FACULTY OF SCIENCE AND TECHNOLOGY

MASTER'S THESIS

Study program/specialization: Petroleum Engineering Drilling & Well Engineering	Spring semester, 2020 Open
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Title of master's thesis:

Pre-feasibility Study for Drilling a Multilateral Well (TAML 4) in an Oil Field in Ecuador Based on a Technical, Economic, and Risk assessment models.

Credits:

30 ECTS

Keywords:	
• Multilateral wells • Horizontal wells • Technical evaluation • Economic evaluation • Risk assessment • Inflow performance	Number of pages: 141 + supplemental material/other: 10 Stavanger, 05th July / 2020

Dedication

This work is dedicated in a very special way to the following people:

Granny Socorro,

I am convinced that from heaven you protect us and you continue praying for each one of us with that pure love that always characterized you. You are the person with the largest and purest heart I have ever known. Your memory will always live in us. I love you so much granny.

Uncle Querubín,

You are a warrior, you did not allow yourself to be overcome by your illness. After a hard fight now is the time to rest. I will miss our conversations and listen to your stories. I remember with nostalgia the last hug we gave each other. I will always thank you for your show of love to my family, especially thanks for taking care of my mom. I love you uncle Cobín.

TinTin,

My other half, our bond will endure in eternity. I hug you with all my strength. I am strongly convinced that we will be together again, mi viejito. You are that little angel that will always be in the heart of all of us; wherever I go you will be with me. I miss you so much. I love you so much and I miss you more than ever.

María Victoria,

The illusion and longing to hold you in my arms, the excitement of knowing that you will soon be with us filling our lives with happiness, imagining your smile, filled me with hope and strength to get ahead in these difficult times. I am waiting for you with my arms wide open

God bless you all.

Acknowledgments

I want to thank my Almighty Heavenly Father for giving me the opportunity to come to Norway to continue my academic and professional development. God, I have faith that this is all part of your perfect plan. Thank you for filling me with strength and wisdom to get ahead, for being with me at every step. I owe you everything, God.

I would like to express my thanks to *Dr. Mesfin Belayneh* for all his advice and guidance both as a teacher and as a thesis supervisor. His door was always open to listen and solve all my questions. I greatly admire your dedication as a teacher and as a professional. In *Mesfin* I found an excellent professor and thesis supervisor, especially a great person and an unconditional friend. God bless you. Gracias amigo.

To my parents, my heroes, *Fabio* and *María*, who have always been and will continue to be my engine to fight every day, the reason to improve myself. Thank you for always being by my side, even more in the distance, with your unconditional support giving me words of encouragement and motivating me to fly higher and higher. The values and principles that the two of you taught me have always served me as a compass to not lose my horizon and to achieve this goal, despite being 9,600 km from home. Life will not be enough to pay you for all the effort and sacrifice you have made for us.

To my sister and my brother-in-law, *María José* and *Santiago*, I have no words to express my gratitude for all the unconditional support I have received from you; I greatly admire you two for who you are and all that you represent to me. To my brother *Juan*, thank you for your help and your words of encouragement, I admire and respect you very much for fighting tenaciously to achieve your dreams. To *Hilda*, thanks for always being with my family, for taking care of them. We will always be together under God's blessing, in good times and bad times, to support us, united through faith, love, friendship and trust.

To my family, *Ricardo* and *Yolanda*, who opened their arms to me and adopted me as a son. Thank you for having me present every day in your prayers to God. You were a fundamental part in this whole process. As part of this family, I also thank Mrs. *Jannet P*. (+) for her support and help at such a decisive moment for me.

With all my heart, I thank the love of my life, Estefania, for having unconditionally supported me in this challenge. Your love has always propelled and sustained me, especially in the hardest moments when I felt myself breaking. Thank you life companion for being by my side day and night, supporting, encouraging me not to give up and move on, thank you for reminding me every day of the reasons why I am fighting. Your arms have been and always will be my refuge of peace.

We live in difficult times, but together, as a family, supporting each other, we will overcome all the obstacles we find along the way. With all my heart, I thank you infinitely. None of this would have been possible without you. God bless you all. This achievement is for all of you ... my family, my greatest treasure.

Fabio A. Bastidas Guadamud,

Stavanger 05.07.2020

Abstract

The oil and gas industry is constantly in search of developing new technologies that allow to reduce operational costs and maximize the recovery of hydrocarbons in onshore and offshore fields. There are several alternatives that can be selected, among them are multilateral wells, which is an emerging technology as a result of an evolution of horizontal wells. Multilateral technology has shown several benefits in the development of oil and gas fields, such as increase the production of hydrocarbons, generate significant savings, potentially increase profits, and has high flexibility of applications in different types of reservoirs which it may be applied. Based on the benefits mentioned, the feasibility of drilling a TAML Level 4 multilateral well in an oil field in Ecuador is analyzed in this research work.

Therefore, to determine the feasibility or not of drilling a multilateral well in Ecuador, this master's thesis comprises a technical, economic and risk analysis, which are based on the evaluation and comparison of the performance of a multilateral well (dual lateral stacked) against the performance of a horizontal well that produces oil through 2 different sections at the same time (vertical and horizontal section).

Based on the technical analysis results, it can be concluded that drilling a Level 4 multilateral well would increase production 2.85 times compared to a horizontal well system. Different economic performance indicators like NPV, FCF, PI, show that the multilateral well is the most profitable option compared to the horizontal well. Furthermore, the risk assessment performed using deterministic decision tree model, which is based on the results of the economic analysis and quantifying the risks involved in the drilling stage, shows that by drilling a TAML Level 4 multilateral well the highest EMV can be achieved, even though it is the option with the highest risks involved.

The study demonstrates the feasibility of drilling a TAML Level 4 multilateral well in the Ecuadorian oil field, providing benefits from both a technical and economic point of view. This is also supported by the different field case studies analyzed that indicate a 100% success rate.

Table of Contents

List of Figures

List of Tables

List of Nomenclature

A	Drainage area	[ft^2]
a	Reservoir width	[ft]
b	Reservoir length	[ft]
B_o	Oil formation volume factor	[bbl/STB]
C_H	Shape factor	[DI]
D	Diameter	[in]
f_f	Fanning friction factor	[DI]
g	Acceleration of gravity	[ft/sec^2]
g_c	Gravitational constant	[ft-lbf/lbm-sec^2]
h	Reservoir thickness	[ft]
i	Discount rate	[%]
I	Initial investment	[USD]
I_{ani}	Anisotropy ratio	[DI]
K_h	Horizontal permeability	[mD]
K_v	Vertical permeability	[mD]
K_x	Permeability in the x-direction	[mD]
K_y	Permeability in the y-direction	[mD]
K_z	Permeability in the z-direction	[mD]
L	Wellbore length	[ft]
L_s	Segment length of pipe	[ft]
n	Number of years	[years]
N_{Re}	Reynolds number	[DI]
$\bar{P}$	Average reservoir pressure	[psia]
P_{wf}	Flowing bottom-hole pressure	[psi]

P_{xy}	Partial penetration skin component x-y plane	[DI]
P_{xyz}	Partial penetration skin component x-y-z plane	[DI]
$\bar{q}$	Average flow rate in the segment	[bbl/day]
q_i	Inflow rate per unit length	[bbl/day-ft]
r_e	Drainage radius	[ft]
R_n	Annual revenue	[USD]
r_w	Wellbore radius	[ft]
S	Skin factor	[DI]
S_R	Partial penetration skin	[DI]
T	Temperature	[°F]
t	Time	[year]
X_{mid}	Mid-point of horizontal well location	[ft]
x_o	Well location in x-axis	[ft]
y_o	Well location in y-axis	[ft]
z_o	Well location in z-axis	[ft]

Greek Symbols

Δp	Differential pressure / Pressure Drop	[psi]
μ	Axial velocity (velocity in the segment)	[ft/min]
μ_o	Oil viscosity	[cP]
ρ	Density	[lb/ft^3]
ρ_o	Oil density	[lb/ft^3]
ϕ	Porosity	[%]

List of Abbreviations

API	American Petroleum Institute
CAPEX	Capital Expenditure
DCA	Declination Curve Analysis
DI	Dimensionless
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
ESP	Electric Submersible Pump
FCF	Financial Cash Flow
HW	Horizontal well
ICV	Inflow Control Valve
ID	Inside Diameter
IOR	Improves Oil Recovery
IRR	Internal Rate of Return
ITT	Ishpingo Tambococha Tiputini
K	Thousand (1,000)
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
M	Million (1,000,000)
MD	Measured Depth
ML	Multilateral well
MLT	Multilateral Technology
MScf	Thousand Standard Cubic Feet
NFP	Near Facilities Potential

NPV	Net Present Value
OCF	Operating Cash Flow
OPEX	Operating Expenditure
OWC	Oil Water Contact
P&A	Plug and Abandonment
PI	Profitability Index
PIR	Profit Investment Ratio
POT	Pay out Time
PV	Present Value
QAR	Quantitative Analysis Risk
ROR	Rate of Return
SBHP	Static Bottom Hole Pressure
STB	Stock Tank Barrel
STOIIP	Stock Tank Oil-Initially-In-Place
TAML	Technology Advancement for Multilaterals
TVD	True Vertical Depth
USD	United States Dollar
VIR	Value Investment Ratio
VW	Vertical Well

1. Introduction

The oil and gas industry are constantly in search of developing new technologies that allow to reduce operational costs and maximize the recovery of hydrocarbons in onshore and offshore fields. There are several alternatives that can be selected, among them are multilateral wells, which is an emerging technology as a result of an evolution of horizontal wells. The application of the technology of multilateral wells has allowed to considerably increase the production of hydrocarbons, generate significant savings, potentially increase profits, and has high flexibility of applications in different types of reservoirs which it may be applied. Due to the benefits brought by MLT, thousands of multilateral wells have been drilled worldwide. (Paiaman, Al-anazi, Safian, & Moghadasi, 2009)

This master's thesis comprises a technical, economic and risk analysis, which are based on the evaluation and comparison of the performance of a multilateral well (dual lateral stacked) against the performance of a horizontal well that produces oil through 2 different sections (vertical and horizontal section) at the same time; This horizontal well system is highly used in Ecuador, whereas the multilateral well is new in the country.

For the technical analysis, reference values of the main geological properties are used to calculate and compare the performance of the different well systems. The economic analysis is developed based on the results obtained in the previous analysis and using approximate drilling costs in Ecuador. Regarding to risk analysis, by preparing a decision tree, the best option between drilling a multilateral well and a horizontal well is considered. The results obtained in the different analyzes will lead to the decision of whether the multilateral technology can be applied or not in Ecuador considering the conditions of the industry in the country.

To reinforce the study, an analysis of the advantages and disadvantages of multi-lateral wells is carried out based on field case studies in different parts of the world (Brazil, United States, Indonesia, North Sea, and Caspian Sea,)

1.1. Background

With the development and growth of the oil and gas industry, the construction of wells faces new operational challenges that demand the use of new techniques and novel solutions that allow optimizing the design of wells to reach and produce hydrocarbons more efficiently, reason why the geometry of the wells has been changing over time. Up to the early 1980s, the main geometry used was vertical wells, until directional / deviant wells applied mainly in offshore fields began to gain strength. However, both vertical and deviated wells had the disadvantage of penetrating the reservoir vertically, which drastically reduced the contact area with the pay zone. Seeking to implement an option that will increase the area of contact with the reservoir, horizontal wells emerge, which have the main advantage of achieving higher production rates by having a greater area of contact with the reservoir. Multilateral wells emerge as a development from drilling horizontal wells, sidetracks, and directional wells.

Multilateral wells offer several advantages to the development of oil and gas fields, among which stand out: considerably increase oil drainage area, increase the recovery factor compared to other well geometries, improve the hydrocarbon well production, allows the production of hydrocarbons from different reservoirs at the same time through its laterals or branches, generally at lower costs than drilling several single horizontal wells.

In Ecuador, the oil extraction zone is located mainly in environmentally sensitive zones in the Amazon region. The oil production rate through its operations is 526,383[1] barrels per day, of different API gravity (light oil, medium oil, and heavy oil). The main well geometries used throughout the oil activity in Ecuador are vertical, directional, and horizontal wells, so the multilateral wells are relatively a new in the country. Most fields in Ecuador have more than one pay zone, which facilitates the implementation of MLT, however, a horizontal well is drilled in the deepest pay zone and produce through a vertical well in the pay zone which is above of it, or another single horizontal well is drilled in the upper pay zone.

[1] Value obtained from the official website of: *ARCH (Agencia de Regulación y Control Hidrocarburífero),* Ecuador: https://www.controlhidrocarburos.gob.ec/indicadores/

On the other hand, the recovery factor (average) in the reservoirs in Ecuador is 32%[2], reflecting the need to implement techniques and new technologies that allow increasing the recovery factor, therefore achieving greater oil production rates.

It is important to mention that the Ecuadorian government plans to increase oil production in the period 2020-2021 by drilling 24 wells in the ITT oil block, which is located in the middle of an environmentally protected area. This field has 4 billion barrels of oil (proven reserves), making it an extremely important field for the industry in Ecuador. Petroamazonas (Ecuadorian state-owned oil company) plans to implement new technologies that considerably reduce environmental impact, maximize oil production, and reduce costs.

Halliburton Ecuador, based on its experience around the world, proposes the option of drilling TAML level 4 multilateral wells to develop oil fields in Ecuador considering the situation of the industry in the country. Table 1 shows the success rate the company has had drilling multilateral wells all over the world.

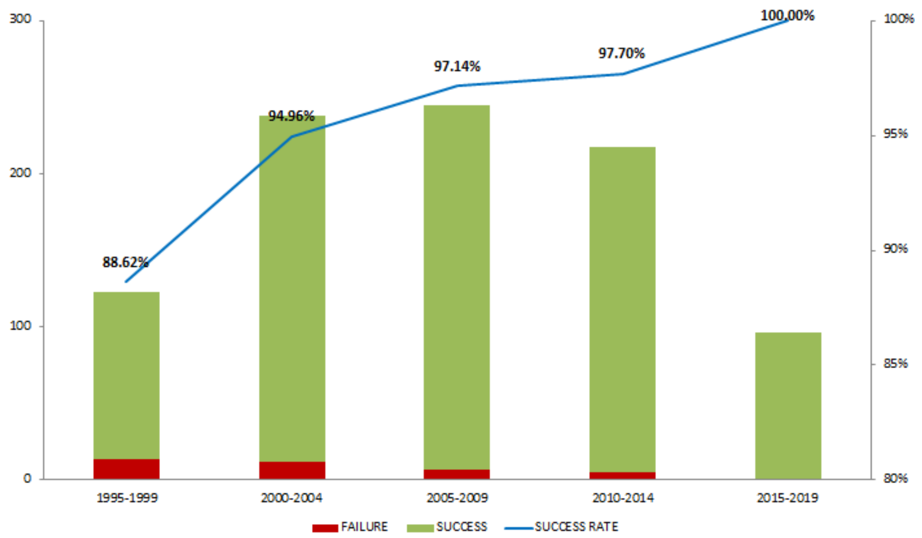


Figure 1 Multilateral wells drilling success rate[3].

[2] Value obtained from the official website of: Ministerio de Energía y Recursos Naturales no Renovables del Ecuador.
[3] Obtained from: Halliburton's internal document.

Multilateral well system is a relatively new technology in Ecuador, so this thesis is designed to study the feasibility of implementing MLT in Ecuador, for this reason a technical, economic and risk analysis is carried out.

1.2. Problem Statement / Research approach

The problem statement in this thesis is based on three main aspects, related to the stages of drilling and oil production in Ecuador:

1.2.1. Environmental Problem Statement

The oil extraction zone is located mainly in the Amazon region of Ecuador, a region that is environmentally protected. With the development of the oil industry since 1970 it has generated an environmental impact mainly by constructing new platforms to drill more wells. Companies seek to implement new technologies that reduce the facility footprint in vulnerable areas or sensitive locations.

1.2.2. Operational Problem Statement

From an operational point of view, the main challenges that the production and drilling stages of oil wells in Ecuador have to face are:

- Water conning. In most of the oil fields in Ecuador, oil is driven in reservoirs by active aquifers.
- Heavy crude oil reservoirs (10 °API) like Pungarayacu oil field.
- Locaciones con espacios reducidos ubicadas en zonas ambientalmente protegidas, por lo que el número de pozos a perforar se ve totalmente reducido.
- Locations in environmentally protected areas with a limited number of slots, so the number of wells to be drilled is reduced.
- Oil fields with low production rates.
- High production costs

Based on these drawbacks, Petroamazonas seeks to implement alternatives that mitigate the aforementioned problems in order to extend the life of the well, increase hydrocarbon production, increase the drainage radius, optimize time and resources.

1.2.3. Economic Problem Statement

Solving the operational problems associated with the drilling and oil production stages considerably increase project costs, reducing the profit margin. It seeks to implement techniques or new technologies that allow increasing profits and reducing costs at the same time. Factors such as reducing drilling time, reducing operational costs, reducing equipment mobilization time, lengthening the useful life of the well, among others, are aspects that generate savings and must be considered when implementing new technologies.

Based on the aforementioned problems, this thesis covers the technology of multilateral wells as an option to overcome the challenges that arise in the stages of drilling and oil production in Ecuador, therefore, this thesis addresses issues such as:

- Multilateral and horizontal wells performance.
- Multilateral technology advantages
- Multilateral / Smart wells field case studies.
- Economic features of multilateral wells.

1.3. Thesis Objectives

- ❖ To use an existing methodology to calculate the performance of a TAML Level 4 multilateral well (double lateral stacked) and of a horizontal well. Based on the results obtained, an analysis of the technical, economic and risk aspects of the two proposed well systems (horizontal and multilateral) is carried out to determine which of the two systems maximizes the production of reserves at a lower cost.

- ❖ Determine the feasibility of drilling a TAML Level 4 multilateral well in Ecuador based on the results obtained from the technical, economic and risk analysis.

- Analyze different field case studies in order to identify and quantify the advantages and/or disadvantages of multilateral well technology in order to support the criterion of whether drilling of multilateral wells is feasible or not in Ecuador.

1.4. Structure of the Thesis

The present thesis is structured mainly based on two different approaches: a qualitative approach and a quantitative approach. It has been decided to structure the thesis in this way to meet the study objectives.

The qualitative approach is oriented to generate technical criteria from the literature review and the analysis of case studies. On the other hand, the quantitative approach is oriented to generate results from different types of analyzes carried out. Figure 2 graphically represents the main axes on which the different approaches will be based on.

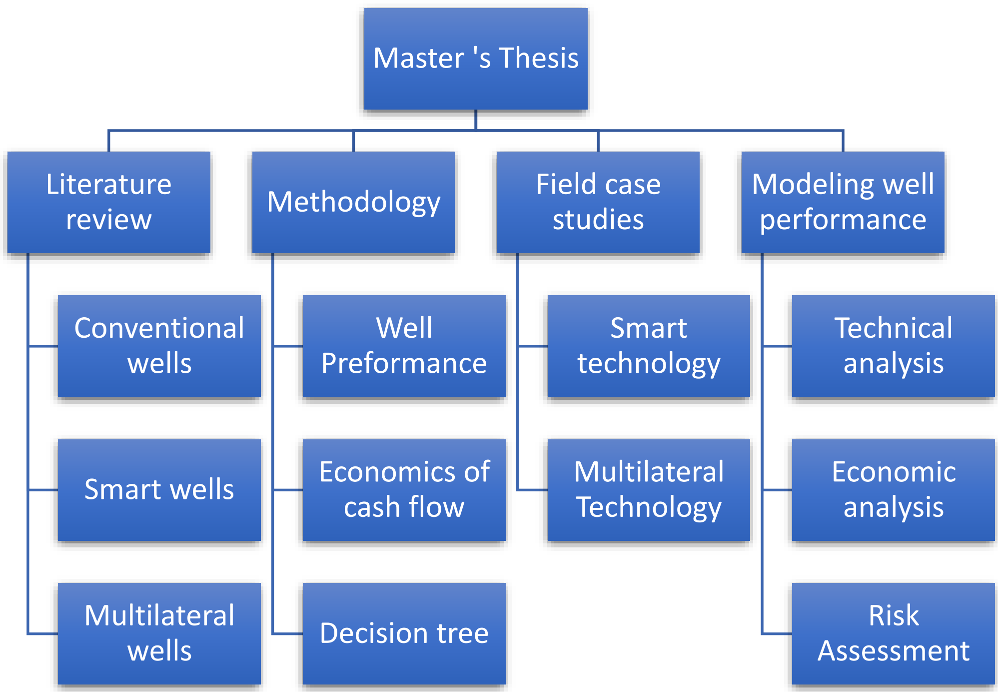


Figure 2 Main axes of the thesis.

The present master's thesis is divided into 7 main chapters, and each of them consist of sub- chapters.

- ***Chapter 1:*** is an introduction to the thesis detailing aspects such as background, scope of work, stated objectives, and research focus.

- ***Chapter 2:*** comprises a review of the literature providing an overview of conventional wells and smart wells, and a more detailed description of multilateral wells.

- ***Chapter 3:*** analyzes eight different field case studies where multilateral wells have been drilled and smart wells have been used.

- ***Chapter 4:*** describes the methodology used to carry out the different types of analysis.

- ***Chapter 5:*** geological description of the reservoirs in Ecuador.

- ***Chapter 6:*** starts with a technical analysis, followed by an economic analysis that considers the results obtained from the previous analysis to perform calculations. As part of the economic analysis, a risk analysis is performed.

- ***Chapter 7:*** summarizes the results obtained in the different analyzes carried out in this thesis.

- ***Chapter 8:*** provides conclusions based on the results obtained from the different analyzes, including the analysis of the field case studies.

2. Literature Review

2.1. Conventional wells

A conventional well or also known as a traditional well are those vertical, horizontal, or deviated wells that do not demand the use of advanced technology to be drilled or efficiently produce hydrocarbons where greater control over production is required.

The biggest disadvantage of vertical and deviated wells is that they penetrate the reservoir vertically, so the contact area is not so big, which limits the production rate of hydrocarbons. As evolution of vertical wells, horizontal wells appear which have a greater exposure area with the area of interest, so the production rate is generally higher than in vertical and deviated wells. The development of horizontal wells allowed drilling multilateral wells to produce oil from different reservoirs at the same time and at a lower cost than drilling several separate horizontal wells.

Based on the need to collect, transmit, and analyze the measurement of some parameters in conventional wells, achieve greater control over the production process, and obtain real-time information about production, smart well technology emerges.

2.2. Smart wells

The oil / gas industry is constantly in search of developing new technologies that can overcome the problems and challenges that especially arise in the production stage in conventional wells with the main purpose of increasing production with less operational cost.

The fundamental principle of smart wells is to employ electric down-hole sensors and valves to actively monitor the well and control its production. Among the main advantages are that operations can be carried out remotely from the surface, for example, it is possible to open or close sliding sleeves to select from which zone to produce hydrocarbon, real-time pressure, temperature, and flow rate information can be obtained, and water production can be monitored as well. (Gao, Rajeswaran, & Nakagawa, 2007).

The true value of the technology used in smart wells is that it allows permanent monitoring in the well, so the components that make up the monitoring system must work during the useful and productive life of the well, otherwise, erroneous readings could be generated, and spoil the well.

Among the main applications of smart wells are:

- **Water or gas shut-off:** The completion string in a smart well contemplates the installation of sleeves and inflow control valves in each of the pay zones, allowing the benefit to control each of those zones individually. In the event of water breakthrough, valves or sleeves can be closed remotely. Valves can close automatically by installing sensors in the control valves.

- **Commingled production:** When two or more reservoirs have a common wellbore or flowline through which the different oil or gas productions are channeled, inflow control valves are used to control production.

In general, a well that has a completion string with new technology components that can be installed down-hole and can be operated remotely can be said to be a smart well. Brouwer (2004) made a graphic description of the components of a smart well, which is shown in Figure 3.

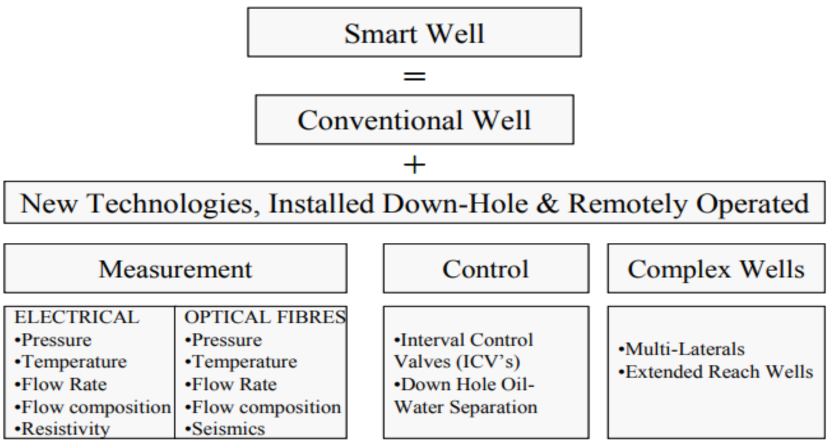


Figure 3 Illustration of the elements that make up a smart well.
Obtained from (Brouwer, 2004)

In order to improve the reliability of the downhole electronic components used in the monitoring system that allow obtaining down-hole real-time information, fiber optic technology has been adapted in the sensors used in smart wells and a system hydraulic control has been implemented. With these improvements, the transfer data of the measurement of parameters such as pressure, temperature, resistivity and flow rate is more accurate. (Xiaoyu et al., 2012)

2.3. Multilateral Wells

In a simple and general way, a multilateral well can be considered as a vertical well made up of several horizontal wells called *laterals* or *branches*, which are drilled with the purpose of producing hydrocarbons at the same time from different pay zones, whose production flows to a common well string.

Multilateral technology has proven its multiple technical and economic benefits in the development of oil and gas fields by effectively draining reservoirs with different geological characteristics (e.g. naturally fractured reservoirs, low permeability reservoirs) and by production enhancement, therefore this technology has become an increasingly applied method to improve oil recovery. These benefits have given horizontal and multilateral wells the lead over other technologies in developing complex reservoirs.

Table 1 lists the challenges that multilateral well technology faces and the solutions it can provide. This information can also be considered as key factors to consider when selecting multilateral technology for a particular reservoir application.

Challenges	Multilateral Solutions
✓ Increase reservoir exposure ✓ Slot-constrained pads. ✓ Maintaining production without drilling new wells. ✓ Maintaining production while constructing additional branches. ✓ Reduce facility footprint in sensitive or restricted locations. ✓ Ensuring consistency and quality of services	✓ Optimizing advance well architecture for increased reservoir exposure. ✓ Managing pressure drawdown ✓ Managing water coning or gas influx ✓ Efficient slots use reducing pads to drain larger field area. ✓ Full functionality with mainbore and lateral access. ✓ Single surface location. ✓ Reducing large drilling pads improving available slots

Table 1 MLT challenges and solutions[4].

Laterals or branches have the same characteristics and geometries as the horizontal wells, so boreholes can also be ultra-short (100 – 200 ft.), short (250 – 450 ft.), medium (500 – 3000 ft.), and long (1000 – 3000 ft.). (Joshi, 1991)

It is important to mention that a long horizontal well is more susceptible to the "heel-toe effect", where the drawdown (pressure differential) is higher at the heel section than at the toe section since the friction pressure increases along the well. The production is higher at the heel since the production is proportional to the pressure difference, this being a great risk of gas and water coning; multilateral wells have been successfully used in reservoirs with coning problems. (Elyasi, 2016).

To understand multilateral technology, it is important to start by defining and clarifying the most basic concepts.

Multilateral well: Can be defined as a sophisticated structural drainage design consisting of one or more lateral / branches boreholes drilled from the same main wellbore (mother wellbore) which can be vertical or horizontal. The design of a multilateral well is characterized by two main aspects; by the number of laterals that it

[4] Obtained from: Halliburton's internal document.

contains, for example, double lateral (two laterals), trilateral (three laterals), quadrilateral (four laterals) and by the geometry of the lateral such as: dual opposed lateral, stacked lateral (i.e. dual or triple), forked, horizontal fishbone, among others. (Hyne, 2014)

Lateral wells or Root wells: Refer to wellbores drilled out from a vertical main wellbore in order to reach different pay zones. (Guo, Sun, & Ghalambor, 2008)

Branches: Refer to wellbores drilled out from a horizontal lateral destined to reach different areas within the same pay zone. (Guo et al., 2008)

Junction: Chambers (1998) defined the concept of a junction as “the intersection point of laterals to the main wellbore or branches to the lateral". (Chambers, 1998)

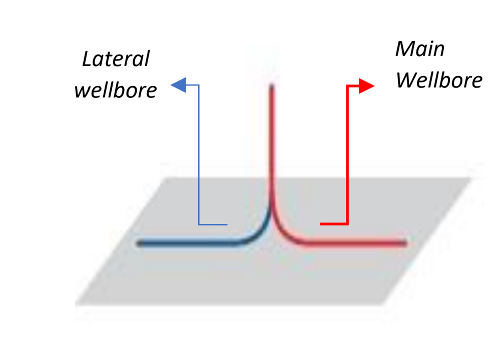
Water coning / Gas coning: Process in which gas from a gas cap or water from an aquifer moves toward a production well in a cone manner. Coning represents a production problem since it reduces crude oil production and simultaneously the production of either water or gas increases progressively after the recovery time and it is a phenomenon caused due to high production rates or due to a significant pressure drawdown. Water/gas coning should not be confused with water influx from the OWC or with free-gas production from an expanding gas cap, respectively. (Hatzignatiou & Mohamed, 1994)

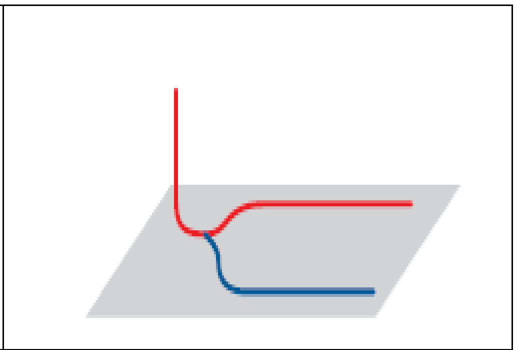
Pressure drawdown: Differential pressure (SBHP - Pwf) that allows fluids migrate from the reservoir into the wellbore. (Brebbia & Vorobieff, 2013)

2.3.1. Multilateral Well Configuration

The design of a multilateral well will depend on several factors, such as the number of targets that the reservoir has, the number of targets that need to be drilled, the depth at which the layers of interest are found, the dimensions of the targets, among others. It is important to mention that the design of a multilateral well will be essentially based on two categories:

1. Drill laterals in the same horizontal plane at the same depth, either in the same direction or in the opposite direction. Examples of this type of wells are planar opposed dual lateral (gullwing) configuration or planar dual lateral (pitchfork), as shown in Figure 4.

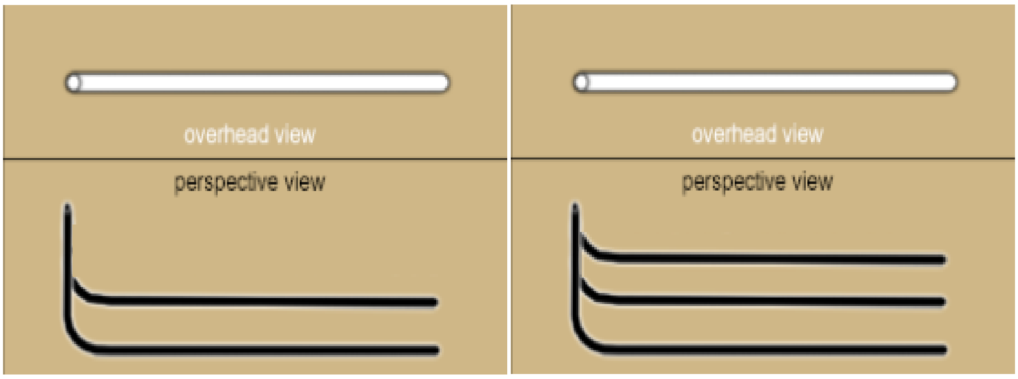




Planar opposed dual lateral (gullwing)	Planar dual lateral (pitchfork)

Figure 4 Examples of multilateral wells drilled in the horizontal plane. Obtained and modified from (Von Flatern, 2016).

2. Drill laterals in the same vertical plane, either in the same direction or opposite direction but at different depths. There are different possible designs for this type of configuration, for example, dual opposed and stacked opposed triple lateral well (Figure 6), however, the most widely used well design under this category is a stacked lateral design which is shown in Figure 5.



Stacked dual lateral	Stacked Tri Lateral

Figure 5 Types of tacked multilateral well. Obtained and modified from Modified from (King, 2018)

Stacked Laterals multilateral configuration can produce oil or gas from two or more productive zones (at the same time) by drilling a single lateral in each layer.

Reservoirs that have two or more productive zones that are separated and there are not communicated vertically between each other or reservoirs that must be produced from above and below a permeability barrier are the perfect scenario to implement this type of design of multilateral well. (Denney, 1998a)

There are two possible ways through which this type of well can produce fluids separately. The first way is that all the sides are connected to the same string, installing a check valve below the union to avoid a mixture of fluids; The second is through various production strings in which each side has its own string (Denney, 1998b).

The main advantage offered by this multilateral well system apart from producing from several zones at the same time is that they have greater exposure to the zone of interest, so a greater volume of hydrocarbon can flow into the well, increasing the well's productivity. On the other hand, water of gas conification process is slower and the number of single horizontal wells to be drilled is reduced.

Bearing in mind those two categories, it can be affirmed that there are an infinite number of designs and configurations of wells that can be drilled though multilateral technology in order to drill multiple zones or extend in several directions in the same reservoir.

It is important to understand that the design of a multilateral well will depend on several factors, such as the number of targets that the reservoir has, the number of targets that need to be drilled, the depth at which the layers of interest are found, the dimensions of the targets, among others. It is important to mention that the design of a multilateral well will be essentially based on two categories:

Different examples of possible multilateral wells configurations are shown in Figure 6.

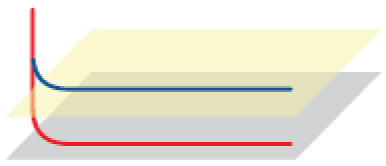
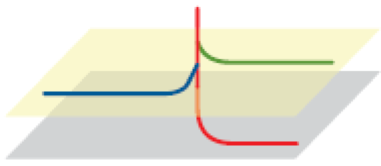
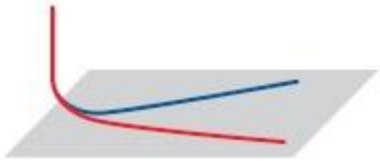
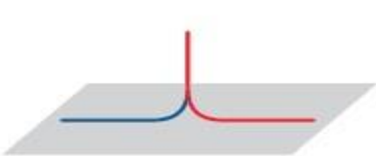
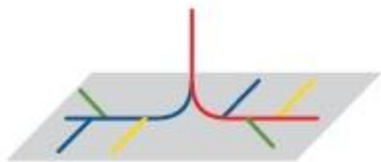
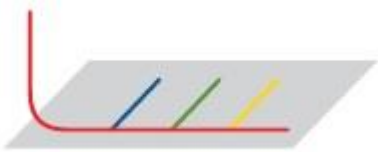
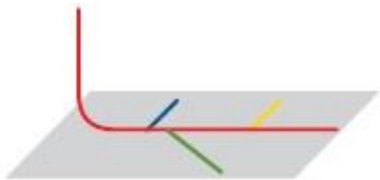
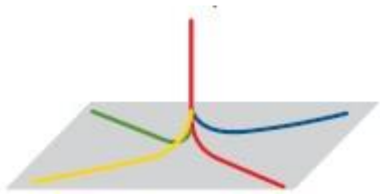
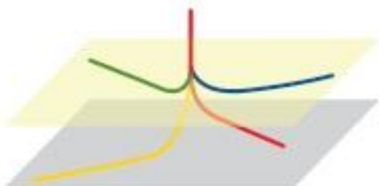
	
Stacked dual lateral / Parallel	Dual opposed and stacked opposed triple lateral
	
Planar dual lateral	Planar dual lateral (pitchfork)
	
Planar opposed dual lateral (gullwing)	Planar opposed dual lateral with herringbone pattern
	
Lateral with herringbone pattern	Lateral with opposed herringbone pattern
	
Planar quadrilateral	Stacked planar quadrilateral

Figure 6 Different types of multilateral wells.
Obtained and modified from (Von Flatern, 2016).

In general, the different multilateral configurations mentioned above can be described as follows:

- **Stacked laterals**: Laterals are drilled in the same vertical plane either in the same or different direction at different depths but same azimuth.

- **Planar Opposed laterals (Gullwing):** Two laterals in the horizontal plane, in the same zone drilled out from the same main wellbore that are oriented 180 degrees opposed to each other.

- **Planar dual lateral (pitchfork):** Two lateral drilled in the same the same horizontal plane in different directions.

- **Herringbone patterns or fishbone design:** They are made up of several laterals drilled out from the same horizontal mainbore, extending outward in different directions to cover the area.

However, regardless of the configuration or design of the multilateral well, each of theme requires a junction to connect the laterals to the main wellbore or to connect branches to the laterals; from the junction the laterals / branches diverge.

This classification groups multilateral wells into 7 different levels depending on the complexity and functionality of the multilateral well, where level one is the simplest and the last level the most complex and advanced. It is important to mention that each level refers to a specific junction, but not to the design of the well. A multilateral well can be made up of junctions of the same level of complexity or be made up of junctions of different levels of complexity, which means that junctions of different levels can be found in a same multilateral well. (Chambers, 1998).

The different types of joints will be discussed later in the following chapters.

2.3.2. Technology Advancement of Multilateral (TAML) / Junction Classification

A group made up of operator and service companies, both with experience in multilateral wells, formed a consortium called *Technology Advancement of Multilaterals* (TAML), which in 1997 developed the TAML classification in order to unify the theory and concepts related to MLT with the purpose of classifying into 6 the mechanical complexity and functionality of the junctions that connect the two lateral wellbores (Pasicznyk, 2001). Each level refers to a type of junction depending on the type of support, integrity and isolation provided at the junction in the well (Westgard, 2002). As the level of the union increases in the TAML classification, the level of complexity of the system increases, therefore the cost also increases.

2.3.2.1. TAML Level 1 – Main bore and Lateral open

This junction is the simplest one of all junctions; it is used in the most basic designs of multilateral wells. This level is characterized by the fact that both the main wellbore, as the lateral wellbore or laterals are uncased (open-hole) and the junction does not have hydraulic isolation or mechanical support, so its integrity will depend exclusively on the stability of the borehole, however, a slotted liner can be ran in the main wellbore or lateral to help keep the hole open during production. (Westgard, 2002)

In this design, the lateral is used in consolidated formations with the purpose of improving the drainage in the reservoir. Among its main advantages stands out the low cost of drilling and completion. On the other hand, its main disadvantage is that, since the open-hole junction does not have any type of support, the intervention works or a re-entry operation that may be required in the future, either in the main bore or in the lateral, will be highly difficult or impossible because the integrity of the junction can be compromised in the process. (W. C. Hogg, 1997)

In this type of multilateral well, the production of the main bore and the lateral bore is commingled in the main bore since it is not possible to install a selective control production control or zonal isolation in this system of multilateral wells.

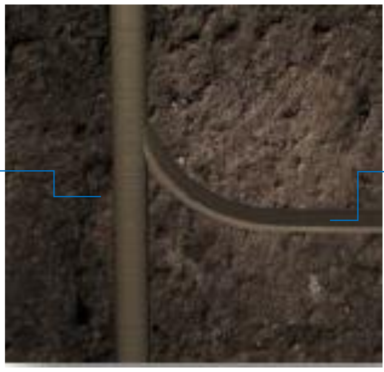


Figure 7 TAML Level 1.
Obtained and modified from (Butler, Grossmann, Parlin, & Sekhon, 2017)

Based on the aforementioned information, Table 2 presents the main aspects that must be considered for TAML Level 1.

Level	Description	Objective
TAML Level 1 *(Main bore and lateral open)*	• Open hole junction. • Junction without support. • Main wellbore and lateral uncased (open hole). • Neither slotted liner not liner string. • No mechanical connection at the junction. • No mechanical support.	• Produce hydrocarbons from consolidated formations. • Commingled production.

Table 2 TAML Level 1 main aspects.
(Butler et al., 2017; C. Hogg, Cham, & Hicks, 2016).

2.3.2.2. TAML Level 2 – Main bore cased and cemented, lateral open

TAML level 2 multilateral wells are those that have cemented and cased the main bore, and the lateral bore is uncased (open-hole), however, a slotted liner can be placed on the lateral to help maintain wellbore stability.

The benefits of having the main wellbore cased and cemented are:

- Provides a means of hydraulic isolation between production areas
- Provides isolation between main bore and lateral or between laterals.
- Greatly reduces the chances of wellbore collapsing.

The advantage of this level compared to the previous one is that it allows the installation of packers and sliding sleeves in the main bore, allowing production to be singly or commingle (Westgard, 2002).

Like the previous level (Level 1), this lateral junction does not have a mechanical support either.

Figure 8 TAML Level 2.
Obtained from (Butler et al., 2017)

Based on the aforementioned information, Table 3 presents the main aspects that must be considered for TAML Level 2.

Level	Description	Objective
TAML Level 2 (Main bore cased and cemented, lateral open)	• Main wellbore is cased and cemented. • Uncased lateral. • Slotted liner can be used in the lateral bore. • No connection at the junction. • No mechanical support.	• Provide isolation between laterals. • Maintain wellbore stability. • Singly or commingled production.

Table 3 TAML Level 2 main aspects.
(Butler et al., 2017; C. Hogg et al., 2016).

2.3.2.3. TAML Level 3 – Main bore cased and cemented, lateral cased but not cemented

In a TAML Level 3 multilateral well, the main bore is cased and cemented whereas the lateral is lined but not cemented at the junction. The liner string is anchored or suspended inside a casing joint located in the main bore, allowing the two wellbores to be mechanically connected to each other. It is important to emphasize that the junction is not cemented, however, this system offers mechanical support to the lateral junction, which allows access to both laterals, and allows the re-entry operation to be safer without compromising the integrity of the joint. Compared to levels 1 and 2, the junction at level 3 has better support (Fipke & Oberkircher, 2002).

This system does not provide hydraulic isolation and is mainly used in reservoirs that have consolidated formations.

Like the TAML Level 2, packer plugs and sliding sleeves can be installed in the main bore to select the production method, singly or commingle. Like the TAML Level 1, TAML Level 3 is restricted to be used in consolidated formations. (Pasicznyk, 2001)

Figure 9 TAML Level 3.
Obtained from (Butler et al., 2017)

Based on the aforementioned information, Table 4 presents the main aspects that must be considered for TAML Level 3.

Level	Description	Objective
TAML Level 3 (Main bore cased and cemented, lateral cased but not cemented)	• Main wellbore is cased and cemented. • Lateral is lined but not cemented. • Screen, slotted liner, or conventional liner can be used in the lateral section. • Liner is anchored to a casing joint located in the mother bore. • Main wellbore and lateral wellbore are mechanically jointed. • Junction is not cemented. • Junction is not hydraulically sealed.	• Allow access to both laterals. • Allow re-entry. • Mainly used in reservoirs that have consolidated formations. • Singly or commingled production.

Table 4 TAML Level 3 main aspects.
(Butler et al., 2017; C. Hogg et al., 2016).

2.3.2.4. TAML Level 4 – Main bore and Lateral cased and cemented

The main characteristic of the TAML Level 4 is that both the main bore and lateral bore are cased and cemented, including the junction, making this system capable of being used in consolidated as well as unconsolidated formations. Since the junction is cased and cemented, provides the lateral mechanical support, allowing full access to the lateral without any restriction.

On the other hand, it can be said that the limitation of this system is the cement in the junction. Since the cement has a maximum limit of resistance to differential pressure it does not provide hydraulic isolation, and there is the possibility that the junction fails eventually if it is exposed to significant drawdown, however, TAML Level 4 has a greater resistance and support than the previous levels (Level 1 – Level 3).

By installing packers above and below the junction in the main wellbore, zonal isolation can be achieved, allowing to select of manner the well will produce hydrocarbon.

Figure 10 TAML Level 4.
Obtained from (Butler et al., 2017)

Based on the aforementioned information, Table 5 presents the main aspects that must be considered for TAML Level 4.

Level	Description	Objective
TAML Level 4 (Main bore and Lateral cased and cemented)	• Main wellbore is cased and cemented. • Lateral is lined and cemented. • Liner is also anchored back into the main bore. • Maximum mechanical support at the junction. • Hydraulic integrity depends on the quality of the cement. • Full casing ID.	• It can be used in both consolidated and unconsolidated formations. • Allow full access to the lateral without any restriction. • Singly or commingled production.

Table 5 TAML Level 4 main aspects.
(Butler et al., 2017; C. Hogg et al., 2016).

2.3.2.5. TAML Level 5 – Pressure integrity at the junction; Achieved by completion equipment

TAML Level 5 is characterized by having both the main bore and the lateral bore cased but not cemented; the junction can be cemented or not, it is optional. The main advantage of the TAML Level 5 is that it has hydraulic isolation at the junction since pressure integrity is supplied by the completion string, which means that the completion string isolates the junction, generating greater resistance to pressure than cement.

This system allows full access to both the main bore and the lateral bore. Depending on the design of the completion system, each of the zones can produce individually or the production can be commingled.

TAML Level 5 is very similar to Level 3 or Level 4, with the only difference that a completion string is fixed, which provides hydraulic isolation, this means that before completion string is installed the multilateral well can be a Level 3 or Level 4.

Figure 11 TAML Level 5.
Obtained from (Butler et al., 2017).

Based on the aforementioned information, Table 6 presents the main aspects that must be considered for TAML Level 5.

Level	Description	Objective
TAML Level 5 (Pressure integrity at the junction; Achieved by completion equipment)	• Main wellbore is cased but not cemented. • Lateral is lined but not cemented, is anchored. • Lateral may be cemented or not. • The integrity of the junction is achieved through the completion. • Hydraulic isolation achieved through the completion. • Provide pressure integrity. • There is a point with ID restriction.	• Singly or commingled production. • Allow full access to both the main bore and the lateral bore.

Table 6 TAML Level 5 main aspects.
(Butler et al., 2017; C. Hogg et al., 2016).

2.3.2.6. TAML Level 6 – Pressure integrity at the junction achieved by casing

TAML Level 6 Multilateral Wells also have hydraulic isolation at the junction; this junction is prefabricated. Unlike the TAML Level 5, mechanical and pressure integrity is achieved through the casing string located in the main wellbore and the liner placed on the lateral, which may be cemented or not. The junction is an integral part of the main bore casing string. In TAML Level 6 integrity is not achieved through a completion system, eliminating the need to use complex completion system to create pressure integrity (W. C. Hogg & MacKenzie, 1998).

The junction cannot be cemented as in TAML Level 4, so cement is not considered as an option to achieve pressure integrity (W. C. Hogg, 1997).

It is important to emphasize that Level 6 multilateral system could not be developed on a large scale due to its high cost, high degree of complexity, its difficult installation process, and because it reduces the internal diameter (ID) significantly, which is why it is not considered a viable system. Currently it is an expired technology since it is no longer used (Pasicznyk, 2001).

Figure 12 TAML Level 6.
Obtained from (Butler et al., 2017)

Table 7 summarizes the main aspects of each of the different levels for multilateral wells classification that were put forward as the standard classification TAML Level 6.

Level	Description	Objective
TAML Level 6 *(Pressure integrity at the junction achieved by casing)*	• Specialized casing/junction is required. • Pre manufactured junction • Junction cannot be cemented. • Hydraulic isolation at the junction. • The integrity of the junction is achieved by the casing string. • No ID restriction.	• Intended for experiments

Table 7 TAML Level 6 main aspects.
(Butler et al., 2017; C. Hogg et al., 2016).

2.3.3. Multilateral Level Selection

Sunagatullin et al. (2010) defined a schematic algorithm, structured based on data from multilateral technology literature that points out the key factors such as type of junctions, type of completion, requirement of flow control and type of re-entry to be able to select the best multilateral level option without the need to consider the criteria of experts or the result of geomechanical studies. The algorithm is shown in Figure 13.

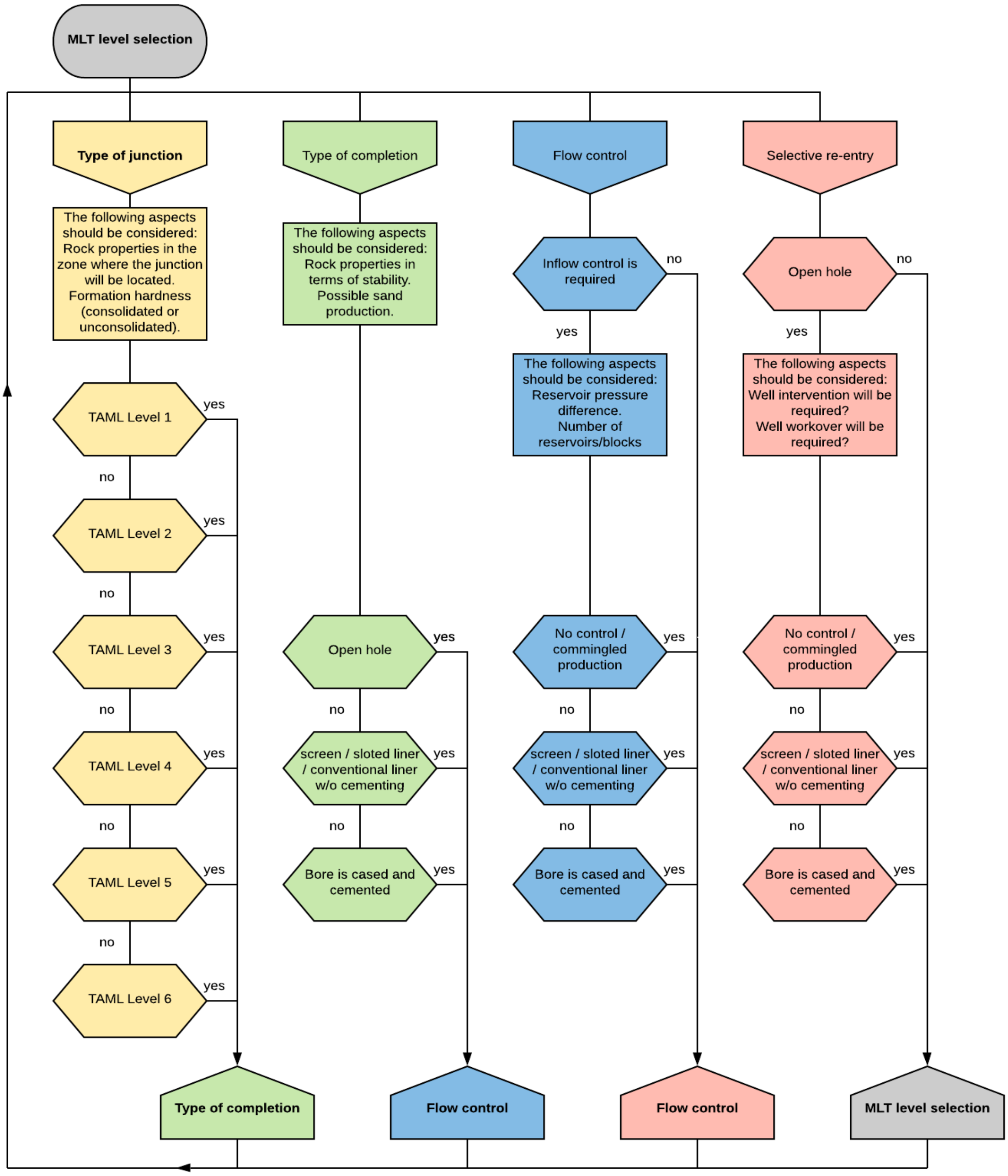


Figure 13 Key factors to be considered in selecting a ML junction level.
Obtained and modified from (Sunagatullin, Arzhilovskiy, Manapov, & Mikheev, 2010).

2.3.4. Criteria for selecting a multilateral well candidate.

Drilling a horizontal well is the basis for constructing a multilateral well, therefore it is imperative to mention the selection criteria for drilling a multilateral well considering the characteristics of the reservoir.

Garrouch et al. defined a decision tree (Figure 14) to determine if a well can be a candidate to be horizontal according to reservoir conditions, however, this decision tree can also be applied to determine if a well is a candidate to be multilateral taking into account the following considerations that must be fulfilled: limited number of slots, environmental impact specially in sensitive environmental areas and economic aspects.

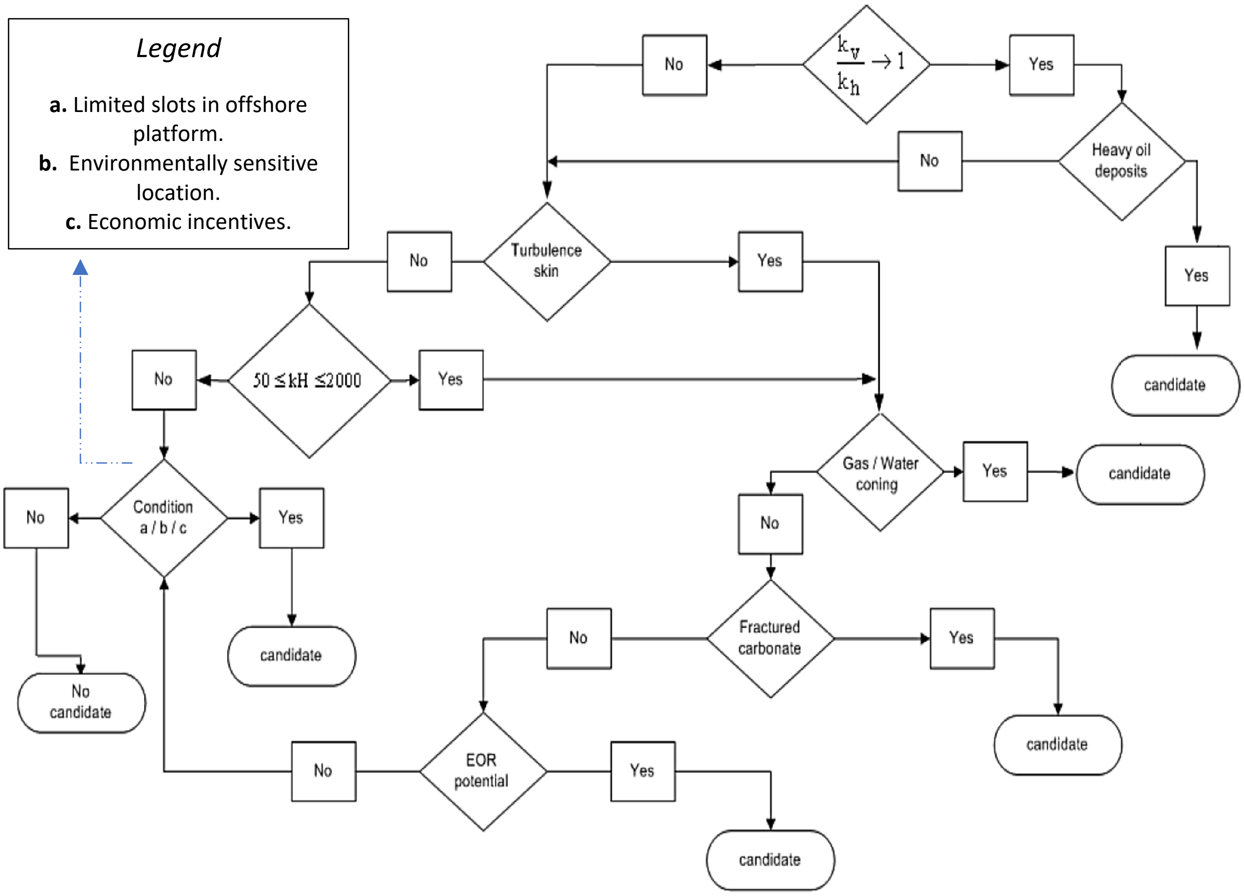


Figure 14 Decision tree for horizontal / multilateral well.
Obtained and modified from (Garrouch, Lababidi, & Ebrahim, 2003).

3. Filed Case Studies

For this chapter, different field case studies have been selected in different operational scenarios to extract and present the technical, economic, and environmental aspects that multilateral technology can contribute to the development of oil/gas fields, either onshore or offshore.

In the technical part, the problems, and challenges that the technology of multilateral wells had to face and under what geological conditions are detailed. In the economic aspect, an economic evaluation is presented, which is based on comparing the costs associated with a multilateral well and the costs of a horizontal well in order to determine which is the most profitable. This chapter is developed to assess the potential of MLT technology.

3.1. Deepwater in Brazil (Brazil)

3.1.1. Multilateral Wells Technical Aspects in a Deepwater Oil Field

In 1998, on the Brazilian coast, in a water depth of 565 meters, a TAML Level 5 (with hydraulic isolation of the junction) multilateral well (planar opposed dual lateral design design) was drilled as shown in Figure 15.

The main driver for drilling this multilateral well was the reservoir conditions, whose oil production decreased due to a decline in pressure. A reservoir study directed by the operator company determined that the best way to keep reservoir pressure at an acceptable level was through an injection method for enhancing the oil production , so in this case, the multilateral well was not drilled for production purposes, it was drilled to be an injector well (multilateral injector well) (W. C. Hogg, 2005).

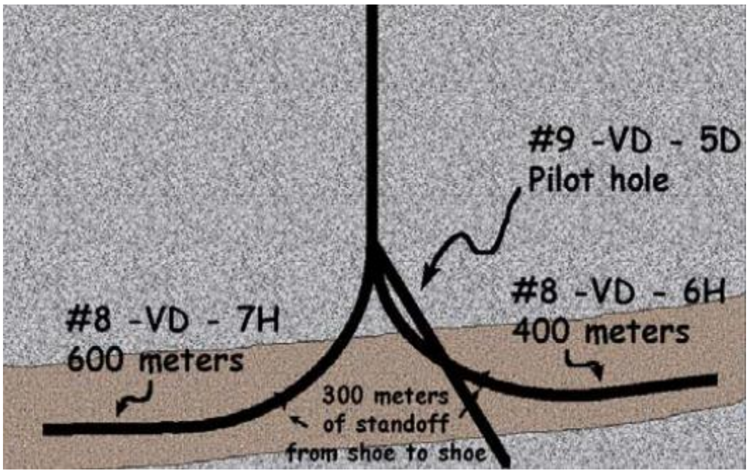


Figure 15 Sketch of Brazilian Deepwater multilateral well**.**
Obtained and modified from (W. C. Hogg, 2005).

For this multilateral well, a planar opposed dual lateral design (as shown in Figure 15) was selected as a result of a further reservoir study, which determined that this type of multilateral configuration has a greater exposure to the reservoir and more efficient sweeping effect could be achieved.

With this multilateral well configuration, it was possible to cover a length in the reservoir of 1,300 meters since one branch has 600 meters of horizontal section, the second branch has 400 meters, and there is a distance of 300 meters of standoff between casing shoes, which means a total horizontal length of 1,300 meters.

3.1.2. Economic Evaluation

The alternative of drilling the multilateral well was originally selected because of the technical solutions that it could provide to the depleted reservoir, however, the main benefit obtained from drilling the multilateral well was the cost savings that could be generated in the project. Table 8 shows the cost savings of drilling a multilateral well (TAML 5) over 2 conventional horizontal wells.

ITEM	*Multilateral Well Injector (Level 5)*	*2 conventional horizontal injection wells*	*MLT cost savings*
	COST (U.S. DOLLARS)	*COST (U.S. DOLLARS)*	*COST (U.S. DOLLARS)*
Drill & Complete	$20,357,600.00	$25,387,300.00	$5,029,700.00
Wellhead, lines, etc.	$4,550,000.00	$9,150,000.00	$4,600,000.00
5 days mobilization to drill the second well	$0.00	$367,750.00	$367,750.00
TOTAL	**$24,907,600.00**	**$34,905,050.00**	**$9,997,450.00**

Table 8 Cost savings generated by MLT technology in Deepwater oil field. Modified from (W. C. Hogg, 2005).

Hoog (2005) performed an analysis on the multilateral cost savings on the project where it was determined that the cost to drill a single conventional well was approximately USD 17.2 million, whereas the estimated cost to drill a multilateral well was USD 24.9 million. At first glance, the cheapest option was to drill a conventional well since the cost of a multilateral was 1.45 times higher. However, a two-branch multilateral well provides twice the exposure over a conventional well, which means that to achieve the same level of exposure, two horizontal wells must be drilled, which would represent a total cost of USD 34.5 million; consequently, a multilateral well represented a cost savings of USD 9.6 million, that is, 38% less than it would have cost to drill two horizontal wells. On the other hand, only a one injection tubing string was required, which meant a saving of 5 million dollars in the completion stage.

The cost savings that were achieved with the multilateral well technology are remarkable, however, conducting a deeper analysis, it is possible to determine that the savings not only occurred in the drilling and completion stages, which was USD 5,029,700; There was also a saving of USD 4.6 million associated with the reduction in the number of flow lines required and the number of well heads used since only one well was drilled instead of two. Likewise, a saving of USD 367,000 was generated by eliminating from the schedule 5 days required to mobilize the platform to drill the second well.

In closing, this multilateral well brought technical benefits to the project allowing oil production to continue through an increase in reservoir pressure, at the same time generated economic savings by reducing costs by $ 9,997,450 million (W. C. Hogg, 2005).

3.2. Milne Point Field (United States)

3.2.1. Multilateral Wells Technical Aspects in an Arctic Region

The Milne Point field, located on the North Slope in Alaska, is characterized by having a reservoir with heavy oil. In order to optimize the development of this heavy oil reservoir, multilateral wells were drilled with mechanically supported junction as shown in Figure 16.

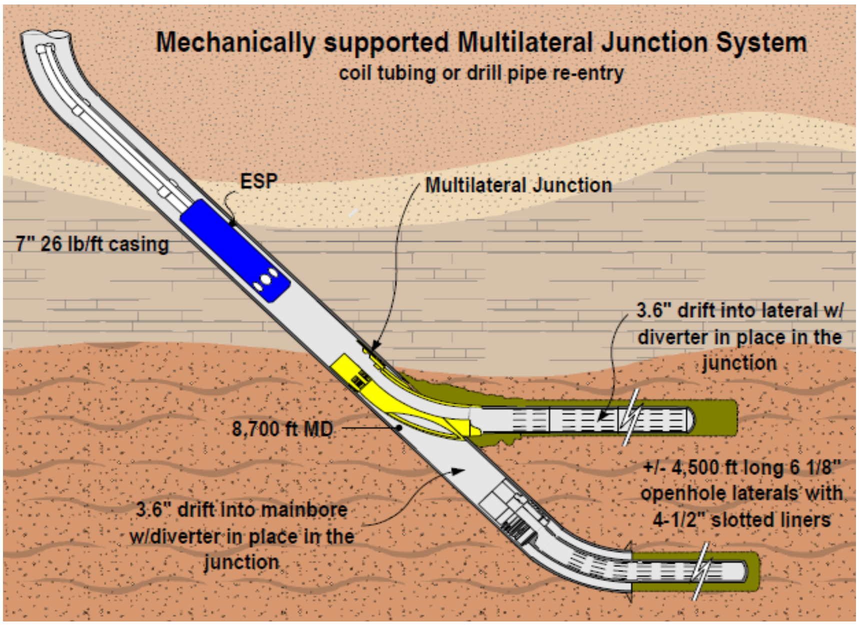


Figure 16 Sketch of mechanically supported multilateral junction system. Obtained from (W. C. Hogg, 2005).

3.2.2. Economic Evaluation

Based on a field development study, which specially analyzed the characteristics of the reservoir and its type of oil (heavy oil), it was planned to increase the production rate by 3 times through the drilling of multilateral wells (stacked dual lateral), and it was also estimated that the project costs would decrease by 30% by reducing the number of conventional wells to be drilled and by minimizing the number of flow lines and surface equipment required on the surface.

Increasing production rates and reducing costs represent technical and economic benefits that MLT technology can bring in the drilling, completion and surface facilities stages, however, there are more areas where savings can be generated with a multilateral approach, for example, it allows you to save costs when selecting an artificial lift system.

In the original field development plan, it was planned to drill between 500 to 1,000 conventional wells and to install an Electric Submersible Pump (ESP) system in each well as artificial lift method to produce oil. Replacing the ESP system in each of the wells has an average cost of USD 300,000, therefore, the project costs increased significantly considering the number of ESP installed in each well and the personnel involved in the ESP system installation process. Therefore, the number of ESPs required for multilateral wells drilled for the development of Milne Point field was greatly minimized and all that entails, for example, reduction in the number of ESP failures. An important aspect to be considered is that when multilateral wells are drilled, the amount of sand produced is considerably reduced, increasing the life of the ESP system.

On the other hand, in order to drill the number of wells contemplated in the original field development plan (500 - 1000 wells), it was necessary to build 22 gravel pad[5] platforms, 16 kilometers of roads, set 120 kilometers of flow pipes lines, however, with the Multilateral wells were only required to build 5 gravel pads, build 1.6 kilometers of road and 12 kilometers of pipes, therefore, the savings was highly considerable. The cost reduction was so considerable that drilling of multilateral wells was also considered to develop a neighbor field called West Sak (Herlugson, McKendrick, & Parnell, 1996; W. C. Hogg, 2005).

[5] Herlugson et al. (1995) explain that in arctic or near-arctic regions, such as Alaska, where permafrost dominates, gravel pads are placed on the frozen ground to provide a solid foundation and achieve a stable surface to place the necessary infrastructure.

3.3. East Rama Field (Indonesia)

3.3.1. Multilateral Well Technical Aspects in an Offshore Well

East Rama field located southeast of Sumatra in Indonesia, was operated by Repsol-YPF – Maxus. In August 2001, two pilot wells were successfully drilled : AC-6P (vertical well) and AC-7P (directional sidetrack well from AC-6P) to verify the existence of hydrocarbons.

These two wells discovered that the Talang Akar formation (made up for channel sands) contained pay sands with excellent hydrocarbon reserves, producing gas from two different pay sands at low production rates. However, both pay sands showed a tendency to decline pressure, which is why production rates would continue decreasing over time, being the major drawback in this field (Kovacs, 1992).

On the other hand, the fact of having excellent hydrocarbon reserves allowed to cover the costs of implementing new technologies that would be beneficial to optimally develop the field with good production rates.

Repsol-YPF – Maxus selected the multilateral technology as the most optimal option to develop this field in an attempt to increase the production rates, reduce the costs related to the drilling and production stages and save costs by reducing the number of subsurface production facilities. Therefore, it was decided to drill a TAML level 3 multilateral well for different reasons: to produce oil from multiple zones and to have access to the main bore and branches in case repair work is required. Figure 17 shows a schematic of the multilateral well. Combining different technologies and tools such as expandable insolation sleeves and external casing packer, zonal isolation for each branch was achieved allowing future re-completions.

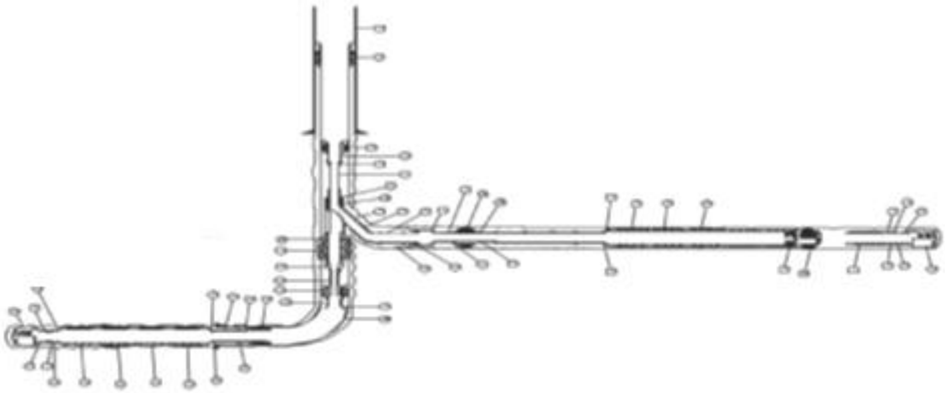


Figure 17 Multilateral well (TAML Level 3) drilled in East Rama field.
Obtained and modified from (Tanjung, Saridjo, Provance, Brown, & O'Rourke, 2002).

3.3.2. Economic Evaluation

Therefore, multilateral technology proved to be the best option since it reduced drilling time and increased production rates compared to drilling two individual wells. The TAML Level 3 multilateral well was drilled in 34 days at a total cost of USD 4,663,361. A production of 6,500 bbl/day was achieved, compared to 2,000 bbl/day that produced two individual wells that were previously drilled (Tanjung et al., 2002).

3.4. Tern Field (North Sea)

3.4.1. Multilateral Wells Technical Aspects in The North Sea

Tern field is located in the North Sea, in the sector belonging to the United Kingdom. The initial development of the field included drilling conventional wells to produce oil from the deltaic sands of the Middle Jurassic of the Etive reservoir, (belonging to the Brent group) considered as the most prolific reservoir.

In 2000, it was estimated that the STOIIP field was 95 million m^3 of crude oil, where 55.1 million m^3 of that value corresponds to the Etive reservoir; 85% of total production of the field comes from Etive. On the other hand, the Upper Ness and Rannoch reservoirs, also belonging to the Brent group, were considered of low quality, so their contribution to production was considered marginal.

Figure 18 shows the configuration of the reservoirs that comprise the Brent group (Roberts & Tolstyko, 1997).

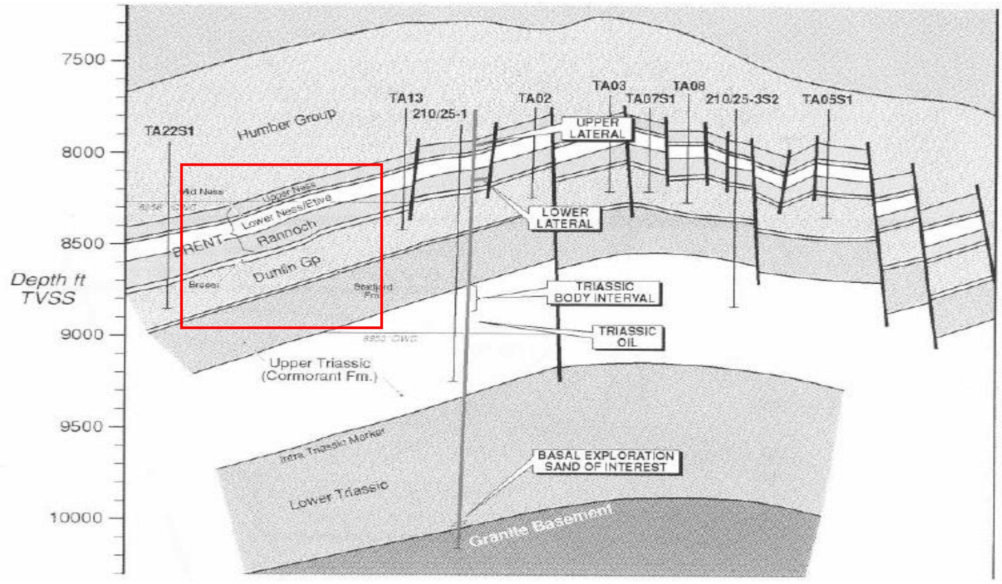


Figure 18 Cross-section Tern field.
Obtained and modified from (Roberts & Tolstyko, 1997).

In order to improve the development of the Tern field, it was considered to Implement a strategy with a sustained approach that would allow the hydrocarbon potential in the formations considered to be of poor quality to be accurately quantified to develop a plan to optimally produce oil from those formations. Shell, the operator company of the Tern field, chose to implement the NFP (Near Facilities Potential) strategy, which based on the restrictions of the platform space and seeking to maximize the profitability of the project by increasing the production levels of the field, it was decided to implement the Multilateral well technology to unlock the trapped reserves in the Upper Ness and Rannoch formations, which is why the TA-06 well was drilled.

Figure 19 shows a schematic of the TA-06 multilateral well (Oberkircher, 2000).

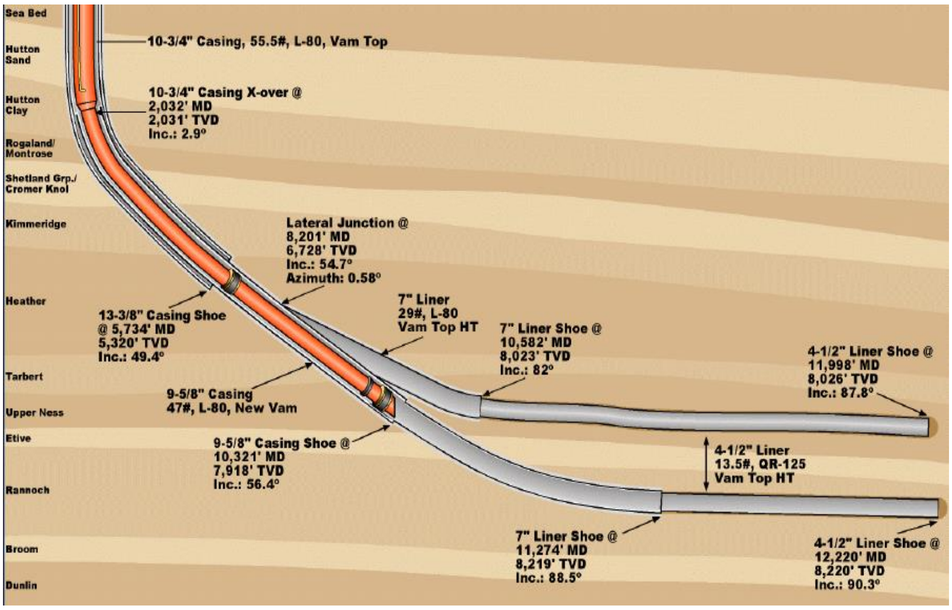


Figure 19 TA-06 multilateral well.
Obtained from (Oberkircher, 2000).

The TA-06 multilateral well was successfully drilled allowing to produce 600 m^3/ m^3/day compared to the 400 m^3/day that were planned to be produced by drilling two conventional wells. However, over time the production decreased to 450, however, its production was still higher than initially expected by a conventional system.

The well was drilled within the budgeted value and 7.5 days ahead of schedule. Based on the favorable results obtained with the TA-06 multilateral well, Shell decided to drill 4 more multilateral wells (TA-14, TA-16, TA-17, TA-19) (Oberkircher, 2000; Roberts & Tolstyko, 1997) with junction levels 1 through 4. Figure 20 shows the field-development for the Tern field (Denney, 2000).

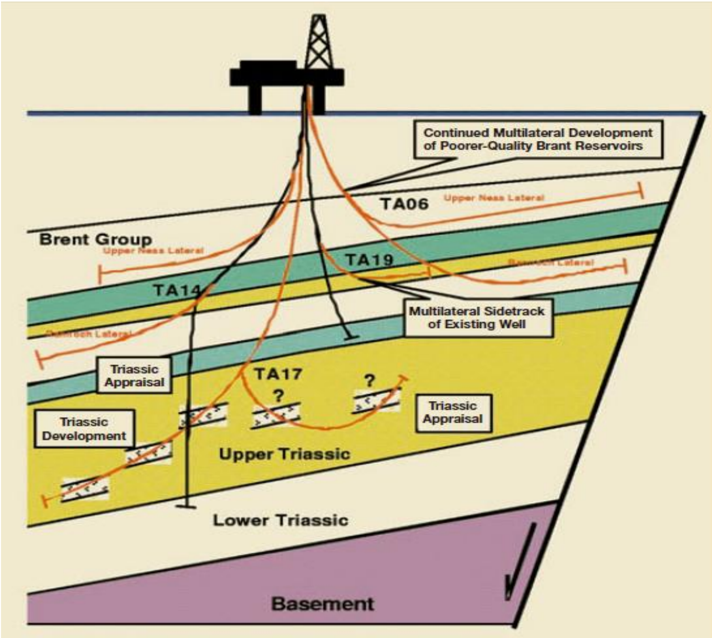


Figure 20 Multilateral wells drilled in Tern field.
Obtained from (Denney, 2000).

3.4.2. Economic Evaluation

On the other hand, the economic benefits contributed by the multilateral technology when drilling the TA-06 well was a reduction of CAPEX of 22% and an increase in Net Present Value (NPV) of 12% at an oil price of USD 19.5 per barrel. The mentioned values were obtained comparing the drilling costs of two conventional wells (Oberkircher, 2000).

Drilling of the TA-14 multilateral well resulted in savings of £ 4.5 million pounds compared to conventional drilling methods (Roberts & Tolstyko, 1997).

3.5. Urucu Field (Brazil)

3.5.1. Multilateral Well Technical Aspects in an Onshore Well

This field is an example of the environmental and economic benefits that a multilateral well approach can bring to the development of a field located in a protected environmental zone.

The main concern of Petrobras, operator company in charge of Urucu field, was to implement a technology that would increase production and preserve the environment in which the field is located, which is located 650 km southwest of Manaus, a region considered the heart of the Brazilian Amazon, it has one of the greatest diversity of flora and fauna in the world, making it a highly sensitive region.

Due to its location, it was impossible to access new spaces for the construction of new platforms due to restrictions and regulations of the Brazilian government. Therefore, Petrobras relied on environmental impact as a determining factor in opting for a technology capable of increasing field production and at the same time being compatible with environmental regulations.

Multilateral well technology was the most optimal for this scenario since it has several significant advantages compared to horizontal wells, for example: it minimizes the footprint of the drilling site by avoiding he installation of new drill rigs / equipment and allowing to produce a higher volume of oil from a single surface platform through multiple wells.

The importance of increasing hydrocarbon production in this field lies in the excellent quality of its crude oil, which has an oil gravity of 45 ° API (light oil) (Campos, Teixeira, Vieira, & Sunjerga, 2010).

The field's average production was 50,000 bbl/day (oil) and 10.5 million Nm^3/day of natural gas. The primary recovery mechanism is gas expansion and the second recovery method is processed gas re-injection at a rate of 8 million Nm^3 / day (Campos et al., 2010).

The Urucu field produces oil from three reservoirs: Río Urucu (RUC) (main oil producer), Este de Urucu (LUC), and Sudeste de Urucu (SUC). Since 1986, (year in which production activities began) until 2013, 95 oil-producing wells and more than 20 gas injection wells had been drilled (Mendes, Albuquerque, Vento, & Batista, 2013)

The main objective of implementing multilateral wells was to produce oil from a fourth reservoir called Juruam located in the Paleozoica Solimões basin, a basin that contains an important oil system.

As a result, Petrobras drilled three TAML Level 4 multilateral wells (dual-lateral), where both the main bore and laterals, including the junction, and the Junction Isolation Tool (JIT) were cased and cemented. It was decided to install a JIT as a safety measure to protect the joint from the stimulation of fluids and pressure effects and to have access to the main bore and branches to carry out any operation that was required (as long as the well has not been cemented and abandoned).

Figure 21 shows the final scheme (including its completion) of one of the dual-lateral well drilled in Urucu filed.

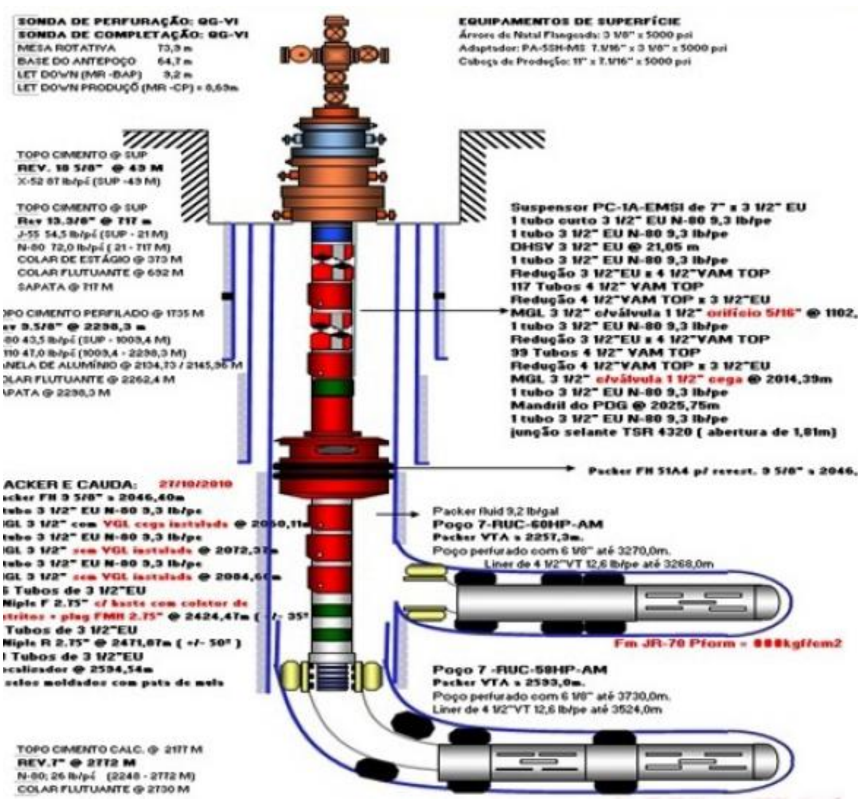


Figure 21 Dual-lateral well schematic.
Obtained and modified from (Mendes et al., 2013).

3.5.2. Economic Evaluation

The time required to drill each multilateral well was 202 days (average), with a final cost of approximately USD 27 million, achieving a production of 2,201 bbl/day for each multilateral well.

In the Urucu field, a horizontal well was drilled in an average drilling time of 153 days with a final cost of approximately USD 19 million and a production of 1,258 bbl / day.

By comparing the results achieved between a multilateral well with the results from a horizontal well, we will be able to determine the technical, economic and environmental benefits:

- ✓ From a technical point of view, the production of a multilateral well was 1.75 times greater than the production of a horizontal well.

- ✓ From an economic point of view, drilling a multilateral well was 1.40 times more economical compared to the cost of drilling two horizontal wells, on the other hand, savings of $ 3 million were generated by avoiding the construction of two additional platforms to drill additional wells.

- ✓ From an ecological point of view, the use of multilateral technology considerably reduced the environmental impact by having a smaller footprint at the drilling site.

3.6. Filanovskogo Field (Caspian Sea)

3.6.1. Multilateral Wells Technical Aspects in the Caspian Sea

Filanovskogo offshore field, located in the north of Caspian Sea, produce oil and gas condensate. It was discovered in 2005 by the Lukoil Company, which drilled six exploratory wells from 2005 to 2011, confirming the presence of several potential oil and gas producing sands.

In the field development plan, drawn up in 2011, it was planned to drill 20 horizontal development wells to produce oil from the Neokomian reservoir (upper and lower part), and from the upper Aptian formation produce gas and condensate. Of those 20 wells, 6 are injection wells and 14 are producing wells, of which 11 are multilateral (dual-lateral, TAML level 5) to produce oil from two sections of the Neokomian reservoir and the remaining 3 wells are monobore wells.(Valisevich et al., 2014).

The first phase of the field development plan was based on drilling two multilateral wells (Well A and Well B), both dual lateral, designed to drain the same reservoir (Neokomian). A TAML level 5 was selected as a security measure to prevent gas from entering in the event that the interval has gas, both were completed with smart technology (intelligent completion) with pressure-temperature gauges and flow control valves to monitor and control production in each branch. These wells were considered as Intelligent Multilateral TAML 5. Figure UT shows the schematic of well A. (Golenkin, Latypov, Shestov, Bulygin, & Khakmedov, 2017).

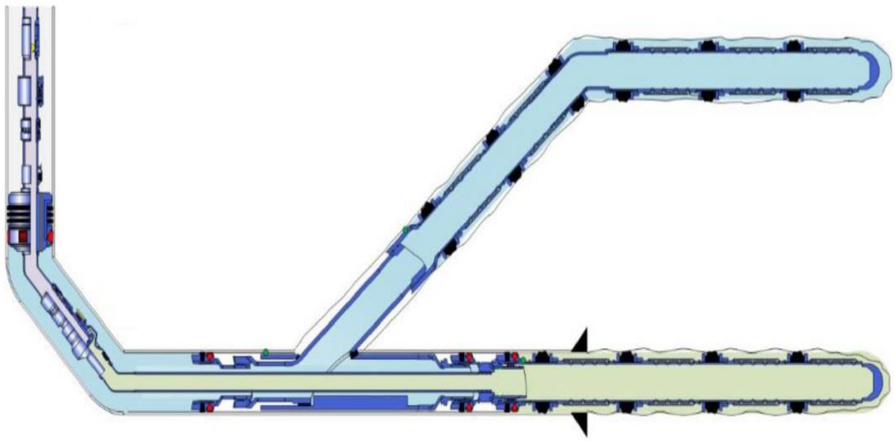


Figure 22 Intelligent multilateral well (TAML Level 5) / Well A.
Obtained and modified from (Golenkin et al., 2017).

The main reason why multilateral technology was chosen is because of the technical challenges of drilling a well due to the complex geology of the field: anticline trap crossed by a series of faults, highly fractured reservoir, wellbore instability, relatively shallow reservoir, high formation collapse gradient (Valisevich et al., 2014).

3.6.2. Economic Evaluation

Based on what was argued by Golenking et al. (2017) in his research work on the results obtained from having drilled this type of wells, it could be said that the two intelligent wells were successfully drilled and completed, achieving consistent results. It was possible to increase the productivity index, high production rates were obtained, therefore the production increased between 20% and 60%, compared to nearby wells drilled in a conventional way. Production results show that intelligent multilateral wells provide benefits by achieving faster production buildup, higher productivity indices, and higher cumulative production.

On the other hand, the drilling of these two intelligent wells (well A and well B), optimized CAPEX being a great example of how new technologies allow developing complicated fields optimizing economic resources.

3.7. Oseberg Field (North Sea)

The case of the Oseberg field is presented since it serves as a reference for smart wells and multilateral wells. The advantages and disadvantages of the new technologies applied in this field will be analyzed.

3.7.1. Smart Well Technical Aspects in the North Sea

Osberg field was considered to be an offshore laboratory because it is used to test and implement new technologies, as is the case with smart wells. From the Oseberg B platform, several smart wells were drilled: B-30 B, B-21 B, B-41 A, B-29 B.

Horizontal well 30-B was the first well where smart completion was installed with a single smart zone to monitor pressure and temperature and two conventional sliding sleeves. The main reason it was decided to make well 30-B smart was to control production in the event of an early gas or water breakthrough in Tarbert formation. Almost at the end of the lifetime of the well, the water cut increased so the smart zone which was remotely operated had to be closed, which allowed to reduce the water cut and increase the oil rate production. The prompt response from the smart zone showed one of the benefits of smart wells. (Rundgren, Algeroy, Hestenes, Jokela, & Raw, 2001)

Well 21-B was drilled horizontally to produce hydrocarbon from the Ness formation. The completion string had 4 smart zones installed for zonal control. Each zone had sensors to monitor pressure and temperature. Sensors were working without problems, however, during installation the back-up system failed partially. It is important to note that failure in parameter measurements can lead to severe gas productions, limiting oil production. In this case, it can be considered that smart well technology was not as successful. (Erlandsen, 2000)

Regarding well B-41, the main reason for considering installing a smart completion with 4 smart zones was because early gas breakthrough was a potential risk. Forty-one days after production started, communication was lost in smart zones 2, 3 and 4. However, since zones 1 and 2 were 1/3 open, gas-oil-ratio development was restricted.

3.7.2. Multilateral Well Technical Aspects in the North Sea.

From the Oseberg C platform three TAML Level 4 multilateral wells (C-07, C-10, C-12) were drilled to produce hydrocarbons from two formations: Oseberg and Ness (upper and lower) as shown in Figure 23.

The main reason it was decided to drill multilateral wells was due to limited number of well slots to drill more wells in order to continue the development of the field, mainly to produce more oil from the Oseberg formation since productivity it is 3-4 times greater than in the Ness formation. (Erlandsen, 2000)

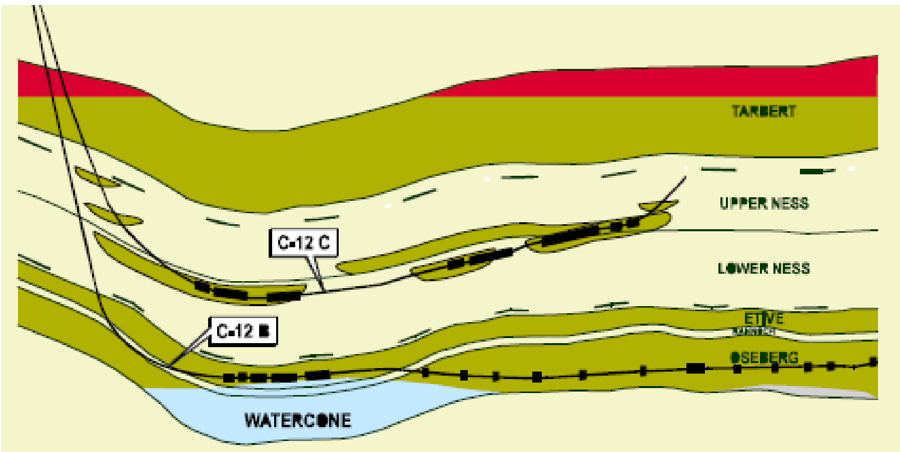


Figure 23 Oseberg C multilateral well scheme.
Obtained from (Erlandsen, 2000).

Thanks to the benefits of TAML Level 4, the multilateral wells were drilled and completed without any major problems. Among the main benefits of having selected a level 4 is that there is full access to each lateral to carry out well interventions if required. In the multilateral wells, several sidetracks were performed on the laterals without experiencing problems at the junction since both main wellbore and laterals are cased and cemented and since the junction had zonal isolation.

3.7.3. Economic Evaluation

Based on the results obtained, it can be said that the benefits that smart well technology can bring to the production stage of a well is strictly limited to the proper function of the components. Considering the failures presented in wells B-30 B, and B-21 B it can be said that the technology still needs improvement. In the event of a component failure, performing a well intervention is highly costly.

On the other hand, regarding the multilateral wells drilled from platform C, it can be said that the TAML Level 4 is an option that has high technical benefits, including full access to the sides and protection to the junction

3.8. Snorre B Field (North Sea)

3.8.1. Smart Well Technical Aspects in the North Sea

The Snorre B field can be used as a reference to analyze the performance of smart wells since in this field 10 of 13 (up to 2007) wells in operation are smart wells in which smart completions have been installed. All completions have 4 down-hole sliding sleeves used to control the flow of the different zones and 4 packers used to divide the formations into isolated zones. In addition, gauges are installed on the tubing side and in each of the sliding sleeves to measure pressure and temperature and notify the user when a pressure or temperature drop occurs between the sleeves placed on the tubing. (Kulkarni, Belsvik, & Reme, 2007)

The main reason why smart wells were considered in the Snorre B field is for alerting the user to changes in the inflow performance of sleeves located in the completion string placed in the Starfjord and upper Lunde formations. Both formations are divided into 11 main zones, which are subdivided into 44 sub-zones. By having many zones and subzones zonal isolation was required to have control over those zones. Wells produce from different formations at the same time, production is comingled, so control over production is required, one more reason to have smart wells. (Birkeland, Kviljo, Brustad, & Aasgaard, 2002; Kulkarni et al., 2007).

Figure 24 shows a schematic of the smart well in the Snorre B field.

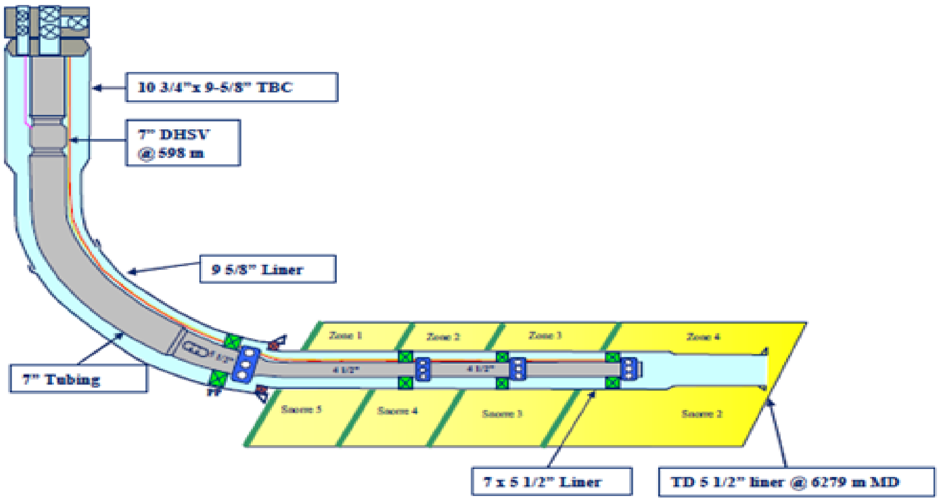


Figure 24 Snorre B smart completion scheme.
Obtained from (Kulkarni et al., 2007).

In general, it can be concluded that the technology used in the different smart wells allowed production to be increased to 2,600 Sm^3/day, however, despite that a higher production was achieved, it is important to mention that some components of the technology failed. Of the 72 gauges installed on the tubing, 18 failed, representing 25% of the total gauges. On the other hand, of the 36 downhole sliding sleeves installed, 14 failed, representing 38.89% of the total gauges. Considering the percentage of components that failed, it could be said that the technology is not entirely feasible.

3.8.2. Economic Evaluation

Smart wells increased production, allowing increased profits. One of the main advantages obtained with smart wells is having prevented an early gas or water breakthrough, which represents cost savings by eliminating expenses in surface water treatment. A critical aspect to be considered is that the failures generated represent extra costs causing a decrease in profits due to the fact that these components must be replaced.

3.9. Considering the Intangibles Savings

In the field case studies presented above, the emphasis is placed on the technical and economic benefits that the technology of multilateral wells contributes to the development of oil and gas fields in the stages of drilling and completion, in the different lifting mechanisms associated to IOR (Improved Oil Recovery) and EOR (Enhanced Oil Recovery) methods, and in the installation of surface facilities. However, there are other areas, no less important, in which the multilateral approach generates improvements and cost savings, however, quantifying the savings generated in those areas can be a complex task. Brister (2000), in his research work screens these areas :

- **Health and Safety:** In the oil and gas industry, the health and safety of workers has been a high priority. The operations that take place in the oil and gas fields must be carried out in environments with high pressures, chemicals that are toxic and caustic, large and heavy equipment, so companies have sought to emphasize the safety of workers. Multilateral Well Technology by minimizing the number of surface maneuvers and reducing drilling time compared to the time required to drill two independent wells, minimizes exposure to hazards thereby enhancing worker health and safety. It is an arduous task to quantify or estimate an economic value to the benefit provided by technology in this regard, however, it is important to emphasize that this type of benefit should be a main driver to implement this technology more frequently.

- **Environmental benefits:** Environmental responsibility has continued to grow in the oil field, as have health and safety problems. To drill a multilateral well a single platform is required instead of two or more platforms to drill conventional wells. This will result in less environmental impact, especially in sensitive environmental areas, therefore fewer environmental permits and licenses are required, fewer fluid pits, therefore cleaning costs are substantially reduced.

- **Reduction of the final cost of the project:** All oil or gas producing wells, whether conventional, deviated or multilateral, reach a point where it is not economically profitable to produce hydrocarbon since the value of production is less than the cost of production. At this point, the well should be cemented and abandoned. The technology of multilateral wells allows to reduce costs in the P&A stage since only the main wellbore must be cemented, therefore, the number of cement plugs and the amount of cement required is reduced compared to two conventional well systems, generating general savings in project costs.

4. Methodology

Halliburton Ecuador, based on its experience drilling multilateral wells, recommends to select a level 4 junction to drill a multilateral well in the country, based on the fact that this level is the most widely used in the world, making it more reliable. *From an operational point of view, it is safer since the system has a pre-milled window, which* makes easier to drill the lateral well, incorporates a "latch-coupling" that allows the whipstock to be oriented in the right direction in which the lateral well must be drilled. From a technical point of view, it was recommended to select level 4 for the benefits it provides, among which stand out: full access to the lateral without any restriction, full casing ID, maximum mechanical support at the junction can be achieved, protecting the junction since is the weakest point in the system, and since that the main wellbore and lateral are cased and cemented provides more protection in the event of a formation collapse.

Therefore, a Level 4 junction has been selected for the present study to determine its applicability or not in Ecuador.

4.1. Overview

The objective of the methodology used in this thesis is to determine the feasibility or not of implementing multilateral wells in Ecuador through an evaluation process, which will analyze whether its application is the most efficient alternative to be chosen taking into account the characteristics of a reservoir of a specific oil field located in Ecuador.

Two well systems are considered in the methodology: A horizontal well, and a multilateral well (dual branch system / TAML 4). Both systems have the same geological features with two-layer formation (pay zone 1 and pay zone 2), however each formation layer has different characteristics.

The evaluation process analyzes three different aspects:

- **Technical evaluation:** Will analyze and compare the well inflow performance between a horizontal well and multilateral well (dual branch). Two different methods will be used to estimate the well performance from each well system:

Babu and Odeh’s method and Ouyang and Aziz method (analytical / analytical models).

The purpose of using two different methods for technical evaluation is to combine Babu and Odeh’s inflow model with Ouyang and Aziz’s method to illustrate a semi analytical approach to predict a multilateral well deliverability model for academic purposes, to explain how the inflow performance of a multilateral well can be calculated and the parameters involved in the process.

- **Economic analysis:** It will be based on the following economic performance indicators: Net Present Value (NPV), Internal Rate of Return (IRR), and Profitability Index (PI), which are obtained, based on the results of the technical analysis.

- **Risk assessment:** Multilateral wells has improved the drilling and production economics on many wells (Shadizadeh, Kargarpour, & Zoveidavianpoor, 2011); however, failures can be very expensive, for this reason a statistical decision tree analysis will be used to assess the risks involved in the project. The risk assessment will be based on the results of the economic analysis and on risk matrices created from lessons learned from drilling of previous wells.

4.2. Technical Analysis

The starting point of any technical analysis to evaluate the performance of a multilateral well is to predict the inflow performance of the reservoir on each lateral, which must be considered as a single horizontal lateral well.

To estimate the horizontal well reservoir inflow performance (performance of a multilateral well), different methods that can be used:

- **Analytical methods for horizontal well inflow:** The following models were derived based on the assumption of reservoirs with drainholes of infinite conductivity: Borisov 1964; Joshi 1988; Giger et al. 1984; Furi et al. 2003; Babu and Odeh 1989. These models are easy to use and useful to study the effect of some parameters in the prediction of productivity. To perform the calculations several assumptions must be made, such as constant pressure drop along the wellbore, wellbore flow behavior as in a regular pipe. (Tabatabaei & Ghalambor, 2011).

- **Semi analytical models:** Are based in analytical models and correlations to predict multilateral well deliverability. Compared to analytical methods, less-simplified assumption must be made to perform calculations; therefore, good estimations of productivity can be obtained. Current models used: Chen et al. 2000; Ouyang and Aziz 1998; Guo et al. 2007; Ozkan et al. 2000 (Tabatabaei & Ghalambor, 2011).

- **Point / line source methods for horizontal inflow:** This model can provide a more accurate approach to estimate the well performance of a horizontal well with a complex trajectory, however, more complex processes are involved, for example: the model is based on diffusivity equations and numerical integration is required and it (Hill, Zhu, & Economides, 2007).
  This model was developed considering a parallelepiped-shaped anisotropic reservoir with a single-phase flow with slightly compressible fluid.

- **Reservoir simulation software:** Are the best options for field applications since they avoid excessive simplification in their calculation processes and perform a deeper analysis discretizing the wellbore along the production section in several segments according to the number of grids covered in the model and since more sensitive parameters are considered, such as: pressure drop along the wellbore, pressure distribution in the system, pressure/rate behavior in each lateral, reservoir behavior, in order to obtain accurate estimations of productivity of horizontal wells (flux profile) and more accurate pressure results.

  Reservoir simulation is helpful especially when the equilibrium junction pressure needs to be calculated considering commingled production from different laterals in different reservoirs.

  Two different iterative processes or simultaneous solutions are fundamental in the calculation procedures to achieve accurate solutions. The first iteration process generates a pressure and flow rate profile for each lateral based on the drawdown according the pressure distribution in the system (reservoir). The second iteration process generates a pressure equilibrium condition to obtain the pressure at the junctions based on commingled production from all the laterals that make up the multilateral.

Simulators are powerful tools to be used; however they are not available to most petroleum engineers and petroleum engineering students, which makes simulators a tool for a small group of engineers.

4.2.1. Horizontal Well Inflow Performance Prediction: Babu and Odeh's method

Babu and Odeh developed a method to estimate horizontal lateral's performance through an inflow equation considering uniform flux along the wellbore.

The method was developed for a pseudo steady state in a box-shaped homogeneous reservoir (anisotropic) with a length "*b*" in the x-direction (parallel to horizontal well), and a width "*a*" in the y-direction (perpendicular to the horizontal well / x-direction) thickness "*h*". A horizontal well of length "L" lies in the reservoir in the x-direction. The lateral can be located in any location within the reservoir; however, the location will be defined by specifying the location of the heel through coordinates (x_o, y_o, z_o). Figure 25 shows a schematic of the reservoir model proposed by Babu and Odeh.

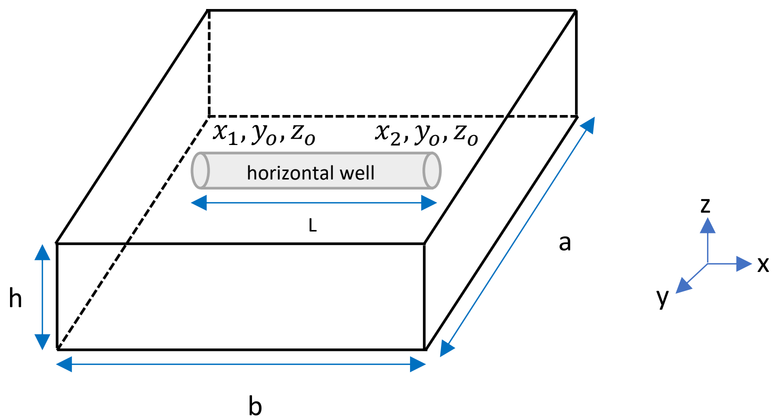


Figure 25 Babu and Odeh's schematic box-shaped model. Obtained and modified from (Zarea & Zhu, 2011).

In the reservoir, the principal permeabilities are k_x, k_y, and k_z, which are based on axes that make up the Cartesian coordinate system. The laterals are represented in x-y plane from the direction of the principal permeability that is the permeability in the x-direction (k_x). (Yildiz, 2005). The method considers laterals with different diameters, lengths, and phasing angle.

The model is subject to certain limiting assumptions (Grassi, Zhu, & Hasan, 2015) :

- A constant and uniform fluid flows to a uniform well.
- Homogeneous reservoir.
- Constant porosity.
- Circular shape drainage area.
- Radial flow (in the y-z plane).
- The wellbore is orientated parallel to the direction of principal permeability.
- The reservoir boundaries are no-flow boundaries.
- Pseudo steady-state flow.
- Pressure declines uniformly in the reservoir.

The inflow equation used in the Babu and Odeh's model is formulated as follows:

$$q_o = \frac{b\sqrt{k_y k_z}\left(\overline{P} - P_{wf}\right)}{141.2\mu_o B_o\left(\ln\left(\frac{\sqrt{A}}{r_w}\right) + \ln(C_H) - 0.75 + S_r + \left(\frac{b}{L}\right)S\right)} \tag{1}$$

Where:

- b: reservoir length $[ft]$.
- $k_y(permeability\ in\ y - direction) = k_x$: $permeability\ in\ x - direction =$ k_h: horizontal permeability $[mD]$.
- $k_z(permeability\ in\ z - direction) = k_v$: vertical permeability $[mD]$.
- $\bar{P}$: average reservoir pressure $[psia]$.
- P_{wf}: flowing bottom-hole pressure $[psi]$.
- μ_o: oil viscosity $[cP]$.
- B_o: oil formation volume factor [RB/STB].
- A: $drainage\ area$ $[ft^2]$.
- C_H: shape factor

- S_R: partial penetration skin. For horizontal wells (full penetrating), $S_R = 0$.
- S: skin factor $[DI]$.

In order to use the inflow equation, the following equations must be used

- Drainage area (A) can be calculated as follows:

$$A = a\,(reservoir\ width) \times h\,(reservoir\ thickness)\ [ft^2] \tag{2}$$

- Location of the heel of the well (y_o, z_o) Relative to any corner of origin of the reservoir.

$$y_o = \frac{a}{2} \tag{3}$$

$$z_o = \frac{h}{2} \tag{4}$$

- To calculate Anisotropy ratio (I_{ani}):

$$I_{ani} = \sqrt{\frac{k_h}{k_v}} \tag{5}$$

- Shape factor (C_H) can be obtained applying either of the two-following equations:

$$ln\, C_H = 6.28\, \frac{a}{I_{ani}h}\left[\frac{1}{3} - \frac{y_0}{a} + \left(\frac{y_0}{a}\right)^2\right] - ln\left(sin\frac{\pi z_0}{h}\right) - 0.5\, ln\left[\left(\frac{a}{I_{ani}h}\right)\right] - 1.088 \tag{6}$$

or:

$$ln\, C_H = 6.28\, \frac{a}{h}\sqrt{\frac{k_z}{k_x}}\left[\frac{1}{3} - \frac{y_0}{a} + \left(\frac{y_0}{a}\right)^2\right] - ln\left(sin\frac{\pi z_0}{h}\right) - 0.5\, ln\left[\left(\frac{a}{h}\sqrt{\frac{k_z}{k_x}}\right)\right] - 1.088 \tag{7}$$

In order to calculate the partial penetration skin (S_R) two different cases must be evaluated. Each case will depend on the dimensions of the reservoir. The first case is for a wide reservoir which means that the reservoir extends farther in the perpendicular direction of the lateral (a>b). The second case is for a long reservoir which means that the reservoir extends farther in the direction for the lateral (b>a).

For **case 1** (a>b), the following criteria must be met:

$$\frac{a}{\sqrt{k_y}} \geq 0.75\frac{b}{\sqrt{k_x}} > 0.75\frac{h}{\sqrt{k_z}} \tag{8}$$

- Then, partial penetration skin (S_R) is subject to:

$$S_R = P_{xyz} + P'_{xy} \tag{9}$$

Where:

$$P_{xyz} = \left(\frac{b}{L} - 1\right)\left[ln\frac{h}{r_w} + 0.25\,ln\frac{k_x}{k_z} - ln\left(sin\frac{\pi z_0}{h}\right) - 1{,}84\right] \tag{10}$$

And

$$P'_{xy} = \frac{2b^2}{Lh}\sqrt{\frac{k_z}{k_x}}\left\{F\left(\frac{L}{2b}\right) + 0.5\left[F\left(\frac{4x_{mid} + L}{2b}\right) - F\left(\frac{4x_{mid} - L}{2b}\right)\right]\right\} \tag{11}$$

Where x_{mid} represents the coordinate (in the x-axis) of the midpoint of the lateral.

$$x_{mid} = \frac{x_1 + x_2}{2} \tag{12}$$

Then,

$$F\left(\frac{L}{2b}\right) = -\frac{L}{2b}\left[0.145 + ln\left(\frac{L}{2b}\right) - 0.137\left(\frac{L}{2b}\right)^2\right] \tag{13}$$

In order to calculate $F\left(\frac{4x_{mid}+L}{2b}\right)$ and $F\left(\frac{4x_{mid}-L}{2b}\right)$ two different cases must be evaluated considering the following expression:

- If the values of $\left(\frac{4x_{mid}+L}{2b}\right) \leq 1$ and $\left(\frac{4x_{mid}-L}{2b}\right) \leq 1$:

$$F\left(\frac{4x_{mid} + L}{2b}\right) = -\left(\frac{4x_{mid} + L}{2b}\right)\left[0.145 + ln\left(\frac{4x_{mid} + L}{2b}\right) - 0.137\left(\frac{4x_{mid} + L}{2b}\right)^2\right] \tag{14}$$

Combined with

$$F\left(\frac{4x_{mid}-L}{2b}\right)=-\left(\frac{4x_{mid}-L}{2b}\right)\left[0.145+ln\left(\frac{4x_{mid}-L}{2b}\right)-0.137\left(\frac{4x_{mid}-L}{2b}\right)^2\right] \qquad (15)$$

- If the values of $\left(\frac{4x_{mid}+L}{2b}\right) > 1$ and $\left(\frac{4x_{mid}-L}{2b}\right) > 1$:

$$F\left(\frac{4x_{mid}+L}{2b}\right)=\left[2-\frac{4x_{mid}+L}{2b}\right]\left[0.145+ln\left(2-\frac{4x_{mid}+L}{2b}\right)-0.137\left(2-\frac{4x_{mid}+L}{2b}\right)^2\right] \qquad (16)$$

And

$$F\left(\frac{4x_{mid}-L}{2b}\right)=\left[2-\frac{4x_{mid}-L}{2b}\right]\left[0.145+ln\left(2-\frac{4x_{mid}-L}{2b}\right)-0.137\left(2-\frac{4x_{mid}-L}{2b}\right)^2\right] \qquad (17)$$

On the other hand, for **case 2** (a < b), the following criteria must be met:

$$\frac{b}{\sqrt{k_x}} \geq 1.33\frac{a}{\sqrt{k_y}} > 0.75\frac{h}{\sqrt{k_z}} \qquad (18)$$

- Then, for this case the partial penetration skin (S_R) can be calculated as follows:

$$S_R = P_{xyz} + P_y + P_{xy} \qquad (19)$$

Where P_{xyz} can be calculated using equation 10. On the other hand, P_y formula is:

$$P_y = \frac{6.28b^2}{ah}\frac{\sqrt{k_x k_z}}{k_y}\left[\left(\frac{1}{3}-\frac{x_{mid}}{b}+\frac{x_{mid}^2}{b^2}\right)+\frac{L}{24b}\left(\frac{L}{b}-3\right)\right] \qquad (20)$$

And

$$P_{xy} = \left(\frac{b}{L}-1\right)\left(\frac{6{,}28a}{h}\sqrt{\frac{k_z}{k_x}}\right)\left(\frac{1}{3}-\frac{y_0}{a}+\frac{y_0^2}{a^2}\right) \qquad (21)$$

To estimate the pressure drop in a wellbore segment with constant and uniform flow across de lateral, the following equations should be used (Eq 22 - 27). Ouyang and Aziz model incorporates a frictional factor for pressure calculation.

There may be situations in which the pressure drop can be despicable since the value is insignificant, in this case, a constant pressure can be assumed along the horizontal section or lateral.

- Calculate the inflow rate per unit length has follows:

$$q_i = \frac{q_o}{L} \tag{22}$$

- Then, the average flow rate in the segment must be calculated based on the following equation:

$$\bar{q} = q_i \frac{L}{2} \tag{23}$$

- Reynolds number is a function of the average flow rate in the segments:

$$N_{Re} = \frac{1.48 \times \bar{q} \times \rho}{D \times \mu_o} \tag{24}$$

- The friction factor is calculated based on the value of the Reynolds number obtained:

$$f_f = \frac{0.0791}{Re^{0.25}} \tag{25}$$

- Now, the axial velocity (velocity in the segment) must be calculated based on the average flow rate.

$$\mu = \frac{4 \times \bar{q}}{\pi \times D^2} \tag{26}$$

- Then, the pressure drop can be estimated:

$$\Delta p = \frac{2 \times f_f \times \rho \times \mu^2 \times L_s}{g_c \times D} + \frac{8 \times \rho \times \mu \times \bar{q}}{\pi \times g_c \times D^2} \tag{27}$$

4.2.2. Multilateral Well Deliverability Model

One of the greatest capabilities of multilateral wells is that they can produce hydrocarbons from multiple pay zones (different deposits or formations) at the same time through different horizontal (laterals) wells, therefore multilateral wells work with commingled production from those laterals (Tabatabaei & Ghalambor, 2011).

Since each horizontal branch must be considered as an individual horizontal well that is affected by other branches (Shadizadeh et al., 2011), it is essential to develop a model that can be applied to this type of well systems whit more than one lateral with commingled production to a main wellbore to be able to predict the production form each lateral and the total production rate. As a result, a well deliverability model for multilateral well was developed.

Well deliverability for a multilateral well can be defined as flow rate distribution among the laterals as a function of surface pressure. The basis of this model is the reservoir inflow model, moreover pressure-drop behavior in each horizontal branch, in each build up section, and in the main wellbore must be considered too, to predict the production from each branch, thus the total production rate from the multilateral. (Grassi et al., 2015; Hill et al., 2007).

The semi analytical approach to predict multilateral well deliverability can be applied for multilateral wells with *n* number of branches and multiple junctions.

It is possible to start the calculations with any branch; however it is always recommended to follow one order, from bottom to top, which means that the first branch to be analyzed is the bottommost branch; this is the most simple way to find the converged solution of the problem (Salas, Clifford, & Jenkins, 1996).

Figure 26 shows the multilateral well system used for this approach.

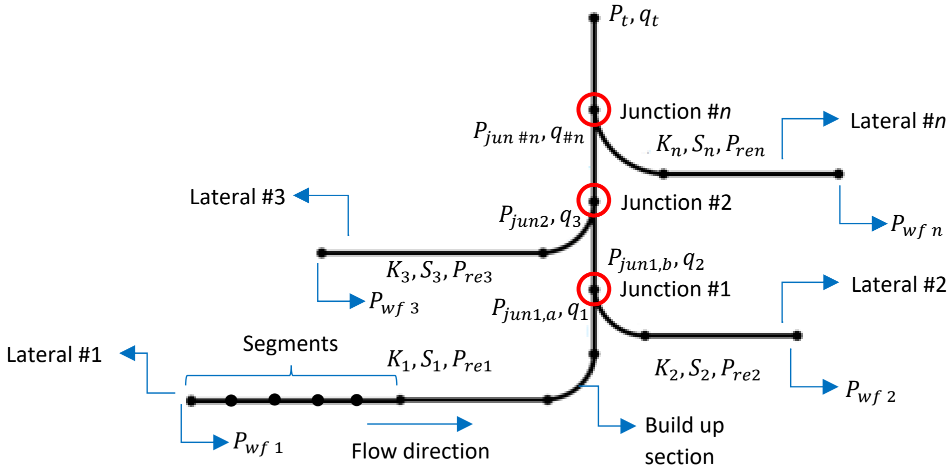


Figure 26 Schematic of deliverability calculation procedure for a ML with multiple laterals. Obtained and modified from (Guo et al., 2008).

The simplest way to predict multilateral well deliverability is using a semi analytical models (for example: Babu and Odeh's model, Ouyang and Aziz's model), and correlations. The calculation procedure for multilateral well deliverability is described as follows:

1. The bottommost lateral (lateral 1) must be divided into several segments. Calculate the flow rate using an inflow model. A value of wellbore flowing pressure (P_{wf}) at the toe of lateral 1 must be assumed in order to get the drawdown in the toe segment. The notation used to represent the different segments will be as follows: (i, j) where the letter i represents the number of the lateral and letter j the number of the segment, for example, in lateral 1, the first segment (toe) will be represented as (1,1) and the last segment (heel) will be represented as (1,6) assuming that the lateral is divided into 6 segments.

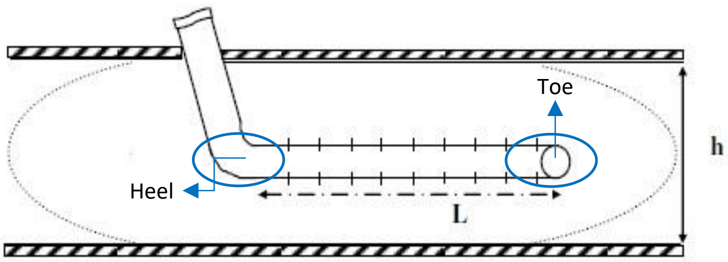


Figure 27 Schematic of a horizontal well.
Obtained and modified from (Shadizadeh et al., 2011).

2. Based on the results from the previous step, calculate a drawdown for the next segment. Using the same inflow model calculate the flow rate, and calculate the pressure drop.
   The calculation procedure must be repeated along the entire lateral, in each of the segments, until the heel segment has been reached, just then the total production of the lateral is calculated.

3. Pressure drop in each build section must be calculated using a flow-in-pipe model (e.g. Beggs and Brill's two-phase correlation can be used) to obtain the junction pressure (P_{jun}).

4. Moving upwards, steps 1,2 and 3 must be repeated and applied to each branch to obtain the total production at the heel segment of each branch.

5. Comparing two junction pressures from lateral 1 and lateral 2. If they are different, repeating step 3 and 4 with a different bottomhole flowing pressure until the junction pressures from two laterals equal.

6. Calculating the pressure drop between the top-most junction and the surface to obtain wellhead pressure.

4.3. Economic Analysis

There are many criteria to perform an economic analysis of a project. In a multilateral well project, multilateral cost estimation is a complex task since many variables must be considered, for example: well trajectory, number of laterals, drilling methods to be used, possible risks associated with the drilling operation should also be included into the well drilling costs.

It is essential that an economic analysis include the following economic yardsticks:

- **Net Present Value (NPV):** Represents the value of cash flows (from operating activities) in the future over a period of time. NPV is defined as the difference between the current value of receipts (cash inflows) and the current value of disbursements (cash outflows) based on a specified discount rate (M. A. Mian, 2002). NPV method is a useful economic performance indicator for financial analysis to determine the profitability of an investment in a project.

For a long-term project with multiple cash flows and a given investment, the calculation for the NPV is as follows:

$$NPV = \sum_{n=1}^{N} \frac{R_n}{(1+i)^n} - I \tag{28}$$

Where:

- R_n: annual revenue (cash inflow – outflows).
- n: number of years for which the project is considered.
- i: discount rate or required return. The discount rate reflects several considerations, one of which is inflation.
- I: initial investment

If the net present value is positive and different from zero, means that the project profits will be greater than the anticipated costs, which means that the project's investment can be profitable, thus a positive NPV is a basic requirement. On the other hand, a negative NPV indicates the investment will result in a net loss. In general, only projects with positive NPV should be considered. (M. A. Mian, 2002)

If NPV is set equal to zero, ROR (rate of return) and POT (payout time) can be calculated, both of which are used for economic analysis.

- **Internal Rate of Return (IRR):** Also referred to as rate of return (ROR), it is another important economic performance indicator that allows measuring the profitability of an investment in a project, and it is considered as a complementary indicator to the net present value. IRR is measured in percentage, whereas NPV is measured in monetary value. (Range, Santos, & Savoia, 2016).

IRR is defined as the discount rate that makes the net present value equal to zero, or as the condition in which the value of cash inflows is equal to the value of cash outflows in regular payments periods. (M. A. Mian, 2002).
IRR can also be defined as the percentage of profit or loss that a project will have in a period of time.

The Internal Rate of Return can be calculated with the following equation:

$$IRR = NPV = \sum_{n=1}^{N} \frac{R_t}{(1+i)^n} = 0 \tag{29}$$

- **Profitability Index (PI):** Also known as value investment ratio (VIR) or profit investment ratio (PIR), is a profitability criterion that measures the capital efficiency based on buck invested (Park, Kumar, & Kumar, 2013). Unlike the NPV, the PI does measure the investment efficiency.
  Profitability index is a dimensionless ratio that describes the relationship between the total values of future cash flow over a given initial investment. It can be calculated with the following equation.

$$PI = \frac{PV\ of\ future\ cash\ flows}{Initial\ investment} \tag{30}$$

  For the case where the cash flow was calculated without considering the investment, profitability index of 1 indicates break-even.
  The lowest ratio acceptable for a project is 1.0, if a profitability index lower than 1.0 is obtained, means the PV will be less than the initial investment.
  The financial attractiveness of the project will be higher as long as the profitability index increases, which means, the higher the ratio the greater the financial attractiveness. (Park et al., 2013).

The internal rate of return and net present value are well-known basic methods used for investment analysis in projects (Range et al., 2016) .

Based on the economic performance indicators described above, an economic analysis for multilateral wells project can be performed through a Financial Cash Flow Model (FCF)

$$FCF = Operating\ Cash\ Flow\ (OCF) - Capital\ Expenditure\ (CAPEX) \qquad (31)$$

Free Cash Flow equation can also be written as follows, including how to estimate the operating cash flow.

$$\begin{aligned} FCF = (&Net\ Income\ +\ Non - cash\ Expenses \\ &-\ Increase\ in\ Working\ Capital) \\ &- Capital\ Expenditure\ (CAPEX) \end{aligned} \qquad (31)$$

Free cash flow represents the cash that a company's project can generate after accounting for cash outflows like accounting capital expenditures (CAPEX) and operating expenses (Zhu, Arcos, & Bickel, 2008). Basically, it is cash received (income) less cash spent (investment) during a specific time period resulting from a project investment (Khayal, 2019).

Mian (2002) defines the cash received or gross revenue, as the product stream times the project price of a certain product. In the oil industry, the product stream could be any hydrocarbon such as:

- Crude oil reported in stock tank barrels (STB).

- Natural gas liquefied natural gas (LNG) or liquefied petroleum gas (LPG) in million standard cubic feet (MMScf) or thousand standard cubic feet (MScf).

The gross revenue from an oil and/or gas well is the basis for estimating the free cash flow for a project in the oil industry (Zhu et al., 2008).

FCF is an important financial performance indicator used to measure the economic worth of an investment project in order to determine how efficient the project will be in generating profits after accounting for all cash outflows (operations and capital expenditures) (Shrieves & Wachowicz, 2001).

The cash expended can be divided into three different categories: capital expenditure (CAPEX), operating expenditure (OPEX) and abandonments costs.

Capital Expenditures (CAPEX): is considered as the operating cost during the project implementation phase, which typically consists of:

- **Drilling costs:** will depend on the technical aspects of the well to be drilled, such as: type of drill bits to be used, type of drilling mud (water-based mud, oil-based mud or gaseous drilling fluid), drilling mud rheology, drilling rental tools, casing scheme, type of casing required, completion tools among others aspects. The drilling cost will vary depending on the configuration of well to be drilled (vertical, deviated, horizontal, multilateral, sidetrack). However, it is essential to mention that the major percentage of the total drilling cost is the rig cost, which has a daily rate. The type of drilling rig to be selected will depend on the depth of the well, and on the complexity of the formations through which the well is drilled.

- **Facility / Process facilities costs:** Leasing services of different surface equipment necessary to produce hydrocarbons or used in the production stage such as: tanks, storage tanks, separators, flow lines, wellheads, etc.

On the other hand, a different economic criterion that takes into account the design complexity level, and that can be applied to estimate the economic viability or not of drilling multilateral wells compared to a horizontal well is (Sunagatullin et al., 2010).

$$\frac{Multilateral\ well\ Production}{Horizontal\ well\ Production} > \frac{Multilateral\ well\ drilling\ cost}{Horizontal\ well\ drilling\ cost} \qquad (32)$$

Based on the formula described above, drilling a multilateral well can be economically feasible if it meets the following two simple criteria:

- Oil production from the multilateral well must be high enough to justify the total cost of the well, including the cost of technology and design.

- The ratio between multilateral well (ML) and horizontal well (HW) production must be higher than the relative drilling cost ratio between multilateral well and horizontal well $(ML\ cost/HW\ cost)$.

In general, drilling a multilateral well can be economically feasible if ML cost will not exceed the HW cost by 50% (Sunagatullin et al., 2010).

In a first approximation, the total cost of a multilateral well, can be calculated as follows:

$$\text{ML cost} = \text{horizontal well} + \text{cost of sidetrack hole} + \text{junction cost} \qquad (33)$$

For each branch, or for each case, horizontal well and sidetrack hole costs are going to be constant. Junction cost will depend on the TAML (junction classification), and whether if any additional equipment or tools are needed to drill the sidetrack hole. (Sunagatullin et al., 2010).

The cost of drilling a multilateral well increases with depth, whereas the cost of drilling a horizontal well depends on depth exponentially.

For a relative cost less than 1.4, drilling a multilateral well is economic feasible, as it is shown (green zone) in Table 9. For a range in between 1.4 – 1.7 ML and HW efficiencies are almost similar (yellow zone, Table 9); for this case, the type of well to be drilled will be selected taking into account geological factors, such as anisotropy (kv/kh), permeabilities, porosity, reservoir thickness, etc. A relationship over 1.7, drilling a multilateral well is unfeasible (red zone, Table 9).

DEPTH		TAML LEVELS				
[m]	[ft]	1	2	3	4	5
1,000	3,281	1.44	1.64	1.87	2.27	2.55
1,500	4,921	1.34	1.51	1.71	2.07	2.32
2,000	6,562	1.27	1.42	1.59	1.88	2.09
2,500	8,202	1.23	1.35	1.48	1.72	1.89
3,000	9,843	1.19	1.29	1.4	1.59	1.73
3,500	11,483	1.17	1.24	1.33	1.48	1.59
4,000	13,123	1.15	1.21	1.28	1.40	1.49
4,500	14,764	1.13	1.18	1.24	1.33	1.40
5,000	16,404	1.12	1.16	1.20	1.28	1.33

Table 9 Cost ratio ML/HW for different TAM Levels
Taken and modified from (Sunagatullin et al., 2010).

Operating Expenditures (OPEX): It can be considered as one of the most important aspects since the viability of the project largely depends on it. They are those periodic expenses, necessary for daily field operations. Operating costs can be expressed in several ways: in terms of expenditure per year, in terms of oil production (per barrel) or in terms of gas production (MScf). Maintenance (workover) of wells and maintenance of facilities are some examples of operating expenses.

It is important to pay close attention to operating costs since a high OPEX will reduce the life of the project, which will yield a high probability of abandoning the project (Al Omair, 2007).

4.4. Risk Assessment in Multilateral Wells Developments

An in-depth economic analysis should include a risk analysis to assess the risks involved in all phases of a project, this can be achieved through a decision tree analysis, which is a deterministic tool, that based on information about project costs, profits, and possible associated risks in the different phases of the project, to predict possible outcomes or scenarios and to determine the probability that any of those risks occur in a set of possible outcomes (Miller & Gouveia, 2019)

It is important to mention that the focus of a risk assessment is the possible outcomes that could occur depending on the perspective of the decision maker.

A risk assessment based on a decision tree aids in the decision-making process by reducing the uncertainty due to its capability to add valuable information to the process, and gauge potential occurrence, adding basis for a strong decision rather than a random decision. (Waddell, 1999).

Risk analysis quantifies in monetary terms the consequences associated with risk. This type of evaluation is called Quantitative Risk Analysis (QRA). In this process, each of the consequences is quantified in economic terms, generally providing the NPV as a measure.

In general, a risk assessment is made up of the following elements (Grąbczewski, 2014) :

1. Develop a model of the process.
2. Identify the inherent risks or problems that may arise during the execution of the project.
3. Develop a graphical model describing the process and the inherent risks/problems.
4. The risk must be described with its probability of occurrence, which must be duly estimated.
5. Through a random number generator, multiple simulations must be run in order to predict possible outcomes.

A QRA can be applied to multilateral technology projects, in order to obtain information that allows a better understanding of the implications, both technical and economic, of the application of this technology (Waddell, 1999).

A deterministic decision tree is made up of three different types of nodes:

Decision node: represented by squares (□), displays nodes where decisions must be made, and the decision-maker has the control to choose the optimum alternative, which is generally the one with the highest expected monetary value (M. A. Mian, 2002). This type of node can be followed by a chance node or even another decision node. The branches that come off a decision node are called decision forks, which connect and lead to the available options.

Chance node: Can be represented by either ovals or circles (◯). At a chance node, there will be different possible outcomes associated with the chance. These nodes show a series of possible events that might result in different outcomes, which will be used later on to make decisions.

The decision-maker has no control over the outcome, which will be determined by nature or probability since a chance node is linked to a probabilistic event.

This type of node can be followed by more chance nodes or by decision nodes. The branches that come out of a chance node are called chance forks, which represent the possible outcome of a chance event. (M. A. Mian, 2002)

- ***Terminal node, End node, or Payoff node:*** represented by triangles (◁). Provides a final result (financial outcome) which is the profit or loss of an outcome. The financial outcome is the expected monetary value (EMV) which is based on an economic performance indicator, mostly is the Net Present Value. The EMVs are shown on the right-hand side of the end node. This is the only node that does not have branches coming out.

  The economic estimator and risk analysis are connected through this type of node. The value described next to a terminal is its payoff. The expected monetary value can be calculated by using the following equation:

$$V_{em} = \sum_{i} (probability\ of\ outcome\ \times\ value\ of\ outcome)_{outcome\ i} \qquad (34)$$

- ***Probability or Chance:*** Reports the probability in percentage (%) of possible outcomes happening. If it is a fact that the outcome will occur, then the probability of occurrence is 1 (100%), it there is complete certainty that it will not occur, then the probability is 0 (zero).

Figure 28 shows a decision tree (with its respective elements) example for a project that must decide whether to drill or not drill a well. To structure a decision tree, we have to start from the left side with a decision node, followed by other decisions along with a sequence of events in chronological order.

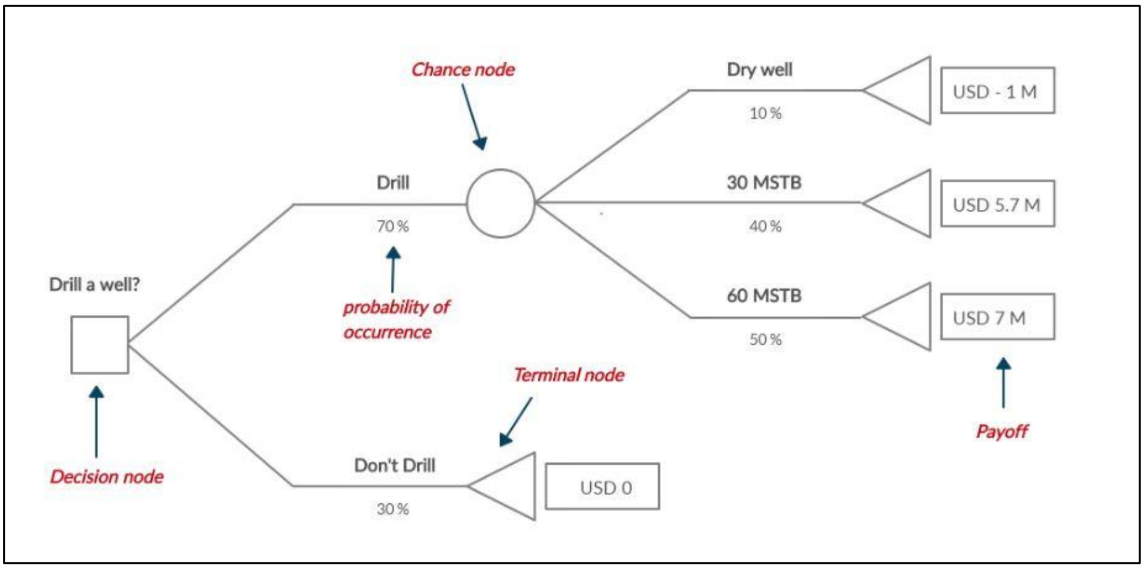


Figure 28 Decision tree example

A decision tree considers a whole set of parameters used in the risk analysis and the sensitivity for the previous-mentioned parameters in order to analyze alternative outcomes and compare the probable returns of those outcomes with the aim to assist in making the best decision to maximize the monetary value and minimize the associated risks (Clemen & Reilly, 2014).

A complete decision tree should be made considering all possible events as precisely as possible. To design a complete decision tree the following guidelines should be considered:

1. It is important to note that there are different ways to structure the same decision tree, obtaining the same results and possible scenarios.

2. The decision tree should be structured chronologically from left to right.

3. Each node in a decision tree must have a value, either a probabilistic value or a monetary value, which will depend on the type of the node.

4. During the decision tree building process, the structure of the tree will change as the decision maker reformulates the problem.

5. The actual problem along with the possible scenarios must be represented in model the most direct and simple way possible. Complex and extremely large trees can obscure the objectivity in decision-making process.

6. It is advisable that the decision nodes are structured in such a way that a single option can be chosen in each node among all the options displayed.

7. The sum of the estimated probabilities at each chance node must be equal to 1.

The main challenge in making a decision tree is to identify the events that could occur and the percentage of probability of occurrence. It is important to note that all nodes must be numbered sequentially for ease of reference (Sharma, 2009).

5. Geology and Petroleum prospects in Ecuador

5.1. Oil Fields Location in Ecuador

In Ecuador, the oil extraction zone is located mainly in the Ecuadorian Amazon region, which is one of the most biodiverse areas in the world. The oil blocks occupy 68% of the Amazon region, which represents an area of 68,196 Km^2 (Lessmann, Fajardo, Muñoz, & Bonaccorso, 2016). Ecuador's oil production rate through its operations is~526,383 barrels per day, of different API gravity (light oil, medium oil, and heavy oil).

Figure 29 shows the Amazon region where the oil fields / blocks and protected areas are located. Each block is represented by a number for its respective identification. The graph shows that there are several oil fields located in protected areas, such as the ITT oil block, which is one of the most important in the country. Likewise, it can be seen through the colors which are the most sensitive environmental zones.

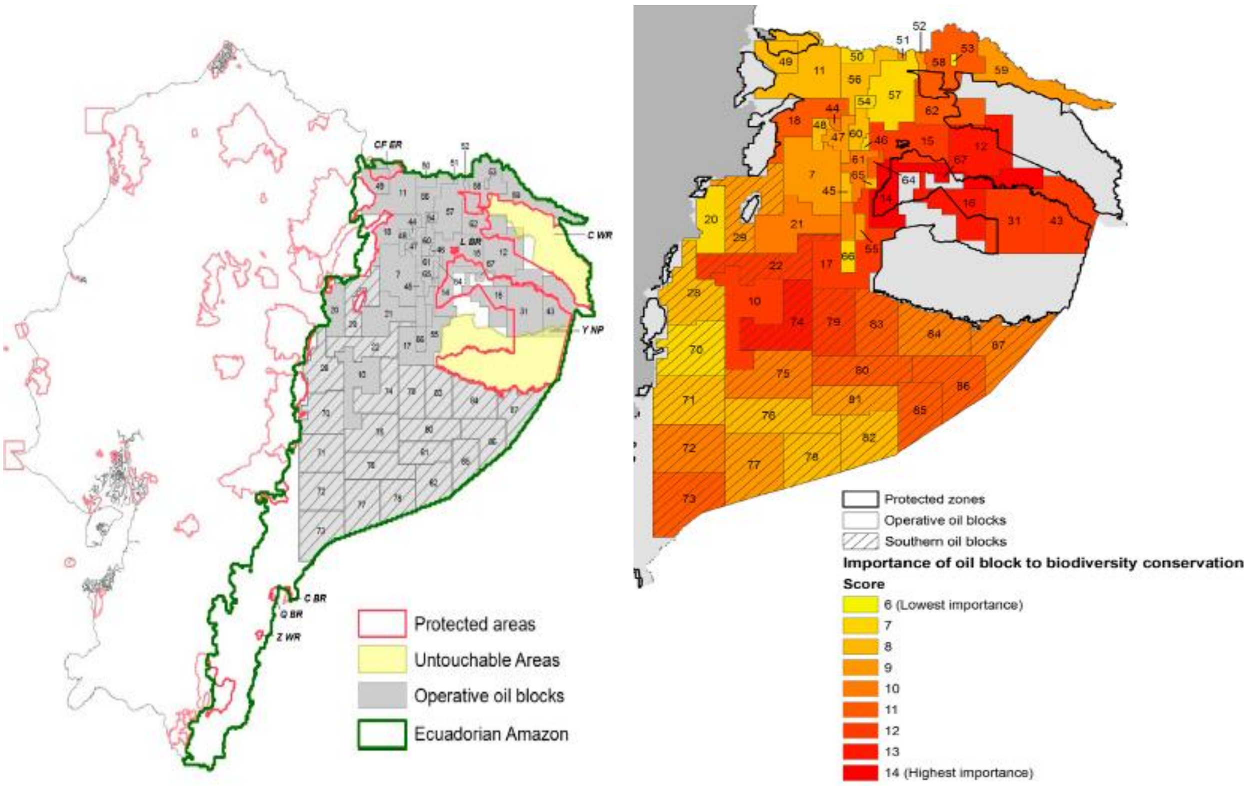


Figure 29 Oil blocks/fields location in Ecuador.
Obtained and modified from (Lessmann et al., 2016).

5.2. Geology of Oriente Basin

Ecuador produces oil mainly from the different formations that make up the Oriente basin, which is one of the most productive sub-Andean basins in South America, has 30 billion barrels of oil (in situ), and accumulated in more than 100 fields, by which is highly attractive from an economic point of view. (P. Baby, Rivadeneira, & Barragán, 2004)

The cretaceous section of the eastern basin is made up of the following formations in ascending order in the stratigraphic column (Mancilla, Albariño, Meissinger, Rivadeneira, & Sciamanna, 2008):

- ***Hollín***: consisting mainly of continental sandstones, covered by shallow marine deposits.

- ***Grupo Napo***: made up of sandstones, limestones and pelites. Group Napo is made up of different formations, the most important of which are: *Arenisca "U" Principal* (*Napo "U"*), *Arenisca "T" Principal* (*Napo "T"*).

- ***Basal Tena:*** made up of fluvial sandstones, with marine influence.

Table 10 shows the range of values of the main geological properties, and average values of formation thickness and approximate depths of the main formations of the Oriente Basin.

Formation	Porosity [%]	Permeability [mD]	Thickness [ft]	TVD [ft]	Comments
Basal Tena	5 - 12	20 - 200	< 30	+/- 7,886	Secondary objective
Napo "U"	10 - 22	30 - 900	> 50	+/- 8,561	Secondary objective
Napo "T"	8 - 12	10 - 450	> 80	+/- 8,759	Secondary objective
Hollín	12 - 19	10 - 250	50 - 300	+/- 8,900	Primary objective

Table 10 Main reservoirs in the Oriente Basin.
Obtained and modified from (Zura, 2018).

The technical analysis is based on the geological properties of the Hollín and Napo "U" formations, where it is planned to drill the different types of wells. Average values will be taken from Table 10 for the analysis.

Figure 30 shows the stratigraphic column of the Oriente Basin where the different formations can be observed.

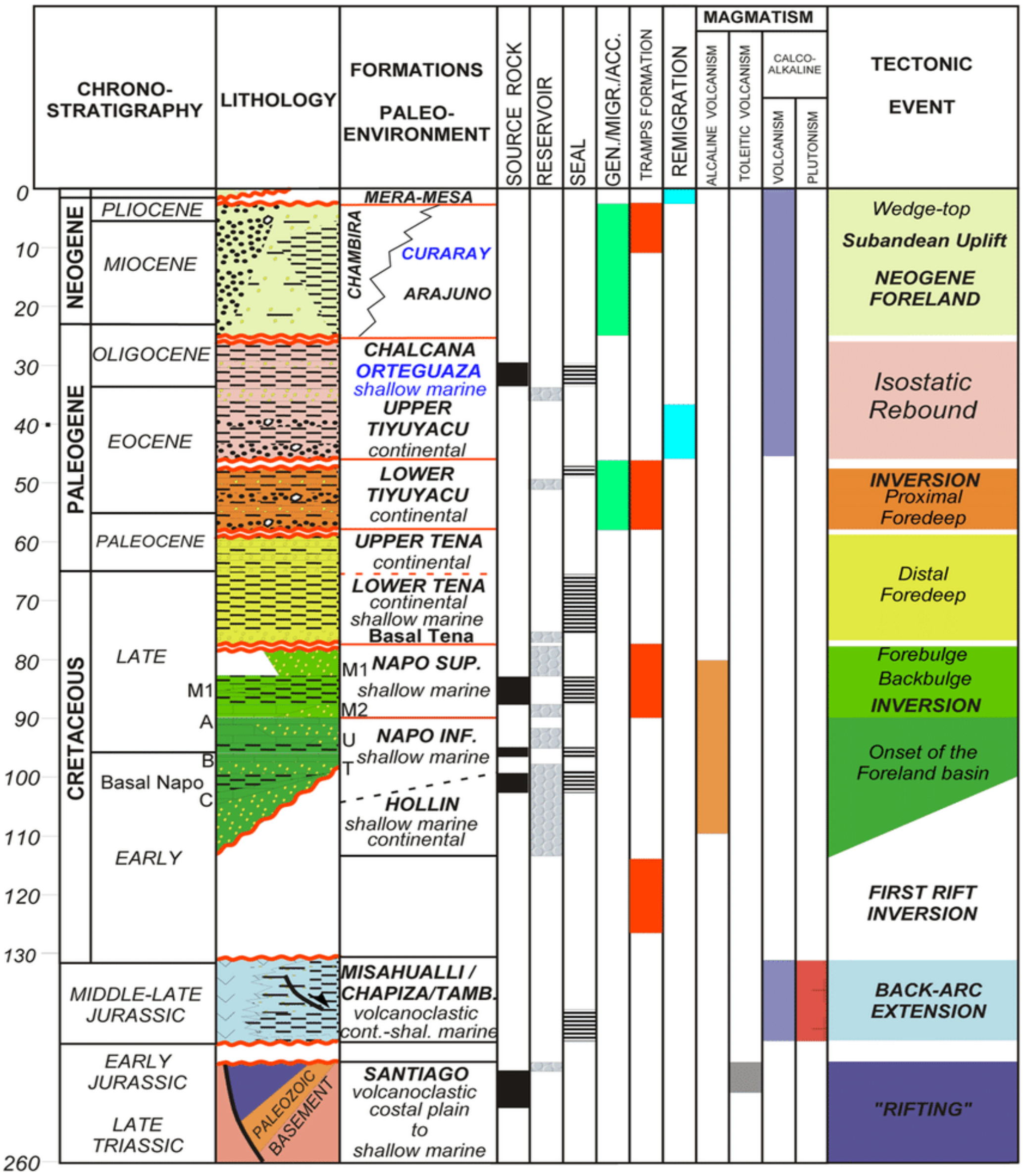


Figure 30 Stratigraphic column of the Oriente Basin.
Obtained from (Patrice Baby, Rivadeneira, Barragan, & Christophoul, 2013).

6. Modeling Well Performance

To estimate the performance of the horizontal and multilateral oil wells, Babu and Odeh´s has been selected. The analysis is based on comparing the performance of a two-branch multilateral well (dual lateral stacked) against the performance of a horizontal well that produces oil through 2 different sections (vertical and horizontal) at the same time as shown in figure 31.

6.1. Technical Analysis

To illustrate the applicability of the methodology described in the previous chapter, the geological characteristics of an oil field in Ecuador have been taken as a reference to estimate the performance (production rate) or to predict the production performance that the field could have under two possible scenarios.

All two scenarios have a similar geological description, which is a two-layer oil formation (pay zones): *Hollín Principal* and *Napo "U"*. Each scenario contemplates a different type of well to drill both formations.

- In the first scenario, the development plan is based on a horizontal well, where the formation *Hollín Principal* will produce through the horizontal section of the well, and formation *Napo "U"* will produce through the vertical section. Figure 31 illustrates the well configuration for this scenario.

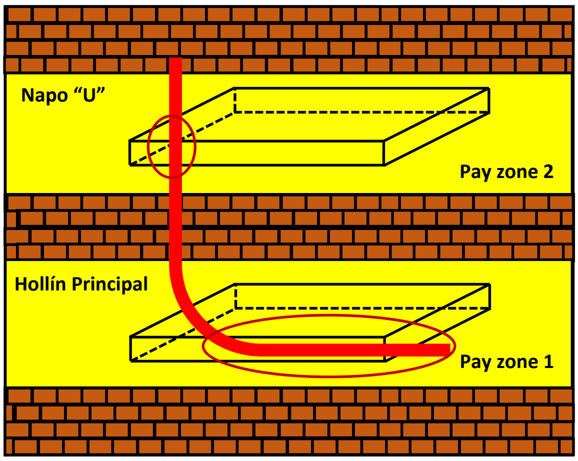


Figure 31 Horizontal well system configuration for scenario 1.

- In the second scenario, the development plan is based on a multilateral well (stacked dual lateral branch well, TAML 4). Both formations, *Hollin principal* and *Napo "U"* will be drained through the laterals. Figure 32 illustrates the well configuration for this scenario.

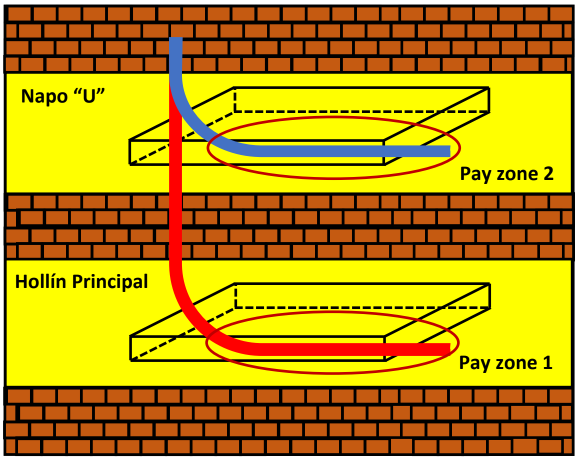


Figure 32 Multilateral well system configuration for scenario 2.
(Stacked dual lateral multilateral well)

The main reason for working in two scenarios with two different types of well is to technically compare the performance of the horizontal well with the multilateral well system's performance in order to determine whether or not there is an advantage of one over the other. A horizontal well was taken as a reference to make the comparison, since this is the competing technology and the basis for drilling a multilateral well.

Since this analysis is for academic purposes, and in order to simplify this analysis, the quality of the reservoir will depend completely on the permeability.

In both scenarios, the reservoir formations are characterized by being highly permeable formations, where both horizontal (K_h) and vertical K_v permeabilities are considered in the analysis.

Before starting the analysis, it is important to emphasize that a bottom-flowing pressure (P_{wf}) value of 2900 psi is assumed for pay zone 1 (*Hollín Principal*). This value will be used to calculate the bottom-flowing pressure for pay zone 2 (*Napo "U"*). To estimate the production of the vertical section, a hydrostatic pressure drop of 0.111 psi / ft is considered.

Before beginning the analysis, it is important to emphasize that for payment zone 1, a value of 2,900 is assumed as the bottom pressure, which will be used to calculate the pressure in zone 2.

It was mentioned previously that the technical analysis is based on real geological information from an oil field in Ecuador; however some assumptions were made to simplify the analysis:

- Single-phase flow (oil).
- Pseudo-steady state flow regime.
- No-flow boundaries.
- Homogeneous reservoir.
- Anisotropic reservoir.
- The reservoir fluids and the well fluids have the same density, which remains constant at any point either in the reservoir or in the well.
- Constant flow rate throughout the entire lateral section.
- Constant gradient pressure throughout the entire lateral section.
- The frictional effects are negligible.
- In many cases, the pressure drops in the lateral itself is negligible compared with the reservoir drawdown, in which case it can be ignores and a constant pressure along the lateral is assumed.

The well is completed with a perforated liner hanger having 20 spf with 90 degrees.

For the technical analysis, a project life of 20 years is assumed for both scenarios (horizontal well and multilateral well).

6.1.1. Scenario 1

The well configuration for scenario 1 is based on a horizontal well, where the horizontal section will be drilled through the pay zone 1 (*Hollín Principal*) since it is the thickest formation. Pay zone 1 will produce through the lateral section, whereas the pay zone 2 (*Napo "U"*) will produce through the vertical section.

The input data for scenario 1 is presented in Table 11, which shows all reservoir information.

INPUT DATA FOR SCENARIO 1 (VW + HW system)				
PARAMETERS	**SYMBOL**	**UNITS**	**PAY ZONE 1**	**PAY ZONE 2**
Porosity	Ø	%	19	19
Horizontal permeability	kh	mD	250	900
Vertical permeability	kv	mD	25	90
Lateral (hole)diameter	Ø	inch	6.5	-
Net vertical formation thickness	h	ft	80	60
Oil formation volume factor	Bo	bbl/STB	1.1	1.1
Oil viscosity	µo	cP	5	5
Density	ρ	lb/ft³	58	58
Wellbore radius	rw	ft	0.27	0.27
Total skin factor	S	Dl	10	10
Reservoir pressure	Pre	psia	3,400	1,900
Flowing bottom-hole pressure	Pwf	psi	2,900	1,800
Reservoir width	a	ft	1,500	-
Reservoir length	b	ft	3,000	-
True Vertical Depth	TVD	ft	8,983	8,561
Length of horizontal section	L	ft	2,000	-

Table 11 Reservoir properties for scenario 1.

For the vertical section, the flowing bottom-hole pressure for the pay zone 2 is 1,800 psi (2,900 – 1,100 psi). It considers only the hydrostatic pressure drop (pressure gradient) between pay zone 1 and pay zone 2.

To estimate the total well performance for scenario 1 through an inflow equation based on Babu and Odeh's model, we start by calculating the initial production or initial oil flow rate [bbl/day] in pay zone 2 with the following equation:

$$q_o = \frac{k \times h \times (\overline{P} - P_{wf})}{141.2\mu_o B_o \left(ln \frac{0.472 r_e}{r_w} + S\right)}$$

Then, initial oil flow rate for pay zone 2 is:

$$q_o = \frac{900 \times 80 \times (1{,}900 - 1{,}800)}{141.2 \times (5) \times (1.1) \times \left(ln \frac{0.472 \times (1{,}500)}{0.27} + 10\right)}$$

$$q_{o\ vertical\ section} = 519\ [STB/day]$$

For the horizontal section, the oil production is calculated using equations 1 through 27 presented in the previous chapter (chapter 5 - Methodology).

According to the procedure to calculate the multilateral well deliverability, the first step is to divide each lateral branch or horizontal section into small segments. Since the lateral length is 2,000 ft., we can divide the lateral into five segments, which means that each segment is 400 ft. long. The first segment is toe and the last one is the heel

The geological properties such as porosity, permeability, and fluid properties such as density and viscosity remain constant in each of the segments, only the dimensions of the segments would vary.

The dimensions of each segment used in this semi analytical approach are listed in Table 12.

			SEGMENT NUMBER		
PARAMETERS	*SYMBOL*	*UNITS*	*1 (toe)*	*2, 3, 4 (middle)*	*5 (heel)*
Net vertical formation thickness	h	[ft.]	80	80	80
Reservoir width	a	[ft.]	1,500	1,500	1,500
Reservoir length	b	[ft.]	900	400	900
Length of horizontal section	L	[ft.]	400	400	400

Table 12 Dimensions of each segment for lateral section, scenario 1 (pay zone 1) .

We start by finding the location of the hell of the horizontal well based on the corner of origin of the reservoir:

$$y_o = \frac{1{,}500}{2} = 750 \tag{22}$$

$$z_o = \frac{80}{2} = 40 \tag{23}$$

Then, we calculate the anisotropy ratio:

$$I_{ani} = \sqrt{\frac{250}{25}} = 3.162 \tag{24}$$

Now we can proceed to calculate the shape factor ($ln\, C_H$) either with equation no. 6 or with equation no. 7, the result will be the same.

$$ln\, C_H = 6.28 \frac{1{,}500}{(3.162)(80)} \left[\frac{1}{3} - \frac{750}{1{,}500} + \left(\frac{750}{1{,}500}\right)^2\right] - ln\left(sin\frac{\pi(40)}{80}\right) - 0.5\, ln\left[\left(\frac{1{,}500}{(3.162)(80)}\right)\right] - 1.088 \tag{25}$$

$$ln\, C_H = 1.125$$

To calculate the partial penetration skin (S_R) the dimensions of the reservoir must be considered. It must be verified which case (a > b or b < a) we must use to carry out the calculation. Since the reservoir width (a) is greater than the reservoir length (b), (a>b), case 1 applies, thus equations no.8 through no.17 must be used to find (S_R).

It must be verified that the condition of equation 8 is met:

$$\frac{1{,}500\, ft}{\sqrt{250}\, md} \geq 0.75 \frac{900\, ft}{\sqrt{250}\, md} > 0.75 \frac{80\, ft}{\sqrt{25}} \tag{26}$$

$$95 \geq 43 > 12 \tag{27}$$

Since it meets the condition, we can proceed with the following equations:

$$P_{xyz} = \left(\frac{900}{400} - 1\right)\left[ln\frac{80}{0.27} + 0.25\, ln\frac{250}{25} - ln\left(sin\frac{\pi(40)}{80}\right) - 1,84\right] \qquad (10)$$

$$P_{xyz} = 5.53$$

We calculate the midpoint of the lateral in the x-axis.

$$x_{mid} = \frac{800 + 600}{2} = 700 \qquad (12)$$

Then,

$$F\left(\frac{L}{2b}\right) = -\frac{400}{2(900)}\left[0.145 + ln\left(\frac{400}{2(900)}\right) - 0.137\left(\frac{400}{2(900)}\right)^2\right] = 0.3035 \qquad (13)$$

Prior to continuing, the value of the following expressions must be evaluated in order to calculate P'_{xy}.

$$\frac{4x_{mid} + L}{2b} = \frac{(4 \times 700) + 400}{2\ \times 900} = 1.778$$

$$\frac{4x_{mid} - L}{2b} = \frac{(4 \times 700) - 400}{2\ \times 900} = 1.333$$

Since the values of the expression $\left(\frac{4x_{mid} \pm L}{2b}\right)$ are higher than 1, we proceed with equations no. 16 and no. 17:

$$F\left(\frac{4x_{mid} + L}{2b}\right) = [2 - 1.778][0.145 + ln(2 - 1.778) - 0.137\,(2 - 1.778)^2] \\ = -0.304 \qquad (14)$$

$$F\left(\frac{4x_{mid} - L}{2b}\right) = [2 - 1.333][0.145 + ln(2 - 1.333) - 0.137\,(2 - 1.333)^2] \\ = -0.214 \qquad (15)$$

Now, we can proceed to calculate P'_{xy}, having been calculated all the variables required:

$$P'_{xy} = \frac{2(900)^2}{(400)\times(80)}\sqrt{\frac{25}{250}}\{0.3035 + 0.5[(-0.3034) - (-0.214)]\} = 4.14 \qquad (11)$$

Then, we can calculate the partial penetration skin (S_R) considering the values of P'_{xy}, and P_{xyz}.

$$S_R = 5.53 + 4.14 = 9.68 \qquad (9)$$

Finally, que proceed to calculate the initial flow rate.

$$q_o = \frac{(900)\times\sqrt{250\times 25}\times(3{,}400 - 2{,}900)}{141.2(1.1)(5)\left(\ln\left(\frac{\sqrt{(80)(1{,}500)}}{0.27}\right) + 1.125 - 0.75 + 9.678 + 10\right)} \qquad (1)$$

$$q_o = 1683.55\ [STB/day]$$

With the calculated value of flow rate, we can proceed with the next step according to the procedure in order to predict the well deliverability based on a semi analytical model (Babu and Odeh's inflow model and Ouyang and Aziz's wellbore model) , which would be to calculate the pressure drop in the segment.

We start by calculating the inflow rate per unit length of the segment: (q_i)

$$q_i = \frac{1683.55}{400} = 4.208 \qquad (22)$$

We calculate the average flow rate in the segment:

$$\bar{q} = \left(\frac{1683.55}{400}\right)\frac{400}{2} = 841.8 \qquad (23)$$

Then, we calculate the Reynolds number based on the inflow rate per unit length (q_i)

$$N_{Re} = \frac{1.48 \times 841.9 \times 58}{6.5 \times 5} = 2{,}223.65 \tag{24}$$

Since the calculated value (Reynolds number) is less than 2,300, the flow is laminar (Mott & Untener, 2015), therefore we use equation no. 25 to calculate an empirical friction factor:

$$f_f = \frac{0.0791}{(2{,}223.65)^{0.25}} = 0.012 \tag{25}$$

Now, we calculate the mean velocity of the fluid in the segment.

$$\mu = \frac{4 \times 5.615 \times 841.8}{\pi \times 86{,}400 \times (6.5/12)^2} = 0.237 \tag{26}$$

Finally, we calculate the pressure drop in the wellbore segment:

$$\begin{aligned} \Delta p &= \frac{2 \times 0.012 \times 58 \times (0.237)^2 \times 400}{32.17 \times 144 \times (6.5/12)} \\ &+ \frac{8 \times 58 \times 0.237 \times 841.8 \times 5.615}{\pi \times (6.5/12)^2 \times 86{,}400 \times 32.17 \times 144} = 0.0138\ [psi] \end{aligned} \tag{27}$$

Notice that the pressure drop (0.0138 psi) in the first segment (1,1) it is insignificant. Based on this value we can calculate the flowing pressure in the next segment (1,2) which is $P_{wf(1,2)} = 2900 - 0.0138 = 2899.99\ psi$. This new flowing pressure will be used to perform the next calculations in order to calculate the well deliverability.

The calculations made for segment (2,1) should be repeated for segments (2,2), (2,3), (2,4), and (2,5) considering the information provided in Table 12.

The results of the calculations made for segments 1 to 5 are summarized in Table 13.

	HORIZONTAL SECTION (LATERAL 1) / PAY ZONE 1				
	SEGMENT NUMBER				
PARAMETERS	1	2	3	4	5
I_{ani}	3.162	3.162	3.162	3.162	3.162
y_0	750.00	750.00	750.00	750.00	750.00
z_0	40.00	40.00	40.00	40.00	40.00
x_{mid}	700.00	200.00	200.00	200.00	200.00
$\ln C_H$	1.125	1.125	1.125	1.125	1.125
$F\left(\frac{4x_{mid}+L}{2b}\right)$	-0.304	-0.219	-0.219	-0.219	0.252
$F\left(\frac{4x_{mid}-L}{2b}\right)$	-0.214	0.363	0.363	0.363	0.511
$F\left(\frac{L}{2b}\right)$	0.304	0.291	0.291	0.291	0.304
P_{xyz}	5.53	0.000	0.000	0.000	5.534
P'_{xy}	4.14	0.000	0.000	0.000	4.14
S_R	9.68	0.000	0.000	0.000	9.68
q_0	1683.54	1161.323	1161.292	1161.292	1686.91
q_i	4.21	2.903	2.903	2.903	4.22
$\bar{q}$	841.77	580.66	580.65	580.65	843.455
N_{Re}	2223	1534	1534	1534	2 228
f_f	0.012	0.013	0.013	0.013	0.012
μ	0.237	0.164	0.164	0.164	0.238
Δ_p	0.013	0.007	0.007	0.007	0.013
P_{wf}	2900	2899.99	2899.98	2899.97	2899.966

Table 13 Results obtained for segments 1 to 5, scenario 1 (pay zone 1).

It is important to mention that the 5 segments will have the same shape factor $(ln\, C_H)$ value since the shape factor is independent of the location of the segment in the x-direction. On the other hand, in the middle segments (2,3, and 4) partial penetration skin (S_R) is zero since fully penetrating horizontal well and there is no flow in the x-direction inside the reservoir.

Based on the production flow rates calculated for each of the segments, which are described in Table 13, the total flow rate for the horizontal section can be calculated by adding each of the flow rates:

$$q_{o\ horizontal\ section} = 1{,}686.54 + 1{,}161.323 + 1{,}161.292 + 1{,}161.292 + 1{,}686.91$$

$$q_{o\ horizontal\ section} = 6{,}854.35\ [\mathbf{STB/DAY}]$$

Consequently, the total oil production for the horizontal well system is estimated to be:

$$q_{o\ horizontal\ well} = q_{o\ vertical\ section} + q_{o\ horizontal\ section}$$

$$q_{o\ horizontal\ well} = 519 + 6{,}854.35 = \mathbf{7373.35}\ [\mathbf{STB/DAY}]$$

For this semi-analytical analysis, a nominal decline rate of 5% per year has been established, however, in real a field analysis, the production history and the characterization of the field must be considered to perform a production forecasting analysis and a decline curve analysis (DCA).

Based on the initial production rate calculated for the horizontal well system (vertical section and horizontal section), production rates are then estimated for twelve years to perform a DCA based on an exponential decline analysis. Table 14 shows the results obtained for the production forecast.

YEAR	VERTICAL SECTION (pay zone 1) [STB/year]	HORIZONTAL SECTION (pay zone 2) [STB/year]	TOTAL PRODUCTION Vertical + Horizontal
1	189,435	2,501,838	2,691,273
2	180,196	2,427,897	2,608,093
3	163,048	2,286,508	2,449,556
4	140,337	2,089,711	2,230,047
5	114,898	1,853,407	1,968,305
6	89,483	1,595,242	1,684,725
7	66,290	1,332,458	1,398,749
8	46,714	1,080,070	1,126,784
9	31,313	849,613	880,926
10	19,966	648,577	668,543
11	12,110	480,478	492,588
12	6,987	345,427	352,414

Table 14 Production forecast for scenario 1.

On the other hand, based on the calculated initial production, a declination curve analysis (DCA)is performed for the next 12 years production rates. Arp's equation (Eq.) for general decline in a well is used; a minimum decline rate of 3% is assumed.

$$q = q_i e^{-dt} \tag{36}$$

Figure 33 shows the results obtained from de DCA analysis for scenario 1 considering de production from the vertical and horizontal section.

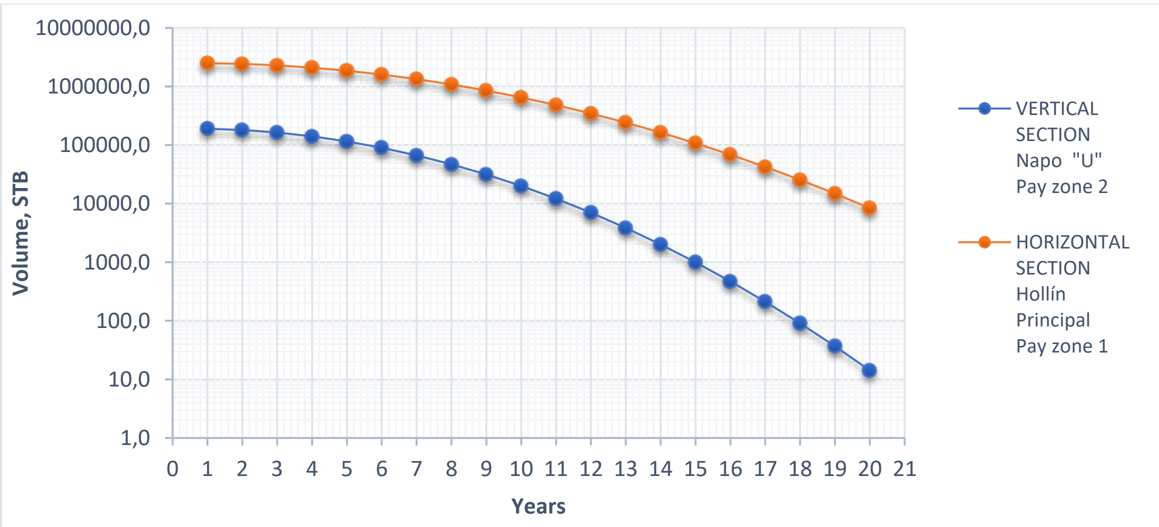


Figure 33 Annual decline curve analysis – scenario 1.

Overall, the semi-log chart exposes a sizeable benefit of drilling a horizontal well versus a vertical well since it shows a higher production from the horizontal section vs the vertical section. Based on the results obtained, it can be concluded that a horizontal well yields a higher production than a vertical well.

Figure 34 plots the cumulative production rate for the horizontal well system considering the production rates of the vertical and horizontal section. This cumulative production curve will be used later to compare against the cumulative production curve of the multilateral well in order to determine which well system has the best production performance.

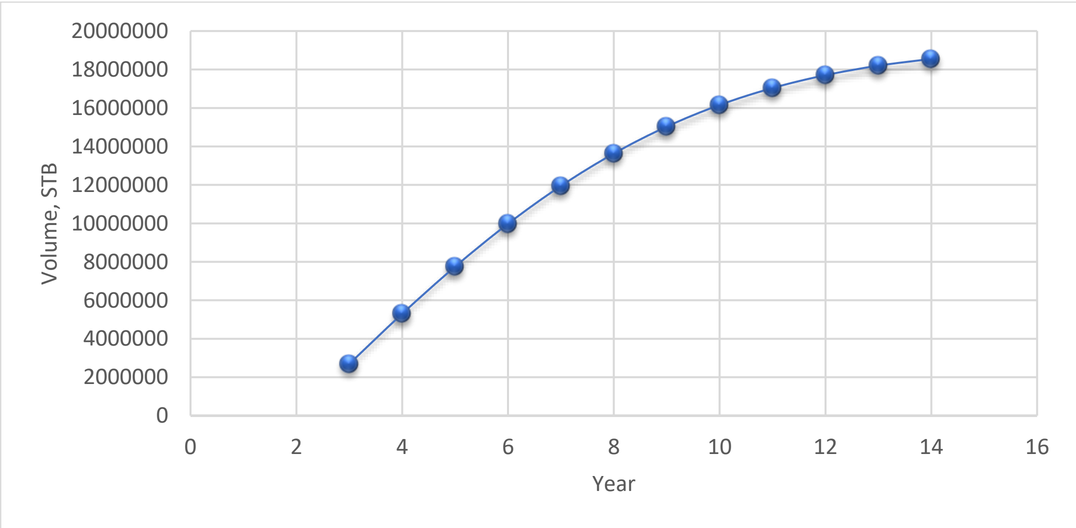


Figure 34 Cumulative production rate - scenario 1.

6.1.2. Scenario 2

The well configuration for scenario 2 is based on a multilateral well: stacked dual lateral, TAML 4, where the branches (laterals) are in the same vertical plane, which means that both pay zones (*Hollín Principal and Napo "U"*) will produce through the lateral sections.

The reservoir information necessary to predict multilateral well deliverability is presented in Table 15, information that will be used as input data in the equations presented in the previous chapter.

INPUT DATA FOR SCENARIO 2 (ML system)				
PARAMETERS	SYMBOL	UNITS	PAY ZONE 1	PAY ZONE 2
Porosity	Ø	%	19	19
Horizontal permeability	kh	mD	250	900
Vertical permeability	kv	mD	25	90
Lateral (hole)diameter	Ø	inch	6.5	-
Net vertical formation thickness	h	ft	80	60
Oil formation volume factor	Bo	bbl/STB	1.1	1.1
Oil viscosity	μo	cP	5	5
Density	ρ	lb/ft³	58	58
Wellbore radius	rw	ft.	0.27	0.27
Total skin factor	S	DI	10	10
Reservoir pressure	Pre	psia	3,400	1,900
Flowing bottom-hole pressure	Pwf	psi	2,900	1,751
Reservoir width	a	ft	1,500	-
Reservoir length	b	ft	3,000	-
True Vertical Depth	TVD	ft	8,983	8,561
Length of horizontal section	L	ft	2,000	-

Table 15 Reservoir properties for scenario 2.

It is possible to notice that the reservoir properties for scenario 2 are the same as for scenario 1, therefore, for the technical analysis of scenario 2, the results obtained in the horizontal section of scenario 1 will be used since the only variant between scenario 1 and scenario 2 is that pay zone 2 will not produce through a vertical section, but through a horizontal well.

For scenario 2, only the production for pay zone 1 will be calculated considering that this time a branch (horizontal well) will be drilled through this zone.

Since the aim of this analysis is to show the reader the procedure to calculate the multilateral well deliverability through a semi-analytic analysis, the step-by-step procedure for calculating the pressure drop in build section has been skipped, however, a reference value for the pressure drop in the build section of lateral 1 has been estimated based on Beggs and Brill the two-phase correlation taking into account the input data shown in Table 16.

PIPE INFORMATION		
PARAMETERS	VALUE	UNITS
Pipe inside diameter	3.5	inch
Pipe length	12,180	ft
Pipe roughness	0.000071	inch
Inclination angle with horizontal	90	°
GAS INFORMATION		
PARAMETERS	VALUE	UNITS
Volumetric flowrate	0.00001	inch
Density	0.00001	lb/ft^3
Viscosity	0.00001	cP
OIL INFORMATION		
PARAMETERS	VALUE	UNITS
Inlet pressure	2,899.96	psia
Volumetric flowrate	27	ft^3/min
Density	58	lb/ft^3
Viscosity	5	cP
Surface tension	0.1	dyne/cm

Table 16 Input data for Beggs and Brill's two-phase correlation

Therefore, considering the information provided in Table 16, and Beggs and Brill correlations, the pressure drop in the build section is 2,252.24 psi.

Since the aforementioned correlations consider two phases in the reservoir (oil and gas) and considering that the reservoir in this analysis only has oil, minimum values have been established for the properties of the gas (volumetric flowrate, density and viscosity).

Regarding the information on oil, a clarification should be made on the values shown in Table 16:

- *Inlet pressure:* corresponds to the Pwf calculated for section 5 (heel section) of lateral 1 (2,899.96 psi).
- *Volumetric flowrate*: represents the value of the total flow rate from lateral 1 (6,854.35 B/D) for scenario 1. Units barrels/day must be transformed to ft^3/min.
- *Surface tension*: a minimum reference value has been established since this parameter does not directly influence the pressure drop.

- *Density* and *viscosity* were taken from the Table 15.

The pressure drop in the build section can be used to calculate the pressure at the junction from lateral as follow:

$$P_{build\ section\ 1} = P_{wf\ (1,5)} - Pressure\ drop\ in\ the\ build\ section \tag{37}$$

$$P_{build\ section\ 1} = 2899.96\ [psi] - 2{,}252\ [psi] = 647.96\ [psi]$$

So, the pressure at the junction of lateral 1 is 647 psi. Taking into account the recommendation made it in point 5 in section *4.2.2 Multilateral Well Deliverability Model*, to determine if the pressure at the junction is correct, must match by the total flow rate from lateral 2.

Following the same procedure as in lateral 1, using the Babu and Odeh model for inflow calculations, and Ouygan's model for wellbore pressure drop at each segment, Following the same procedure as in scenario 1 for the lateral section (horizontal well), the lateral branch for pay zone 2 is also divided into small segments; the length of this branch as for pay zone 1 is also 2,000 feet, therefore it is divided into 5 segments, where each one is 400 ft. long.

Considering that the reservoir pressure in zone 2 is 1,900 psi, the first assumption is made (as was done for the horizontal section in scenario 1). We assume that we have a pressure drop of 150 psi in the first segment of lateral 2, segment (2,1) , therefore we start our calculations with a flowing bottom-hole pressure of 1,750 psi.

$$P_{wf\ (2,1)} = 1{,}900\ psi - 150\ psi = 1{,}750\ psi$$

The geological properties such as porosity, permeability, and fluid properties such as density and viscosity remain constant in each of the segments, only the dimensions of the segments would vary.

Both geological properties and fluid properties remain constant in each of the segments, only the dimension of the segment will vary, however they all have the same length.

The dimensions of each segment used in this semi analytical approach are listed in Table 17.

			SEGMENT NUMBER		
PARAMETERS	SYMBOL	UNITS	1 (toe)	2, 3, 4 (middle)	5 (heel)
Net vertical formation thickness	h	[ft]	60	60	60
Reservoir width	a	[ft]	1,500	1,500	1,500
Reservoir length	b	[ft]	900	400	900
Length of horizontal section	L	[ft]	400	400	400

Table 17 Dimensions for each segment for lateral section, scenario 2 (pay zone 2).

We start by finding the location of the hell of the horizontal well based on the corner of origin of the reservoir:

$$y_o = \frac{1{,}500}{2} = 750 \tag{3}$$

$$z_o = \frac{60}{2} = 30 \tag{4}$$

Then, we calculate the anisotropy ratio:

$$I_{ani} = \sqrt{\frac{900}{90}} = 3.162 \tag{5}$$

Now we can proceed to calculate the shape factor ($ln\, C_H$) either with equation no. 6 or with equation no. 7, the result will be the same.

$$ln\, C_H = 6.28 \frac{1{,}500}{(3.162)(60)} \left[\frac{1}{3} - \frac{750}{1{,}500} + \left(\frac{750}{1{,}500}\right)^2\right] - ln\left(sin\frac{\pi(30)}{60}\right) - 0.5\, ln\left[\left(\frac{1{,}500}{(3.162)(60)}\right)\right] - 1.088 \tag{6}$$

$$ln\, C_H = 2.016$$

Since the reservoir width (a) is greater than the reservoir length (b), (a>b), case 1 applies, thus equations no.8 through no.17 must be used to find (S_R).

It must be verified that the condition of equation 8 is met:

$$\frac{1{,}500\, ft}{\sqrt{900}\, md} \geq 0.75 \frac{900\, ft}{\sqrt{900}\, md} > 0.75 \frac{60\, ft}{\sqrt{90}} \tag{8}$$

$$50 \geq 22.5 > 4.74 \tag{8}$$

Since it meets the condition, we can proceed with the following equations:

$$P_{xyz} = \left(\frac{900}{400} - 1\right)\left[ln \frac{60}{0.27} + 0.25\, ln \frac{900}{90} - ln\left(sin \frac{\pi(30)}{60}\right) - 1{,}84\right] \tag{10}$$

$$P_{xyz} = 5.17$$

We calculate the midpoint of the lateral in the x-axis.

$$x_{mid} = \frac{800 + 600}{2} = 700 \tag{12}$$

Then,

$$F\left(\frac{L}{2b}\right) = -\frac{400}{2(900)}\left[0.145 + ln\left(\frac{400}{2(900)}\right) - 0.137\left(\frac{400}{2(900)}\right)^2\right] = 0.304 \tag{13}$$

Prior to continuing, the value of the following expressions must be evaluated in order to calculate P'_{xy}.

$$\frac{4x_{mid} + L}{2b} = \frac{(4 \times 700) + 400}{2 \times 900} = 1.778$$

$$\frac{4x_{mid} - L}{2b} = \frac{(4 \times 700) - 400}{2 \times 900} = 1.333$$

Since the values of the expression $\left(\frac{4x_{mid} \pm L}{2b}\right)$ are higher than 1, we proceed with equations no. 16 and no. 17:

$$F\left(\frac{4x_{mid} + L}{2b}\right) = [2 - 1.778][0.145 + ln(2 - 1.778) - 0.137\ (2 - 1.778)^2] \\ = -0.304 \quad (14)$$

$$F\left(\frac{4x_{mid} - L}{2b}\right) = [2 - 1.333][0.145 + ln(2 - 1.333) - 0.137\ (2 - 1.333)^2] \\ = -0.214 \quad (15)$$

Now, we can proceed to calculate $P_{xy}^{'}$, having been calculated all the variables required:

$$P_{xy}^{'} = \frac{2(900)^2}{(400) \times (60)} \sqrt{\frac{90}{900}} \{0.3035 + 0.5[(-0.3034) - (-0.214)]\} = 5.53 \quad (11)$$

Then, we can calculate the partial penetration skin (S_R) considering the values of $P_{xy}^{'}$, and P_{xyz}.

$$S_R = 5.17 + 5.52 = 10.70 \quad (28)$$

Finally, que proceed to calculate the initial flow rate.

$$q_o = \frac{(900) \times \sqrt{900 \times 90} \times (1{,}900 - 1{,}751)}{141.2(1.1)(5)\left(\ln\left(\frac{\sqrt{(60)(1{,}500)}}{0.27}\right) + 2.016 - 0.75 + 10.70 + 10\right)} \quad (1)$$

$$q_o = 1695.85\ B/D$$

Now we proceed to calculate the inflow rate per unit length of the segment: (q_i)

$$q_i = \frac{1695.85}{400} = 4.24 \tag{22}$$

We calculate the average flow rate in the segment:

$$\bar{q} = \left(\frac{1695.85}{400}\right)\frac{400}{2} = 848 \tag{23}$$

Then, we calculate the Reynolds number based on the inflow rate per unit length (q_i)

$$N_{Re} = \frac{1.48 \times 848 \times 58}{6.5 \times 5} = 2{,}240 \tag{24}$$

Since the calculated value (Reynolds number) is less than 2,300, the flow is laminar (Mott & Untener, 2015), therefore we use equation no. 25 to calculate an empirical friction factor:

$$f_f = \frac{0.0791}{(2{,}240)^{0.25}} = 0.011 \tag{25}$$

Now, we calculate the mean velocity of the fluid in the segment.

$$\mu = \frac{4 \times 5.615 \times 848}{\pi \times 86{,}400 \times (6.5/12)^2} = 0.239 \tag{26}$$

Finally, we calculate the pressure drop in the wellbore segment:

$$\Delta p = \frac{2 \times 0.011 \times 58 \times (0.239)^2 \times 400}{32.17 \times 144 \times (6.5/12)} + \frac{8 \times 58 \times 0.239 \times 848 \times 5.615}{\pi \times (6.5/12)^2 \times 86{,}400 \times 32.17 \times 144} = 0.0130\ [psi] \tag{27}$$

Notice that the pressure drop (0.0130 psi) in the first segment of the latera 2 (2,1) it is insignificant. Based on this value we can calculate the flowing pressure in the next segment (2,2) which is $P_{wf(2,2)} = 1750 - 0.0130 = 1750.98\, psi$. This new flowing pressure will be used to perform the next calculations in the next segment, in order to calculate the well deliverability.

The calculations made for segment (2,1) should be repeated for segments (2,2), (2,3), (2,4), and (2,5) considering the information provided in Table 17.

The results of the calculations made for segments 1 to 5 are summarized in 18 Table.

	HORIZONTAL SECTION (LATERAL 2) / PAY ZONE 2				
	SEGMENT NUMBER				
PARAMETERS	**1**	**2**	**3**	**4**	**5**
I_{ani}	3.162	3.162	3.162	3.162	3.162
y_0	750.00	750.00	750.00	750.00	750.00
z_0	30.00	30.00	30.00	30.00	30.00
x_{mid}	700.00	200.00	200.00	200.00	200.00
$\ln C_H$	2.016	2.016	2.016	2.016	2.016
$F\left(\frac{4x_{mid}+L}{2b}\right)$	-0.304	-0.219	-0.219	-0.219	0.252
$F\left(\frac{4x_{mid}-L}{2b}\right)$	-0.214	0.363	0.363	0.363	0.511
$F\left(\frac{L}{2b}\right)$	0.304	0.291	0.291	0.291	0.304
P_{xyz}	5.17	0.000	0.000	0.000	5.174
P'_{xy}	5.53	0.000	0.000	0.000	5.53
S_R	10.70	0.000	0.000	0.000	10.70
q_0	1695.88	1195.104	1195.292	1196.869	1701.570
q_i	4.24	2.988	2.989	2.992	4.25
$\bar{q}$	847.94	597.55	597.33	59843	850.787
N_{Re}	2240	1578	1579	1581	2247
f_f	0.011	0.013	0.013	0.013	0.011
μ	0.239	0.169	0.169	0.169	0.240
Δ_p	0.014	0.007	0.007	0.007	0.014
P_{wf}	1751	1750.986	1750.979	1750.972	1750.964

Table 18 Results obtained for segments 1 to 5, scenario 2 (pay zone 2).

It is important to mention that the 5 segments will have the same shape factor $(ln\, C_H)$ value since the shape factor is independent of the location of the segment in the x-direction. On the other hand, in the middle segments (2,3, and 4) partial penetration skin (S_R) is zero since fully penetrating horizontal well and there is no flow in the x-direction inside the reservoir.

Based on the production flow rates calculated for each of the segments, which are described in Table 18, the total flow rate for the horizontal section can be calculated by adding each of the flow rates:

$$q_{o\ horizontal\ section\ 2} = 1{,}695.88 + 1{,}195.104 + 1{,}195.292 + 1{,}196.869 + 1{,}701.570$$

$$q_{o\ horizontal\ section\ 2} = 6{,}984.715\ [\mathbf{STB/DAY}]$$

Consequently, the total oil production for the horizontal well system is estimated to be:

$$q_{o\ multilateral\ well} = q_{o\ horizontal\ section\ 1\ (lateral\ 1)} + q_{o\ horizontal\ section\ 2\ (lateral\ 2)}$$

$$q_{o\ multilateral\ well} = 6{,}854.35 + 6984.715 = \mathbf{13{,}839.065}\ [\mathbf{STB/DAY}]$$

Just like we did for the scenario 1, for this semi-analytical analysis a nominal decline rate of 3% per year has been established to perform a decline curve analysis (DCA).

Based on the initial production rate calculated for the multilateral well system (horizontal section 1 and horizontal section 2), production rates are then estimated for twelve years to perform a DCA based on an exponential decline analysis. Table 19 shows the results obtained for the production forecast.

YEAR No.	HORIZONTAL SECTION 1 (pay zone 1) [STB/year]	HORIZONTAL SECTION 2 (pay zone 2) [STB/year]
1	2,501,838	5,051,258.725
2	2,427,897	4,901,971
3	2,286,508	4,616,503
4	2,089,711	4,219,166
5	1,853,407	3,742,065
6	1,595,242	3,220,825
7	1,332,458	2,690,259
8	1,080,070	2,180,682
9	849,613	1,715,385
10	648,577	1,309,490
11	480,478	970,094
12	345,427	697,423

Table 19 Production forecast for scenario 2.

Figure 35 shows the results obtained from de DCA analysis for scenario 2 considering de production from the two horizontal laterals.

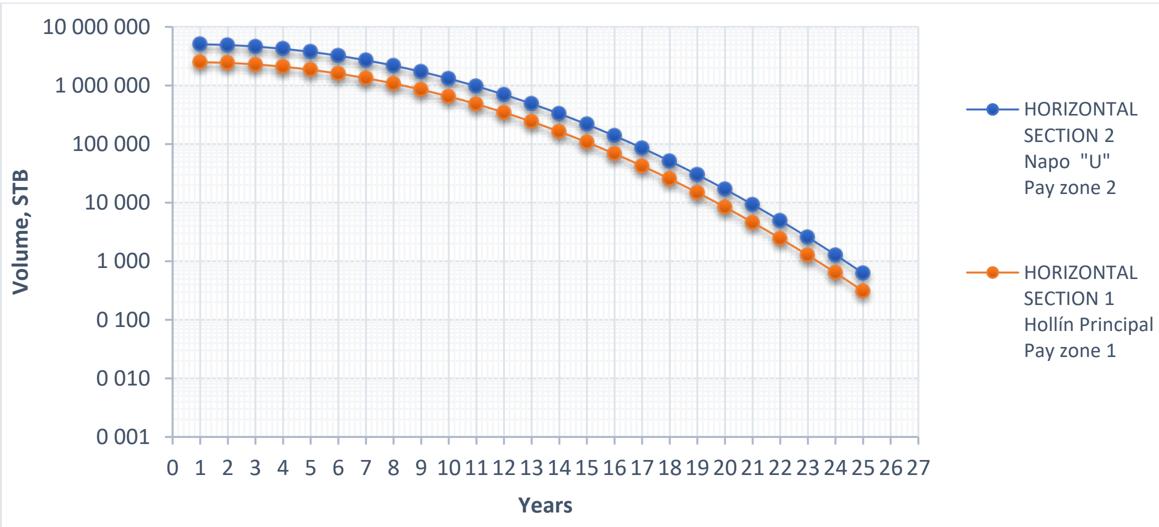


Figure 35 Annual decline curve analysis – scenario 2.

Overall, the semi-log chart exposes a sizeable benefit of drilling a multilateral well versus single horizontal well system since it shows a higher production from the multilateral well. Based on the results obtained, it can be concluded that a multilateral well yields a higher production than a single horizontal well system.

Figure 36 plots the cumulative production rate for the multilateral well system considering the production rates of both horizontal sections.

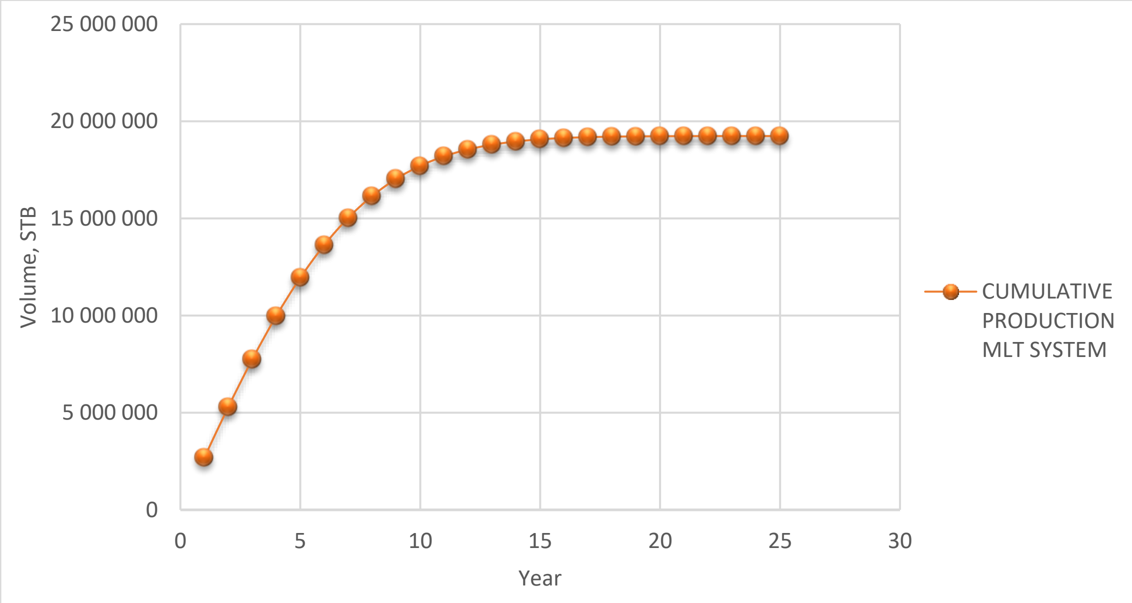


Figure 36 Cumulative production rate – scenario 2.

Figure 37, compares the cumulative production rates of the horizontal well system and multilateral well system, showing the benefit of drilling a multilateral well since its production rates exceeds the production of a horizontal well system by almost 3 times.

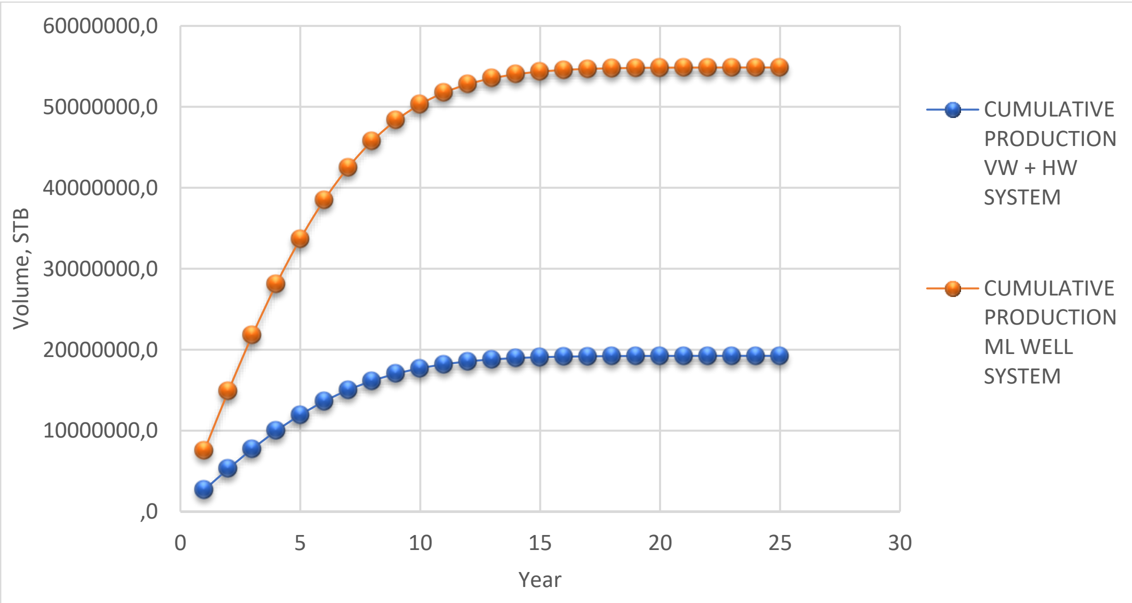


Figure 37 Comparison of cumulative production rates – scenario 1 vs. scenario 2

As a result of the DCA performed for the two different scenarios (scenario 1 and scenario 2), Figure 38 shows and compare the different the decline curves obtained for the different well systems assuming a nominal decline rate (constant) of 3% for each scenario.

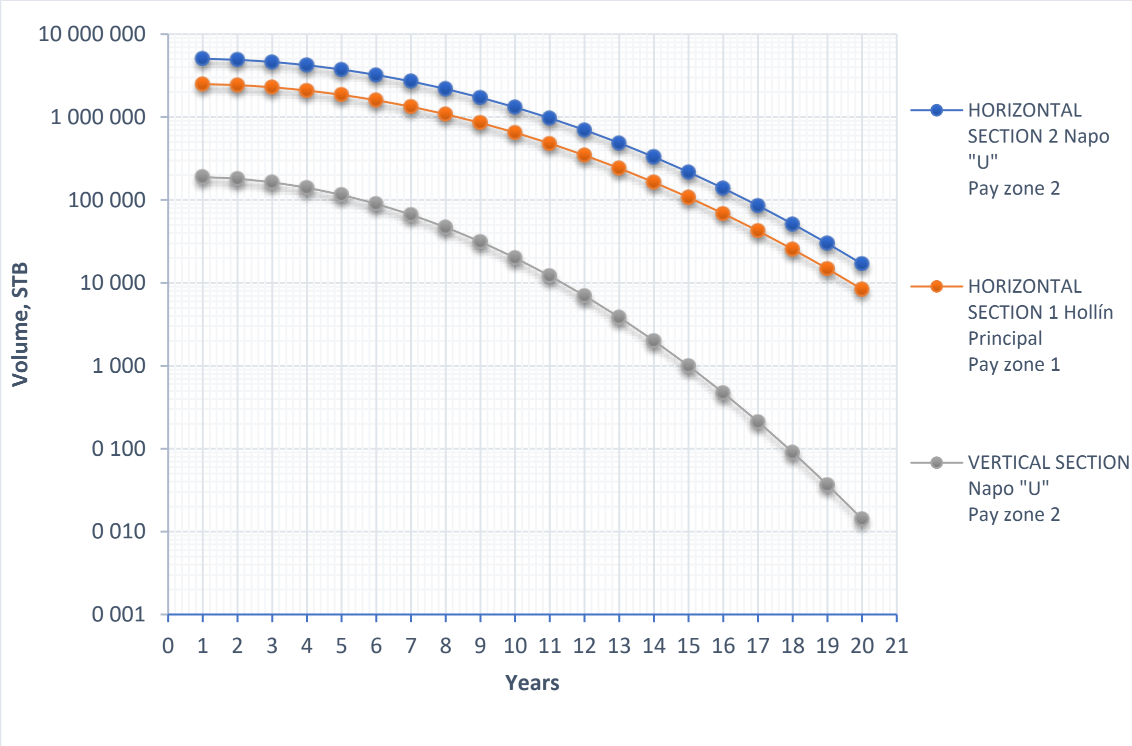


Figure 38 Comparison of annual decline curve analysis – scenario 1 vs. scenario 2.

Clearly, horizontal sections for both scenarios have a higher production rate than the vertical section since they have a greater contact area with the producing zone. On the other hand, horizontal section 2 for scenario 2 obtained better results than horizontal section 1 since it has a higher permeability value regardless of having a lower formation thickness, which means that the production rate (increase or decrease) is directly proportional to the permeability.

6.2. Economic Analysis

The economic analysis in this research work embraces the economic indicators most commonly used in the oil/gas industry to evaluate projects; however, it is mainly based on the estimation of the financial cash flow to measure the economic worth of the different well systems. FCF will be calculated from the production forecast and taking into account the following economic indicators: NPV (Eq. 28), IRR (Eq. 29) and PI (Eq. 30); These indicators will be calculated considering the operating costs (CAPEX) associated with the drilling and completion phases for a horizontal and multilateral well with two laterals (stacked dual lateral).

It is important to emphasize that to carry out the economic analysis the results of the production forecast calculated for the proposed scenarios (scenario 1 and scenario 2) in chapter 6.1 *Technical analysis* were considered.

In order to determine which of the two well systems (horizontal well or multilateral well) is more profitable, the economic performance indicators obtained for each scenario will be compared.

Figure 39 shows a diagram of the different costs that were considered for this economic analysis.

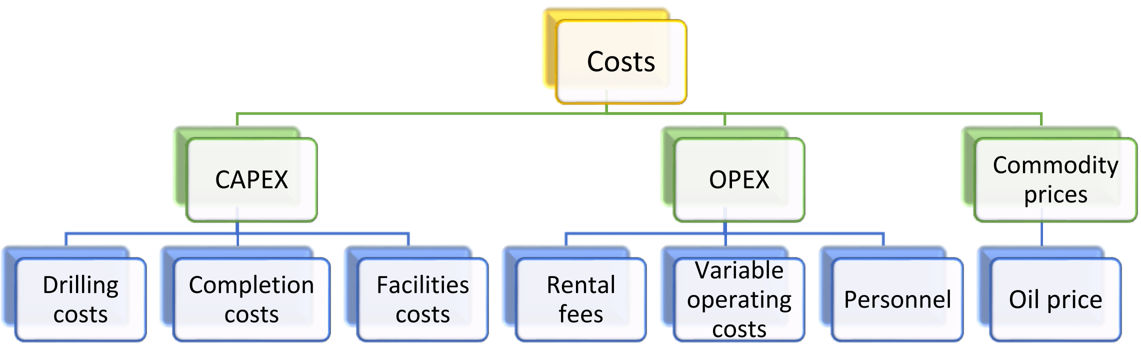


Figure 39 Costs considered in the economic analysis.

The main input data used to estimate the economic indicators for both well systems are shown in the following tables (Tables 20, 21, and 22)

Table 20 shows the information required to estimate the total cost of drilling a horizontal and multilateral well.

	Horizontal Well	Multilateral Well
Drilling costs	$4,615,450	$5,709,386
Completion costs	$430,000	$705,000
Infrastructure [USD/well]	$157,621	$123,641
Personnel [USD/well]	$347,000	$473,000
Rental fees [USD/well]	$1,066,173	$1,402,295
Variable operating costs [USD/well]	$1,117,375	$1,286,575
Multilateral Technology [USD/well]	-	$1,050,000
TOTAL	**$7,733,619**	**$10,749,897**

Table 20 Total drilling cost for each type of well.

The costs were estimated considering that the horizontal well was drilled in 36 days, total depth: 12,550 feet (MD), with an 800 ft. long horizontal section. On the other hand, the drilling costs of the multilateral well (stacked dual lateral) were estimated considering that, the well was drilled in 49 days and that both horizontal sections are 800 feet long.

On the other hand, Table 21 shows the financial information that is not associated with the drilling stage but that is essential to consider for the economic analysis. Mainly, this information will be useful to calculate the OCF. It is important to keep in mind that the information contemplates a useful life of the project of 20 years.

	Horizontal Well	Multilateral Well
Assets	$700,000	$1,750,000
Depreciation [USD/year]	$35,000	$87,500
Production cost [USD/bbl]	$18.53	$18.53
Repair / stimulation works [USD]	$15,000,000	$19,000,000
Non - cash expenses [USD]	$50,035,000	$50,087,500
Accounts Payable / Expenses [USD]	$346,144,715	$986,956,560

Table 21 Economic information for oil production stage.

For this economic analysis, two different oil prices have been considered which are shown in Table 22.

	Positive scenario	Base scenario
Oil price (WTI crude) [USD/bbl]	$66.52	$43.31

Table 22 Economic input data for scenario 1 and scenario 2.

The oil price for the positive scenario is a weighted average calculated considering different oil prices from 2000 to 2019 with the purpose of establishing a price trend[6], giving greater weight to the prices of the last 5 years (2019, 2018, 2017, 2016, and 2015). On the other hand, the years with the highest oil prices (2014, 2013, 2012, 2011, 2010, 2008) were assigned a lower weight since those oil prices are atypical since are values that have not been previously recorded.

The oil price for the base scenario was taken from the projection made for 2021 by the Statistical and Analysis Agency of the United States Department of Energy U.S. Department of Energy (eia).

6.2.1. Scenario 1

Bearing in mind all the costs that will be considered in the economic analysis; we start by calculating the net income that the reservoir will generate by drilling a horizontal well considering the production forecast for scenario 1 calculated in Chapter 5.1.1. and by calculating the OCF required to estimate the FCF.

Table 23 shows the estimated net income for the entire project considering the oil price in an optimistic scenario and in a base scenario.

Total production [bbl]	**Net income [USD]**
	Positive scenario
19,230,262	$1,279,197,023

Total production [bbl]	**Net income [USD]**
	Base scenario
19,230,262	$832,862,644.00

Table 23 Net income for the entire project – scenario 1.

[6] The different oil prices used to calculate the weighted average were taken from the official website of the Statistical and Analysis Agency of the United States Department of Energy.

Taking into account the net income shown in Table 23 and the information presented in Table 21, the Financial Cash Flow is calculated with equation number 31. Table 24 presents the results obtained considering the different oil price scenarios.

Net income [USD] **Positive scenario**	**Non - cash expenses** [USD]	**Inventory / Accounts Payable / Expenses** [USD]	**OCF** [USD]	**CAPEX** [USD]	**FCF** [USD]
$1,279,197,023.00	$50,035,000	$346,144,714.66	$983,087,308.63	$32,733,619.00	**$950,353,689.63**

Net income [USD] **Base scenario**	**Non - cash expenses** [USD]	**Inventory / Accounts Payable / Expenses** [USD]	**OCF** [USD]	**CAPEX** [USD]	**FCF** [USD]
$832,862,644.00	$50,035,000	$346,144,714.66	$536,752,929.34	$32,733,619.00	**$504,019,310.34**

Table 24 Financial Cash Flow – scenario 1.

Considering the information mentioned in Table 24 and using equations 28, 29, and 30, we proceed to calculate the other economic performance indicators that will be used to determine which of the two systems is more profitable. The economic indicators were calculated considering an initial investment of USD 50 million and a discount rate of 10%. Table 25 presents the results obtained. It is important to note that NPV will be used as an economic criterion to carry out the risk analysis.

NPV [USD]	**NPV [USD]**
Positive scenario	**Base scenario**
$548,680,194.48	$259,241,464.59
IRR [%]	**IRR [%]**
Positive scenario	**Base scenario**
255%	130%
PI [DI]	**PI [DI]**
Positive scenario	**Base scenario**
18.36	9.43

Table 25 Summary of economic performance indicators results – scenario 1.

6.2.2. Scenario 2

As it was done in the previous scenario, we will begin the economic analysis calculating the FCF considering the production forecast calculated for scenario 2 in chapter 5.1.1 with the purpose of estimating the Net Present Value. The information provided in Tables 20, 21, and 22 will also be considered.

Table 26 shows the estimated net income for the entire project considering the oil price in an optimistic scenario and in a base scenario.

Total production [bbl]	**Net income [USD]**
	Positive scenario
54,830,920	$3,642,966,325

Total production [bbl]	**Net income [USD]**
	Base scenario
54,830,920	$2,374,727,145.20

Table 26 Net income for the entire project – scenario 2.

To calculate the Financial Cash Flow, equation 31 is used considering the estimated Net Present Value in Table 26, and the information provided in Table 21. Table 27 presents the results obtained considering the different oil price scenarios.

Net income [USD]	**Non - cash expenses [USD]**	**Inventory / Accounts Payable / Expenses [USD]**	**OCF** [USD]	**CAPEX** [USD]	**FCF** [USD]
Positive scenario					
$3,642,966,325	**$50,087,500**	**$986,956,560**	**$2,706,097,264.80**	**$35,749,897.00**	**$2,670,347,367.80**

Net income [USD]	**Non - cash expenses [USD]**	**Inventory / Accounts Payable / Expenses [USD]**	**OCF** [USD]	**CAPEX** [USD]	**FCF** [USD]
Base scenario					
$2,374,727,145.20	$50,087,500	$986,956,560	$1,437,858,085.20	$35,749,897.00	$1,402,108,188.20

Table 27 Financial Cash Flow – scenario 2.

Considering the information mentioned in Table 27 and using equations 28, 29, and 30, we proceed to calculate the other economic performance indicators that will be used to determine which of the two systems is more profitable. The economic indicators were calculated considering an initial investment of USD 50 million and a discount rate of 10%. Table 28 presents the results obtained. It is important to note that NPV will be used as an economic criterion to carry out the risk analysis.

NPV [USD]	**NPV [USD]**
Positive scenario	**Base scenario**
$1,660,948,243.38	$839,445,593.15
IRR [%]	**IRR [%]**
Positive scenario	**Base scenario**
728%	377%
PI [DI]	**PI [DI]**
Positive scenario	**Base scenario**
52.91	27.46

Table 28 Summary of economic performance indicators results - scenario 2.

On the other hand, as part of this analysis, a different economic criterion is analyzed that allows estimating the economic viability or not of drilling a multilateral well compared to a horizontal well. This criterion determines that, if the production relation between of a multilateral and a horizontal well is greater than the drilling costs relation, drilling a multilateral well is feasible. The result of the ratio $(ML\ cost/HW\ cost)$ allows selecting the best TAML Level option based on the depth at which the lateral is drilled, as shown in Table 9.

For this analysis, equation 32 and the information provided in the Tables 20, 23, and 25 are used.

$$\frac{54{,}830{,}920\ [bbl]}{19{,}230{,}262\ [bbl]} > \frac{10{,}749{,}897[USD]}{7{,}733{,}619\ [USD]} \tag{32}$$

$$2.9 > 1.4$$

ML / HW cost ratio is 1.4, which means that the efficiency of the horizontal and multilateral well are almost similar, still, drilling a multilateral well is economically feasible since the value of the ML / HW production ratio is greater than the ML / HW cost ratio, which indicates that the oil production of the multilateral well is high enough to justify to drill a ML, including the cost of the junction, this being a factor to be considered when making the decision to drill a multilateral well, however, others factors such as anisotropy, permeability, thickness of the zone, should also be considered to make a decision on what type of well to drill.

On the other hand, with the value obtained in the ML / HW cost ratio and taking into account that the formations to be drilled are approximately at a depth of 8,561 and 8,900 feet, it can be select between a TAML Level 3 or TAML Level 4 multilateral well. To determine the level that can be selected, the information provided in Table 9 was considered.

6.3. Risk Assessment

Applying the theory of risk analysis and a decision tree model to this research work, an option is proposed considering the different types of nodes which are associated with the main possible risks involved in the drilling and completion stages of a horizontal and multilateral wells in order to determine the best decision on the most optimal well system.

Next to each node, the expected monetary value (EMV) is specified, which is estimated in relation to the probability of occurrence of the different estimated risks. The best decision is the one with the highest EMV.

The probabilities assigned in this decision tree were estimated taking into account risk matrices and matrices of lessons learned from horizontal wells previously drilled and completed in the last 3 years in Ecuador. The judgment and experience of drilling engineers has also been taken into account.

The decision tree is structured in such a way that the analysis begins by dividing the quality of the reservoir in two groups: good reservoir / bad reservoir, according to the geological characteristics of the reservoir (porosity and permeability) as shown in Table 19. Along with each type of reservoir the probability of occurrence is detailed.

Reservoir quality based on geological features	***Occurrence probability***
Good reservoir *Sandstone / Limestone / Non-fractured* *Porosity:* 11% - 30% Permeability: 10 - 1,000 mD	65%
Bad reservoir *Dolomite / Fractured / Non-consolidated* *Porosity: 2%* - 12% Permeability: 1 - 10 mD	35%

Table 29 Probability of good reservoir and bad reservoir quality

Subsequently, three different scenarios in which drilling can be carried out are analyzed, as shown in Table 30; a normal scenario in which drilling proceeds without any problem maintaining the initially estimated costs (normal costs), a scenario in which unforeseen events or problems occur in the drilling process generating an increase in costs, (high costs) and a scenario where the drilling operation due to inconvenience cannot continue (failure). Along with each possible drilling scenario, the probability of occurrence is detailed depending on the quality of the reservoir.

Reservoir quality based on geological features	*Occurrence probability*			
	Multilateral well		*Horizontal well*	
	Good reservoir quality	*Bad reservoir quality*	*Good reservoir quality*	*Bad reservoir quality*
Normal costs	84%	9%	90%	12%
High costs* *Stuck pipe, borehole instability, loss of circulation, sever doglegs, key seats*	12%	83%	8%	82%
Fail *Among the main reasons, the following stand out: Failed fishing operation (irretrievable fish), collapsed wellbore, junk in the hole.*	4%	8%	2%	6%
* High costs are due to the different possible failures mentioned.				

Table 30 Possible drilling scenarios.

After the chance node that evaluates the possible drilling scenarios, it is evaluated whether the completion of the well was successful or failed, this being the last aspect to be analyzed in the decision tree.

The success / failure of drilling is not affected solely by the type of well to be drilled, it will largely depend on the geological characteristics and quality of the reservoir. Furthermore, the success / failure of completion will depend exclusively on the well system.

Each branch of the decision tree has a specific probability of occurrence depending on the established or predetermined conditions. To determine the monetary value to be expected at each of the terminal nodes, it will be estimated based on the current value of the node estimated in the economic analysis.

Regarding the costs detailed in the decision tree, they are structured from right to left, estimating a monetary value for each node terminal. In this risk analysis, the net present value calculated for each of the different well systems (horizontal well and multilateral well) will be used, considering the oil price of the positive scenario and a 10% discount (discount rate).

Table 31 shows the NPV for each of the systems, which will be assigned to the terminal nodes where the well was drilled and successfully completed in the "normal cost" scenarios.

	Base scenario [USD]
Net Present Value (Horizontal well)	$259,241,465
Net Present Value (Multilateral well)	$839,445,593

Table 31 NPV for the different well systems.

It should be clarified that, to quantify the expected monetary values of the terminal nodes in the cases where the well was drilled and successfully completed in the "high cost" scenarios, the net present value presented in Table 31 table is taken as the base considering that costs can increase between 5% and 10%. Table 32 shows the estimated values for the "high cost" scenario.

	Horizontal well [USD]	Multilateral well [USD]
Good reservoir quality		
__Completion cost (normal cost)	$259,241,465	$839,445,593
Completion cost (high cost)	$272,203,538	$881,417,873
Bad reservoir quality		
Completion cost (normal cost)	$259,241,465	$839,445,593
Completion cost (high cost)	$279,980,782	$923,390,152

Table 32 NPV for wells drilled and completed successfully**.**

On the other hand, Table 33 shows the costs where the well was drilled but could not be completed due to any operational problem. As a reference, the completion cost presented in Table 20 are taken considering that the cost can increase between 15% and 35% depending on the quality of the reservoir and the type of well.

	Horizontal well [USD]	Multilateral well [USD]
Good reservoir quality		
Completion cost (normal cost)	$494,500	$846,000
Completion cost (high cost)	$516,000	$902,400
Bad reservoir quality		
Completion cost (normal cost)	$533,200	$916,500
Completion cost (high cost)	$550,400	$951,750

Table 33 Costs for wells drilled but not completed.

To estimate the values of the “failure” drilling scenario, the drilling costs presented in Table 20 were taken as a reference considering an increase between 20% and 35% depending on the quality of the reservoir and the type of well. Table 34 shows the values obtained.

	Horizontal well [USD]	Multilateral well [USD]
Good reservoir quality		
Drilling cost	$5,538,540	$8,111,263
Bad reservoir quality		
Drilling cost	$6,000,085	$9,125,171

Table 34 Failure drilling costs.

The expected monetary value for the other nodes is calculated with equation number 34. The most effective choice to be made will be represented by the “leftmost” decision node with the highest expected monetary.

Figure 40 shows the decision tree proposed for this risk analysis, for its formulation the information provided in each of the tables in this chapter was considered.

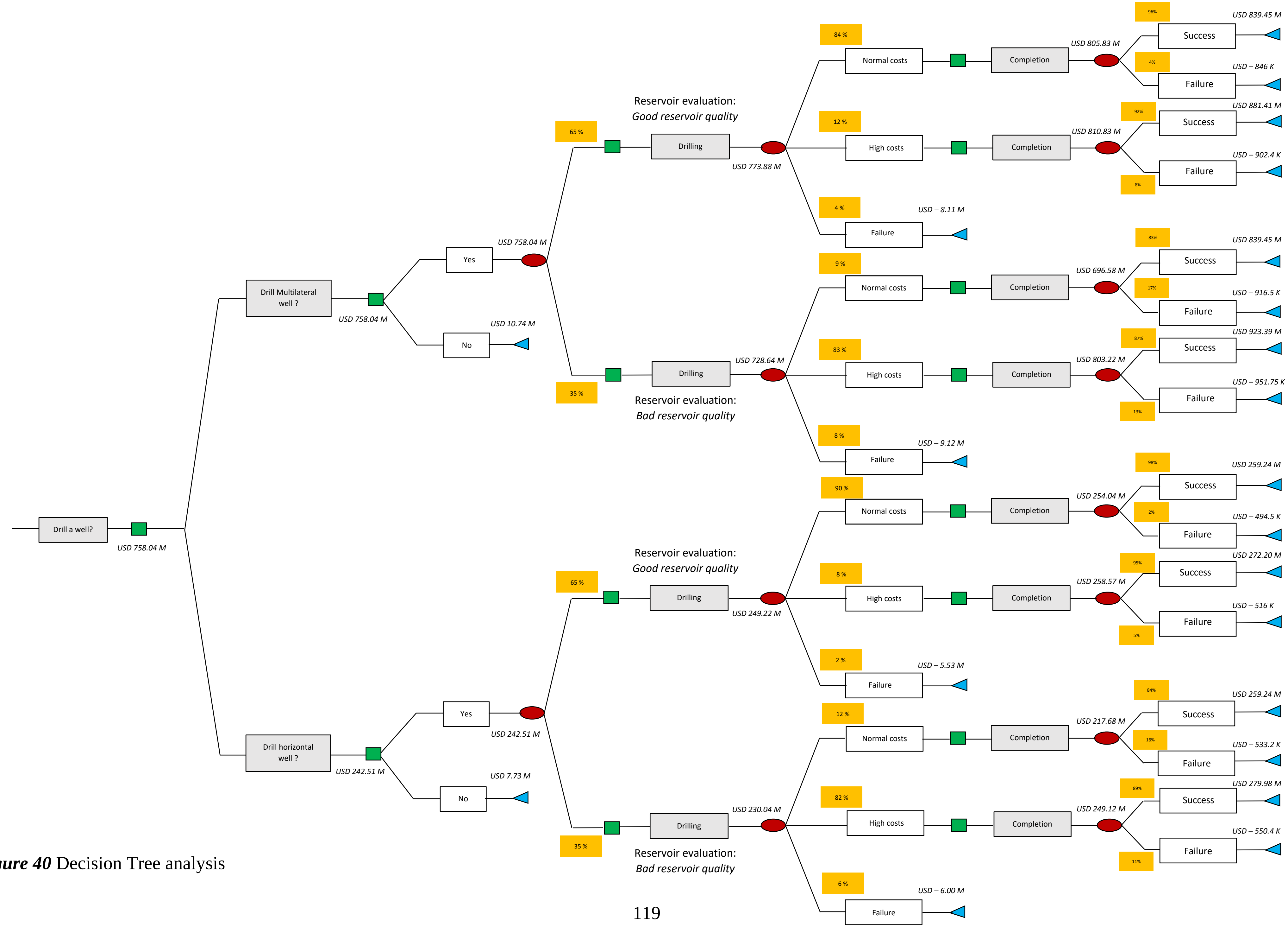


Figure 40 Decision Tree analysis

7. Summary and Discussion

The main objective of the technical analysis is to specifically focus on determining which of the two well systems can produce more oil. Therefore, from a technical point of view, considering the results obtained, it can be affirmed that the technology of multilateral wells has a significant advantage over a horizontal well. For the scenario outlined in this thesis, the production obtained through the drilling of the multilateral well exceeded the production of a horizontal well by 3 times, this being the main technical advantage of this technology. From the first year, to year 20 (last year of the project), the production of the multilateral well is higher than that of the horizontal well, which shows that the benefit of multilateral technology is constant over time. Figure 41shows the productions obtained in the different systems throughout the entire useful life of the project.

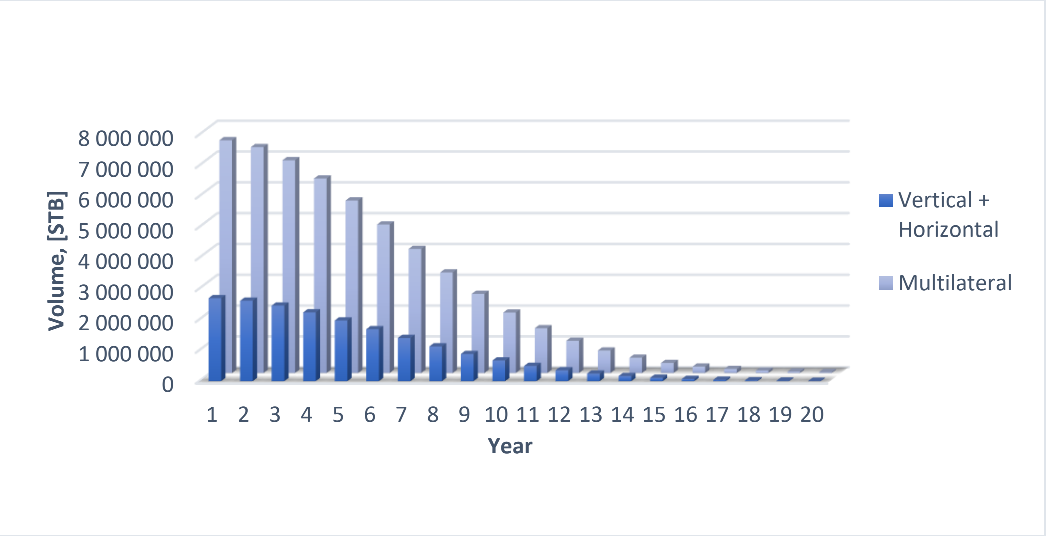


Figure 41 Annual oil production for the different scenarios

On the other hand, Figure 42 shows the total values of the production obtained over the 20 years of the project in each of the different types of wells, allowing us to have a more direct notion about which of the two systems is more advantageous since the technical point of view.

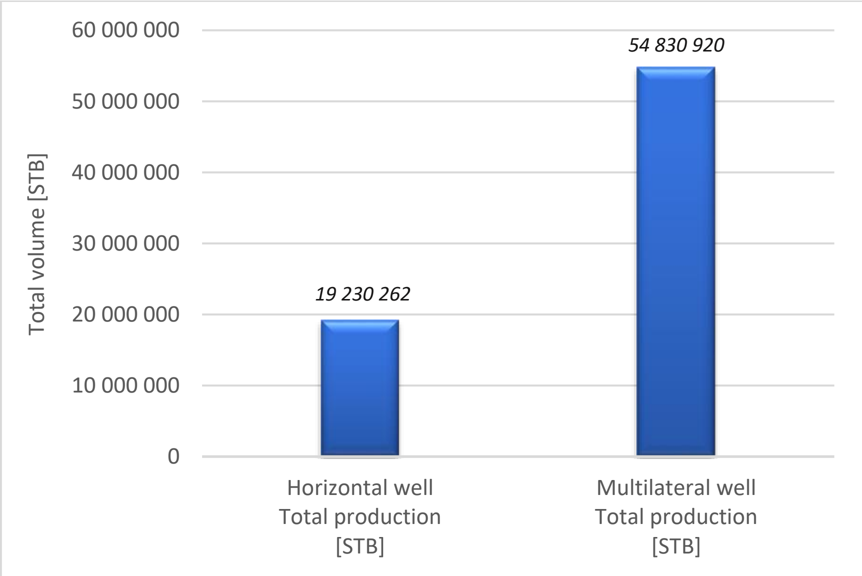


Figure 42 Total oil production for the different scenarios.

It is important to mention that since the production of the multilateral well is greater throughout the project, the accumulated production will also be greater than the accumulated production of the horizontal well, which represents an additional advantage.

The benefit of a multilateral well respect to the declination rate seems to be insignificant compared to declination rate of a horizontal well since the difference is minimal, however it is slightly higher, as shown in Figure 43. Despite having a higher rate of decline, production is still higher.

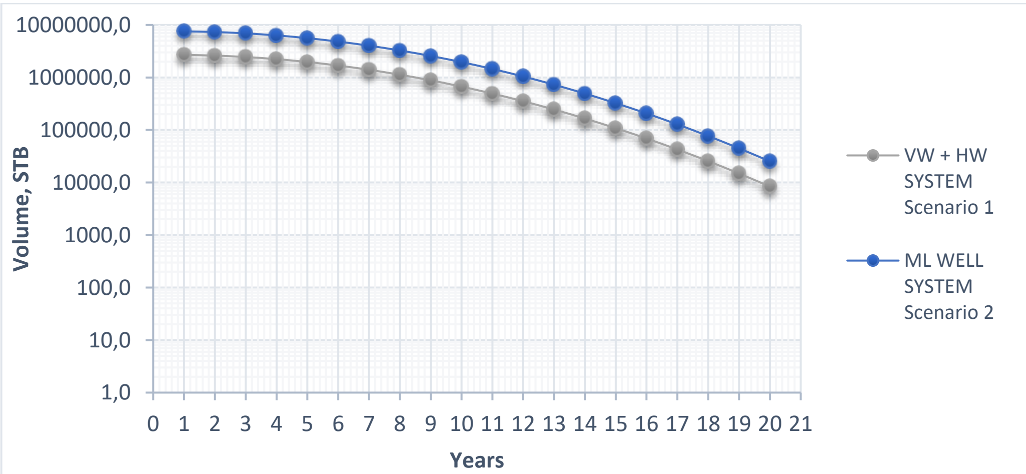


Figure 43 Decline rate comparison for the different scenarios.

On the other hand, from the economic point of view, the technology of multilateral wells is economically more profitable than a horizontal well, given the following reasons considering the economic indicators obtained:

- To equal or exceed the production obtained in the multilateral well in the scenario considered for this thesis, two horizontal wells must be drilled, this being the most expensive option. Figure 44 compares the drilling costs of the different types of wells, where it can be seen that the most economical option is to drill a single multilateral well instead of drilling two horizontal wells. It should be noted that the costs are strictly related to drilling, so the platform construction costs are not included.

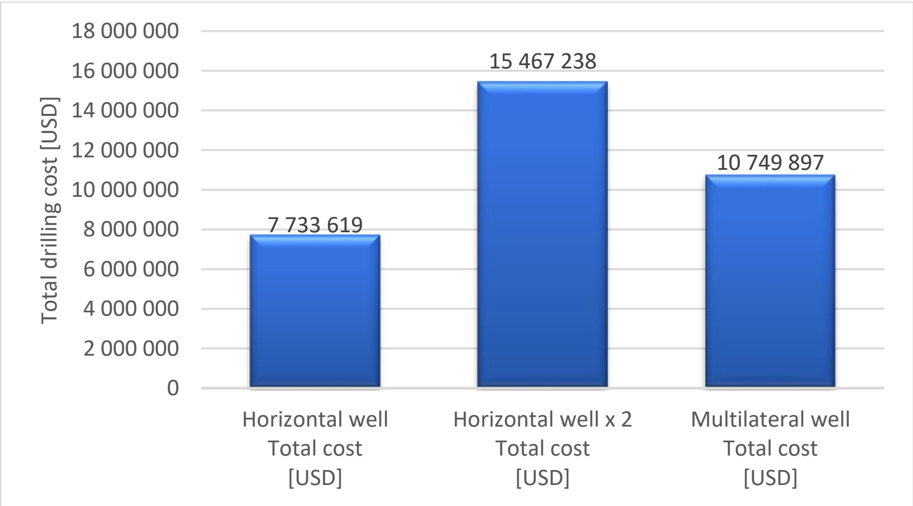


Figure 44 Total drilling costs for the different well systems.

- Based on the results obtained in the economic analysis, it can be said that the most profitable option, the one that will generate the greatest revenue stream, is a multilateral well. Taking as reference the results obtained in the base scenario with an oil price of 43.31 USD, the economic indicators for the multilateral well were more profitable than for a horizontal well. The net income generated by a multilateral well is 3 times greater than the net income generated by a horizontal well. Figure 45 shows the net income for each of the different types of wells.

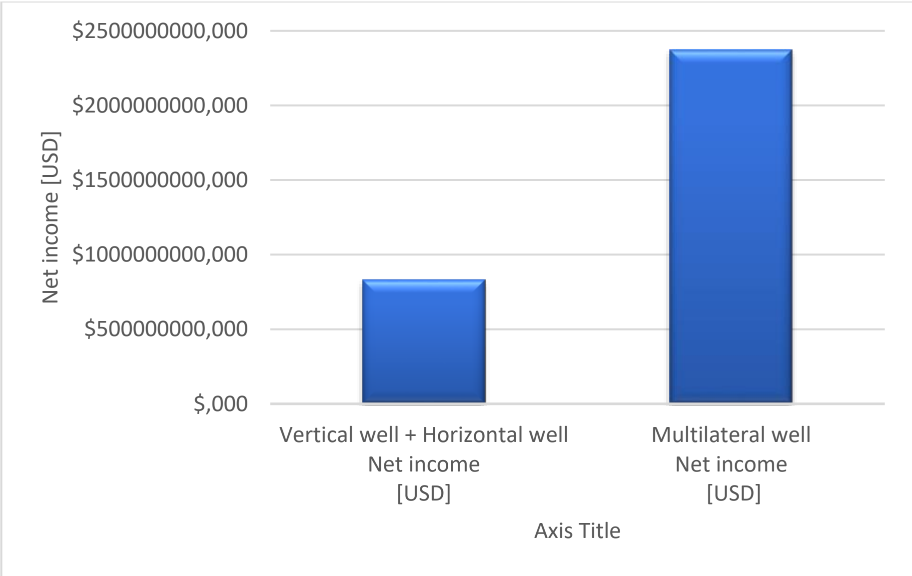


Figure 45 Net income obtained in the different well system.

- Regarding the financial indicator net present value, after accounting for the flows of future income, expenses and discounting the initial investment (USD 50,000,000), a greater viability was determined for the project to drill a multilateral well since its NPV is higher 3.28 times the NPV obtained for the horizontal well. However, in the last year of the multilateral well project, the expense flows are greater than the income flows, so a negative NPV is obtained, which means that from that year onwards, the project is no longer profitable. For the horizontal well from year 18 (18, 19 and 20), the project is no longer profitable because a negative NPV is obtained for those years. Taking into account the negative NPVs, it can be said that one of the advantages obtained with the multilateral technology is that it allowed obtaining 2 more years of profits than the horizontal well project. Figure 46 shows the NPV obtained for the types of wells, where you can see the years in which the NPV was negative.

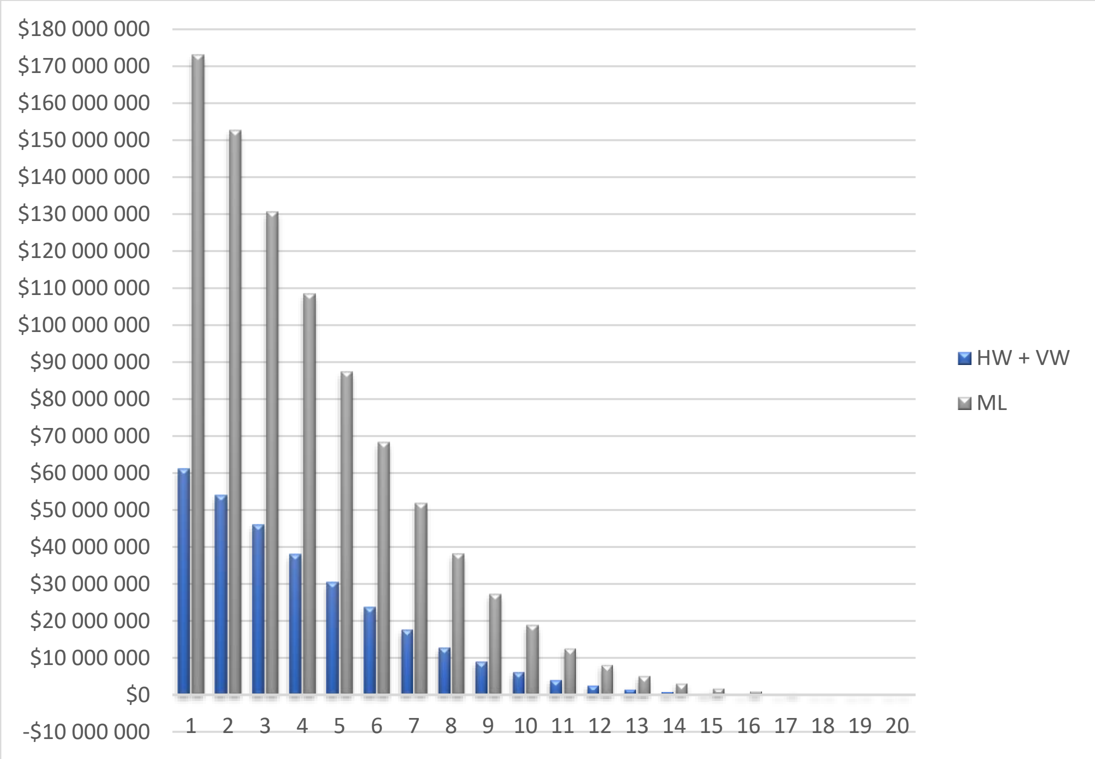


Figure 46 NPV obtained in the different well systems.

- Regarding the internal rate of return (IRR), the multilateral well (377%) exceeds the horizontal well (130%). Since the internal rate of return in both well systems exceeds the discount rate and the rate of return does not exceed IRR, it can be stated that both projects are profitable, however, the multilateral well is more profitable by having a higher IRR because it produces more oil, therefore, the income will be higher.

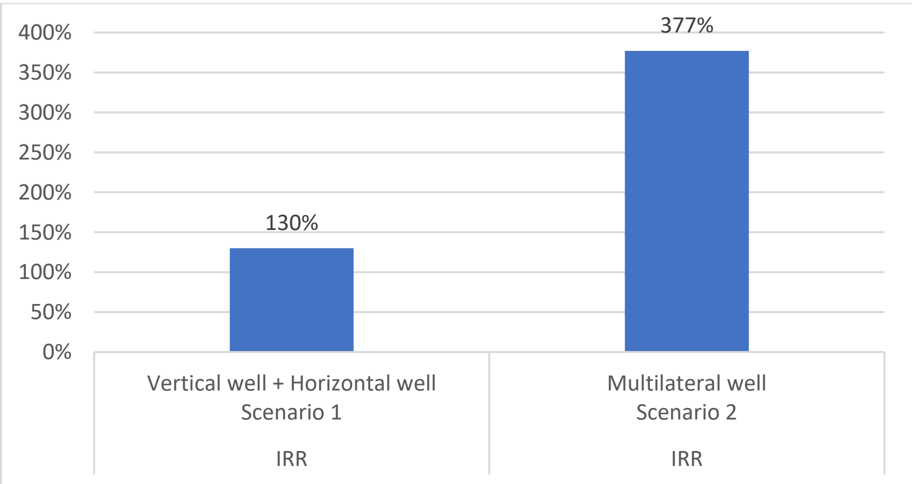


Figure 47 Profitability index of the different well systems.

- The profitability index of a horizontal well is 9.43, which means that for every dollar invested, the project will return nine and a half dollars. On the other hand, the profitability index of a multilateral well is 27.46, which means that the multilateral technology will return $ 2.91 more for each dollar invested than in the horizontal well drilling project. Figure 48 compares de profitability index for both scenarios.

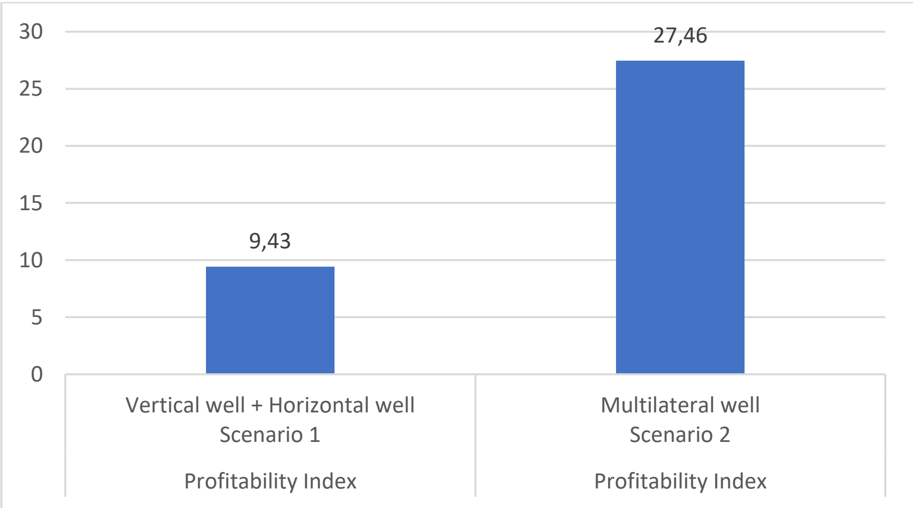


Figure 48 Profitability index of the different well systems.

As part of the economic analysis, a risk analysis was developed considering the main risks involved in the drilling and completion stage of a horizontal well and a multilateral well in order to determine which of the two systems is the most optimal. Based on the results obtained, it can be affirmed that the most optimal option for the scenario proposed in this thesis is to drill a multilateral well, despite the higher risks involved in the process; For this type of well, an EMV of USD 758.04 M was obtained, while the expected monetary value for a horizontal well is USD 242.51 M.

Figure 49 graphically represents the decision tree with the final results obtained in the risk analysis after having considered and evaluated the technical and economic aspects of the project.

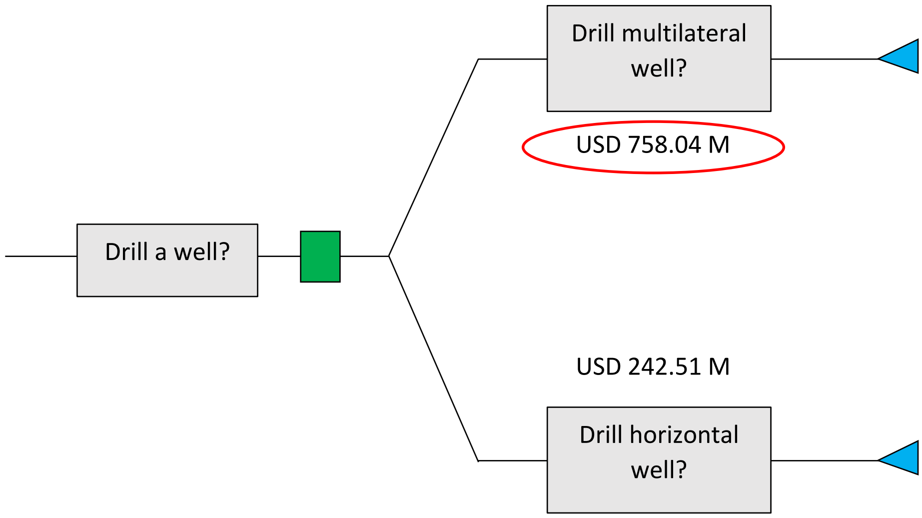


Figure 49 Decision tree analysis. EMV for each well system.

As part of the analysis, 10 field case study cases were also considered to analyze the operational and economic side of multilateral wells drilled around the world in order to determine the advantages / disadvantages provided by this technology. The results obtained will serve to support the conclusion of whether or not this technology should be implemented in Ecuador based on both technical and economic benefits.

From the general analysis carried out in the field case studies, the main results obtained are presented in the Table 35.

In general, it can be said that the results show that this technology is feasible and beneficial from both a technical and economic point of view.

CASE STUDY	FIELD NAME/ LOCATION/ REFERENCE	OPERATION AND CHALLENGES INVOLVED		MLT BENEFITS	TYPE OF BENEFIT	SUCCESS / FAILURE
		OPERATION	CHALLENGES			
1	(Deepwater Brazil) *TAML Level 5* (W. C. Hogg, 2005)	Drilling	➢ Maintain reservoir pressure through an injection system.	✓ A dual opposed wellbore multilateral injection system resulted in an important cost savings of 9.5 million U.S. dollars, which means 38% of the project costs. ✓ Only one injection tubing string was needed at the junction, saving 5 million U.S. dollars in the completion stage.	Economic	Success
2	Milne Point filed (United States) *TAML Level 5* (W. C. Hogg, 2005) (Herlugson et al., 1996)	Drilling	➢ Produce heavy oil	✓ Project costs reduced by 30%. ✓ By reducing the number of wells to be drilled, MLT optimized the artificial lifting mechanisms. ✓ It reduced from 22 to 5 the number of gravel pad platforms that had to be built for the development of the field. ✓ By constructing 5 platforms, the distance of the roads to be built in the field was reduced from 120 km to 16 km. ✓ Only one injection tubing string was needed at the junction,	Economic	Success

				saving 5 million U.S. dollars in the completion stage.		
3	East Rama field (Indonesia) *TAML Level 3* (Kovacs, 1992) (Tanjung et al., 2002)	Drilling	➢ Low production rates. ➢ Produce hydrocarbons from two different pay sands at the same time.	✓ A production of 6,500 bbl/day was achieved; 3.25 times higher than the production of two horizontal wells. ✓ Reduced the drilling time to 34 days.	Technical Economic	Success
4	Tern field (North Sea, UK) *TAML Level 4* (Roberts & Tolstyko, 1997) (Oberkircher, 2000) (Denney, 2000)	Drilling	➢ Produce oil from two reservoirs considered of low quality.	✓ One multilateral well produced 600 m3/day compared to the 400 m3/day that were planned to be produced by drilling two conventional wells. ✓ The well was drilled within the budgeted value and 7.5 days ahead of schedule. ✓ Drilling the TA-06 multilateral well reduced the CAPEX by 22%. ✓ An increase in Net Present Value of 12% was achieved.	Technical Economic	Success
5	Urucu field (Brazil) *TAML Level 4*	Drilling	➢ Drill several wells in a field located in a protected environmental zone.	✓ An oil production of 2,201 bbl/day was achieved, compared to 1,258 bbl/day produced by a horizontal well, which means	Technical Economic Environmental	Success

	(Campos et al., 2010) (Mendes et al., 2013)	Drilling	➢ Increase the production rate due to its excellent quality of oil. ➢ Protect the environment in the Brazilian Amazon.	that the production of the multilateral well was 1.75 times greater than the horizontal well. ✓ Drilling a multilateral well was 1.40 times more economical compared to the cost of drilling two horizontal wells ✓ From an ecological point of view, the use of multilateral technology considerably reduced the environmental impact by having a smaller footprint at the drilling site.		
6	Filanovskogo field (Caspain Sea) *TAML Level 5* (Valisevich et al., 2014) (Golenkin et al., 2017)	Drilling	➢ Produce oil from two formations located in the same Neokomian reservoir. ➢ Prevent gas coning. ➢ Anticline trap. ➢ Complex geology. ➢ Fractured reservoir.	✓ 2 intelligent multilateral TAML level 5 were drilled. ✓ Production increased between 20% and 60%, compared to nearby wells drilled in a conventional way. ✓ CAPEX was optimized through the drilling of 2 intelligent multilateral TAML level 5 wells. ✓ Faster production buildup was achieved. ✓ Higher productivity indices were reached.	Technical Economic	Success
7	Oseberg field (North Sea, Norway) *TAML Level 4*	Production Drilling	➢ Prevent early gas / water breakthrough.	✓ New technology was implemented and tested successfully in well 30-B.	Technical	3 multilateral wells drilled successfully 1 successful smart well

	(Rundgren et al., 2001) (Erlandsen, 2000)		➢ Monitor and measure pressure and temperature. ➢ Limited well slots in offshore platform.	✓ Reduced water cut by closing remotely a downhole sliding sleeve (horizontal well B-30 B). ✓ Increased oil rate production (horizontal well 30-B). ✓ Smart technology failed after being installed (wells: B-21 B, B-41 A, B-29 B). ✓ Three TAML Level 4 multilateral wells as response to a limited number of well slots in an offshore drilling platform. ✓ Thanks to the advantages provided by TAML Level 4, the multilateral well could be drilled and completed successfully without problems. ✓ TAML Level 4 allowed to perform several sidetracks on the laterals without affecting the junction.		
8	Snorre B field (North Sea, Norway) (Birkeland et al., 2002) (Kulkarni et al., 2007)	Production	➢ Prevent early gas / water breakthrough. ➢ Monitor and measure pressure and temperature. ➢ Zonal isolation	✓ Production rate increased ✓ 25% of installed sliding sleeves failed. ✓ 38.39% of installed pressure gauges failed. ✓ Prevented breakthrough	Technical Economic	Success

Table 35 Field case studies summary.

Regarding the analysis carried out on the field case studies, the key findings can be summarized as follows.

- Reduce CAPEX by decreasing the costs compared to drilling multiple single wells.
- Facilities costs optimized.
- Multilateral wells can also be drilled to inject gas or water to maintain or increase reservoir pressure.
- By reducing the numbers of wells to be drilled, MLT optimized the artificial lifting mechanisms.
- By drilling multilateral wells, the number of platforms to be built is considerably reduced.
- Reduces drilling time, so operating costs are also reduced.
- Multilateral well drilling is more cost-effective compared to drilling two horizontal wells.
- The use of multilateral technology considerably reduced the environmental impact by having a smaller footprint at the drilling site.
- Smart wells can reduce water cut successfully.

8. Conclusions

The main objective of this thesis was to determine if the technology of multilateral wells can be applied in Ecuador through a technical analysis, economic analysis, risk analysis and by conducting different filed case studies in which multilateral wells were drilled. Each analysis involves a comparison between a horizontal well and a multilateral well to determine the benefits that multilateral technology can provide.
Most of wells are horizontal and deviated

- Based on the results obtained from the technical analysis, it can be concluded that, through drilling a multilateral well, oil production can be increased by 2.85 times compared to the production obtained through the horizontal well system used in Ecuador where oil is produced simultaneously from two different sections through the same well. Therefore, a multilateral well has technical feasibility to be drilled in Ecuador.

- Based on the results obtained from the economic analysis, it can be concluded that the multilateral well is the most profitable option compared to the horizontal well. The highest NPV is achieved by drilling a ML, which is 3.23 times higher than the obtained by drilling a HW, on the other hand, the cumulative FCF for the multilateral well is 2.78 times higher than for the horizontal well. In terms of financial attractiveness, the profitability index of the multilateral well project is 2.91 times higher than the horizontal well project.

- As part of the economic analysis, the cost ratio multilateral well / horizontal well was calculated, which is 1.4. Considering the ratio obtained, the depth at which the multilateral well is to be drilled, and the information provided in Table 9, it can be concluded that both TAML Level 3 and TAML Level 4 junction qualify to be applied in the oil fields of Ecuador.

- The total cost of the multilateral well is 39% higher than the total cost of the horizontal well. Since the cost is less than 50%, the multilateral well is economically feasible.

- From the results obtained in the risk assessment, it can be concluded that drilling a multilateral well is the best decision to can be made, considering that it is the option that achieves the highest EMV, despite the fact that it is the option that presents more risks.

- In terms of information gathered from the field case studies, in 100% of the cases studied, the technology of multilateral wells proved to be successful in achieving both technical and economic benefits in the development of oil and gas fields.

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9. Appendix

A1 Criteria for selecting junction Level.

LEVEL	MAIN BORE	LATERAL	JUNCTION	CROSS FLOW CONTROL	FLUID INJECTION	PRODUCTION ISOLATION	SAND CONTROL	RE-ENTRY	PRESSURE DRAWDOWN	FRACTURED LATERAL	RADIUS
TAML LEVEL 1	hard rock	open hole	hard	no need	no need	no need	no need	no need	insignificant	could be	all types
TAML LEVEL 2	soft rock	open hole / slotted liner	hard	low need	no need	low need	low need	low need	insignificant	could be	short / medium / long
TAML LEVEL 3	soft rock	conventional liner / slotted liner / perforated liner	medium to weak	low need	no need	moderate need	moderate need	moderate need	low to moderate	could be	medium / long
TAML LEVEL 4	all type of rocks	cased hole	weak	moderate need	moderate need	all range	low need	moderate need to high need	heavy	can't be	medium / long
TAML LEVEL 5	soft rock	cased hole	weak	high need	high need	high need	high need	high need	heavy	can't be	medium / long
TAML LEVEL 6	all type of rocks	slotted liner	weak	high need	high need	high need	low need	high need	heavy	could be	short / medium / long

Table 36. Criteria for selecting junction TAML Level.
Obtained from (Garrouch et al., 2003).

A2 Input Data for Technical Analysis.

			LATERAL 1					LATERAL 2				
PARAMETERS	SYMBOL	UNITS	SEGMENT 1	SEGMENT 2	SEGMENT 3	SEGMENT 4	SEGMENT 5	SEGMENT 1	SEGMENT 2	SEGMENT 3	SEGMENT 4	SEGMENT 5
Horizontal permeability	kh	mD	250	250	250	250	250	900	900	900	900	900
Vertical permeability	kv	mD	25	25	25	25	25	90	90	90	90	90
Lateral (hole)diameter	Ø	inch	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Net vertical formation thickness	h	ft	80	80	80	80	80	60	60	60	60	60
Oil formation volume factor	Bo	bbl/STB	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Oil viscosity	μo	cP	5	5	5	5	5	5	5	5	5	5
Density	ρ	lb/ft^3	58	58	58	58	58	58	58	58	58	58
Wellbore radius	rw	ft	0.270	0.270	0.270	0.270	0.270	0.270	0.270	0.270	0.270	0.270
Total skin factor	S	DI	10	10	10	10	10	10	10	10	10	10
Reservoir pressure	Pre	psia	3,400	3,400	3,400	3,400	3,400	1,900	1,900	1,900	1,900	1,900
Flowing bottom-hole pressure	Pwf	psi	2900	2899.99	2900.0000	2900.0000	2899.0000	1751	1750.98	1750.9100	1750.7600	1750.50
Reservoir width	a	ft	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500
Reservoir length	b	ft	900	400	400	400	900	900	400	400	400	900
Length of Horizontal section	L	ft	400	400	400	400	400	400	400	400	400	400

Spreadsheet - Technical Analysis

PARAMETERS	SYMBOL	FORMULA	LATERAL 1 SEGMENT 1 RESULT	LATERAL 1 SEGMENT 2 RESULT	LATERAL 1 SEGMENT 3 RESULT	LATERAL 1 SEGMENT 4 RESULT	LATERAL 1 SEGMENT 5 RESULT
Anisotropy ratio	I_{ani}	$I_{ani} = \sqrt{\frac{k_h}{k_v}}$	3.162	3.162	3.162	3.162	3.162
Well location in y-axis	y_0	$y_0 = \frac{a}{2}$	750.00	750.00	750.00	750.00	750.00
Well location in y-axis	z_0	$z_0 = \frac{h}{2}$	40.00	40.00	40.00	40.00	40.00
x-coordinate of the midpoint of the well	x_{mid}	$x_{mid} = \frac{x_1 + x_2}{2}$	700.00	200.00	200.00	200.00	200.00
Shape factor	$\ln C_H$	$\ln C_H = 6.28 \frac{a}{I_{ani}h}\left[\frac{1}{3} - \frac{y_0}{a} + \left(\frac{y_0}{a}\right)^2\right] - \ln\left(\sin\frac{\pi z_0}{h}\right) - 0.5\ln\left[\left(\frac{a}{I_{ani}h}\right)\right] - 1.088$	1.13	1.13	1.13	1.13	1.13
Shape factor	C_H	$\ln C_H = 6.28 \frac{a}{h}\sqrt{\frac{k_z}{k_x}}\left[\frac{1}{3} - \frac{y_0}{a} + \left(\frac{y_0}{a}\right)^2\right] - \ln\left(\sin\frac{\pi z_0}{h}\right) - 0.5\ln\left[\left(\frac{a}{h}\sqrt{\frac{k_z}{k_x}}\right)\right] - 1.088$	1.13	1.13	1.13	1.13	1.13
If a > b	**TRUE**	$\frac{a}{\sqrt{k_y}} \geq 0.75\frac{b}{\sqrt{k_x}} > 0.75\frac{h}{\sqrt{k_z}}$	TRUE	TRUE	TRUE	TRUE	TRUE

$\frac{4x_{mid} + L}{2b} > 1$	**TRUE**	$\frac{4x_{mid} + L}{2b}$	1.78	1.50	1.50	1.50	0.67
$\frac{4x_{mid} - L}{2b} > 1$	**TRUE**	$\frac{4x_{mid} - L}{2b}$	1.33	0.50	0.50	0.50	0.22
$F\left(\frac{4x_{mid} + L}{2b}\right)$		$F\left(\frac{4x_{mid} + L}{2b}\right) = \left[2 - \frac{4x_{mid} + L}{2b}\right]\left[0.145 + \ln\left(2 - \frac{4x_{mid} + L}{2b}\right) - 0.137\left(2 - \frac{4x_{mid} + L}{2b}\right)^2\right]$	-0.304	-0.291	-0.291	-0.291	0.252
$F\left(\frac{4x_{mid} - L}{2b}\right)$		$F\left(\frac{4x_{mid} + L}{2b}\right) = \left[2 - \frac{4x_{mid} - L}{2b}\right]\left[0.145 + \ln\left(2 - \frac{4x_{mid} - L}{2b}\right) - 0.137\left(2 - \frac{4x_{mid} - L}{2b}\right)^2\right]$	-0.214	0.363	0.363	0.363	0.511
$\frac{4x_{mid} + L}{2b} \leq 1$	FALSE	$\frac{4x_{mid} + L}{2b}$	1.78	1.50	1.50	1.50	0.67
$\frac{4x_{mid} - L}{2b} \leq 1$	FALSE	$\frac{4x_{mid} - L}{2b}$	1.33	0.50	0.50	0.50	0.22
$F\left(\frac{4x_{mid} + L}{2b}\right)$		$F\left(\frac{4x_{mid} + L}{2b}\right) = -\left[\frac{4x_{mid} + L}{2b}\right]\left[0.145 + \ln\left(\frac{4x_{mid} + L}{2b}\right) - 0.137\left(\frac{4x_{mid} + L}{2b}\right)^2\right]$	-0.511	-0.363	-0.363	-0.363	0.214
$F\left(\frac{4x_{mid} - L}{2b}\right)$		$F\left(\frac{4x_{mid} + L}{2b}\right) = -\left[\frac{4x_{mid} - L}{2b}\right]\left[0.145 + \ln\left(\frac{4x_{mid} - L}{2b}\right) - 0.137\left(\frac{4x_{mid} - L}{2b}\right)^2\right]$	-0.252	0.291	0.291	0.291	0.304
$F\left(\frac{L}{2b}\right)$		$F\left(\frac{L}{2b}\right) = -\frac{L}{2b}\left[0,145 + \ln\left(\frac{L}{2b}\right) - 0,137\left(\frac{L}{2b}\right)^2\right]$	***0.304***	***0.291***	***0.291***	***0.291***	***0.304***

Partial penetration skin component x-y-z plane	P_{xyz}	$P_{xyz} = \left(\frac{b}{L} - 1\right)\left[\ln\frac{h}{r_w} + 0.25\ln\frac{k_x}{k_z} - \ln\left(\sin\frac{\pi z_0}{h}\right) - 1{,}84\right]$	***5.53***	***0.00***	***0.00***	***0.00***	***5.53***
Partial penetration skin component x-y plane	P'_{xy}	$P'_{xy} = \frac{2b^2}{Lh}\sqrt{\frac{k_z}{k_x}}\left\{F\left(\frac{L}{2b}\right) + 0.5\left[F\left(\frac{4x_{mid} + L}{2b}\right) - F\left(\frac{4x_{mid} - L}{2b}\right)\right]\right\}$	***4.14***	***0.00***	***0.00***	***0.00***	***4.14***
Partial penetration skin	S_R	$S_R = P_{xyz} + P'_{xy}$	***9.678***	***0.00***	***0.00***	***0.00***	***9.68***
Flow rate	***q***	$q_o = \frac{b\sqrt{k_y k_z}(\bar{P} - P_{wf})}{141.2\mu_o B_o\left(\ln\left(\frac{\sqrt{A}}{r_w}\right) + \ln(C_H) - 0.75 + S_r + \left(\frac{b}{L}\right)S\right)}$	***1683.5***	***1161.32***	***1161.29***	***1161.29***	***1687.91***
inflow rate into lateral	q_i	$q_i = \frac{q_o}{L}$	***4.21***	***2.90***	***2.90***	***2.90***	***4.22***
Average flow rate	$\bar{q}$	$\bar{q} = q + q_i\frac{L}{2}$	***841.8***	***580.7***	***580.6***	***580.6***	***843.5***
Reynolds number	***Re***	$N_{Re} = \frac{1.48 \times q \times \rho}{D \times \mu_o}$	***2223***	***1534***	***1534***	***1534***	***2228***
Wall Reynolds number (based on pipe inned diameter and equivalent inflow/outflow velocity)	$N_{Re.w}$	$N_{Re,w} = 0.096726\frac{q_i \times \rho}{\pi \times \mu_o}$	***1.50***	***1.04***	***1.04***	***1.04***	***1.51***
Fanning friction factor	f_f	$f_f = \frac{0.0791}{Re^{0.25}}$	***0.012***	***0.013***	***0.013***	***0.013***	***0.012***

Fanning friction factor (Laminar flow)	f_f	$f_f = \frac{16}{N_{re}}\left[1 + 0.04304 N_{Re,w}^{0.6142}\right]$	0.01	0.01	0.01	0.01	0.01
Fluid velocity	μ	$\mu = \frac{4 \times q}{\pi \times D^2}$	0.24	0.164	0.164	0.164	0.238
Pressure drop	Δp	$\Delta p = \frac{2 \times f_f \times \rho \times \mu^2 \times L_s}{g_c \times D} + \frac{8 \times \rho \times \mu \times q}{\pi \times g_c \times D^2}$	0.013	0.007	0.007	0.007	0.013

PARAMETERS	*SYMBOL*	*FORMULA*	*LATERAL 2 SEGMENT 1 RESULT*	*LATERAL 2 SEGMENT 2 RESULT*	*LATERAL 2 SEGMENT 3 RESULT*	*LATERAL 2 SEGMENT 4 RESULT*	*LATERAL 2 SEGMENT 5 RESULT*
Anisotropy ratio	I_{ani}	$I_{ani} = \sqrt{\frac{k_h}{k_v}}$	3.162	3.162	3.162	3.162	3.162
Well location in y-axis	z_0	$y_0 = \frac{a}{2}$	*750.00*	*750.00*	*750.00*	*750.00*	*750.00*
Well location in y-axis	y_0	$z_0 = \frac{h}{2}$	*30.00*	*30.00*	*30.00*	*30.00*	*30.00*
x-coordinate of the midpoint of the well	x_{mid}	$x_{mid} = \frac{x_1 + x_2}{2}$	700.00	200.00	200.00	200.00	200.00
Shape factor	$\ln C_H$	$\ln C_H = 6.28 \frac{a}{I_{ani} h}\left[\frac{1}{3} - \frac{y_0}{a} + \left(\frac{y_0}{a}\right)^2\right] - \ln\left(\sin\frac{\pi z_0}{h}\right) - 0.5 \ln\left[\left(\frac{a}{I_{ani} h}\right)\right] - 1.088$	2.016	2.016	2.016	2.016	2.016
Shape factor	C_H	$\ln C_H = 6.28 \frac{a}{h}\sqrt{\frac{k_z}{k_x}}\left[\frac{1}{3} - \frac{y_0}{a} + \left(\frac{y_0}{a}\right)^2\right] - \ln\left(\sin\frac{\pi z_0}{h}\right) - 0.5 \ln\left[\left(\frac{a}{h}\sqrt{\frac{k_z}{k_x}}\right)\right] - 1.088$	2.016	2.016	2.016	2.016	2.016
If a > b	TRUE	$\frac{a}{\sqrt{k_y}} \geq 0.75 \frac{b}{\sqrt{k_x}} > 0.75 \frac{h}{\sqrt{k_z}}$	TRUE	TRUE	TRUE	TRUE	TRUE
$\frac{4x_{mid} + L}{2b} > 1$	TRUE	$\frac{4x_{mid} + L}{2b}$	1.78	1.50	1.50	1.50	0.67

$\frac{4x_{mid} - L}{2b} > 1$	**TRUE**	$\frac{4x_{mid} - L}{2b}$	**1.33**	**0.50**	**0.50**	**0.50**	**0.22**
$F\left(\frac{4x_{mid} + L}{2b}\right)$		$F\left(\frac{4x_{mid} + L}{2b}\right) = \left[2 - \frac{4x_{mid} + L}{2b}\right]\left[0.145 + \ln\left(2 - \frac{4x_{mid} + L}{2b}\right) - 0.137\left(2 - \frac{4x_{mid} + L}{2b}\right)^2\right]$	**-0.304**	**-0.291**	**-0.291**	**-0.291**	**0.252**
$F\left(\frac{4x_{mid} - L}{2b}\right)$		$F\left(\frac{4x_{mid} + L}{2b}\right) = \left[2 - \frac{4x_{mid} - L}{2b}\right]\left[0.145 + \ln\left(2 - \frac{4x_{mid} - L}{2b}\right) - 0.137\left(2 - \frac{4x_{mid} - L}{2b}\right)^2\right]$	**-0.214**	**0.363**	**0.363**	**0.363**	**0.511**
$\frac{4x_{mid} + L}{2b} \leq 1$	FALSE	$\frac{4x_{mid} + L}{2b}$	**1.78**	**1.50**	**1.50**	**1.50**	**0.67**
$\frac{4x_{mid} - L}{2b} \leq 1$	FALSE	$\frac{4x_{mid} - L}{2b}$	**1.33**	**0.50**	**0.50**	**0.50**	**0.22**
$F\left(\frac{4x_{mid} + L}{2b}\right)$		$F\left(\frac{4x_{mid} + L}{2b}\right) = -\left[\frac{4x_{mid} + L}{2b}\right]\left[0.145 + \ln\left(\frac{4x_{mid} + L}{2b}\right) - 0.137\left(\frac{4x_{mid} + L}{2b}\right)^2\right]$	-0.511	-0.363	-0.363	-0.363	0.214
$F\left(\frac{4x_{mid} - L}{2b}\right)$		$F\left(\frac{4x_{mid} + L}{2b}\right) = -\left[\frac{4x_{mid} - L}{2b}\right]\left[0.145 + \ln\left(\frac{4x_{mid} - L}{2b}\right) - 0.137\left(\frac{4x_{mid} - L}{2b}\right)^2\right]$	-0.252	0.291	0.291	0.291	0.304
$F\left(\frac{L}{2b}\right)$		$F\left(\frac{L}{2b}\right) = -\frac{L}{2b}\left[0{,}145 + \ln\left(\frac{L}{2b}\right) - 0{,}137\left(\frac{L}{2b}\right)^2\right]$	0.304	0.291	0.291	0.291	0.304
Partial penetration skin component x-y-z plane	P_{xyz}	$P_{xyz} = \left(\frac{b}{L} - 1\right)\left[\ln\frac{h}{r_w} + 0.25\ln\frac{k_x}{k_z} - \ln\left(\sin\frac{\pi z_0}{h}\right) - 1{,}84\right]$	5.17	0.00	0.00	0.00	5.17

Partial penetration skin component x-y plane	P'_{xy}	$P'_{xy} = \frac{2b^2}{Lh}\sqrt{\frac{k_z}{k_x}}\left\{F\left(\frac{L}{2b}\right) + 0.5\left[F\left(\frac{4x_{mid}+L}{2b}\right) - F\left(\frac{4x_{mid}-L}{2b}\right)\right]\right\}$	5.526	0.00	0.00	0.00	5.53
Partial penetration skin	S_R	$S_R = P_{xyz} + P'_{xy}$	10.70	0.00	0.00	0.00	10.70
Flow rate	q	$q_o = \frac{b\sqrt{k_y k_z}\left(\overline{P} - P_{wf}\right)}{141.2\mu_o B_o\left(\ln\left(\frac{\sqrt{A}}{r_w}\right) + \ln(C_H) - 0.75 + S_r + \left(\frac{b}{L}\right)S\right)}$	1695.88	1195.10	1195.67	1196.87	1701.57
inflow rate into lateral	q_i	$q_i = \frac{q_o}{L}$	4.24	2.99	2.99	2.99	4.25
Average flow rate	$\bar{q}$	$\bar{q} = q + q_i\frac{L}{2}$	847.9	597.6	597.8	598.4	850.8
Reynolds number	Re	$N_{Re} = \frac{1.48 \times q \times \rho}{D \times \mu_o}$	2240	1578	1579	1581	2247
Wall Reynolds number (based on pipe inner diameter and equivalent inflow/outflow velocity)	$N_{Re.w}$	$N_{Re,w} = 0.096726\frac{q_i \times \rho}{\pi \times \mu_o}$	1.51	1.07	1.07	1.07	1.52
Fanning friction factor	f_f	$f_f = \frac{0.0791}{Re^{0.25}}$	0.011	0.013	0.013	0.013	0.011
Fanning friction factor (Laminar flow)		$f_f = \frac{16}{N_{re}}\left[1 + 0.04304N_{Re,w}^{0.6142}\right]$	0.01	0.01	0.01	0.01	0.01

f_f

Fanning friction factor (Turbulent flow)	f_f	$f_f = f_o\left[1 - 0.0153 N_{Re,w}^{0.3978}\right]$	0.011	0.012	0.012	0.012	0.011
Fluid velocity	μ	$\mu = \dfrac{4 \times q}{\pi \times D^2}$	0.239	0.169	0.169	0.169	0.240
Pressure drop	Δp	$\Delta p = \dfrac{2 \times f_f \times \rho \times \mu^2 \times L_s}{g_c \times D} + \dfrac{8 \times \rho \times \mu \times q}{\pi \times g_c \times D^2}$	0.014	0.007	0.007	0.007	0.014