*c*). Locking dogs 248 are adapted and positioned to partially extend through slots 253 as they slide along tapered surface 255 of end cap 240. Locking dogs 248 are further adapted to include a latching portion adapted to protrude past the outside diameter of a sleeve 252. Locking dogs 248 are retained within sleeve 252 by wings 235 (shown in FIG. 9*b* and 9*c*) which engage the inner surface of sleeve 252.

Push ring 254 is provided between the end cap 240 and sleeve 252 to press uniformly on the ends of the locking dogs 248 as spring 246 inserted behind the push ring 254 biases push ring 254 away from stop nut 242. The slots 253 allow the locking dogs 248 to slide axially along the tapered surface 255 of end cap 240. As the latching mechanism 56 is inserted into the lateral receiver coupling 22, the latching dogs slide backward against spring 246 or other biasing member and inward toward the smaller diameter of conical surface 255. When the latching mechanism 56 reaches the full insertion depth into the lateral receiver coupling 22, the latch dogs 248 mate with a latch profile within the lateral receiver coupling 22 and are pushed up the conical surface 255 by spring 246 such that they protrude into the latch profile and engage bearing shoulder 257.

Accordingly, a spring-actuated latching mechanism 56 is provided to automatically engage the lateral liner 50 within the lateral receiver coupling as the lateral liner 50 is inserted into the lateral receiver coupling 22.

To ensure alignment of the locking dogs 248 and the mating latch profile as the latching mechanism 56 is inserted into the lateral receiver coupling 22, key 245 may be machined into the outer surface of the main mandrel 241 and adapted to engage a matching keyway 250 provided in the lateral receiver coupling 22 to index the rotational position of the lateral connector 62 relative to the receiver coupling 22. Seals 244 may be elastomeric interference fit, or chevron shaped non-elastomeric interference fit, or non-elastomeric spring metal energized or expandable metal or shape memory alloy or lens ring crush seals or other suitable seal design and material.

Second Latching Mechanism Embodiment

With reference now to FIGS. 10 and 11, a second embodiment of latching mechanism 56 is shown intersecting lateral receiver coupling 22. In this embodiment, at least one seal 244 is mounted onto the main mandrel 24 1on a surface 263. A plurality of seals 244 may be separated and held in position by a snap ring 249 positioned in a groove 267. A stop shoulder 268 retains seals 244 on main mandrel 241. In this embodiment, a plurality of keys 260 are preferably machined onto the outer surface of main mandrel 241. Keys 260 preferably have a flat lower face 261 facing the distal end of the main mandrel 241 and also facing lateral receiver coupling 22. Keys 260 preferably further include an angled upper face 259 facing the running length of the lateral liner 50. A plurality of opposing keys 273 are preferably machined onto the inner surface of lateral receiver coupling 22.

Referring now to FIG. 11, a set of keys 273 of lateral receiver coupling 22 and the keys 260 of main mandrel 241 are shown in a flat projection to illustrates the relationship of the various keys and keyways. The keys 273 are machined into the lateral receiver coupling 22 to create a set of keyways 269 therebetween. The keys 260 of main mandrel 241 are adapted to fit through the keyways 269 of the lateral receiver coupling 22 as main mandrel 241 is inserted within the lateral receiver coupling 22. In particular, a set of latch keys 271 includes a plurality of narrow keys 260*a* and a wide key 260*b*. The narrow keys 260*a* fit through a mating plurality of narrow keyways 269*a* and the wide key 260*b* must pass through a wide keyway 269*b*. When the latch mandrel 241 is inserted into the coupling 22, the set of latch keys 271 follows the path of arrow y and pass beyond the plurality of latch keys 273. Thereafter, main mandrel 241 is rotated clockwise in the direction of arrow x so that angled faces 259 engage angled faces 275 interlocking the lateral connector 62 with the lateral receiver coupling 22. Due to the singular wide key 260*b* there is only one orientation in which the two parts will engage. As the lateral connector is rotated clockwise the angled faces 259 and 275 bear against one another creating an axial movement of the connector 62 into the coupling 22. Referring again to FIG. 10, a nose seal 258 is preferably machined into the end of the mandrel 266 with a gap 256 ensuring that the nose seal 258 has suitable flexibility to sealingly engage a seal face 270 as the angled faces 259 and 275 move the seal mandrel 266 into the coupling 22. Stop shoulder 272 prevents the rotational over travel of the keys to rotationally index the connector 62 and coupling 22 and to prevent improper deformation of the nose seal 258.

FIG. 12 shows a cross section of an alternative embodiment of the receiver coupling 22 and a lateral connector 362. In this embodiment the lateral connector 362 need not be rotationally indexed with the coupling 22 since the connector 362 in this case only consists of a latch mechanism 56 connected directly to the lateral liner 277. A seal bore 276 and an equipment receptacle 278 are in this case suspended below a packer 274 which is set in lateral liner 277 to anchor these devices in the lateral liner. An indexing member 280 engages a mating profile in the coupling 22 before the packer 274 is set. The indexing member may be a clutch mechanism as described relative to FIG. 9 or it may be a spring loaded key which finds a mating recess in coupling 22 or other such devices known to those skilled in the art. The full bore of liner 277 is available for operations in the lateral liner in this embodiment until the assembly comprising items 278, 280, 274, and 276 is inserted. This inserted assembly may also be retrievable through lateral liner 277 or permanently installed.

In operation, a main vertical wellbore 18 may be drilled through which production fluids are desired to be pumped or otherwise recovered to the surface. Thereafter, a production string of main wellbore casing, including lateral receiver coupling is inserted within the main vertical wellbore. A lateral wellbore, which may be horizontal or have some other orientation, is drilled from a location outside of the main wellbore casing in a direction generally towards the lateral receiver coupling until the lateral wellbore interconnects with the main wellbore. Thereafter, lateral liner having a latching mechanism according to the present invention connected to the distal end thereof is inserted within the lateral wellbore until it reaches the lateral receiver coupling. The lateral liner is then inserted further within the lateral receiver coupling until the latching mechanism engages within the lateral receiver coupling. In a first embodiment, the latching mechanism is automatically engaged with the lateral receiver coupling as the locking dogs reach the matching profile within the lateral receiver coupling. In the second embodiment, the latching mechanism is engaged with the lateral receiver coupling by rotating the lateral liner and thereby rotating the locking mechanism until the tapered keys associated with the lateral liner engage with the matched tapered keys associated with the lateral receiver coupling.

After the lateral wellbore has been connected to the main, substantially vertical wellbore, the lateral wellbore may be referred to as the main wellbore. Consequently, this new main wellbore may include axial receiver couplings to interconnect successive lengths of lateral liners **50** and/or include lateral receiver couplings to receive locking mechanisms of other lateral wellbores. Accordingly, a wide variety of downhole manifold systems may be contemplated using the method and apparatus of the present invention. By incorporating measurement and flow control devices within the lateral wellbores, each of the lateral wellbores can be independently monitored and/or controlled to have complete control of the downhole manifold system. Accordingly, since there may be redundant pathways to the surface through multiple lateral wellbores, the production of all feeder laterals need not be halted to service the main wellbore. Only the wellbores between the bore to be used for servicing and the target wellbore to be serviced need be remotely closed. Flow of other wellbores may be diverted to the alternate main wellbore until servicing operations are complete. Servicing robots may contain "equipment cars" alternated with "push/pull cars". The equipment cars carry items such as the seal assembly **92**, the modules **90**, or the latch modules **98** and the pushlpull devices may move the equipment between the cars and the lateral connector equipment receptacles **74**. The robot "train" may also include "cars" containing repair modules, inspection modules, testing modules, data downloading modules, or device activation modules.

Service work on the feeder wellbores can also be performed through the wellbore from which the feeder wellbores were drilled to allow more extended access or more complete workover/treatment capability without risking operations in the main wellbore.

While the foregoing is directed to the preferred embodiment of the present invention, other and further embodiments of the invention may be devised without departing from the basis scope thereof. For example, the mechanical connection between the lateral receiver coupling and the lateral connector may be achieved by threading the two mating parts and screwing them together downhole, or they may be joined by expanding or swaging the end of the lateral connector inside the receiver coupling, or by a collet on the connector snapped into a groove in the coupling with a sleeve shifted behind the collet to lock it in place, or other such connection methods as are known in the art. Further, the guidance beacons **34** on the lateral receiver coupling **22** may also be sensors receiving signals generated by a drilling tool. The location data collected by these sensors may then be used to guide the corresponding drilling assembly to the desired intersection point. The beacons or sensors may be permanently mounted on the main casing or they may be retrievably located in the main casing in known spatial relationship to the receiver coupling. Accordingly, the scope of the present invention is determined only by the claims that follow.

What is claimed is:

1. In an oilfield downhole well system comprising a main wellbore and at least one secondary wellbore:

a wellbore casing provided in said main wellbore;

at least one lateral receiver coupling mounted in said wellbore casing, said lateral receiver coupling having a receiver bore in fluid communication with said main wellbore and providing an opening through the casing wall;

a lateral wellbore liner provided in said secondary wellbore and extending into a fluid reservoir and laterally towards said main wellbore and such that said lateral wellbore liner intersects with said main wellbore proximate said lateral receiver coupling, said wellbore liner adapted to provide fluid communication with said fluid reservoir;

junction means connecting said lateral wellbore liner and the lateral receiver coupling which is proximate thereto in fluid communication with one another;

means establishing a seal for the connection of said lateral wellbore liner and the lateral receiver coupling proximate thereto such that the main wellbore casing and said lateral wellbore liner are in fluid communication with each other and with said reservoir;

the lateral wellbore liner includes a mechanical latching mechanism adapted to engage with the lateral receiver coupling of the main wellbore, said mechanical latching mechanism comprising:

a first set of a plurality of tapered keys spaced apart and disposed about an outer surface of the lateral wellbore liner, and

a second set of a plurality of tapered keys spaced apart and disposed about an inner surface of the lateral receiver coupling whereby a keyway is provided between each of the plurality of tapered keys in said second set and the next key adjacent thereto in said second set whereby the lateral liner may be inserted into the receiver bore of said lateral receiver coupling and whereby rotation of the lateral wellbore liner causes the keys of the lateral wellbore liner to engage with the keys of the lateral receiver coupling to urge the lateral wellbore liner against a sealing surface associated with the lateral receiver coupling.

2. The downhole well system of claim **1** wherein the lateral receiver coupling is an axial receiver coupling for joining two axially oriented wellbores.

3. The downhole well system of claim **2** wherein the receiver bore of said lateral receiver coupling extends from the main wellbore at an angle substantially 90° from the long axis of the main wellbore.

4. In an oilfield downhole well system comprising a main wellbore and at least one secondary wellbore:

a wellbore casing provided in said main wellbore;

at least one lateral receiver coupling mounted in said wellbore casing, said lateral receiver coupling having a receiver bore in fluid communication with said main wellbore and providing an opening through the casing wall;

a lateral wellbore liner provided in said secondary wellbore and extending into a fluid reservoir and laterally towards said main wellbore and such that lateral wellbore liner intersects with said main wellbore proximate said lateral receiver coupling, said wellbore liner adapted to provide fluid communication with said fluid reservoir;

junction means connecting said lateral wellbore liner and the lateral receiver coupling which is proximate thereto in fluid communication with one another;

means establishing a seal for the connection of said lateral wellbore liner and the lateral receiver coupling proximate thereto such that the main wellbore casing and said lateral wellbore liner are in fluid communication with each other and with said reservoir, said downhole well system further comprising an equipment receptacle, a packer, and an indexing member inserted through said lateral wellbore liner and indexed to the lateral receiver coupling prorate thereto and anchored in place by setting of the packer.

5. The downhole well system of claim 4 wherein the packer, equipment receptacle, and indexing member are permanently installed in said lateral wellbore liner.

6. The downhole well system of claim 4 wherein the packer equipment and indexing member are retrievably installed in said lateral wellbore liner.

7. A method of forming a plurality of interconnected wellbores for producing hydrocarbons from or injecting fluids into earth formations comprising the steps of:

forming a parent wellbore with a parent wellbore casing with one or more lateral wellbore receiver couplings' placed in its casing,

forming a lateral wellbore extending through a fluid reservoir and provided with a wellbore liner to intersect the parent wellbore casing proximate a one of the wellbore receiver couplings, such step of forming the lateral wellbore to intersect the parent wellbore casing proximate the lateral wellbore receiver coupling further comprising the steps of providing a sensor mounted in said casing proximate said one receiver coupling to receive signals emitted from a lateral wellbore drilling assembly; and

steering the drilling assembly towards said one wellbore receiver coupling in response to the signals emitted from said lateral wellbore drilling assembly and received by the sensor;

mechanically connecting the wellbore liner to the parent wellbore casing and flowing fluids between the reservoir and said wellbore liner and said casing.

8. The method of claim 7 including the further step of sealing the connection of the wellbore liner and the parent wellbore casing.

9. The method of claim 8 where said step of sealing is accomplished by mechanically energizing a seal means.

* * * * *

VITA

Name:	Jean-Philippe Atsé
Born:	November 10, 1977, Abidjan, Cote d'Ivoire
Parents:	Atsé Katou Pierre and Thouron Nicole Colette
Permanent Address:	14 BP 248 Abidjan 14, Cote d'Ivoire
Email:	atsejp@yahoo.fr
Education:	Petroleum Engineer (2000), Institut National Polytechnique Felix Houphouet Boigny Yamoussoukro, Cote d'Ivoire
	M.S., Petroleum Engineering Texas A&M University College Station, Texas
Professional Experience:	PETROCI – Petroleum Engineering 2000-2002, Abidjan, Cote d'Ivoire