UNIVERSIDADE ESTADUAL DE CAMPINAS
FACULDADE DE ENGENHARIA MECÂNICA
E INSTITUTO DE GEOCIÊNCIAS

OSCAR JULIAN PEÑA PIRANEQUE

USE OF SUBSEA TECHNOLOGIES FOR PRODUCED WATER MANAGEMENT IN OFFSHORE FIELDS USING INTEGRATED ASSET MODELING

USO DE TECNOLOGIAS SUBMARINAS PARA GERENCIAMENTO DA ÁGUA PRODUZIDA EM CAMPOS MARÍTIMOS USANDO MODELAGEM DE AVALIAÇÃO INTEGRADA

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Este exemplar corresponde à versão final da Dissertação defendida pelo aluno Oscar Julian Peña Piraneque e orientada pelo Prof. Dr. Denis José Schiozer.

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DISSERTAÇÃO DE MESTRADO ACADÊMICO

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A ata dessa defesa com as respectivas assinaturas dos membros encontra-se no processo de vida acadêmica do aluno.

Campinas, 31 de julho de 2018.

DEDICATION

To God, who is the witness of my successes and failures, the power inside me that motivates me to overcome the obstacles and give my best, who guides my life and provides me the happiest moments. God be glory everlasting.

To my mother, whom with her sacrifices, advice, help and words of encouragement, has always helped and given me the enough force to follow ahead, the person who I have fought with since child, my constant example and the being for who I have done everything in my life, the person I always want to see happy.

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"Many of life's failures are people who did not realize how close they were to success when they gave up".

Thomas Alva Edison.

RESUMO

PEÑA PIRANEQUE, Oscar Julian, *Uso de Tecnologias Submarinas para Gerenciamento da Água Produzida em Campos Marítimos usando Modelagem de Avaliação Integrada*, Campinas, Faculdade de Engenharia Mecânica, Universidade Estadual de Campinas, 2018. 124 p. Dissertação (Mestrado)

Este trabalho apresenta uma metodologia para avaliar a atratividade econômica de instalar tecnologias submarinas para separação água-óleo (A-O) e reinjeção de água produzida (*PWRI*) em campos marítimos usando a Modelagem de Avalição Integrada (*IAM*). A metodologia proposta foi testada no caso de referência UNISIM-I-D. Submodelos de reservatório, poços, rede de produção e modelagem econômica foram explicitamente acoplados e usados para obter as previsões de produção e fazer as avaliações econômicas incluindo as tecnologias submarinas. A modelagem do equipamento consiste em um separador submarino A-O, localizado na cabeça do poço produtor, e uma bomba submarina, a qual reinjeta diretamente a água separada na cabeça do poço injetor. Mesmo simplificado, o modelo permitiu a avaliação da implementação sob uma perspectiva de engenharia de reservatórios. A instalação destas tecnologias beneficia o meio ambiente, pois a água produzida pelos poços é usada para reinjeção, reduzindo a descarga ao mar. Separar a água da corrente de hidrocarbonetos tem o intuito de melhorar o fator de recuperação de óleo (FRO), liberar as capacidades de água e líquido da plataforma, antecipar a produção de óleo (associada a grandes quantidades de água produzida) e consequentemente aumentar o valor do projeto. Quantificar o valor destas novas tecnologias é uma tarefa complexa devido às incertezas e riscos envolvidos na instalação e operação. A avaliação econômica da implementação foi feita usando o valor da tecnologia (*VoT*), o qual permitiu estimar seus benefícios incrementais, mostrando melhoras significativas nos casos testados. Este trabalho interdisciplinar combina as áreas de engenharia de reservatórios, engenharia de produção e cálculos econômicos na construção de um modelo acoplado. Este modelo é então usado para analisar cenários de produção e configurações da rede de produção, o cálculo do potencial econômico das tecnologias submarinas para desenvolvimento de campo e dão suporte na tomada de decisão durante o gerenciamento do campo.

Palavras-Chave: Engenharia de Petróleo; Reservatórios (Simulação); Escoamento da Produção, Integração Numérica.

ABSTRACT

PEÑA PIRANEQUE, Oscar Julian, *Use of Subsea Technologies for Produced Water Management in Offshore Fields using Integrated Asset Modeling*, Campinas, Mechanical Engineering Faculty, University of Campinas, 2018. 124 p. Dissertation. (Masters)

This work presents a methodology to evaluate the economic attractiveness of installing technologies for oil-water (O-W) subsea separation and produced water re-injection (PWRI) in offshore fields, using Integrated Asset Modeling (IAM). The proposed methodology was tested in the benchmark case UNISIM-I-D. Submodels of reservoir, wells, production network and economic modeling were explicitly coupled and used to obtain production forecasts and to perform economic evaluations including the subsea technologies. The equipment modeling includes a subsea O-W separator located at the producer wellhead and a subsea pump, which directly re-injects the separated water into the injector wellhead. Although simplified, the model allowed the assessment of the implementation from a reservoir engineering perspective. The installation of these technologies benefits the environment because the produced water from the wells is used for re-injection, reducing discharge to the sea. Separating water from the hydrocarbon stream aims to improve the oil recovery factor (ORF), relieving the water-and-liquid capacity of the platform, anticipating oil production (associated with high amounts of produced water), and consequently, increasing the value of the project. Quantifying the value of these new technologies is a complex task because of the uncertainties and risks involved in installation and operation. The economic assessment of the implementation was performed using the value of technology (VoT), which estimates its incremental benefits, showing significant improvements in the cases tested. This interdisciplinary work combines areas of reservoir engineering, production engineering and economic calculations to build a coupled model. This model is then used to analyze production scenarios and production network configurations, calculate the economic potential of subsea technologies for field development, and support decision-making during field management.

Key Words: Petroleum Engineering; Reservoir (Simulation); Production Flow; Numerical Integration.

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LIST OF ABBREVIATIONS

Abbreviation	
AFFM	Amalgamated Full Field Model
BHP	Bottom-hole Pressure
BSW	Basic Sediment and Water
CAPEX	Capital Expenditures
CPIW	Injection Platform Capacity
CPL	Liquid Handling Capacity
CPO	Oil Handling Capacity
CPW	Water Handling Capacity
ESP	Electro Submersible Pump
FPSO	Floating Production, Storage, and Offloading Vessel
G-L	Gas-Liquid
GLR	Gas-to-Liquid Ratio
GOR	Gas Oil Ratio
GVF	Gas Volume Fraction
HFPT	Hydrocarbon Field Planning Tool
HSP	Hydraulic Submersible Pumps
IAM	Integrated Asset Modeling
IPR	Inflow Performance Relationship
Kr	Relative Permeability
Krg	Relative Permeability to Gas
L-L	Liquid-Liquid
MPI	Message Passing Open Interface
NPV	Net Present Value
OFVF	Oil Formation Volume Factor
OPEX	Operating Expenditures
ORF	Oil Recovery Factor
O-W	Oil-Water
O-W-G	Oil-Water-Gas
PVM	Parallel Virtual Machines

PWRI	Produced Water Re-Injection
ROY	Royalties
RF	Recovery Factor
RM	Representative Model
SCP	Subsea Centrifugal Pumping
SIL	Safety Integrity Level
Skid-SCP	Subsea Centrifugal Pumping in Skid Structure
SPM	Subsea Pumping Module
SSBI	Separation, Boosting and Injection
TB	Time of Breakthrough
THP	Tubing Head Pressure
TPC	Tubing Performance Curves
TSS	Total Suspended Solids
VASPS	Vertical Annular Separation and Pumping Systems
VISG	Gas Viscosity
VISO	Oil Viscosity
VLP	Vertical Lift Performance
VoT	Value of Technology
VoTmax	Maximum-Theoretical Value of Technology
W/O	Water in Oil
WCUT	Water Cut
WHP	Wellhead Pressure
WMR	Well Management Routine

LIST OF SYMBOLS

Symbol

B_o	Oil Volume Formation Factor
d	Pipeline Diameter
dL	Differential of Length
dP	Differential Pressure
$\partial/\partial t$	Differential with respect to Time
$\left.-\frac{dP}{dL}\right)_F$	Frictional Pressure Gradient
$\left.-\frac{dP}{dL}\right)_G$	Gravitational Pressure Gradient
$\left.-\frac{dP}{dL}\right)_A$	Accelerational Pressure Gradient
$\mathrm{Fr^2}_\mathrm{M}$	Froude Number
f_N	Normalized Friction Factor
f_{TP}	Two-phase Friction Factor
g	Gravity Acceleration
H_L	Liquid Holdup
$H_{L(0)}$	Liquid Holdup in Horizontal Conditions
h	Formation Thickness
J	Well Productivity Index
k	Absolute Permeability
k_{ro}	Oil Relative Permeability
L_1, L_2, L_3 and L_4	Lines for determining Flow Regimes in Beggs and Brill correlation (1973)
N_{LV}	Dimensionless Velocity Number for the Liquid Phase
$NPV_{base\ case}$	Net Present Value of Base Case
NPV_{10}	Net Present Value discounted by 10%
NPV_{with}	Net Present Value with Implementation
$NPV_{without}$	Net Present Value without Implementation
P	Pressure
P_e	External Boundary Pressure
p_{cell}	Cell Block Pressure

p_o	Pressure
p_{wf}	Well Sand-face Mid-perforations Pressure
Q	Flow Rate
Q_{gi}	Gas Lift Injection Rate
Q_l	Liquid Rate
q_o, Q_o	Oil Flow Rate
q_{op}	Balanced Rate of Main Fluid
Q_w	Water Flow Rate
Q_{wi}	Water Injection Rate
Q_{wir}	Re-injected Water Rate
Re	Reynolds Number
Re_{NS}	No-slip Reynolds Number
Rs	Gas Solubility
r_e	Drainage Area Radius
r_w	Well Radius
S	Skin Factor
S_o	Oil Saturation
$VoTmax$	Maximum-Theoretical Value of Technology
v_{M}	Mixture Velocity
v_{SG}	Superficial Velocity of the Gas Phase
v_{SL}	Superficial Velocity of the Liquid Phase
v_{TP}	Two-phase Fluid velocity
W_i	Cumulative Injected Water
Wi_p	Cumulative Injected Water to Each Producer
W_p	Cumulative Produced Water
Wp_{RES}	Cumulative Produced Water by the Reservoir

Greek letters

β_0	Independent Regression Coefficient
β_1	Regression Coefficient Dependent on Wp
β_2	Regression Coefficient Dependent on TB
∇	Gradient
∇p_o	Pressure Gradient of the Oil Phase

∇_z	Gradient of Height
ε	Pipeline Roughness
ϕ	Porosity
λ_L	No-slip Holdup
λ_o	Mobility of Oil
ρ_G	Density of the Gas Phase
ρ_L	Density of the Liquid Phase
ρ_{NS}	No-slip Density of the Mixture
ρ_o	Density of Oil
ρ_{SLIP}	Slip Density of the Mixture
ρ_{TP}	Two-phase Density
μ	Fluid Viscosity
μ_G	Viscosity of the Gas Phase
μ_L	Viscosity of the Liquid Phase
μ_{NS}	No-slip Viscosity of the Mixture
μ_o	Oil Viscosity
π	Pi Constant
ψ	Correction Factor for the Inclination Angle
σ	Interfacial Tension
Δt	Differential of Time
θ	Inclination Angle of the Pipe

CONTENT

1 INTRODUCTION

Water production is linked to oil production, especially in reservoirs with water drive as a primary production mechanism or those with water flooding. Mature fields may end up producing more than 90% water in the later stages of production. The production and treatment of large volumes of water during the exploitation of oil fields affect the operating expenditures (OPEX). This is especially true for offshore fields where operations are more complex and the discharge of produced water to the sea is controlled by environmental agencies.

Because of the high water production, engineers must propose new and suitable solutions for water management, extend the life of the reservoir, obtain the highest possible recovery factor (RF) and maximize the revenues of the project.

Oil-water (O-W) subsea separation and produced water re-injection (PWRI) technologies are a possible attractive solution to this water-production management problem. Facilities to process the output flow of the producer wells are installed on the seafloor. Flow from a producer well is separated into two streams: (1) hydrocarbons, produced at the platform, and (2) water, directly re-injected into the reservoir to sustain pressure or for secondary recovery purposes. The first global applications of these technologies have shown promising results including other benefits of subsea technologies besides reducing water production. According to several authors (Hannisdal et al., 2012; Pereira et al., 2012; and Hendricks et al., 2016), the application of these subsea installations improves the oil recovery factor (ORF), relieves the platform capacities to receive and produce more oil, avoids shutting wells with high water cut (WCUT), improves oil reserves and decreases back pressures in pipelines. It is also an environmentally attractive solution because water discharge to the sea is minimized.

Abelsson et al. (2016) found subsea technologies to be a cost-effective solution because of: (1) maximized efficiency of the whole system, leading to more economic use of equipment and (2) the careful planning of maintenance programs, which extends the lifetime of equipment. They also noted advantages of implementation that may provide substantial cost savings in CAPEX and OPEX. For instance, the maximum usage of pre-existing infrastructures in mature fields minimizes the modification of workstations. In new fields, optimized production strategies including these technologies may reduce the number of wells necessary for field development.

Albuquerque et al. (2013) cited subsea technologies as a solution for fields located in remote regions with insufficient oil flow rates to justify a dedicated platform. Bringedal et al. (1999) also concluded that these technologies could be a suitable alternative for flow assurance and multiphase production in remote deep-water fields.

For these reasons, Petrobras proposed revitalization of the Marlim, Voador, and Brava fields using subsea technologies. First project was implemented in the Marlim field and called as *Marlim SSAO 3-Phase Subsea Separation System* (Pereira et al., 2012). The contract for process technology qualification and system prototype supply was established from 2012 to 2013. After this stage, the operation and technology evaluation under field conditions was expected. According to them, depending on successful installation of this project, which was in the year 2011, Petrobras expects to extend these technologies to fields Marlim Sul, Albacora, and Golfinho. No additional information about the results of this application was encountered in the literature.

Although these systems seem to be a competitive solution, the implementation have to be evaluated using a methodology with a reservoir engineering approach that includes a dynamic modeling of the components to predict reservoir production and calculate their impacts on the economic indicators.

According to Silveira et al. (2016) and Rahmawati and Hoda (2015), the best method to assess the proposed subsea technologies is IAM as it quantifies the response of the reservoir by incorporating the production network and realistic models to simulate the fluid flow from the subsurface to the facilities, including the economic calculations. Silveira et al. (2016) and Abelsson et al. (2016) noted the importance of using IAM to analyze the feasibility of implementing these technologies as they allow for fast, accurate analyses of complex scenarios. IAM has already been applied to optimize hydrocarbon production in Brazilian offshore fields, such as Block-10 in the Campos Basin (Barroso et al., 2016).

Before modeling, it is important to identify which wells are suitable for the subsea technologies. De Figueiredo (2005) presented a candidate selection methodology using the parameters WCUT, cumulative water production (Wp), and allowable oil-in-water content in the reinjected water.

Quantifying the value of these technologies is a complex task. The evaluation should include commercialization costs while considering future revenue attributed to these technologies. Valuation assigns an expected value to a technology considering the inherent uncertainties and risks (Santos and Santiago, 2008). The most commonly used indicator in the oil and gas industry for making decisions about the value of technology (VoT) is net present value (NPV). De Naurois and Desalos (2001) calculated the potential value of technologies implemented in a project considering an approach based on the differential NPV. This parameter considered CAPEX, OPEX, and reserves-to-production ratio during the field life.

This work presents a methodology to evaluate the economic attractiveness of installing technologies for O-W subsea separation and produced water re-injection (PWRI) in offshore fields as a solution for water production management using IAM. The methodology was tested on the benchmark case UNISIM-I-D, with promising results.

This work covers reservoir engineering, production engineering and economic calculations to evaluate both the influence of subsea technologies on reservoir production and the economic attractiveness of the implementation.

In this work, the integrated model including subsea technologies was constructed based on work developed by Teixeira (2013). As the main process is the subsea separation of phases, the simple modeling includes some assumptions. The equipment included in the modeling is an O-W subsea separator located at the producer wellhead (to separate water from hydrocarbons) and a subsea pump located at the injector wellhead (to reinject the separated water). This integrated model is used to assess the economic attractiveness of the subsea technologies through varying the configurations, arrangements and times of implementation, as well as support making-decision processes during field management.

This approach allows a global perspective of the field to capture and better understand the complexity of interactions between the reservoir and the production network.

1.1 Motivation

The environmental legislation for the quality of water resulting from petroleum production discharged into the sea has become increasingly strict. While the increasing CAPEX and OPEX associated with water treatment and transport render conventional strategies for produced water management inefficient and economically unviable. One apparently good, cost-effective and environmentally friendly solution is the subsea separation technologies.

Subsea separation and PWRI technologies to manage produced water are being considered for recent discoveries of hydrocarbon reservoirs in the Brazilian pre-salt in deep and ultra-deep waters. Subsea systems have demonstrated other benefits, such as the revitalization and anticipation of production in deep water fields, reduction of CAPEX related to surface facilities, development of marginal fields or those restricted surface facilities. Furthermore, the application of these technologies could provide improvements in ORF and the value of projects when considering them in the production strategy proposal for the development of green fields.

The economic evaluation of these systems in the production network relies on capturing and understanding the complex interaction between the reservoir and installed components. Integrated models facilitate realistic forecasting of reservoir production and generate economic scenarios for evaluation.

1.2 Objective

The main objective of this work is to create a methodology to evaluate the economic attractiveness of installing technologies for oil-water (O-W) subsea separation and produced water re-injection (PWRI) in offshore fields as a solution for water production management using IAM.

1.3 Assumptions

The main assumptions made during the realization of this work are the following:

- Reservoir engineering point of view to analyze the impact on the reservoir production when the subsea systems are considered in the production network and estimation of economic attractiveness as a function of economic parameters.
- Reservoir characteristics and unknowns are represented by representative models (with a subset of possible scenarios considering a probabilistic approach). It includes petrophysical and geologic properties, PVT properties of the produced fluids (oil, water, and gas) and rock-fluid properties (relative-permeability curves).
- Water quality after separation is adequate for re-injection and avoids injectivity impairment in the reservoir, due to the presence of solids, oil-in-water content, sand or heavy metals. Nevertheless, in the simulation, flow resistance in producers and injectors was included because of the expected loss of injectivity and productivity during modeled processes (subsea separation and PWRI).
- Conditions of the project are assumed to be known, including the lifetime of the equipment to be installed, that is, there is no requirement of intervention for replacement and/or repairing. The equipment will work until the final date of simulation (date for field abandonment) without affecting performance.
- A deterministic approach was used to describe the economic scenarios.

- CAPEX for installation, OPEX associated with energy supply, pauses in production for installation and maintenance costs were not included during the calculation of NPV of the project considering the application of the technologies (NPV_{with}) and the new economic indicator called as Maximum Theoretical Value of Technology ($VoTmax$)

1.4 Work Organization

This work is composed of seven chapters. Chapter one is a brief introduction about the importance of using IAM for analyzing the economic attractiveness of implementing subsea systems for water management and revitalization of fields. Chapter two shows all the most important theoretical concepts involved in the research. Chapter 3 is the literature review, where the main works related to IAM and successful executions of subsea systems projects around the world are exhibited. The proposed methodology used to determine the economic attractiveness of the installation is described in Chapter 4 and the applications are contained in Chapter 5. Chapter 6 is composed of results and discussions of the work. Finally, in Chapter 7 the conclusions and recommendations for future studies are included.

2 THEORETICAL BACKGROUND

2.1 Subsea Processing

This process can be defined as any active treatment or conditioning of produced fluids, either on the seabed or down-hole, prior to reaching the host installation facility. Quite simply, it means locating the production equipment on the seafloor rather than on a fixed or floating platform (Marjohan, 2014). It consists of several processes carried out on the seabed to produce hydrocarbons without using surface facilities.

Marjohan (2014) also stated that subsea boosting has demonstrated benefits for increased hydrocarbon recovery through several commercial installations since 1995. Currently, with an increase in knowledge about subsea technologies, it is possible to make viable some projects and enhance RF by locating the equipment on the seafloor and by this way, relieving space in the platform. The incremental recovery has to be enough to cover the investments made in the installation of the subsea systems.

Originally, subsea processing was thought to be applicable only to offshore fields but currently is considered as a viable solution for harsh-environment fields, where treating produced fluids represents a high risk for personnel and to the environment itself or increases the operating expenditures (OPEX). It is an attractive solution for development and revitalization of marginal and mature fields (brown fields), where conventional production is not technical or economically viable.

The reason why there are not so many applications is technological challenges that influence the equipment design, turning difficult the processes of installation and operation. This technology is still in qualification stage of effectiveness and performance and still has technical challenges to overcome to exhibit its full potential. However, by increasing the knowledge in the area, acquiring more operating experience with successful application cases and knowing about its financial advantages; it will be possible to add value to its use and even, to think in the total substitution of surface facilities in offshore fields.

2.1.1 Design Parameters

They depend on the fluid properties, production features of the reservoir and project conditions. The equipment is designed for a specific case and to solve a certain problem. The most important parameters to be considered are:

- Linking distance and pressure drops: one of the most important parameters is the pressure drop due to distance. Sandy and Hasan (2016) stated that implementing the subsea technologies in great distances would increase production of hydrocarbon volumes because wells are producing at their ultimate production capacity. This effect is more evident in wells with greater tieback distances.

  The costs of flow lines can be around up to 30% of CAPEX in deep water projects (Wilson, 2013 and Hendricks et al., 2016). Each well has a particular response to the pressure drop; however, the location of subsea systems has to guarantee the maximum financial payback considering the distance to wells (the closest installed, the lowest the pressure drops), production rates and expenditures related to pipelines.
- Gas oil ratio (GOR): according to Marjohan, 2014, an excellent operating condition for multiphase pumping at low suction pressure is about 89-178 m3std gas/m3std oil. For higher values, it is necessary to install pumps with a higher inlet pressure or with a higher tolerance to the presence of gas.
- Water cut (WCUT): according to De Figueiredo (2005), the optimal stabilized WCUT for implementing this type of technologies is around 80-90% in mature field applications. Executing a project of subsea separation will reduce the amount of produced water, leading to decreased backpressures, and increasing hydrocarbon production and RF. Sandy and Hasan (2016) indicated that as higher the water content as higher RF and NPV.
- Production rates: one of the most important constraints when solving the production network is flow velocity. By installing subsea systems, a greater production is obtained compared with the natural flow. Plateau production stage is prolonged and higher volumes at the end of the productive life of the reservoir are recovered.

2.1.2 Components

The components can be combined to facilitate other subsequent processes. These processes can be grouped in two main branches: subsea boosting and subsea separation. Figure 2.1 shows the main components of subsea processing.

2.1.2.1 Subsea Boosting

It allows adding energy to the produced fluid directly on the seabed to overcome partially or completely the frictional and hydraulic pressure losses in the subsea flow lines and risers until coming to the offshore topside facility (Magi et al., 2012).

It comprises subsea gas compression, produced water re-injection (PWRI) or injection of disposal water, and single-phase and multiphase pumping:

- Subsea Gas Compression

  It is a growing technology considered as a solution for remote gas-offshore fields in deep waters. It is applicable for reservoirs with low pressure and temperature and used in produced gas re-injection for pressure maintenance.

  There are two types of compression: dry gas compression and wet gas compression. The first one uses a centrifugal compressor and scrubber upstream. The second compresses the untreated and multiphase gas stream without any previous procedure of liquid separation from the gas phase.

- PWRI or Disposition-Water Injection

  It consists of using subsea equipment for seawater injection or PWRI into the reservoir for pressure support or in the case of injection of disposal water, to inject produced water into a non-productive zone with good storage features (disposal formation). PWRI is a better strategy for water management because it reduces the pollution of seawater by avoiding the discharge to the sea and eliminating the requirement of water treatment at the surface. For this carrying out successfully, it is necessary an effective separation of water from the hydrocarbons on the seabed, that is, the installed separation vessel be as efficient enough to provide a high water quality for injection into the formation. By this way, it is possible to avoid sudden formation damage and injectivity impairment due to the presence of solids, sand or high oil-in-water content in the water used for injection.

- Single-Phase and Multiphase Pumping

  Good option for subsea oil reservoirs with not enough pressure for producing at high flow rates or not flowing at all. They are applicable in deep and ultra-deep-water fields. Depending on the pumped fluid, they can be single-phase for produced water re-injection or multiphase for oil and gas pumping to the platform.

  For avoiding as maximum as possible the pressure drops in the pipeline and taking advantage of the provided pressure, they are typically located as near as possible the wellheads or manifolds.

  In spite of there is more experience related to single-phase pumps because they provide a higher reliability due to the discharge pressures, nowadays there are new multiphase pumping technologies that permit pumping fluids with up to 100% of gas volume fraction (GVF) with high delivering pressures in heavy-duty applications.

2.1.2.2 Subsea Separation

Although the advantages of subsea separation are recognized, it is less frequently used due to being considered as a risky alternative with implications in CAPEX. To consider the implementation, it is necessary an analysis that takes into account the global impacts of the technology and not only the initial investments and the comparison of the production rates before and after the installation.

According to the purpose of the separation on the seafloor, it could be liquid-liquid (L-L) to dehydrate the hydrocarbon stream, or gas-liquid (G-L) to degas and de-pressurize the liquid current.

- Liquid-liquid separation (L-L Separation)

  It consists of water-oil separation. Separated oil flows until the host facility and separated water can be used in re-injection for pressure maintenance or being disposed of in non-productive formations.

- Gas-liquid separation (G-L Separation)

  It comprises separation of the gas phase from the liquid stream on the seabed. Separated gas flows through a dedicated pipeline and liquid is boosted separately.

  The main purpose is flow assurance by avoiding the formation of hydrates in reservoirs with low temperatures, high pressures, and high GOR. By this way, costs related to the insulation of pipeline and inhibitors are reduced. As well as, it permits a smoother flow in risers, the elimination of slug catchers and lower compression duties.

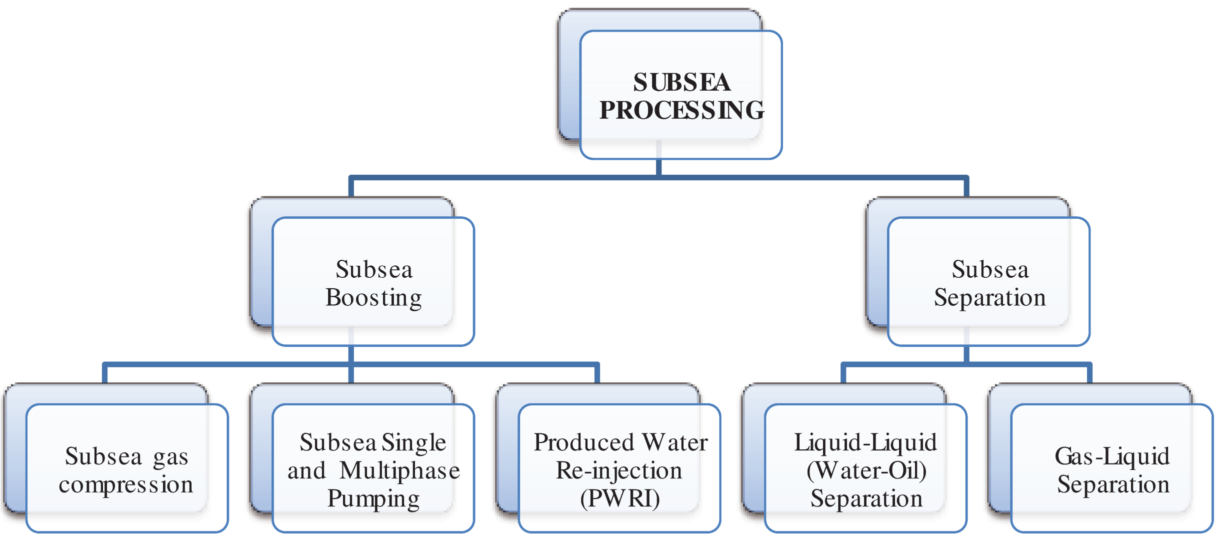

Figure 2.1: Main components of subsea processing (Modified from Karra et al., 2010)

2.1.3 Advantages

Multiple advantages have been listed when installing subsea systems, in both green and brown fields. The most outstanding are:

- Saving space in platform and relieving platform capacities to handle oil and water
- Saving costs related to investment in platform capacities or in some cases, total substitution of platforms
- Relatively low cost of investment: savings in capital expenditures (CAPEX) and OPEX and pay-back in months or years
- Competitive in terms of net present value (NPV) compared to conventional artificial lift systems (e.g., gas lift)
- Accelerating the production: additional energy will permit accelerating the hydrocarbon production in wells with natural lift flow and prolonging the plateau production
- Increase hydrocarbon recovery
- Debottlenecking the system and optimization of processes
- Flow assurance: reduction of slugging, the formation of paraffin, scales, asphaltene, etc., and reduction of chemicals for treatment
- Permit the access to remote fields: ideal inaccessible locations and applicable in projects with great linking distances
- Flexible operation and applicable in single-well or multiple well cases
- Depending on the application, easy installation with removable internals, compact technology with easy intervention and substitution
- Lowering the wellhead pressure (WHP) and bottom-hole pressure (BHP), increasing the differential pressure (dP) between the reservoir and the bottom-hole to increase hydrocarbon production. In Figure 2.2 is shown schematically the incremental recovery factor (RF) due to the decreasing in BHP and WHP

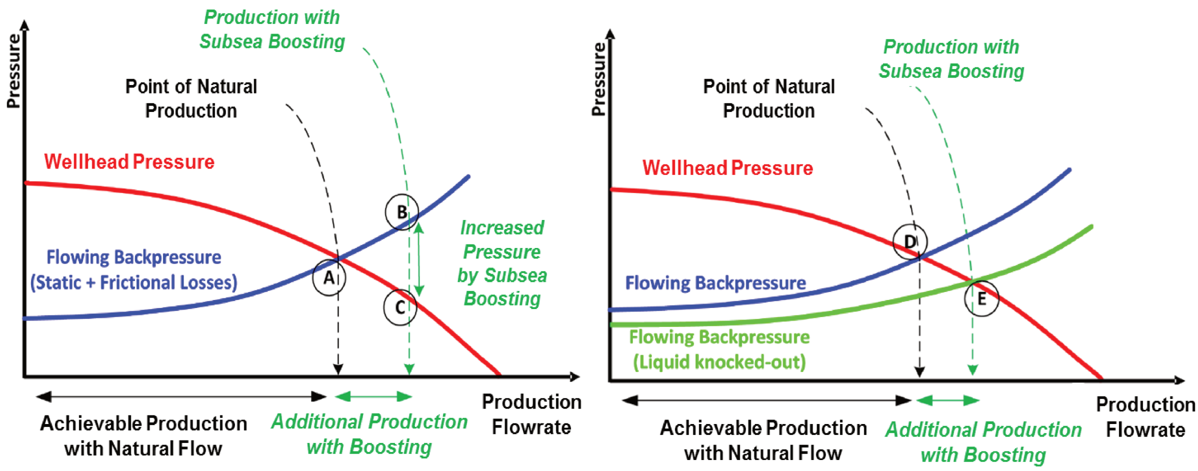

Figure 2.2: Incremental recovery due to the implementation of subsea processing (Sandy and Hasan, 2016)

2.1.4 Limitations

Main limitations of these technologies are related to the lack of knowledge. Being an unconventional hardware, manufacturing and installation processes can be expensive. As well as, operating complexity influences over the decision analysis process. It is required a detailed design of all components in the system and a well-thought production strategy considering these technologies for taking advantage of their multiple benefits.

2.2 Oil-Water Subsea Separation and Produced Water Re-Injection

2.2.1 Components

As seen before, subsea processing components are combined to ensure the success of a certain process carried out on the seabed. In the case of PWRI, several components are required to guarantee an effective injection into the reservoir or into the disposal formation.

2.2.1.1 Pumps

Subsea pumps are generally considered the most mature item of subsea processing technology, which has driven subsea pumping to become the largest number of installed projects, compared to other subsea processing solutions such as separation or compression (Hendricks et al., 2016).

The most used pumps in this kind of application are:

- Piston type
- Twin-screw

- Helico-axial
- Submersible caisson type
- Counter-rotating axial flow
- Linear piston/linear electric motor
- Multistage centrifugal/hydraulic turbine drive
- Multistage centrifugal/electric motor drive
- Diaphragm
- Liquid piston
- Jet pump
- Moineau screw/hydraulic turbine drive
- Rotary ram-slurry pump
- Double-acting piston pump

Most of the pumps are provided with an electrical rotor and based on kinetic energy to increase the pressure with a diffuser. Multiphase pumps permit the operation at high GVF (around 95-100% in heavy-duty implementations) and high solid content. Some of them are provided with a mixer that homogenizes the flow and avoids the formation of slugs.

The most challenging condition these pumps have to overcome is the pressure differential. Some high differential pumps provide up to 60 bar and in some special cases, up to 150 bar; still being economically and technically attractive.

Other challenges besides the pressure requirement and gas tolerance are boosting of viscous heavy oil, deep-water environments, long tiebacks distances, decreasing total power consumption, the requirement of less frequent maintenance, control of the process and guarantee the flow assurance.

All internals susceptible to damage and wear are contained into a casing designed for high-pressure applications (from 34 to 1034 psig for ultra-deep waters) and are removable and replaceable.

2.2.1.2 Separator

Subsea boosting is economically possible with the utilization of a subsea separator, which reduces GVF and enhances the performance of single and multiphase pumps.

The vessel can be horizontal (typically for oil-water separation) or vertical (for G-L separation), based on gravitational force or cyclonic, depending on the project. In fields with high sand production, separators are provided with sand removal internals or jetting-flushing devices. Compact technologies are desirable looking for lighter equipment and easier installation.

The most common subsea separators according to Beran et al. (1993) are the following:

- 2-phase, 1-stage, single deep vertical vessel with electro submersible pump (ESP)
- 2-phase, 1-stage, triple shallow vertical vessels, with gas driven pumping
- 2-phase, 1-stage, single horizontal vessel, with electric drive pump
- 3-phase, 2-stage, triple horizontal vessel, with electric drive centrifugal pump
- 2-phase, 1-stage, single spherical vessel, with electric drive centrifugal pump and gas compression

The main challenges that design has to overcome are tight water-in-oil (W/O) emulsions, foaming, precipitation of heavy components of oil, minimizing the liquid carry over and gas carry under, managing solids and sand, resistance to high hydrostatic pressures and mechanical integrity. Components susceptible to failure are retrievable or easily substituted, being able to handle variable gas-to-liquid ratios (GLR) and ensuring an effective separation of phases. At the same time, it has to be a cost-effective solution and efficient in terms of energy.

Common applications admit up to 500 ppm oil-in-water content for re-injection. In susceptible-to-plugging formations or with a higher requirement of water quality: up to 25-40 ppm oil-in-water content and 10 ppm of total suspended solids (TSS); as defined in the project for executing a 3-Phase Subsea Separation System in Marlim field, Petrobras (Pereira et al., 2012).

2.2.1.3 Desander Module

This module is installed after the subsea separator, at the outlet of water and sand. It is in charge of sand removal before pumping the injection water to the injector wellhead. It is located there because the sand elimination from the water stream permits decreasing pump wear, increasing the lifetime of the equipment and avoiding injectivity impairment due to the sand movement to the formation.

Sand removed can be re-combined with oil and boosted to surface for disposition topsides. Another technique is the injection into a disposal formation: the sand is removed from the bottom of the separator and accumulated in the desander, to be transported with a jet type pump and sent to the injection stream for disposition.

The desander module works without any interruption of production and in some special specifications of high sand production, such as the Tordis Project, it can manage up to 500 Kg per day of sand (Lim and Gruehagen, 2009).

2.2.1.4 Water Injection Pump

Normally, a single-phase pump provides enough pressure to separated water from the separator to be injected into the reservoir or the disposal formation. The pumping speed is set according to the water level in the separator and normally operates at the maximum speed and capacity to minimize the amount of water boosted to the platform.

2.2.1.5 Choke Valve

This valve is installed before the injector wellhead that introduces a variable flow resistance to the water-injection pump to improve the stability of the injection flow. It provides a better control of the amount of water being injected into the reservoir when sudden injectivity impairment appears, avoiding operating the injection pump at low velocities, which decreases efficiency.

According to Beliakova et al. (2000), choke valves are better modeled as a rate constraint for flow control and not by using full hydraulic models because of the simplicity in the resolution of the production network.

2.2.1.6 Energy Suppliers and Remote Control

A subsea cable or electrical connections, sensors can provide the required energy for functioning and controls are self-contained in a casing. Other modern technologies use optical fibers because of transfer speed and coverage distance. Other devices are:

- Control system: remote control from platform or control room of the floating production, storage, and offloading vessel (FPSO). The most common monitored parameters by this system are suction and discharge pressure of the pumps, system temperature, liquid level in the separator, energy consumption, and current in motors.
- Safety integrity level (SIL): to shut down the pumps in case of sudden pressurization of the subsea system
- Variable frequency drive
- Transformer

2.2.1.7 Water Quality Monitoring

Water quality monitoring of produced water being injected into the reservoir is one of the most critical parameters in offshore fields. Water to be injected into the reservoir has to accomplish some quality requirements for avoiding formation injectivity impairment; they are TSS, oil-in-water content, heavy metal content, inorganic material content, size of oil droplets, the capacity of the droplet to transport solids, etc.

On the other hand, if water is going to be discharged to the sea, the environmental regulations are stricter and additional parameters to be considered are:

- Hydrocarbon content: oil, grease and dissolved organic composites
- Salts: chlorides, calcium sulfides, sodium, and magnesium
- Heavy metals: chrome, iron, nickel, and plumb
- Radioactive nucleus: high levels of natural radioactive components
- Production chemicals

For accomplishing these requirements, monitoring sensors are installed before the discharge to the sea or immediately after the water separator outlet. Current measurement technologies have applications for deep-water environments with a useful life of about 20 years. They can be removable and installed using remotely operated vehicles.

2.2.2 Separation and Water Re-Injection Process

Typical process of subsea O-W separation and PWRI is illustrated in Figure 2.3 and summarized in the following steps:

1. The production stream from the wellhead (single-well) or from manifolds (multiple wells) is sent to the separator, which is provided with a cyclonical inlet.
2. Gas separation from the liquid and routed to the bypass line outside the separator.
3. Oil, water, and sand are separated into the separator.
4. At the end of the separator, the gas is sent back and mixed with the oil in the combined liquid-gas outlet.
5. Multiphase boosting (oil and gas mainly) to the platform.
6. Water and sand from the bottom of the separator are sent to the desander module, separating water and sand into two streams. In the case of water disposition, sand is sent with a jetting pump to the water injection stream. This process helps avoiding wearing in the single-phase pump.

7. The separated water is boosted using a single-phase water pump and injected into the reservoir for pressure support. In the case of water disposition, sand from the de-sander module is mixed with separated water at the pump outlet to be disposed into a formation.

Some differences can be noted, depending on the features and configurations for each project, such as:

- Dedicated pipeline for free flow of separated gas, depressurizing effectively the subsea system
- Bypass line when high sand production is expected (e.g., during starting the wells and jetting interventions for cleaning)
- Re-circulation of liquids for a better separation
- Installation of water quality sensors before the choke valve

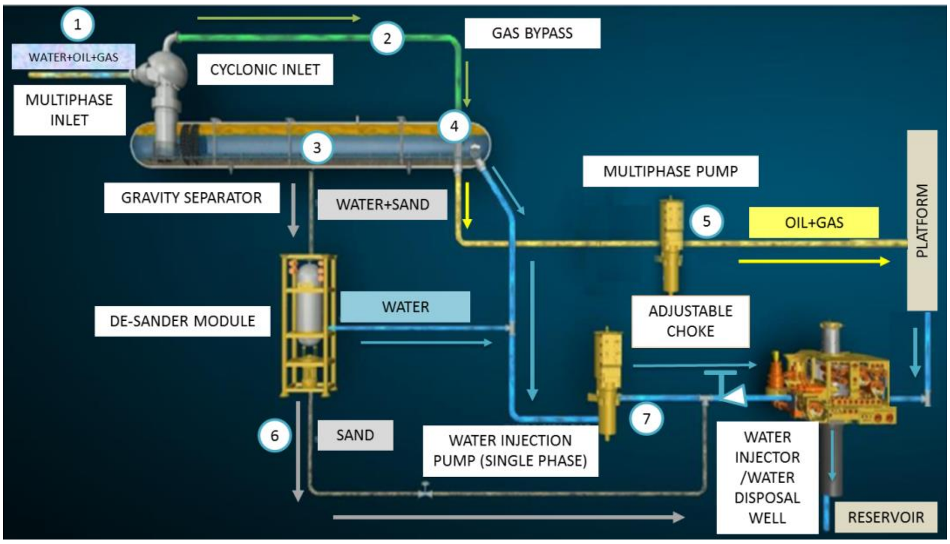

Figure 2.3: Subsea separation and water re-injection process (Modified from Hendricks et al., 2016)

2.2.3 Benefits

- Debottlenecking the production network by decreasing the amount of water sent to the surface
- Reduction of backpressures in the system and pressure losses due to friction in multiphase pipelines
- Increased efficiency in pumps and compressors
- Easier, faster and more effective treatment of streams of fluids

- Elimination of new constructions onboard, reduction of required space and increased water handling platform capacity
- Increased oil capacity topsides and well flow rates
- Increase RF
- Minimizing CAPEX and OPEX
- Reduction in size of production pipelines and risers
- Reduction of maintenance requirements and intervention costs
- Increasing NPV of the project and making viable other projects that were initially considered exploited with conventional artificial lift systems
- Applicable to harsh and deep environments, long tiebacks distances, low-pressure reservoirs and water injection projects with high discharge pressure requirements
- Excellent alternative for production strategy in green fields and flexibility in integration to the existent infrastructure in brown fields
- Flow assurance: reduction of hydrate formation risk, fewer expenditures in hydrates inhibitors, reduction of slugs and scales
- Environmental friendly alternative by avoiding water discharge to the sea

2.3 New Equipment and Technologies for O-W Subsea Separation

These kinds of separators are much smaller than conventional vessels (based on large volume vessels, gravitational separation and retention time) and represent an attractive and cost-effective alternative to be applied in deep water projects. They are considered as the next generation of deep-water subsea separation systems (Hannisdal et al., 2012).

The problems of using large vessels for subsea separation are mainly economic. Large devices impact on the overall cost of a subsea station: from the fabrication to installation in-situ. Hannisdal et al. (2012) established that the design of these devices is less flexible and requires more frequent maintenance compared with compact versions and the response time during flow fluctuation is bigger.

The selection of this type of separators depends on performance requirements, economic considerations and thinking of reducing the complexity of installation and operation.

Their main limitations are related to size reduction, separation effectiveness and capability of handling sudden flow fluctuations. By reducing the superficial area for separation of phases, the risk of non-conformance with the separation requirements of the project increases.

2.3.1 Multi-Pipe Separators

It consists of parallel pipes with a common multiphase inlet. The flow is distributed in the distribution header to lead stratification. The gas flows to the gas pipe and the liquid goes to a tilted down comer. The gas pipe has an upward tilted section to a common gas header so that liquid accumulating in the gas pipe can drain into the liquid pipe through the escape pipe. Gas produced to the liquid pipe can escape through the same pipe to the gas header (Hannisdal et al., 2012). The process is illustrated schematically in Figure 2.4.

This design has been applied to several separation devices such as slug catchers and oil-water-sand separators. Suppliers point out that fabrication is simple and they are provided with special internals depending on the expected problems with the fluid (e.g., foaming and slugging conditions). Their maintenance and installation are easy and economically attractive, compared with conventional horizontal separation vessels (around 80% less expensive, according to Prescott et al., 2016), more suitable for large water depths and high design pressures. Unfortunately, they are a mature technology used in onshore fields mainly and they are not explored as an appropriate solution for deep-water fields.

Their main limitation is sand handling because require desander modules or flushing technologies. However, nowadays there are “W-A-V” designs that permit gas flowing at the top and heavier fluids at the bottom, sand is accumulated at the bottom of the device and after, flushed using a pump.

A G-L harp-type separator was tested in 2012 for analyzing its implementation in the 3-phase subsea separator system in Marlim field, showing excellent results in reducing GVF (less than 30%) before sending the flow to a conventional horizontal separation vessel that completes the O-W separation (Capela et al., 2012).

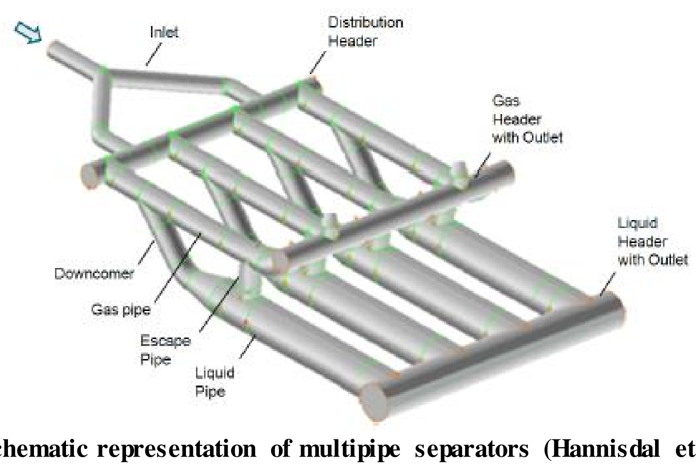

Figure 2.4: Schematic representation of multipipe separators (Hannisdal et al., 2012)

2.3.2 Compact Versions of Traditional Vessels

They use building blocks tested in the surface and arranged in a more optimal way for subsea applications, compared to conventional gravity separators (Khoi et al., 2009). They are also provided with specific internals for a better flow distribution, gas demisting, slug handling and to ensure a homogeneous production of oil and water.

They can be attractive for implementation despite their size and weight because in some cases, show better results in separation performance compared with conventional vessels and reduce CAPEX.

Even reducing the size of the vessel, they result in large separators that require special internals for sand removal. The most common compact technologies are compact scrubbers and cyclonic separators.

2.4 Value of Technology

The quantification of the value of technology (VoT) is not a trivial process and is a significant challenge nowadays. Generally, evaluating the value of technologies being operated and producing a measurable income is simpler than calculating the value of innovative ones (startups), whose impact on the business is in the long-term.

Besides the difficulty related to the quantification, volatility in oil and gas price impacts the perception of the importance of technology and profits due to its application. When the oil price decreases, most of the technologies become unviable and when it increases the role of technologies in the revenues is depreciated, attributing them only to the rising in price.

Valuation consists of giving an expected value to a technology considering the uncertainties that characterize the process of technology innovation and inherent risks (T. Daniel et al., 2008). It is not about giving a commercialization value, but a fair value according to the economic potential and according to the available information during the time of study. This procedure is only applied to the most promissory technologies identified during an evaluation process.

As a rule, the investments in technology must deliver which significantly exceeds the cost of developing and applying the technology. However, there are other benefits besides the revenues due to the application. According to Heinemann et al. (1996), the more profitable operating units in the petroleum industry are those that offer the following benefits: 1) increase the hydrocarbon production, 2) increase the reserves and 3) reduce the risk.

There are many approaches used for quantifying this value, the most known and used in the oil and gas industry are development cost, valorization by multipliers, NPV, the theory of real options, and value/cost ratio. For including the subsea technologies in the study, we selected NPV as a good indicator to quantify the VoT. The adopted methodology including this last approach is going to be explained in detail below.

2.4.1 Net Present Value

It is the most known and used method for making decisions about the valorization of new technologies. It is based on three variables: 1) expected cash flow, 2) risk and 3) lifetime of the product. The value is calculated by summing all future cash flows during the product lifetime and discounting by a rate that quantifies the value of money in time and risk. Generally, during the evaluation using NPV, a project is acceptable if future cash flows carried to the present are higher than zero, that is NPV>0. When evaluating mutually exclusive projects, the decision is tilted to the highest NPV.

In the methodology proposed by De Naurois and Desalos (2001), the potential value of technologies within DeepStar, PAI/Texaco was measured using an approach of full-cycle field economics and considering as the main parameter the differential NPV discounted by 10%, called NPV_{10}. The value was evaluated taking into account the product cost (given by developers and suppliers), CAPEX, OPEX, and reserves/production ratio during all the field life. The final relative value was calculated as:

$$Final\ Relative\ Value = NPV_{10} - NPV_{base\ case} \quad \textbf{(2.1)}$$

Due to costs of the subsea technologies are very variable because depend on the specific application case (e.g., properties of produced fluids, water depth, linking distance), and others) and there is not any explicit information in the literature about the required investment, it is necessary to adopt an analogous methodology to those of De Naurois and Desalos (2001). The costs are contemplated into the analysis without taking into account the value provided by the developer and using as economic indicator a parameter calculated from the differential NPV called as maximum-theoretical value of technology ($VoTmax$).

$VoTmax$ is calculated by subtracting the NPV of the base case ($NPV_{without}$) from the NPV of the installation case (NPV_{with}), as follows:

$$VoT_{max} = NPV_{with} - NPV_{without} \quad \textbf{(2.2)}$$

VoTmax represents the difference between NPVs for cases with and without installation and it is the maximum affordable investment for installing the subsea technologies. In spite of the uncertainty in the costs, this parameter does not include both the initial investment (CAPEX) and the required costs for operation and maintenance (OPEX) during all the time of the project.

This parameter is not the same as installations costs for each well; however, they could be calculated with NPV, initial investment, and implementation date. *VoTmax* could be influenced by the time when the technologies are installed. If they are implemented in the middle of the productive life of the field, the capital required for moving workover equipment and production stops would decrease generated NPV_{with} due to implementation. As well as, if they are installed later, the economic effect of discount rate and the time (number of periods) could also decrease expected values.

It is well known that NPV has been widely adopted due to simplicity and objectivity; however, it is only adequate for low-uncertainty environments where lifetime and discount rate are known. Its main limitation is calculating the future cash flows when dealing with high-uncertainty levels. Because of the risk is represented by the discount rate (which is not easy to calculate and requires information that is rarely available), the VoT can be very low for risky but promissory projects. In order to overcome these limitations using NPV as an indicator, some important assumptions have to be established.

In this perspective, the methodology based *VoTmax* seems to work when evaluating the economic attractiveness of installing the subsea systems without requiring knowing the exact investment and assuming that decision of implementation to be made based on NPV.

2.5 Numerical Reservoir Simulation

It is a tool widely used to forecast field production and support the decision making process during development and management stages. It consists of building a computational and mathematical model of the reservoir that simulates the flow behavior into the porous media.

It is in charge of modeling the dynamic behavior of the reservoir at several scenarios using finite difference or finite element discretization. It requires a history matching process to get a model that obeys the observed production data and permits enhancing the certainty when forecasting future production behavior.

The hydraulic diffusivity equation describes the fluid flow in porous media and governs this model. This equation comes from the continuity equation (mass balance), an equation of state (isothermal fluid compressibility) and a flow equation (Darcy law). For black oil modeling, it is described as follows:

$$\nabla\left[\lambda_o\left(\nabla p_o - \rho_o g \nabla z\right)\right] = \frac{\partial}{\partial t}\left(\frac{\phi S_o}{B_o}\right) + q_o \quad \textbf{(2.3)}$$

with mobility defined as:

$$\lambda_o = \frac{k k_{ro}}{\mu_o B_o} \quad \textbf{(2.4)}$$

where:

$\nabla[\lambda_o(\nabla p_o - \rho_o g \nabla z)]$ is the flow term.

$\frac{\partial}{\partial t}\left(\frac{\phi S_o}{B_o}\right)$ is the accumulation term.

q_o is the source term, where the boundary conditions are related to a value of flow rate or BHP.

It includes the well model, which obeys the well production equation (radial one dimensional flow equation around the well):

$$q_o = \frac{2\pi k k_{ro} h}{\mu_o B_o\left[\ln\left(r_e/r_w\right) + S\right]}\left(p_{wf} - p_{cell}\right) \quad \textbf{(2.5)}$$

- Limitations

The drawbacks of reservoir simulation are related to the reliability of the model. For instance, uncertainties related to reservoir characterization and representation of geological complexities in the simulation model, representation of fluid properties and numerical errors depending on the discretization, scales used, and mathematical modeling of the dynamic process of production.

Nevertheless, there is no doubt that one of the most critical limitations in the use of numerical reservoir simulators for analyzing the behavior of production is well modeling and the integration with production network.

Production forecast of multiple scenarios by using only numerical reservoir simulators limits the study of the influence of flow rates in wellbores and surface facilities in the economic performance of a project. According to Yang et al. (2002), many reservoir management programs have failed because they do not consider wells, surface facilities and the reservoir as an integrated system.

Standalone models do not consider either the flow-resistance effects of the pipeline and the surface networks or the influence of overall constraints of the production network on the reservoir production. It is not able to capture the complexity of the interaction between reservoir and production network.

Any change made in the production network influences well production rates. So, all the efforts made at the initial production strategy using standalone models are obsolete, being necessary remaking all the work for including the modifications made on the network.

2.6 Integrated Asset Modeling

In the past, reservoir and production network models were separated and engineering efforts were focused on the optimization of each part of the system rather than looking for a global optimization. Investments of money were made in spreadsheet models with faulty assumptions and extremely suspect calculations, with almost no update and match to reality (Howell et al., 2006).

Some amalgamated models were initially created to model entire fields producing from several reservoirs and sharing common production constraints, but due to the great amount of information, they required too much computational time and the obtained results were very similar compared with standalone models. Therefore, it was necessary another alternative for making predictions about the production behavior in multi-reservoirs fields and quantify the impact of including production systems. The integrated models permit solving this problem.

Integrated models involve several disciplines, such as reservoir engineering, production engineering, economic engineering and project evaluation. They include near wellbore reservoir submodel, well inflow, choke valves, flow lines, subsea processing station, host surface facilities, and platform. A summarized definition could be the stated by Rahmawati and Hoda (2015): simulation runs from the reservoir up to the surface process and continues with an economic evaluation.

This kind of simulation gives a holistic point of view and takes into account all different parameters of the overall system, and hence avoids developing design and decision with an unstable solution. Executing the simulation early leads to effective and optimal design, ensure maximum return on investment and minimize project risk (Sandy and Hasan, 2016).

It is crucial to consider the economic submodel because oil and gas prices have a strong impact on the company production strategies, the determination of production parameters and the decision-making process. An integrated model includes several price scenarios and permits to perform better field development and management.

Nevertheless, an integrated model cannot include the full level of detail across the whole range; details depend on the system to be judged and the scope of study (Beliakova et al., 2000). To include the integration in a study of field development is necessary to make a balance between the additional required and obtained information, the complexity of the model and reliability, computational costs and accuracy of results obtained.

The implementation of this kind of integrated models have increased production without any significant CAPEX, just only attributable to the use of software, computer simulation and intelligent operation technology. For instance, Shell claims that the additional revenues because of the introduction of integrated asset modeling (IAM) for the Greater Sole Pit Basin exceed five USD million per year (Rotondi et al., 2008).

The key activities into the IAM workflow are:

1. Production capacity planning: identification of current and future strategies for field development.
2. Field development planning: trial and error approach to creating development strategies. It consists of the selection of optimum scenarios for new projects and developments.
3. Economic planning: it is crucial during the decision-making process and selection of the optimal strategy. It requires a rigorous modeling of capital, expenditures, prices, and royalties.
4. Field optimization: evaluation of alternatives and optimal development, permitting obtaining production optimization. It also includes the identification of bottlenecks and opportunities for increasing production and economic benefits.
5. Production forecasting: determination of production and injection capacities with a better level of accuracy, tending to the optimization of resources.

2.6.1 Submodels

The most important parameter to be taken into account is model representativeness; they have to honor the complexity of the system reservoir-production network, and production and injection constraints. At the same time, to maintain a reasonable computational time during simulation when dealing with the evaluation of multiple scenarios. In addition, submodels have to permit changing configurations easily and visualizing the results for better understanding.

The main goals of integrated models based on each submodel are (1) reservoir: optimization of the reservoir performance, maximization of the oil recovery factor (ORF) at the minimum cost and (2) production network optimization.

Main submodels in IAM are the reservoir and the production network.

- Reservoir

  Reservoir simulator is in charge of solving the equations of flow and mass balance in porous media and determining the inflow performance relationship (IPR) through the quantification of flow rates and BHP of each well with the set boundary conditions of the production network (*i.e.*, production target, limitations in surface facilities, maximum well flow rates and pressure restrictions). It is defined by an upscaled geological model and requires a history matching process to ensure the accuracy and the representation of the production reality of the field.

  Other submodels consider compositional modeling (mass balance by phases and pseudo components), dual porosity and/or dual permeability modules, handling nonlinear IPR models, among others.

  The most used simulators for reservoir modeling are ECLIPSE 100 and 300 (Schlumberger), IMEX and GEM (Computer Modelling Group, CMG) and in-house simulators of each company.

- Production network

  Simulator calculates flow rates, pressures and temperature profiles given the boundary conditions through nodal analysis. It responds to the multiphase flow in wells, pipeline, and facilities; starting from the sand face and finishing at the sales point. It compares the successive flow rates at each iteration and determines convergence based on predetermined user-criteria.

  Each device and component of the production network is represented with nodes. According to the sense of flow, they can be (1) sources: inflow or net positive flow to the node, (2) sinks: outflow or net negative flow and (3) junctions: intersections of links, such as manifolds or zero net flow.

  Advanced network simulators include production modeling for oil, gas, condensate and water wells; consider wellheads, choke valves, and attributes of artificial lift systems for production optimization.

  The main limitations of these simulators are the lack of representativeness of some phenomena such as crossflow, flow direction and including some devices such as separators and gas or water injection units.

The most used simulators for production network solutions are GAP and PROSPER (Petex), HYSIS (AspenTech), PIPESIM (Schlumberger), PTUBE (CMG) and in-house simulators of each company.

2.6.2 Production Network Constraints

Constraints and details of the production network are extremely important and should be considered because of dependency between interconnected and coupled simulations. The dependency is given by the total limits of production flows and/or injection (indispensable in systems integration). Therefore, to decrease uncertainties and discontinuities of the integrated and coupled simulation, a more realistic reproduction of production network is necessary. This turns the simulations more difficult due to the higher computational time and can cause convergence problems (Victorino et al., 2016).

When dealing with predictive reservoir submodels that consider gathering networks, the well-boundary conditions are in general variable in time and are dependent on the reservoir behavior, equipment, performance, production strategy, hydraulics relationships, and pressure, rate and source composition constraints that may be applied to the production network (Coats et al., 2003). This means that there should be no constraints imposed on the reservoir submodel that would affect the performance of the coupled simulation (e.g., group constraints and restrictive BHP constraints) (Kosmala et al., 2003) and set up consistently considering the internal boundary conditions of the reservoir submodel and control settings of the production network.

Kosmala et al. (2003) also defined different types of constraints that are added to the production network and may be applied at different levels, such as well, node, and/or separator level. The most common constraints added to the production network are:

- Well constraints: they reproduce operating and production restrictions of a well. They can be maximum flow rates (for liquid and gas) or minimum operating BHP.
- Pipeline constraints: they are related to pipeline specifications and in general, they are set up as erosional velocity or as maximum pressure.
- Group constraints: they are related to production, injection or re-injection limits in manifolds or in separation and re-injection systems. In the case subsea technologies is required to add other constraints to make the simulation process more realistic. Besides the maximum flow rate, separation efficiency and a minimum separation pressure are included.

- Platform constraints: they are maximum platform capacities for handling liquid, oil, water, and injected water; they are specific for each project and set up according to the production forecast of the reservoir.

Besides the constraints, there are also control variables and monitoring rules that have an effect on the coupling process and the computational time, as well as on results of production forecast of the field. Control variables are normally referenced to the artificial lift system (ALS), as injection gas rate for gas lift systems or operating frequency of the pump in the case of subsea centrifugal pumping.

The most common monitoring rules are maximum WCUT and GOR or minimum oil production. In this study, there are other required rules for controlling and monitoring the separation process, such as WCUT, GLR and the properties of the produced and separated fluids (e.g., the specific gravity of liquids and gas, water salinity, content of CO_2 in the produced gas, etc.).

It is required an adequate experience and familiarity with the models that compose IAM for setting them up. It is necessary to understand and know the production network constraints to propose production strategies that maximize oil production while honoring the constraints at any level.

2.6.3 Types of Coupling

Sometimes, stand-alone models are used to make simplified production forecasts without considering the components of the production network when using numerical simulation. Production constraints are usually set up in the reservoir submodel considering the loss of production due to expected pressure drops and backpressures in the production network, or setting a delivering pressure as a constraint. By this way, it is possible to simulate some near-to-reality delivering conditions by avoiding complete modeling the network and backpressures imposed to the flow rate.

Unfortunately, those models do not permit to understand and quantify the changes in the global system when the conditions of each part are modified. They are not able to capture neither the interactions between reservoir and production network nor the interdependencies in production responses when the systems are varying with time.

On the contrary, there are models that permit the interconnection between the components of the network and the reservoir and know their impact on the reservoir production performance; these are the coupled models. Coupling is the process to interconnect two or more simulation submodels (e.g., reservoir and production network) sharing a common interface and interchanging data for solving a specific optimization problem.

Coupled models are very important because allow representing more complex production scenarios such as the mixture of fluids with different properties, deep-water field development, wells producing from different reservoirs to the same platform, among others and allow having more realistic production forecasts. These are considered as a powerful tool for field development and production optimization because consider both reservoir and production-network models as an entire system, permitting analyzing the effects on the production when the configuration of the network is modified. For instance, they provide more realistic forecast and better-supported arguments when analyzing the economic attractiveness of implementing subsea technologies.

2.6.3.1 Decoupled

According to Hohendorff Filho, 2016, in this kind of coupling, the integration between reservoir and network submodels is made by data exchanging from vertical lift performance (VLP) tables or files, which contain the information of the multiphase flow in the pipeline.

This multiphase flow data is usually calculated for different wells using a well-modeling simulator. The accuracy of results depends on the amount of calculated and tabulated data.

This technique was used before for the planning stage of some oil and gas projects in order to determine initial production forecasts. It tends to limit the number of projects and conceptual scenarios due to the interaction speed between the simulators.

Sometimes, it has inconsistencies related with calculations of physical properties (e.g., fluid properties) due to the inexistence of linking between the simulators, making the interaction between models slow.

2.6.3.2 Implicit

There is a unique modeling for the entire system. The equations of multiphase fluid flow in the tubing and surface facilities are solved simultaneously by treating wellheads and nodes of the surface network equivalently to additional grid blocks of the reservoir model. The derivatives are computed and accommodated into the Jacobian matrix of the reservoir simulator (Rotondi et al., 2008). There are both a linearization and a solution for updated values at each Newton iteration.

Rotondi et al. (2008) stated as advantages the accuracy, better consistency and higher stability of the results. However, it requires a single code for the entire simulation from subsurface to surface. On the other hand, it may require a high computational cost depending on the complexity of the systems involved and, results obtained by this approach do not always justify such a refined treatment (Cotrim et al., 2011).

2.6.3.3 Explicit

According to Cotrim et al. (2011), it is the most used method for practical cases. It consists of information exchange between submodels at specific time intervals. The production network submodel is solved at the beginning of each synchronization time step and BHP or THP (tubing head pressure) limits are set accordingly. Reservoir submodel runs independently with its own time steps and maintaining the well control targets. The communication between submodels is usually made by using parallel virtual machines (PVM) or with a programmable controller.

Explicit coupling uses nodal analysis for treating the submodels in an integrated way. In this technique, a reference node is selected for separating the system into two parts, subsurface and surface. Normally, this node can be located at the wellhead or at the bottom-hole (Teixeira, 2013). Independently of reference node location, the system must obey the material balance equation: the sum of the mass flow rates has to be zero and the Kirchoff law for pressures in a node: inlet pressures have the same value of outlet pressures.

By this way, and according to Barroux et al. (2000), the most common configurations of the explicit scheme are:

- Wellhead level: the pressure drops in the tubing are modeled in the reservoir simulator
- Reservoir level with IPR overlap: the most recommended and commonly used node. (Teixeira, 2013). The pressure drops in the tubing are represented in the production network simulator only
- Reservoir level with tubing pressure and IPR overlap: pressure drops are calculated in both simulators

The great advantage of the explicit methodology is related to lower computational effort and time, and flexibility in the use of coupling between reservoir simulator and production network software (Victorino et al., 2016). The complexity of each system can be modeled by specialized software. The choice of the time step and boundary conditions is the main problem in the convergence of solutions. They have to be well defined for avoiding errors during the simulation (Hohendorff Filho and Schiozer, 2012).

The consistency between the network and the simulator computations should be checked because IPR used by the simulator output is computed by solving the well equations with the pressure and saturation of the cells at time t, while other variables, including well rates or pressures, are updated with IPR holding at time t+Δt. This may induce discrepancy between reservoir bottom-hole and network bottom-hole when a controller program under a target fluid rate controls the wells. When the model conditions are rapidly changing, a finer equilibration time stepping should be used (Cotrim et al., 2011).

There are two types of explicit coupling, tight and loose.

- Tight coupling

  It is based on the modification of the reservoir simulator to iterative converge separate solutions of the well and facility domains prior conventional solution of the combined system. For each new Newton's iteration, it is necessary the use of the latest iteration of reservoir submodel for balancing the well-reservoir submodel honoring the constraints. All the simulation tasks have identical time steps.

  This type of explicit coupling is simple, provides more accurate reservoir deliverability forecasts, permits choosing several simulators, reduces data communication, and it is a good tool when dealing with fast changes of pressure and saturation during a time step.

  On the other hand, the reservoir simulator has to permit this kind of coupling where is necessary more iteration for achieving convergence and minor steps for synchronization, which increases the computational time.

- Loose coupling

  The reservoir and surface submodels do not have the same time steps. This type of coupling is performed when dealing with multiple independent reservoirs subject to common global constraints and producing in a common platform.

  The advantage of this kind of integration is allowing the simulator to run in two models: controller and slave by implementing an appropriate communication interface.

There are two kinds of time when dealing with explicitly integrated simulation, they are:

- Reservoir simulator time: required time for convergence and solution of the material balance equation.
- Synchronization time: time to determine new operating conditions that were sent from the production network simulator to the reservoir simulator. At the beginning of this

time, the reservoir simulator provides the IPR curve of each well and the production simulator determines the operating conditions that maximize the desired objective function (e.g., oil flow rate) considering the constraints imposed on the network.

The physical links between the submodels and the way of exchanging information and results are encountered in the controller or integrator, which is considered as the heart of IAM because it provides a seamless integration between the submodels. The instructions are included in the controller, translated by the driver and communicated to the reservoir simulator. The simulators can communicate with each other by:

- PVM: it is a communication interface between simulators, permits the connection between simulators through slave processes and exchanging message packets. Both simulators run on the same workstation but independently on separate machines.
- Message passing open interface (MPI): permits flexibility in the selection of the software
- Open data exchange: it does not require too much information to be exchanged at each balancing iteration

The controller-integrator is flexible and easily programmable for well-management routines (Cotrim et al., 2011). The communication between simulators is reliable, flexible, and it is constituted by an easy-to-understand logic and easily modifiable by the user.

Other functions of the controller are: balancing the models, synchronization in time and apply the global constraints to the model.

The most common integrators for explicit coupling are RESOLVE (Petroleum Experts, Petex), AVOCET (Schlumberger), Pipe-It (Petrostreamz AS.), among others.

The convergence is one of the main problems when working with explicit integration approach. It is based on the modified Newton-Rhapson algorithm.

This algorithm uses IPR of each well for both reservoir and the tubing performance curves (TPC) generated as a function of flow rate (Q), GLR, WCUT, WHP and injection rate for artificial lift (e.g., gas injection flow rates in gas lift. It is performed from the production network submodels to ensure the convergence into a consistent solution (determined by tolerance criteria) for each time step.

The reservoir simulator provides IPR from well equations with saturations and pressures at a certain time (t) and well rates and BHP from holding the calculated IPR at the next time ($t+\Delta t$).

The simulator determines the well production by finding a BHP that satisfies the inflow equation:

$$Q = J(P_e - BHP) \quad \textbf{(2.6)}$$

where $\boldsymbol{P_e}$ is the external boundary pressure or cell block pressure of the well completion

$\boldsymbol{J}$ is the well productivity index

The values are updated in each simulator and successive steady state network models are gotten for every changing reservoir condition.

Due to the complexity of the production network and the reservoir model, sometimes there are some convergence problems depending on selected time step and boundary conditions.

It is common that fluid properties defined in tables as functions of pressure in the input file of the reservoir submodel be calculated considering internal analytical correlations in the network simulator. In such a situation, passing volumetric rates at bottom-hole conditions from the surface to the reservoir or vice-versa is not accurate and may cause trouble to obtain the convergence (Barroux et al., 2000).

The following procedure is carried out for solving explicitly coupled systems at the reservoir level (Cotrim et al., 2011):

- The controller extracts IPR of each well from the reservoir submodel
- IPR is passed to the network simulator that calculates the operational point (intersection between IPR and VLP curve)
- The controller executes the well-management routine to honor the imposed surface constraints
- The controller passes back to the reservoir simulator the network-managed snapshots of well state
- Finally, the controller advances the system in time and the process is repeated until the simulation ends

Figure 2.5 shows a flow chart with the former-explained coupling procedure.

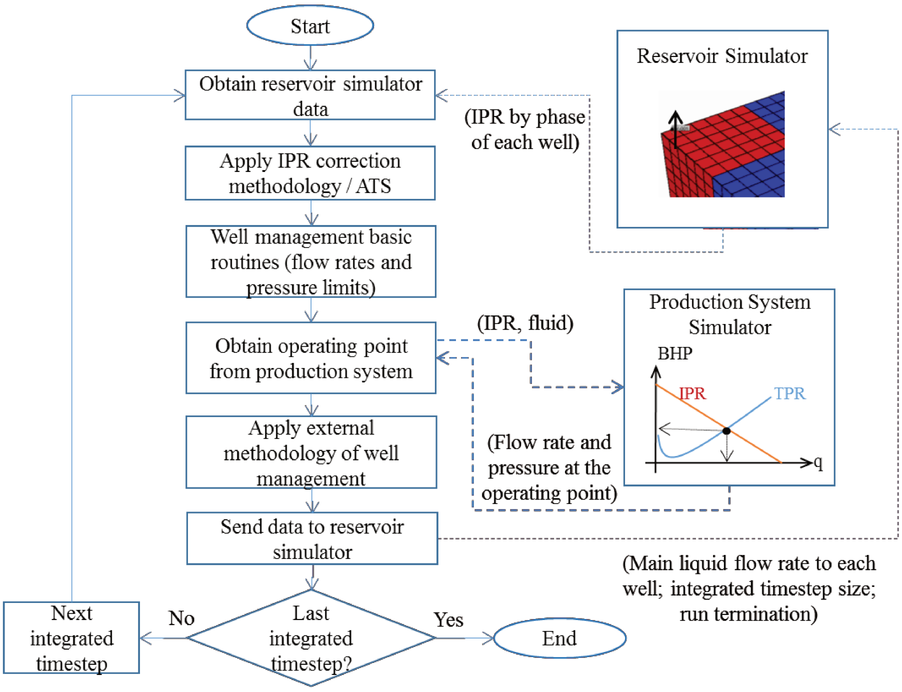

Figure 2.5: Flow chart showing the coupling procedure (Hohendorff Filho, 2012)

2.6.4 Uses and Application

IAM develops real value when dealing with large systems, where the type and number of variables to be controlled lies out of the human capacity (Correa, 2010).

The main purpose of coupling is to generate models that represent the complexity of system reservoir-wellbore-facilities, expecting to maximize or minimize an objective function looking for the maximum benefit or the minimum detriment during the proposal of the production strategy of a field. It is a powerful tool for reduction of errors and supports the decision-making process.

The most common situations where the use of integrated models is advisable are:

- Determination of water-gas handling capacity of facilities
- Enhanced predictions of the behavior of individual reservoirs with different fluid properties producing in a common production network and platforms
- Multiple separate reservoirs sharing global production and injection constraints
- Water injection plant for multiple reservoirs
- Injection of produced water or gas
- Deep and ultra-deep water field development
- Analysis of pressure interaction between reservoir and surface models
- Determination of reservoir deliverability to design facility systems and the influence of the facility constraints on the overall system

- Production strategies for revitalization of mature fields and marginal fields
- Optimization of system reservoir-production network
- Determination of the optimal moment for tie-in of new fields
- Determination of the effect of the implementation of a separator in the network on the ultimate reservoir recovery and determination of its economic attractiveness

The most important use of IAM is the conversion of provided results into conclusions and decisions for field development.

2.6.5 Advantages

Some advantages of the inclusion of IAM were already announced but worth mentioning others such as:

- More realistic production scenarios
- Production anticipation and extension of the productive life of the reservoir
- Better decision making and establishing better production strategies for field development
- Identification and reduction of bottlenecking and backpressures
- Maximization of the overall production (uplift in oil production by 3-25% according to Yang et al., 2002)
- Maximization of NPV and revenue anticipation
- Maximization of hydrocarbon recovery at the minimum cost
- Optimal control of wells while honoring the imposed constraints
- Optimization of artificial lift systems
- Optimization of facilities and flow line connections
- Optimization of well schedule, well location and operating parameters
- Avoiding early breakthrough times during oil recovery processes
- Better management and reduction of produced water

2.6.6 Limitations

Drawbacks associated with the use of IAM are related to computational efforts and efficiency of chosen software. Sometimes, the decision process is delayed when expecting results that are more accurate. It is necessary to consider if the model is appropriate for a certain application.

Other limitations that can be considered are:

- Increasing complexity of the system
- Computational capacity for running the models
- The efficiency of the optimizer and solver used for coupling the simulators
- Software bugs
- Data inconsistency and result accuracy
- Implementation of wrong algorithms
- Wrong simplifications in the models

2.7 Correlations of Two-Phase Flow in Pipeline

Two-phase flow is developed in the petroleum industry during the production and transportation of oil and gas in the pipeline. The flow can be horizontal, vertical or tilted, in both wellbore and flow lines. In offshore fields, these lines can have significant distances before reaching the host facility or the well can be completed in deep reservoirs. For these reasons, it is crucial to know the pressure drop into the pipeline and determine the requirement of boosting produced fluids for carrying them to the platform.

Several empirical correlations have been developed for determining the pressure gradient in two-phase flow. The most known is Beggs and Brill (1973), which was developed at all inclination angles and for many flow conditions.

The map for horizontal flow is illustrated in Figure 2.6, where the coordinates are the mixture Froude number, $\mathrm{Fr}^2{}_{\mathrm{M}} = \mathrm{v}^2{}_{\mathrm{M}}/\ \mathrm{gd}$ and the no-slip liquid holdup, $\lambda_{\mathrm{L}} = \mathrm{v}_{\mathrm{SL}}/\mathrm{v}_{\mathrm{M}}$. There are three flow patterns in horizontal flow: segregated, intermittent and distributed. Note that the flow pattern in used as a correlating parameter and does not represent the actual flow pattern unless the pipe is horizontal (Shoham, 2006). Correction factors for the effect of inclination angle are used for uphill flow patterns for the different flow conditions.

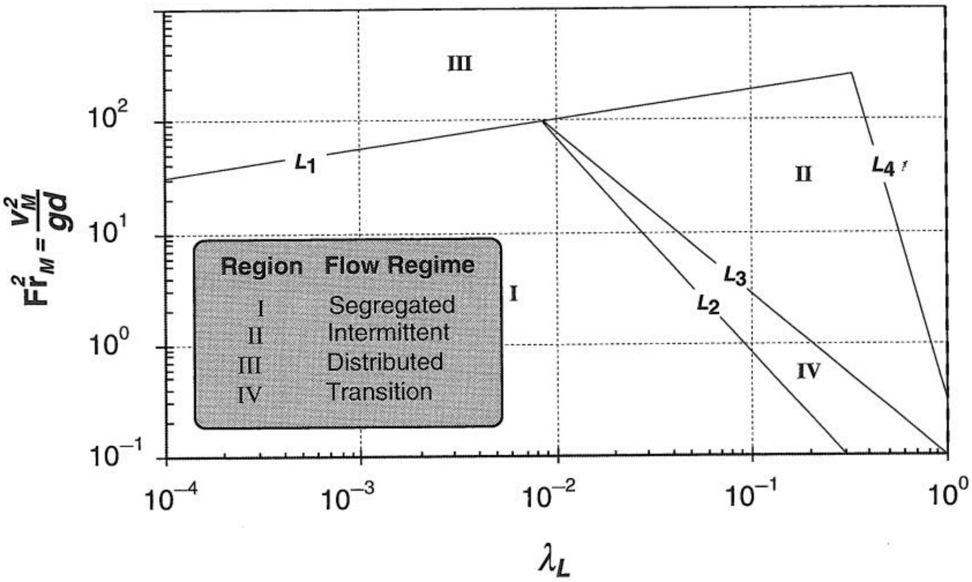

Figure 2.6: Horizontal-flow-pattern map (Beggs and Brill, 1973)

Defining lines L_1, L_2, L_3 and L_4:

$$L_1 = 316\lambda_L^{0.302} \quad \textbf{(2.7)}$$

$$L_2 = 0.0009252\lambda_L^{-2.4684} \quad \textbf{(2.8)}$$

$$L_3 = 0.10\lambda_L^{-1.4516} \quad \textbf{(2.9)}$$

$$L_4 = 0.5\lambda_L^{-6.738} \quad \textbf{(2.10)}$$

The criteria for existence of the horizontal flow patterns are given by:

Segregated: $\lambda_L < 0.01$ and $\mathrm{Fr^2}_\mathrm{M} < L_1$, or $\lambda_L \geq 0.01$ and $\mathrm{Fr^2}_\mathrm{M} < L_2$

Transition: $\lambda_L \geq 0.01$ and $L_2 \leq \mathrm{Fr^2}_\mathrm{M} \leq L_3$

Intermittent: $0.01 \leq \lambda_L < 0.4$ and $L_3 \leq \mathrm{Fr^2}_\mathrm{M} \leq L_1$, or $\lambda_L \geq 0.4$ and $L_3 \leq \mathrm{Fr^2}_\mathrm{M} \leq L_4$

Distributed: $\lambda_L < 0.4$ and $\mathrm{Fr^2}_\mathrm{M} \geq L_1$, or $\lambda_L \geq 0.4$ and $\mathrm{Fr^2}_\mathrm{M} > L_2$

The liquid holdup is given by:

$$H_L = H_{L(0)}\psi \quad \textbf{(2.11)}$$

where $H_{L(0)}$is the liquid holdup that would exist in a horizontal pipe with the same flow conditions and ψ is the correction factor for the inclination angle. The liquid holdup for horizontal conditions can be determined from:

$$H_{L(0)} = \frac{a\lambda_L^b}{(\mathrm{Fr^2}_\mathrm{M})^c} \quad \textbf{(2.12)}$$

where the coefficients a, b and c are functions of the flow pattern, as given in Table 2.1. When the flow pattern falls in the transition region, the liquid holdup must be averaged using the segregated and intermittent liquid-holdup values, as follows:

$$H_{L(TRANSITION)} = A * H_{L(SEGREGATED)} + (1 - A) * H_{L(INTERMITTENT)} \quad \textbf{(2.13)}$$

where

$$A = \frac{L_3 - \mathrm{Fr^2}_{\mathrm{M}}}{L_3 - L_2} \quad \textbf{(2.14)}$$

The correlation factor for the effect of inclination angle is determined by:

$$\psi = 1 + C \times [sin(1.8\theta) - 0.333 sin^3\,(1.8\theta)] \quad \textbf{(2.15)}$$

and

$$C = (1-\lambda_L)\ln[d'\lambda_L^e N_{LV}^f (Fr_M^2)^g] \quad \textbf{(2.16)}$$

Defining the dimensionless velocity number for the liquid phase:

$$N_{LV} = v_{SL}\left(\frac{\rho_L}{g\sigma}\right)^{1/4} \quad \textbf{(2.17)}$$

where θ is the inclination angle of the pipe, and the coefficients d', e, f, and g are given in Table 2.2, with the constraint $C \geq 0$. There is not correction for $C = 0$ and ψ=1.

Table 2.1: Coefficients for liquid-holdup correlation

Flow Pattern	a	b	c
Segregated	0.98	0.4846	0.0868
Intermittent	0.845	0.5351	0.0173
Distributed	1.065	0.5824	0.0609

Table 2.2: Coefficients for pipe-inclination factor

Horizontal Flow Pattern	d'	e	f	g
All flow patterns downhill	4.7	-0.3692	0.1244	-0.5056
Segregated uphill	0.011	-3.768	3.539	-1.614
Intermittent uphill	2.96	0.305	-0.4473	0.0978

The frictional pressure drop is determined by

$$-\left.\frac{dP}{dL}\right)_F = \frac{f_{TP}\rho_{NS}v_M^2}{2d} \quad \textbf{(2.18)}$$

The two-phase friction factor can be determined as

$$f_{TP} = \left(\frac{f_{TP}}{f_N}\right) f_N \quad \textbf{(2.19)}$$

The normalized friction factor, f_N, can be determined as

$$\left(\frac{f_{TP}}{f_N}\right) = e^s \quad \textbf{(2.20)}$$

where

$$s = \frac{\ln(y)}{-0.0523 + 3.182\ln(y) - 0.8725 ln^2(y) + 0.01853 ln^4(y)} \quad \textbf{(2.21)}$$

and

$$y = \frac{\lambda_L}{H_L^2} \quad \textbf{(2.22)}$$

The function s becomes unbounded in the interval $1 < y < 1.2$. For this interval, s is calculated from

$$s = ln(2.2y - 1.2) \quad \textbf{(2.23)}$$

In the original correlation, the no-slip normalizing factor, f_N, was determined from a smooth-pipe correlation. However, as the correlation tended to underpredict the pressure gradient, it was modified later. In the modified correlation, f_N is based on a rough-pipe friction factor. An example of rough-pipe friction factor is the convenient explicit form given by Moody (1947) as given by (Shoham, 2006):

$$f_N = 0.0055\left[1 + \left(2 \times 10^4 \frac{\varepsilon}{d} + \frac{10^6}{Re_{NS}}\right)^{1/3}\right] \quad \textbf{(2.24)}$$

The no-slip Reynolds number is given by

$$Re_{NS} = 1.488 \frac{\rho_{NS} v_M d}{\mu_{NS}} \quad \textbf{(2.25)}$$

where the density and the viscosity of the mixture are determined, respectively, using the no-slip liquid holdup as

$$\rho_{NS} = \rho_L \lambda_L + \rho_G (1 - \lambda_L) \quad \textbf{(2.26)}$$

and

$$\mu_{NS} = \mu_L \lambda_L + \mu_G (1 - \lambda_L) \quad \textbf{(2.27)}$$

The gravitational pressure gradient is determined by

$$-\frac{dP}{dL}\bigg)_G = \rho_{SLIP}\, g sin\theta \qquad \textbf{(2.28)}$$

where the slip density is calculated based on the in-situ liquid holdup (Equation 2.11), given by:

$$\rho_{SLIP} = \rho_L H_L + \rho_G (1 - H_L) \qquad \textbf{(2.29)}$$

The accelerational pressure gradient is usually neglected, except for low-pressure and high-velocity conditions. As follows

$$-\frac{dP}{dL}\bigg)_A = \frac{\rho_{SLIP} v_M v_{SG}}{P}\left(-\frac{dP}{dL}\right) \qquad \textbf{(2.30)}$$

Total pressure gradient is the sum of the frictional, gravitational, and accelerational pressure-gradient components.

$$\frac{dP}{dL} = \frac{-\frac{dP}{dL}\Big)_F - \frac{dP}{dL}\Big)_G}{1 - \frac{\rho_{SLIP} v_M v_{SG}}{P}} \qquad \textbf{(2.31)}$$

3 LITERATURE REVIEW

3.1 Subsea Processing

3.1.1 Current Projects, Prototypes and Proposals

Table 3.1 shows the most important projects executed worldwide using subsea technologies. As noticed, the implementation of this kind of systems permitted to face production challenges of those fields and provided successful results, evident in incremental production.

Table 3.1: Previous and current projects using subsea systems

PROJECT/ LOCATION/ COMPANY	WATER DEPTH (m)	CHALLENGES AND SOLUTIONS
1. Lufeng, South of China Sea (Statoil, 1997)	330	-Subsea electrical pumps for heavy oil boosting in a low-pressure reservoir -Incremental production: 1,272 m^3std/d (+1.6 Mm^3std cumulative) in six years of implementation
2. Topacio, Equatorial Guinea (ExxonMobil, 2000)	550	-Linking distance: 9 km -Flow stabilization and suppression of transient flow and slugs in pipeline with installation of subsea pumps -Incremental production: 1,589-2,384 m^3std/d.
3. Troll field, Norway (Statoil, 2001)	340	-First oil-water (O-W) subsea separation system with 3.5 km of linking distance -Horizontal oil-water-gas (O-W-G) gravitational subsea separator and produced water re-injection (PWRI) with single-phase subsea pump -Objectives: gain experience with subsea processing technologies, increase oil capacity of platform and production rates, decrease discharge of produced water to the sea and avoid flow instabilities. -Incremental production: 560,000 m^3std
4. Tordis field, Norway (Statoil, 2005)	220	-Application in a mature field with water capacity restriction, high flow rates, and increasing water cut (WCUT), reservoir depletion and reduction of oil production. -First commercial full-scale subsea separation, boosting and injection (SSBI) installation in the world -Objectives: lowering topside arrival pressure, water removal and disposition, reduction of wellhead pressure (WHP) and increasing the oil recovery factor (ORF). -Incremental production: 6Mm^3std (+6% ORF)

5. Albacora, Brazil (Petrobras, 2007)	370-400	-Remote control in platform. Pump modules linked 4-10 km far away the platform -Installation of subsea pumps for water injection -Objectives: reservoir pressure maintenance, production acceleration, and increasing ORF -Incremental production: 7,154 m^3std/d.
6. Perdido field, Gulf of Mexico (Shell, 2007)	2682	-Ultra deep water application for oil production in a reservoir with low aquifer support - Vertical gas-liquid (G-L) caisson separators with an electro submersible pump (ESP) for boosting production -Change the hydrate formation temperature in 10-20°F due to degasification of the liquid stream -Elimination of cooling effect due to gas expansion in riser
7. Block BC-10: Parque das Conchas, Campos Basin, Brazil (Shell, 2010)	1500-2000	-Production from seven reservoirs with pressure decline and differences in accumulation process, fluid type and production mechanisms, and heterogeneous geology. -Implementation of vertical cassion separators -Objective: maximizing the production and flow assurance by implementing subsea processing
8. Pazflor field, Angola (Total, 2011)	800-1200	-Production of multiple reservoirs with differences in fluid properties and hydrate formation tendencies -Vertical G-L subsea separation and oil boosting with subsea pumps -Objectives: reduction of pressure in flow lines, avoid the formation of hydrates and slugs, requirement of pigging the pipelines and increasing field recovery
9. Barracuda field, Brazil (Petrobras, 2012)	1040	-Linking distance: 14 km -Incremental production: 1,250 m^3std/d
10. Marlim field, Brazil (Petrobras, 2012)	650-1050	-Increasing water production, heavy and viscous oil and limitation water handling capacity topsides, sand production -First deep water system for O-W separation for heavy oil and water. -PWRI for pressure maintenance -Objective: field revitalization despite of high WCUT and low prices of barrel (Silveira et al., 2016)
11. Gullfaks South, Norway (Statoil, 2014)	135-220	-First installation of a multiphase compressor worldwide -Wet gas compression

12. Asgard field, Norway (Statoil, 2015)	240-300	-One of the most challenging and expensive application worldwide -Dry gas compression -Incremental production: +3% of hydrocarbon recovery

Figure 3.1 shows the installed equipment in the most recognizable projects of subsea separation.

Figure 3.1: Equipment installed in Tordis, BC-10, Perdido, Marlim and Pazflor (Hendricks et al., 2016)

3.1.2 Developed Work about Subsea Systems

3.1.2.1 Revitalization of Mature Fields (Brown Fields)

In these cases, production and pressure in the field have begun to decline and pressure, as well as, started to exhibit restrictions in the topsides processing and injection capacities and maintenance is required more frequently (Silveira et al., 2016).

Revitalization processes depend on remaining reserves, physical and operating conditions of the production system and field production expectation. Subsea technologies can be easily integrated to the current infrastructure of the field, minimizing by this way the costs related to the modification of production workstations. To enable production in mature fields located in remote regions, in which oil flow rates are not high enough to justify a dedicated platform, the adoption of a subsea O-W separation system can be a solution for developing such areas (Albuquerque et al., 2013).

The implementation of these technologies in brown fields has demonstrated the anticipation of oil production, extension of reservoir productive life by establishing a lower abandonment pressure, avert shutting wells with attractive associated reserves with high WCUT, reduce the operational costs (OPEX) related to processing and water disposition, increase oil and water capacities topsides, production optimization and, reduce backpressures in the production network. It is considered as an environmentally friendly solution because decreases discharge of produced water to the sea. The installation of subsea systems will improve reservoir recovery by using the existing infrastructure that was designed for early productive stages of the field.

Some solutions to conventional artificial lift systems have been announced to increase the production in shallow and depleted reservoirs, depending mainly on the gas volume fraction (GVF) in the multiphase stream. For instance, Silveira et al. (2016) showed that subsea centrifugal pumping (SCP) and vertical annular separation and pumping systems (VASPS) are being considered as a revitalization strategy of the Marlim field together with compact O-W subsea separators and subsea multiphase pumps for boosting.

To overcome the production challenges (requirement of high water quality for re-injection and production of heavy oil with sand) in the Marlim field, it was proposed the project called 3-Phase Subsea Separation System. Capela et al. (2012) showed the design process and the technology qualification program executed for this project. They described the prototype and analyzed the effectiveness requirements of new subsea separation technologies. They stated that this project could be considered as the first subsea water separation system that requires high water quality and is a pioneer in comparison to Tordis and Troll fields.

This subsea separation project can be extended to other fields with increasing WCUT such as Marlim Sul, Albacora, and Golfinho; as stated in Pereira et al. (2012). They also announced that after successful implementations in these fields is expected to execute similar projects in Pre-Salt fields. No additional information about the results of operation under field conditions was encountered in the literature.

Other available technologies for subsea pumping applicable to mature fields are subsea pumping module (SPM), continuous subsea submersible pumping in skid structure (Skid-SCP) and hydraulic submersible pumps (HSP). Nowadays, several feasibility studies have been carried out to determine the best option for specific field conditions and fluid properties.

For instance, in 2015, Petrobras implemented SPM and Skid-SCP modules to reduce the amount of gas in the high flow rate stream of oil and reducing the global size of the systems: pipeline diameters and pumps. By this way, they increased the reliability of using subsea-pumping technologies, reduced the maintenance and intervention costs, the stop-times and production losses.

3.1.2.2 Application in New Fields (Green Fields)

Considering the installation of this technology in the production strategy to develop a newly discovered field is an attractive alternative in terms of net present value (NPV), compared with the conventional artificial lift systems (e.g., gas lift).

The optimization of the production strategy together with reservoir studies will permit saving costs related to the number of wells required for field drainage and increase the production at early stages. Generally, the application of subsea systems in new fields will exhibit savings in capital expenditures (CAPEX) and operating expenditures (OPEX).

Figure 3.2 shows the different applications of the subsea processing during the field production life. The main objective is the anticipation of production at early or later stages. When implementing in brownfields, it is expected to extend the field life and increasing the ORF during the stage of declination and before abandonment. In green fields, they are used to improve the cost-effectiveness for field development for starting-up and accelerating the production.

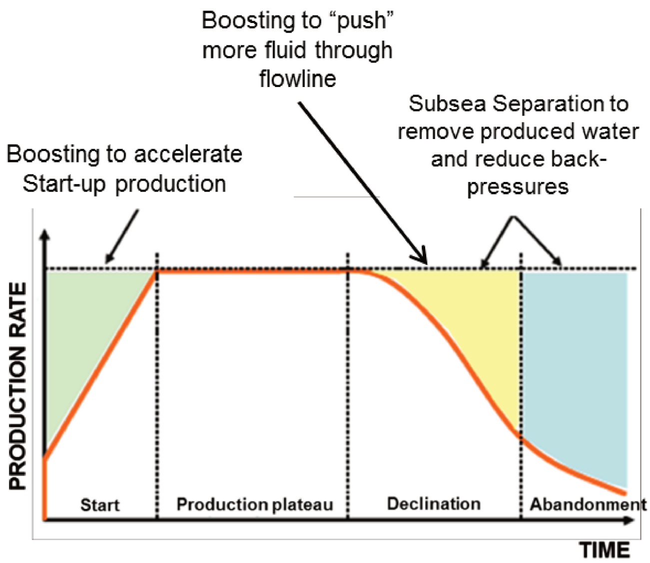

Figure 3.2: Applications of subsea processing at different production stages of a field (Modified from Lim and Gruehagen, 2009)

3.1.3 Requirement of Integrated Asset Modeling (IAM) for considering Subsea Systems

Silveira et al. (2016) and Abelson et al. (2016) pointed out that the right way to analyze implementation feasibility of these technologies is using IAM because it allows the evaluation of several and complex production scenarios with the same production network and platform. The evaluation is faster and more accurate and it is possible to quantify the impact of the installation on the global system. They also distinguished the subsea boosting as an effective-cost solution to face the current situation of low prices of the oil barrel.

Carvalho et al. (1996) developed a numerical simulation method including a subsea separation and boosting system. The equations of mass balance and momentum were solved simultaneously considering an isothermal process. As well as, they presented the modeling equations for oil and gas phases. The method was applied in the Albacora field (Brazil, Petrobras).

Bringedal et al. (1999) simulated the installation of the subsea separation and re-injection system of the Troll Pilot, Statoil. They coupled D-SPICE (dynamic process simulator) to OLGA (multiphase pipeline simulator) to analyze the best operating conditions of the field. They concluded that subsea processing can be an appropriate alternative for flow assurance and multiphase production in remote deep-water fields.

Barroso et al. (2016) pointed out the necessity of using a production-integration and optimization tool (IPSM, Petroleum Experts) to optimize and forecast production in Block-10, Campos Basin, Brazil. The software integrated reservoir, wells, subsea equipment and surface constraints, and optimized the oil flow rate of each well. It also permitted estimating fluid properties in the pipeline. The main challenge was maximizing the production in spite of severe restrictions imposed by wells, such as scaling, pump system, gas-oil separation efficiency, limitations related to power in ESPs, erosional velocity restriction and surface facilities.

3.1.4 Candidate Selection for Implementation

Before starting modeling, it is essential to identify which platforms (in case of giant offshore fields) or wells (in case of medium to small offshore fields) are going to be eligible for the execution of projects contemplating subsea systems. The most recognizable work explaining a candidate selection methodology is De Figueiredo (2005).

He analyzed the application of subsea O-W separation in the Marlim field and pointed out that the most important parameters to consider when dealing with mature fields are: WCUT (stabilization around 80-90%), water production (it is expected to implement the technologies in platforms with a higher water production) and an allowable oil-in-water content in the re-injection water. Based on the reduction of the amount of produced water, a new-smaller platform capacity was defined and as a result, was obtained an incremental oil production of 200 m^3/day and a reduction of the total liquid produced to the floating production unit corresponding to 90% of the water separated subsea.

3.2 Integrated Asset Modeling

3.2.1 Initial Efforts and Approaches

The first registered coupling is the work developed by Dempsey et al. (1971). They coupled reservoir and production network simulators through a rigorous iterative solution applied to the optimization and development of a gas field. Since that, many companies have considered the integrated models during the decision-making process in complex production strategies.

As well as, Startzman et al. (1977) provided the first approach to the integration concept. They implicitly coupled a facility simulator that calculated the capacity of the production network and determined the flow rates for each well. This data was passed to the reservoir simulator (Chevron´s in-house black oil simulator) that calculated the material balance, pressure, productivity index and WCUT for each time step.

Next, Emanuel and Ranney (1981) presented a formulation for three individual systems: reservoir, well flow and surface network using pre-generated tables of multiphase flow for determining the reservoir deliverability to design the gathering units. They moved the interface to the wellhead in order to reduce computational time.

Breaux et al. (1985) and Stoisits et al. (1992) showed the applications and impacts of integrated models on the studies of field development.

Litvak and Darlow (1995) used a compositional reservoir simulator and a multiphase surface network simulator for solving saturations, compositions and flow rates for each well by using a fully integrated implicit coupling. It is the first reported coupling using compositional models. The reservoir simulator provided bottom-hole pressure (BHP) to the surface network software, which solved the mass balance equation to determine the flow rates using flash calculations.

Hepguler et al. (1997), Trick (1998) and Barroux et al. (2000) coupled models of reservoir and production system using parallel virtual machines (PVM). Their main objectives were the optimization of the production strategies in the field, studying multiple production scenarios and the influence of surface facilities on the economic performance of the projects. They also affirmed that by using PVM is possible to reduce computational time and having a faster convergence without any loss in the result accuracy.

Additionally, Barroux et al. (2000) pointed out that by using black oil models, computational time was saved with reasonable accuracy in results, but the main drawback is related to the representativeness of detailed composition of streams, which is necessary to design the surface processing units.

3.2.2 IAM for linking Multiple Reservoirs

As observed before, one of the main applications of IAM is the feasibility evaluation of linking several reservoirs with differences in geological features and fluid properties and sharing common constraints. Some works can be quoted in that regard.

Haugen et al. (1995) compared results of an amalgamated full field model (AFFM) with reservoir coupling and concluded that the coupled model shows great accuracy in results and a significant reduction of the computational time. They also stated the advantages and disadvantages of considering each type of modeling.

Lyons et al. (1995) integrated a Mobil´s reservoir simulator (PEGASUS) with a surface simulator to model multiple reservoirs sharing a common surface pipeline network and processing units. Their objective was to generate curves of WHP versus flow rate (Q) for each well and the entire system.

After, Howell et al. (2006) used IAM to determine the cost/benefit relationship between 1) link a mature reservoir with existing subsea equipment and a new condensate gas reservoir or 2) install a completely new flow line to link the new reservoir to the platform. They also determined the effect of the options on the production and the economic model of the entire project.

Analogously, Rotondi et al. (2008) coupled ECLIPSE (reservoir), GAP (network) using RESOLVE (controller) for modeling three different offshore reservoirs to perform a sensitivity analysis of variables influencing field production strategies and compare the production profiles considering the surface facilities constraints.

Besides the implementation of IAM for carrying out this analysis, some authors expressed additional benefits when applied reservoir and production network coupling. For instance, Hayder et al. (2006) coupled the Saudi Aramco´s in-house reservoir simulator, POWERS, to a commercial surface network simulator, PEGAP, for planning the production strategy for a giant Saudi field. By this way, it was possible to reduce water production by 30%, re-define the oil potentials of reservoirs and optimize the production.

Nevertheless, some authors consider that integrated models can be too much time-consuming and require extra efforts to perform an analysis. For instance, Correa (2010) stated that it is preferable to develop a handcrafted work based on engineering criteria for simpler cases. He linked the reservoir model built in ECLIPSE with PROSPER to generate the vertical lift performance (VLP) curves, GAP for multiphase flow in pipeline and HYSIS for gathering, transport and processing facilities. His results showed that there is not a significant improvement on the already acquired knowledge during the handcrafted work.

3.2.3 Modifications and Improvements in IAM

To avoid inconsistency in results, some authors have innovated in the area by creating special algorithms, programs, controls and tools looking for improving the process and model reliability. The following works are remarkable:

Beliakova et al. (2000) created the hydrocarbon field-planning tool (HFPT), which was an explicitly integrated model of subsurface and surface to forecast several reservoirs with different fluid properties. The tool contained a business optimizer and permitted determining the optimal operational conditions to develop the field. The reservoir simulator was MoReS (Shell´s in-house simulator) and PipePhase for modeling the surface network. The size of the time step was adaptive to the rate of variation in the behavior of the overall model.

Al-Mutairi et al. (2010) explicitly coupled POWERS with an algorithm to calculate the inflow performance relationship (IPR) by replacing the pressure cell by the drainage area pressure, that is, the average pressure of the cells around the well. That was made in order to avoid oscillations in production rates due to events in wells. The system also included a commercial surface network simulator and RESOLVE as controller-integrator. Their objectives were maximizing production and the recovery factor (RF), reservoir pressure maintenance and decreasing water production.

Cotrim et al. (2011) described improvements in a field development project due to production rate management. They coupled explicitly a commercial reservoir simulator and a simplified surface network model to simulate two offshore fields of gas condensate and light oil sharing a gas production constraint due to gas pipeline capacity. The main contribution was incorporating into the controller the well management routine (WMR), which relocated the residual capacity of the system among the wells while honoring their individual constraints. This permitted avoiding unrealistic operating scenarios of successive startups and shutdowns of wells, and sudden changes in flow rates and operating the wells at very low rates where the limited IPR tables could lead to errors. By this way, they obtained a significant increase in NPV and an improved oil production compared to standalone simulation due to revenue anticipation using wells rates from the WMR.

3.2.4 IAM for Optimization of Production Strategies

Another application of IAM is determining optimal operating parameters for field production strategy. Due to there are too many variables in consideration, these models permit the evaluation of several scenarios at the same time in an easy and fast manner. Among the most outstanding works are:

Garcia Ruiz et al. (2015) evaluated the monitoring and optimization of a brown offshore field located in Campos Basin, Brazil using IAM. The assessment included a study of current production, determination of optimization scenarios and the effect of water treatment facilities on the field oil recovery. They used ECLIPSE for modeling the reservoir and PIPESIM for the production network. The model considered each branch of the satellite wells (production and injection) using the Beggs and Brill´s correlation (1973) for fluid flow in flow lines and riser, and gas lift distribution network.

Victorino et al. (2016) carried out a sensitivity analysis of production parameters that affect integration using commercial software of reservoir and production modeling through the explicit coupling. The production parameters they studied were pipeline diameters, gas-to-liquid ratios (GLR), WCUT, gas lift injection rate (Qgi) and WHP. They optimized the production strategy by evaluating NPV with the most influencing parameters: pipeline diameter and gas lift injection rate.

Hohendorff Filho and Schiozer (2017a) investigated the effects of integration on production forecasts, NPV and decisions related to field development. They confirmed that integration gives a more robust production strategy implementing the 12-step methodology proposed by Schiozer et al. (2015). They also studied the influence of the following parameters on the optimization of the strategy: platform location and capacity, geometric and operating features of the production network, pipelines and artificial lift systems.

4 METHODOLOGY

This chapter presents the methodology, which uses NPV and the maximum-theoretical value of technology (*VoTmax*) to analyze the economic attractiveness of installing subsea technologies for water production management. The main processes to be included in the model are the subsea separation and posterior produced water re-injection (PWRI).

An *integrated* model provides a more appropriate representation of phenomena occurring in the field and a better understanding of the overall relationship between the reservoir and the production network. Several scenarios are analyzed to assist the decision-making process.

Although this methodology was developed based on the analysis of a specific field case, it can be applied to other fields where the subsea technologies are being evaluated.

Note that the purpose of this work is not to model nor simulate the process carried out by the devices involved in separation and re-injection. Rather, this is a reservoir engineering approach to quantify the effect of installation on field production.

Future works to assess steps related to the design and sizing of each component of the production network are recommended. These should include a production facility engineering approach to evaluate the properties of the produced fluids and the field features.

The workflow used to consider the economic evaluation comprises the five steps shown in Figure 4.1.

4.1 Analysis of base case

This section comprises steps that were developed along-side the research and were considered to be the best options to select the best arrangements of the separation and re-injection components in the production network.

In the first step, the injector-producer influence to identify wells to be linked is assessed. The allocation criterion is used when analyzing the injection scheme of the field using the streamlines generated by the reservoir simulation software.

For each producer, allocations show the proportion of fluid originating from the contributing injectors, primary depletion, and aquifers. For each injector, allocations show the fraction of the injected fluid received by each producer (Computer Modelling Group, 2014). These contributions are used to calculate the amount of injected water (Wi_p) going to the producer by knowing the amount of injected water by the injector (W_i) and the respective allocation value, given by

$$Wi_p = Allocation * Wi \quad \textbf{(4.1)}$$

Figure 4.2 explains the procedure followed to determine the influence of each injector on the producers and the identification of well pairs.

Once determined the influence of each injector as a function of (Wi_p) and identified the well pairs, the methodology for candidate selection follows.

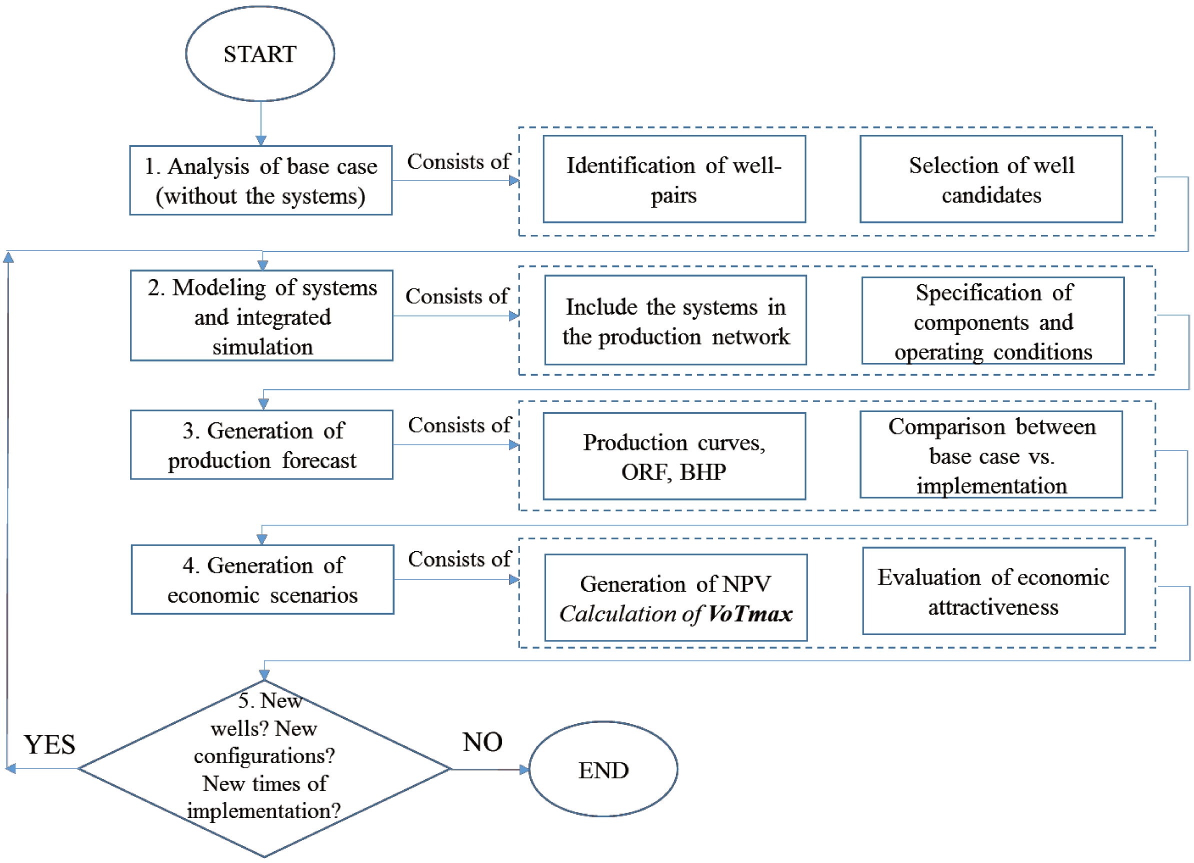

Figure 4.1: Methodology to evaluate the economic attractiveness of implementing the subsea technologies

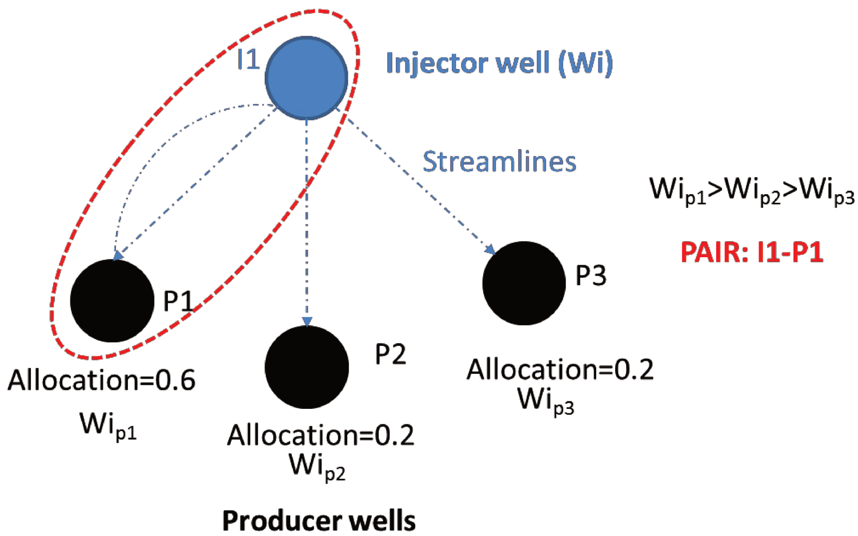

Figure 4.2: Allocation criteria for identification of well pairs

The selection criteria used are similar to those of De Figueiredo (2005). Based on tools of multivariable statistical analysis, the best candidates for subsea technologies are selected through the basic information of the production parameters in the base case. Note that this is only a guideline as the obtained expressions depend on the input data.

Using statistical analysis, we obtained linear multivariable regressions to forecast NPV according to implementation for individual wells as a function of production parameters such as cumulative water production (Wp) and time of breakthrough (TB). Wells are ranked by expected NPV to select the most attractive options. The explanation of how this well-selection methodology was developed, considered variables and models during the analysis, and how the regressions to forecast NPV were obtained are shown in detail in *Appendix A*. The arrangements of the production network are proposed based on the NPV ranking obtained with this selection criterion.

This is a good starting point to identify potential wells when there is a lack of field information.

4.2 Modeling O-W Separation, PWRI and Integrated simulation

Although the modeling of components of the subsea technologies is simplified, the integrated model allows evaluating the implementation from a reservoir engineering perspective that is, quantifying the reservoir production when considering the installation. The model appropriately represents the processes carried out during subsea separation and subsequent PWRI. Future works are required to obtain a better representation of equipment and processes using more sophisticated simulators of production network and production facilities. It would turn the production forecasts more realistic and would improve the accuracy of the economic results.

In this step, the subsea technologies and their components (equipment localization, operating conditions, monitoring rules, and control variables) are modeled. After defining the equipment to be modeled, the integrated simulation begins.

Two possible well arrangements can be proposed to include the subsea systems in the production network: single-well and multi-well. In the case of single-well, we adopted a satellite well approach and it consists of a dedicated O-W subsea separator and a subsea pump to perform the separation and re-injection processes. For multi-well arrangements, several producers can be linked and gathering the production using manifolds. Each producer well has a dedicated O-W subsea separator and can be linked to a dedicated re-injection pump or share a pump to inject the water to the same injector. Figure 4.3 shows schematically the differences between the two arrangements.

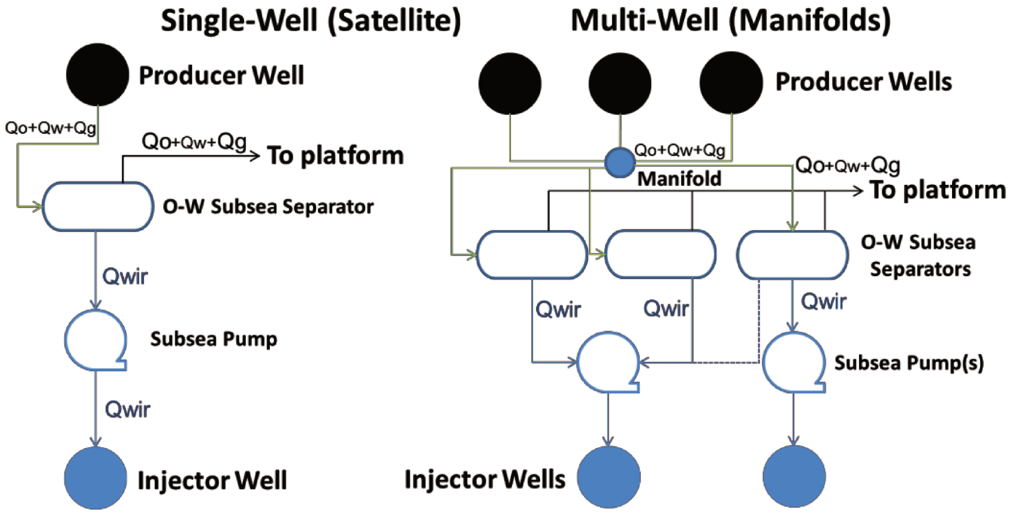

Figure 4.3: Differences between single-well and multi-well arrangements

Figure 4.4 presents the general scheme of a single-well application of technologies for oil-water (O-W) subsea separation and produced water re-injection (PWRI), showing modeled components and production rates of each phase. Other features particular to modeling these technologies are also shown, such as linking distances, water depth, reservoir depth, and distance to the coast.

The fundamental reasons for installing the technologies are (1) to separate the hydrocarbon (Q_o and Q_g) and water streams (Q_w) from the producer well and (2) to reinject the water stream (Q_{wr}). The hydrocarbon stream may contain some water, depending on the efficiency of the separator.

It is assumed that the water quality following separation is adequate to avoid impairing injectivity (due to the presence of solids, oil-in-water content, sand or heavy metals).

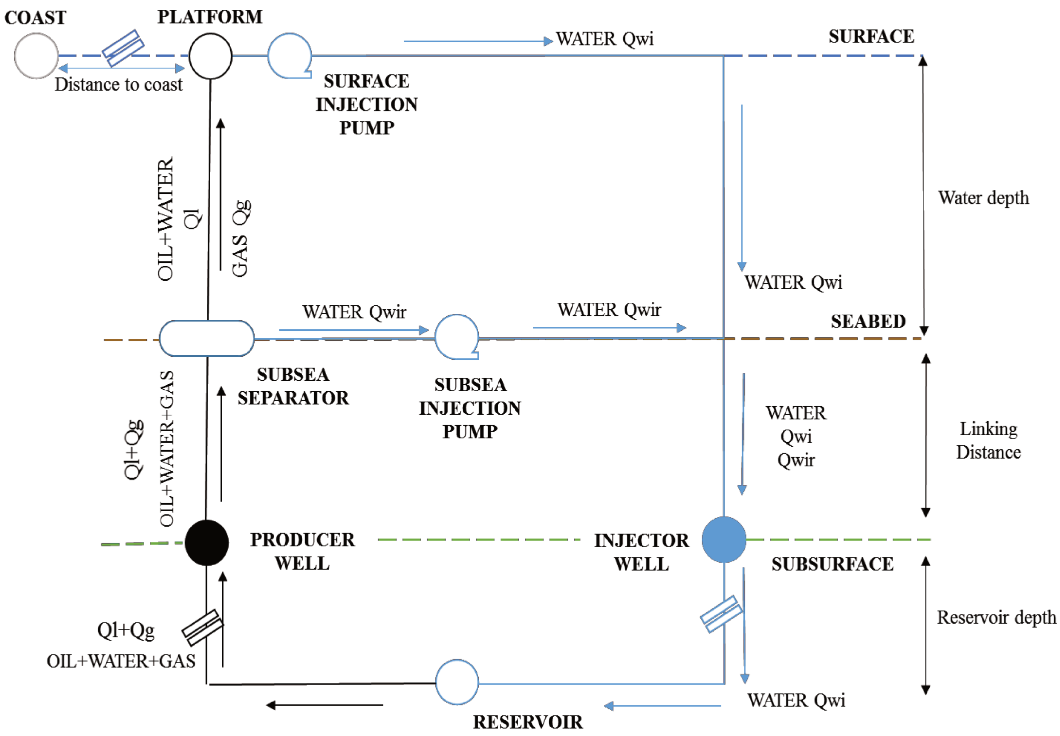

Figure 4.4: Production network for a single-well implementation of O-W subsea separation and PWRI

Following the concept defined by Khoi et al. (2009), the subsea separator should be installed as close as possible to the separator vessel, on the producer wellhead, to minimize pressure drops along the network and take advantage of the reservoir energy.

The water stream can also contain traces of hydrocarbons. This water is sent to the subsea pump that provides the required energy for injection, either for secondary recovery purposes or to sustain pressure. The subsea pump should be located as close as possible to the injector wellhead to utilize the energy and minimize drops in pressure.

Better separation results in more water being sent for re-injection and improves the hydrocarbon stream sent to the platform. The separated and re-injected water is discounted from the available water for injection in the platform, relieving the injection capacity. By directly injecting the produced water at the seafloor, the amount of water sent to the surface for treatment is also reduced, relieving the liquid capacity of the platform to receive more oil. Large amounts of water associated with oil can be produced favoring the increase in ORF.

According to Magi et al. (2012) and Abelsson et al. (2016), besides reducing the amount of water being sent to the platform, the separation also reduces pressure drops from the flow line to the surface, increasing oil production. Increased anticipated oil production associated with high water levels is expected when implementing these systems. Other advantages of these subsea technologies are lower bottom-hole pressure (BHP) and wellhead pressures (WHP) in the producers.

4.3. Generation of production forecast

In this step, the reservoir production curves are generated, including oil, water, and liquid rates (Q_o, Q_w, Q_l, respectively), and curves of water injection rates and re-injected water rates (Q_{wi}, Q_{wir}, respectively). These curves are compared with those of the base case (without the installation) to identify the differences and benefits. This comparison is essential to analyze the response of the reservoir, in terms of production, to the inclusion of the subsea technologies.

Increased and higher anticipated oil production at later stages are observed. The generation of ORF curves is a secondary evaluation and is evidence of increased production.

It is also possible to identify the reduction of water sent to the platform because of PWRI and to quantify the water re-injected into the reservoir to support the injection process. Less water produced at the platform means the liquid platform capacity is available to receive more oil associated with large volumes of water.

Other curves such as BHP of the producers are used to identify lower pressures at the bottom-hole and subsequent increases in differential pressure (dP) between the reservoir and well, explaining increased well-productivity and, therefore, oil production.

4.4 Generation of economic scenarios

Once the production for each time step until the end of the simulation is determined, the next step is to generate economic scenarios, specifying the investments required to install the systems.

Because of the variability in costs of the subsea technologies, the dependency on specific applications, and the lack of explicit information in the literature, we created a methodology similar to that by De Naurois and Desalos (2001). We use differences between NPVs as the objective function (*VoTmax*) to evaluate the economic attractiveness of subsea technology installations, as defined in Equation 2.2.

There are some limitations of using this approach when quantifying the value of new technologies as the ones being evaluated in this work. Therefore, we made some assumptions in the definition and inclusion of *VoTmax* in the analysis to overcome this.

The conditions of the project are assumed to be known including the lifetime of the equipment to be installed, that is, it will work without affecting performance from the installation until the end of the simulation (abandonment date of the field) without requiring repairs or replacements.

Despite incomplete information about the quantification of risk involved in installing operations and failure of the equipment, represented by the discount rate to calculate NPV, we decided to continue working with the same economic scenarios of the field used in the methodology for consistency when comparing results.

Furthermore, capital expenditures (CAPEX) for installation, operating expenditures (OPEX) associated with energy supply, pauses in production, and maintenance costs were also excluded when calculating the NPV_{with} indicator.

Several scenarios are discussed because of different production network setups, such as single (one O-W subsea separator and a subsea pump) and multi-well arrangements (full separation and re-injection scheme using multiple separators and shared pumps), whether to use them in selected or all wells of the field, and determining the optimal time of implementation.

The selection of the best scenarios is based on the most attractive economic results, as a consequence of increased oil production and thus, ORF, and the reduced water production at the surface.

As such, the evaluation of these possibilities requires flexibility in the model used. Integrated asset modeling (IAM) allows the network configuration to be easily altered, production behavior to be forecast, and economic attractiveness to be evaluated by economic results obtained.

IAM is an excellent choice when dealing with complex scenarios and difficult analyses where the variables constantly change.

5 APPLICATION

In this chapter, the details of each submodel comprising the integrated model and the assumptions considered are going to be explained. The integrated model was constructed based on the work developed by Teixeira (2013), who analyzed a gas-liquid (G-L) subsea separation using integrated asset modeling (IAM).

The submodels that were explicitly coupled to achieve the main goal of this work are the following:

- Reservoir: IMEX (Computer Modelling Group, CMG)
- Wells: PTUBE (CMG)
- Production network: CORAL (Research in Reservoir Simulation and Management Group, UNISIM)
- Economic: MERO (UNISIM)
- Integrator-coupler: CORAL (UNISIM)

Each submodel can be as robust and have as detailed information, but this will increase computational time, being in some cases impractical when making decisions or when results do not have significant differences compared to more simplified models. For simpler analysis, as established in Correa (2010), it is preferable to develop a handcrafted work based on engineering criteria than investing efforts in building a more complex model that will not improve the quality of results.

The reservoir submodel was used to calculate the flow in porous media and model the inflow performance relationship (IPR), providing bottom-hole pressure (BHP), oil, water, and gas rates (Q_o, Q_w, and Q_g, respectively). This information is used to model the hydraulic pressure loss in the well by simulating the multiphase flow in the tubing using the Beggs and Brill (1973) correlation for producer wells.

The production network submodel was used to find the operating point (intersection of IPR curve and Vertical Lift Performance, VLP curve) and solve the network while honoring added constraints. This was made for each time step until end of simulation. Next, the production forecast is generated for each time.

The economic submodel used this forecast to generate economic results and indicators based on predefined cost scenarios for this project.

Figure 5.1 shows schematically the workflow and interchanged data between the submodels comprising the integrated model created. This workflow is analogous to the exhibited in Figure 2.5, defined in Hohendorff Filho and Schiozer (2012) and used by CORAL.

Although calculations of flow in the reservoir and total pressure gradient in the tubing are performed one after other (IMEX calling internally PTUBE after finishing the calculations at the end of its time step), we decided to separate reservoir and wells submodels. This was because of data exchange from one simulator to another and the dependency of information (in this case, PTUBE depending on data provided by IMEX).

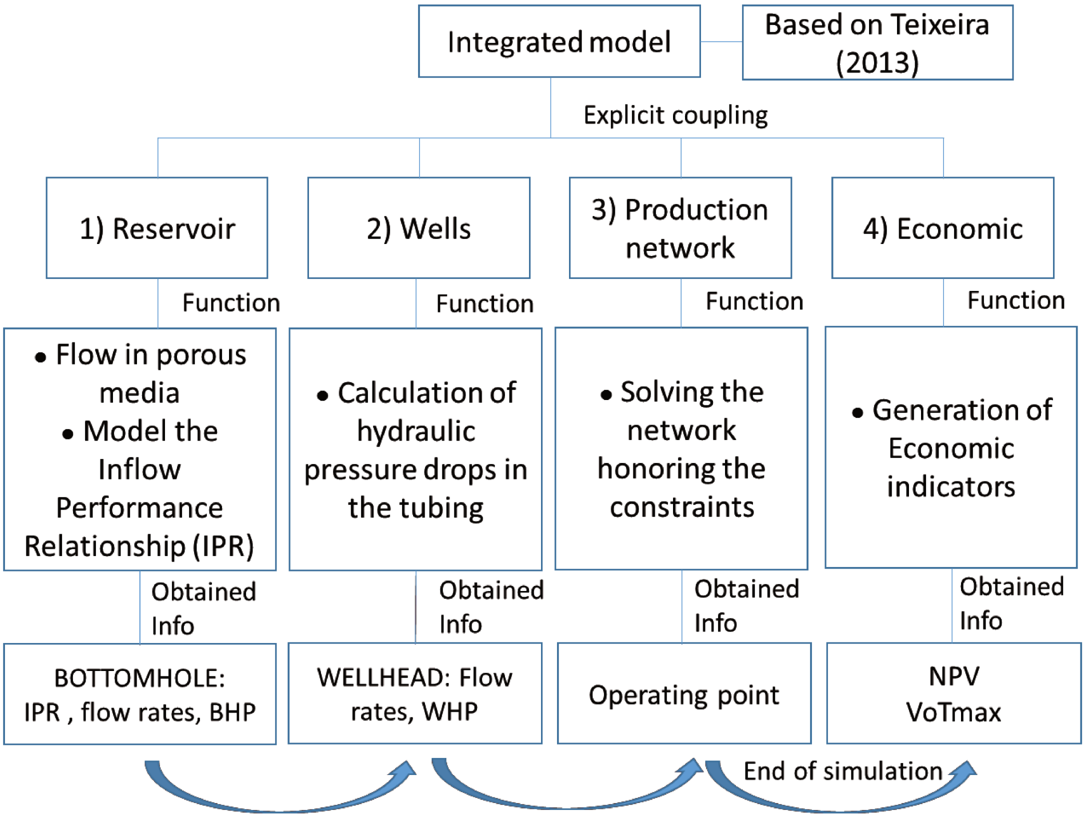

Figure 5.1: Workflow and interchanged data between submodels

Despite some simplifications of the equipment components, the model did not lose the representativeness of the phenomena occurring during the separation process and subsequent PWRI.

IAM was used in the analysis to dynamically forecast production to obtain economic scenarios and, so, evaluate profits. The submodels comprising the integrated model are explained in detail below.

5.1 Reservoir and Components

The features of the reservoir submodel are based on benchmark case UNISIM-I-D (Gaspar et al., 2015) and taking into account the installation of the technologies as an anticipated solution to mitigate the problem of water management at later production stages of the field. Figure 5.2 shows the distribution of oil saturation of the considered reservoir simulation submodel and location of wells of the assumed production strategy.

The implementation of the technologies is considered as a revitalization variable (G3), as established in the 12-Steps methodology to petroleum field development and management in Schiozer et al. (2015).

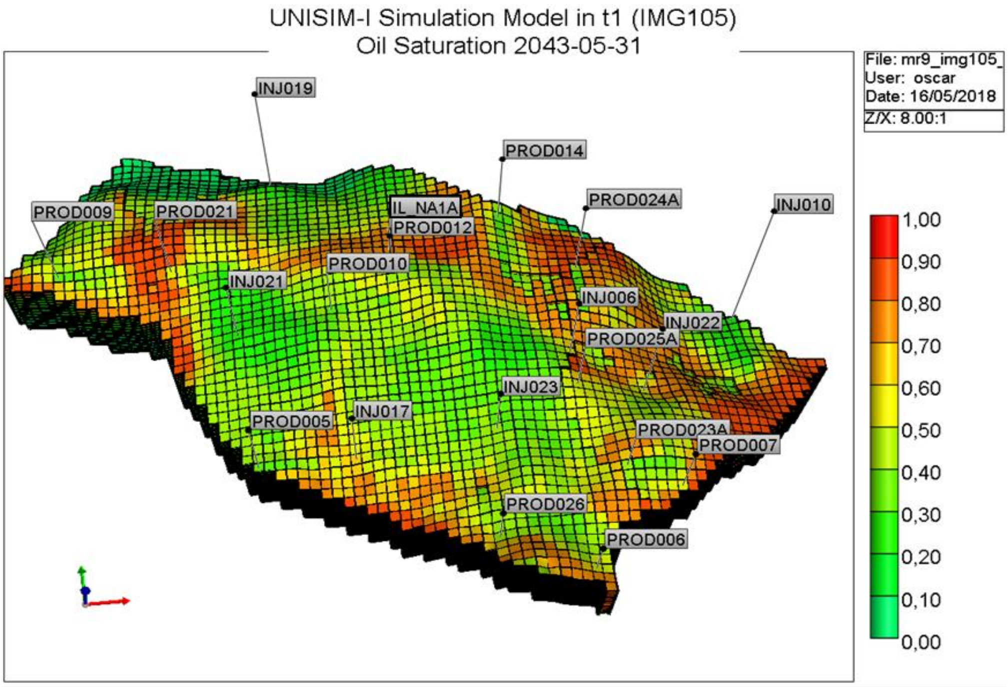

Figure 5.2: Oil Saturation Distribution in case UNISIM-I-D. Time 10957

This benchmark case contains uncertainties in geological, petrophysical and fluid properties. These uncertainties generated several possible scenarios for analysis. The representative models (RMs), a reduced subset of scenarios, are representative of the original set and also free of optimistic or pessimistic bias (Meira et al., 2016).

The properties under uncertainty were included during a stochastic generation of same occurrence probability in 500 images for benchmark case UNISIM-I-D. For this case, RM9 was used to represent the reservoir attributes and assuming as fixed all the values of these properties in img105. For further information about the RMs and images of UNISIM-I-D, see Schiozer et al. (2015) and *https://www.unisim.cepetro.unicamp.br/benchmarks/files/UNISIM-I-D-probabilistic.zip*

The black-oil formulation was used to model fluid behavior in the reservoir simulator as there is no mass exchange between the fluids and, according to the existing reservoir submodel, the rock, and produced fluids do not interact. Moreover, the secondary oil recovery method implemented in the field (water flooding) is considered to be immiscible.

Due to the modeling of fluid properties using IMEX (CMG), that is, using the property array format, the corresponding property will be updated only as a constant property defined previously in the array (Computer Modelling Group, 2014). This works for cases where the fluid behavior is not as complex. For this reason, constant values in the properties are observed when the pressure reaches the bubble point pressure. Table 5.1 shows the fluid properties and components required to model the reservoir.

Table 5.2 summarizes the main reservoir features and simulation times used to establish model RM9. Considered values in the array that model the oil and gas properties: formation volume factor (FVF), gas solubility (Rs) and viscosity are presented in Figures 5.3 to 5.7.

Analogously to PVT tables, petrophysical properties (i.e., porosity and permeability) are also uncertain attributes and defined in RM9 (img105). For this case, these properties were also assumed to be known. Figure 5.8 shows the porosity map of the model and Figures 5.9 to 5.11 show the distribution of permeability in I, J, and K directions, respectively and defined in RM9 and img105.

Rock-fluid properties used for modeling are uncertain too. The relative permeability curves were obtained from one of the four equiprobable scenarios of UNISIM-I-D (Schiozer et al., 2015). The permeability relative curves to oil, water and gas are schematically shown in Figure 5.12.

Table 5.1: Fluid properties and components included in the reservoir submodel. UNISIM-I-D, RM9

PROPERTY	VALUE	UNITS
Stock Tank Oil Density	866	kg/m^3
API Gravity	31.89	° API
Gas Specific Gravity	0.745	Dimensionless
Water Density	1,010	kg/m^3
Water Formation Volume Factor	1.021	m^3/ m^3std
Water Viscosity	0.3	cp
Water Compressibility	47.64 E-06	cm^2/kgf
Reservoir Temperature	80	° C
Rock Compressibility	82.4 E-06	cm^2/kgf
Maximum Gas Volume Fraction (GVF) at reservoir conditions	0.72	%

Table 5.2: Reservoir features established in RM9

PROPERTY	VALUE	UNITS
Grid	Corner Point	-
Blocks	326x234x157 (37,000 active, approximately)	-
Size of blocks	25x25x1	m
Top of Reservoir	2,900	m
Bottom of Reservoir	3,400	m
Range of Permeability I	1-1,275	mD
Range of Permeability J	1-1,722	mD
Range of Permeability K	3-4,277	mD
Range of Porosity	1-30	%
WOC	3,100 (West block), 3,224 (East block)	m
Reference Pressure	327	kgf/cm^2
Bubble Point Pressure	210.03	kgf/cm^2
Oil Volume In-Situ (Time 0)	1.3677E+008	m^3
Simulation start date	05/31/2013 (Time 0)	-
Simulation end date	05/31/2043 (Time 10,957)	-

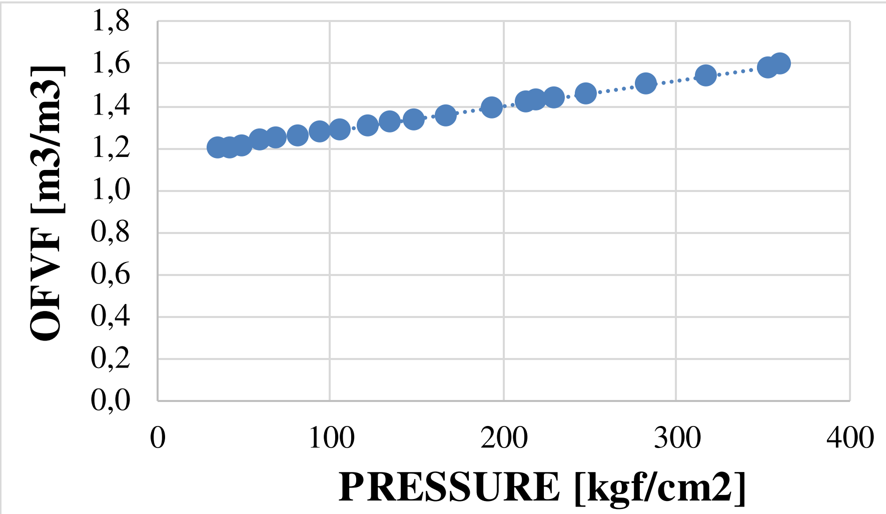

Figure 5.3: Oil formation volume factor (OFVF)

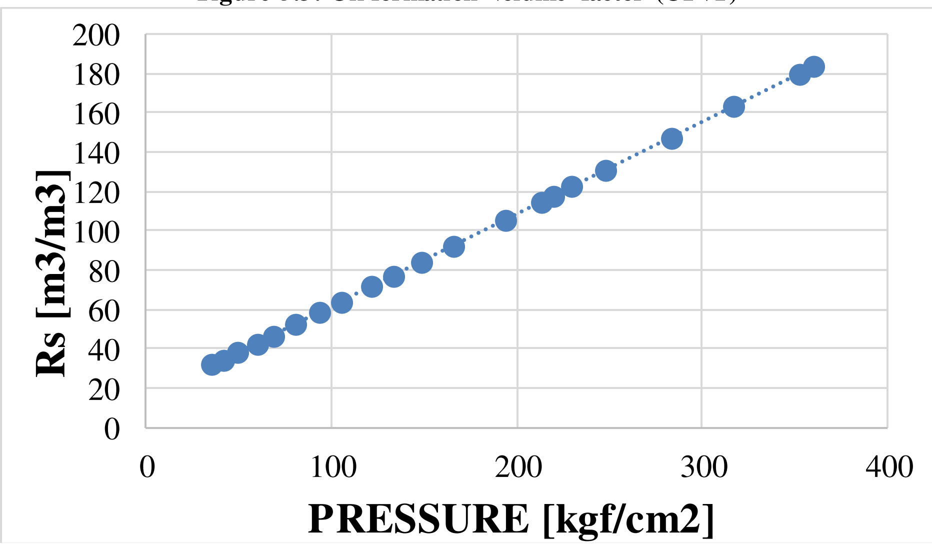

Figure 5.4: Gas solubility (Rs)

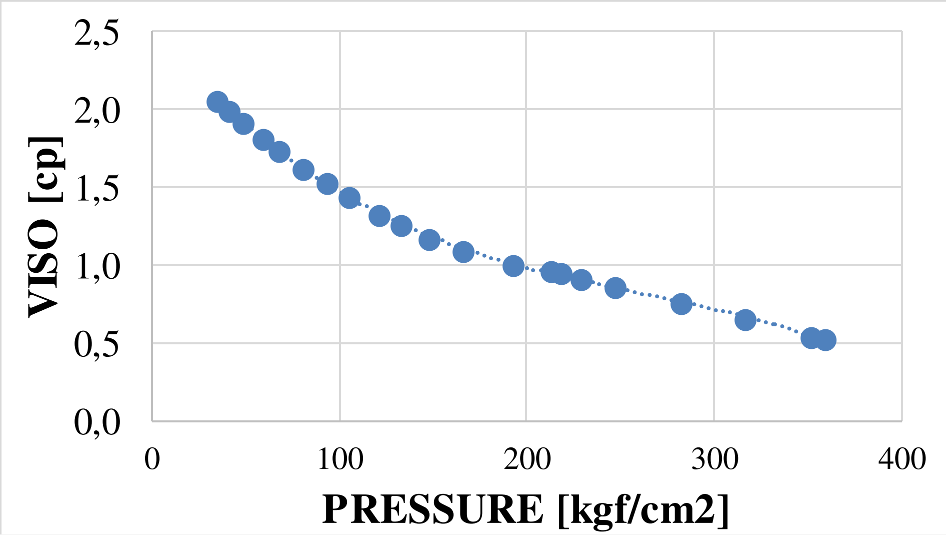

Figure 5.5: Oil viscosity (VISO)

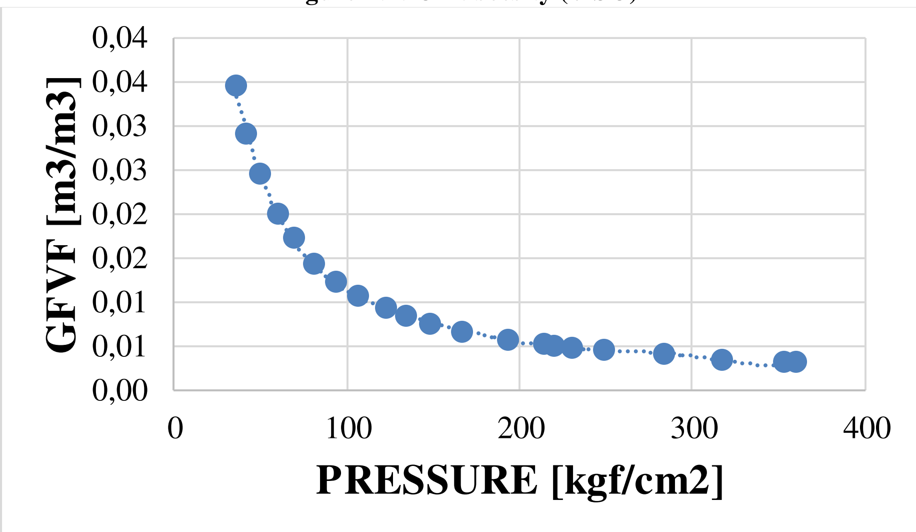

Figure 5.6: Gas formation volume factor (GFVF)

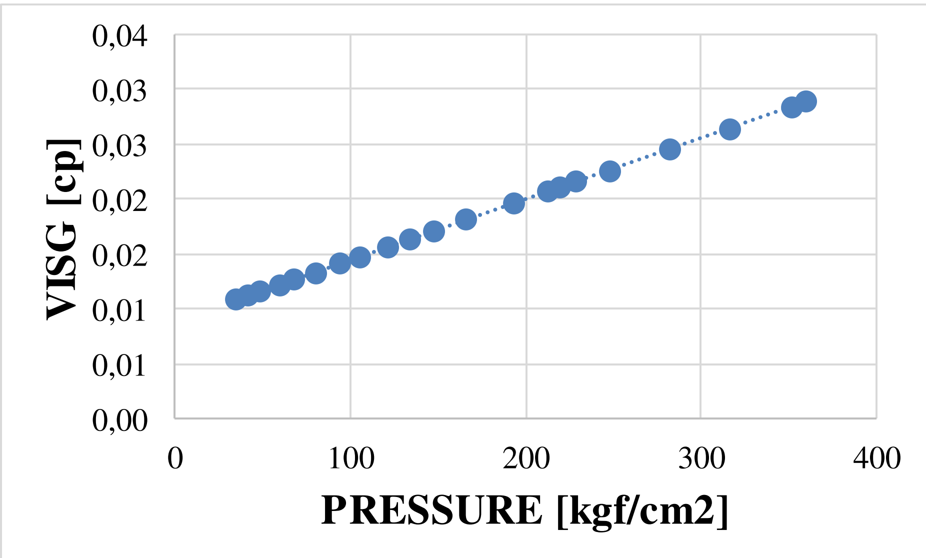

Figure 5.7: Gas viscosity (VISG)

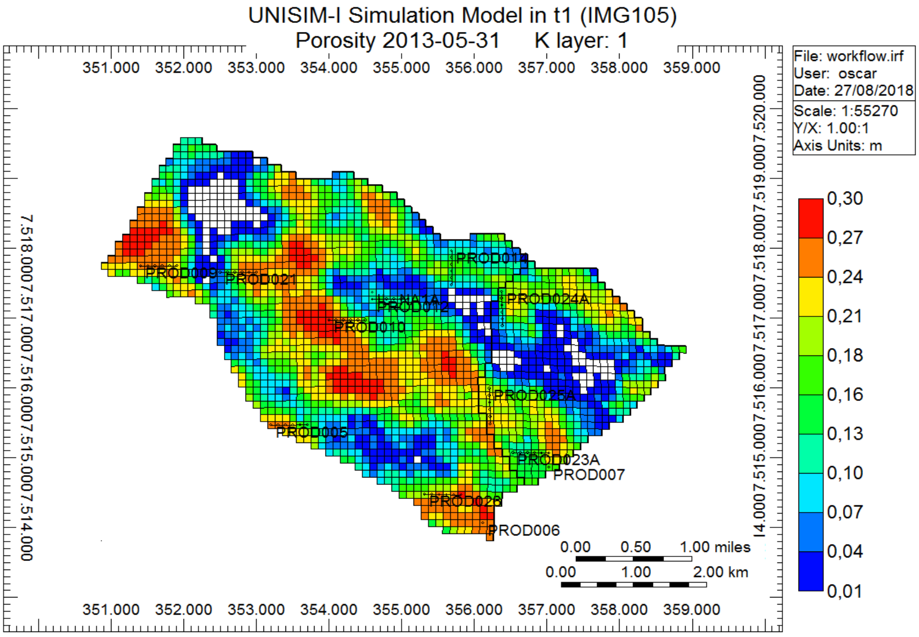

Figure 5.8: Porosity map. UNISIM-I-D (RM9-img105)

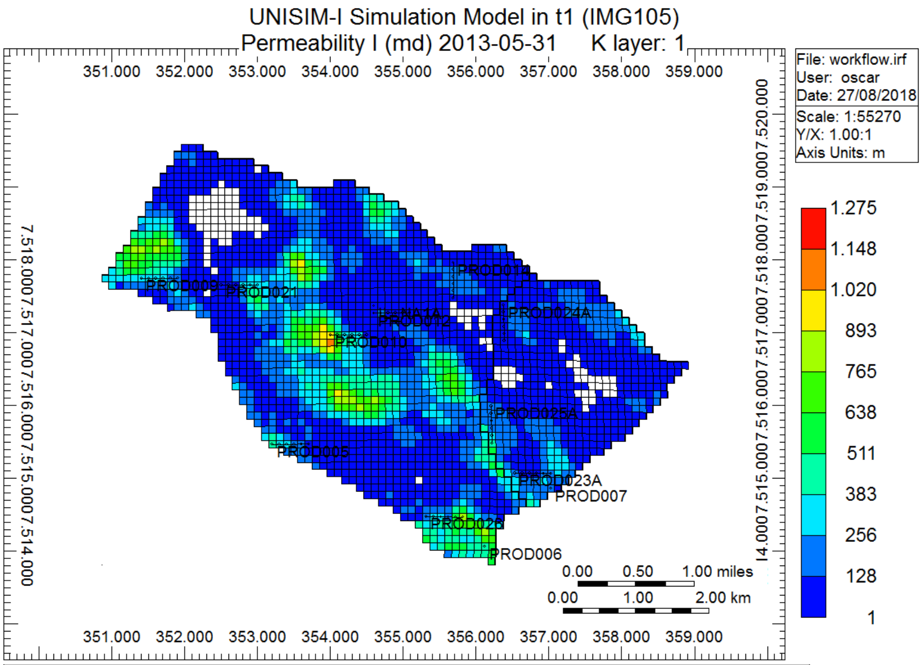

Figure 5.9: Distribution of Permeability in I direction. UNISIM-I-D (RM9-img105)

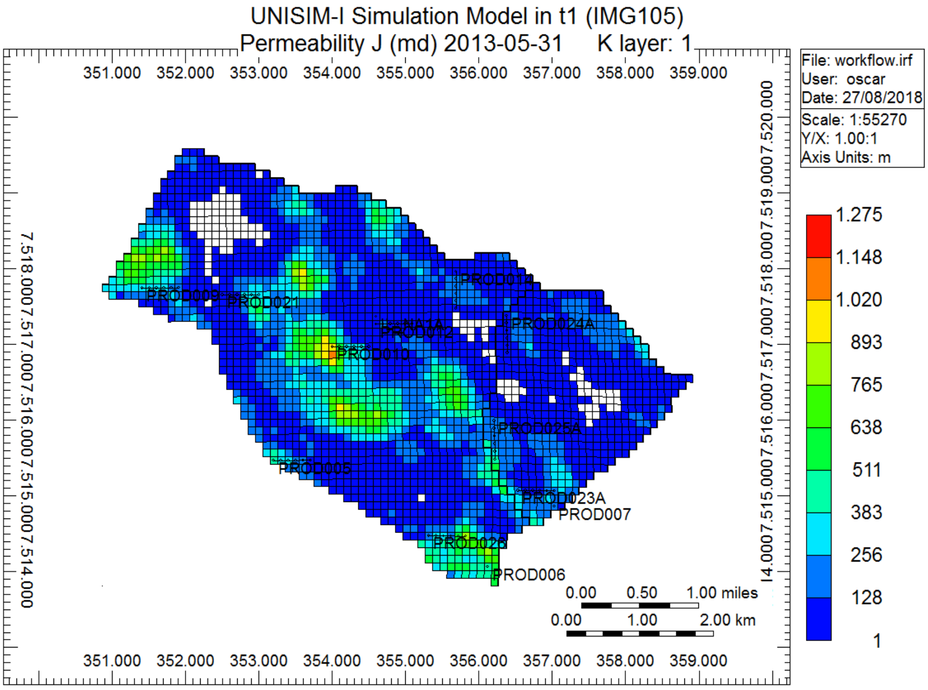

Figure 5.10: Distribution of Permeability in J direction. UNISIM-I-D (RM9-img105)

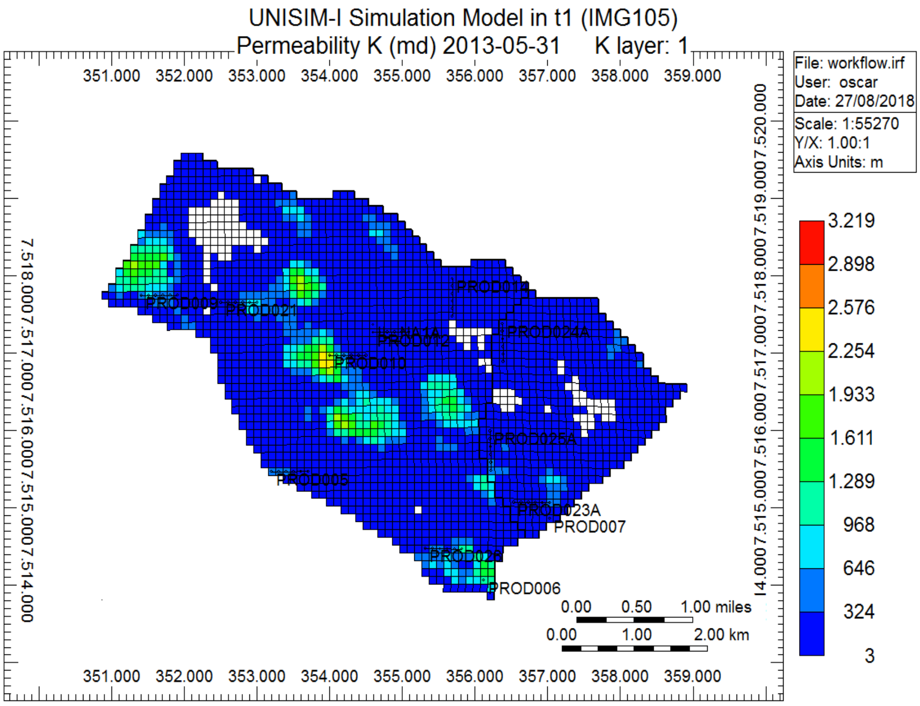

Figure 5.11: Distribution of Permeability in K direction. UNISIM-I-D (RM9-img105)

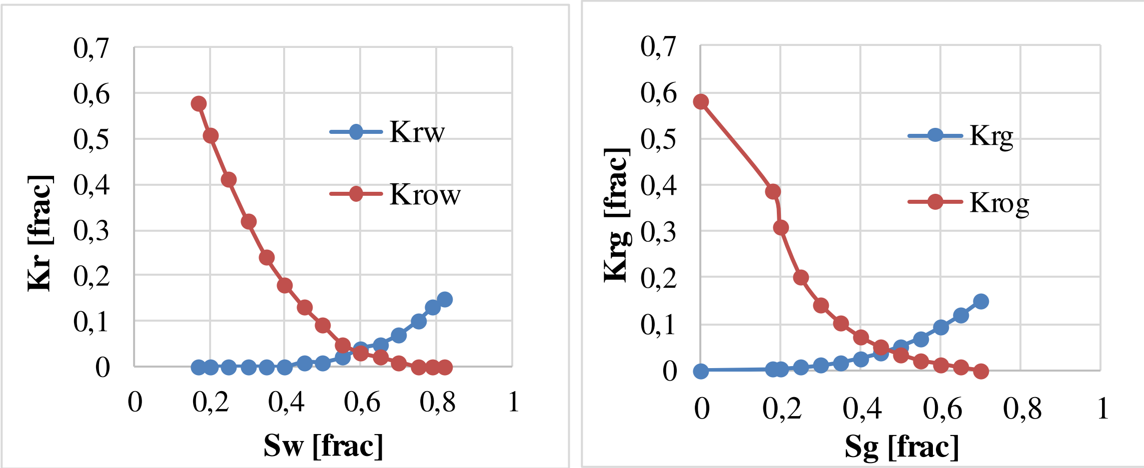

Figure 5.12: Relative permeability curves (Kr and Krg, respectively) used in RM9, UNISIM-I-D

5.2 Wells

The software to calculate the hydraulic-pressure drops receives the information for Q_o, Q_w, Q_g, and bottom-hole pressure provided by the reservoir submodel and uses an empirical correlation of multiphase flow (for this case, Beggs and Brill, 1973) to estimate the total pressure gradient from the bottom to the surface through the tubing. It is noteworthy that this was performed for producer wells only. This correlation is the best known for flow in pipelines and is applicable to all inclination angles (Shoham, 2006). The calculation of pressure drops along pipelines was not the focus of this work; as such, we used empirical models as a good practical approximation of engineering rather than the more rigorous solution using mechanistic models.

The way the software performs these calculations is the same exhibited in the workflow for Beggs and Brill (1973) correlation in content *2.7 Correlations of Two-Phase Flow in Pipeline*. Wellhead pressures (WHP) and flow rates of each phase at the producer wellhead are obtained from this step.

Besides the integration, well modeling requires to honor some operating restrictions to turn the production more realistic. These restrictions can be modifiable according to selected criteria to operate and manage the production of wells and as a field development strategy that varies according to engineer's criteria.

Tables 5.3 and 5.4 specify the operating conditions and monitoring rules adopted for this case for both producers and injector wells, satellite type, and with subsea separators and/or subsea pumps installed.

Table 5.3: Operating conditions and monitoring rules for producers (1) satellite wells and (2) with subsea separators installed

OPERATING CONDITION	VALUE	UNITS
Minimum Wellhead Pressure (Satellite)	15	kgf/cm^2
Maximum Flow Rate	3,200	m^3/day
Minimum Flow Rate	20	m^3/day
Maximum Gas-Oil Ratio	200	Fraction
Maximum Water Cut	0.95	Fraction
Production Efficiency	0.91	Fraction

Table 5.4: Operating conditions and monitoring rules for injector wells. Satellite wells with and without subsea pumps installed

OPERATING CONDITION	VALUE	UNITS
Minimum Bottom-hole Pressure	450	kgf/cm^2
Maximum Flow Rate	5,000	m^3/day
Injection Efficiency	0.98	Fraction

5.3 Production Network Submodel

The subsea technologies and component specification in the production-network are included in this submodel. Location and operating conditions of subsea separators and subsea pumps were established here. These features are easily modifiable to evaluate other more complex configurations such as multi-well applications.

For proposing the wells to be included in the production network arrangements, a previous identification of pairs injector-producer is necessary.

The operating conditions of the subsea technology components and other required features of the production network (i.e., the diameter of pipelines, linking distances, and temperatures) are summarized in Table 5.5.

The final configuration for a single-well installation including values related to the project specifications established in benchmark case UNISIM-I-D as shown in Table 5.5 is illustrated in Figure 5.13.

Table 5.5: Features of the proposed production network and operating conditions of the subsea technologies

FEATURE	VALUE	UNITS
Inner diameter of tubing	6-8	in
Inner diameter of flow line	6-8	in
Inner diameter of riser	6-8	in
Linking distance producer-subsea separator	0	m
Linking distance injector-subsea pump	0	m
Separation temperature	38	°C
Temperature of re-injected water	20	°C

The operating conditions of the subsea separator and subsea pump depend on the incoming flow rates to the devices and pressure drops. The separator works at any flow rate provided by the producer well and separates the fluids at a pressure that balances the flow rate and the pressure drops expected into the vessel. That is, considering the separator as a pressure node.

The efficiency of fluid separation was assumed as 100%, so all the water contained in the input stream is separated and sent to the subsea pump, nevertheless, not all this separated water is re-injected into the reservoir, because it will depend on the well injectivity and the maximum amount of water required to support the injection process. Generally, all the additional separated water that was not injected will be produced in the surface.

Analogously, the subsea pump works at any water rate separated by the subsea separator and provides enough pressure to inject at any water flow rate.

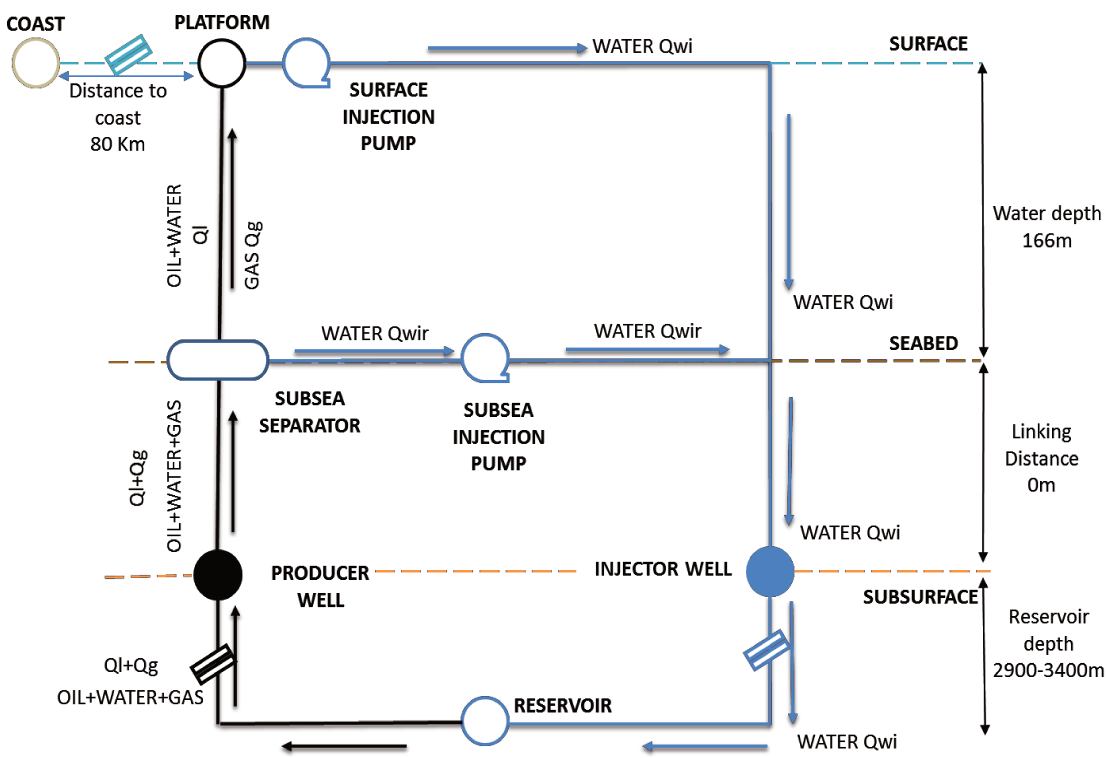

Figure 5.13: Final production network for single-well application

5.4 Economic Submodel

Once the production curves are generated and compared for the entire simulation time, the next step is to perform the economic calculations using net present value (NPV) as the objective function and considering the internal pre-established economic scenarios adopted by the UNISIM group and defined in Gaspar et al. (2015).

The base case (without subsea technologies) was compared to cases with implementation by NPV. NPV was calculated considering the deterministic approach with the most likely scenario, fiscal assumptions based on the Brazilian R&T fiscal regime, and associated costs of the project UNISIM-I-D. Table 5.6 summarizes the associated costs of the project.

Table 5.6: Most likely scenario (deterministic) in UNISIM-I-D (Modified from Gaspar et al., 2015)

FEATURE	VALUE	UNITS
Oil price	314.5	USD/m^3
Oil production cost	62.9	USD/m^3
Water production cost	6.29	USD/m^3
Water injection cost	6.29	USD/m^3
Investment on drilling and completion of horizontal well	61.17	10^3 USD/m
Investment on connection (well-platform)of horizontal well	13.33	USD million
Investment on drilling and completion of vertical well	21.67	USD million
Investment on connection (well-platform)of vertical well	13.33	USD million
Abandonment cost (% investment on drilling and completion)	8.20	%
Annual discount rate (%)	9.00	%

NPV and the new indicator, maximum-theoretical value of technology (*VoTmax)*, are used to identify when subsea technologies can improve the economic return. Because of assumptions in the definition of *VoTmax*, careful consideration is necessary when assessing investment and economic attractiveness of installation.

5.5 Case Studies

The following cases were proposed to analyze and compare production forecast and economic results of the installations during different production stages when the subsea systems are implemented. The two case cases 1) revitalization of field and 2) new (green) field are compared with the base case, OPT PLAT. The cases with installation are further divided into single-well and multi-well installations.

The base case (OPT PLAT) incorporates the features of RM9 and the optimized production strategy S9, which does not consider the installation of subsea technologies, that is, RM9-S9.

S9 comprises 20 wells distributed throughout the field: 13 producers and 7 injectors. The specifications of RM9-S9 are found in Schiozer et al. (2015). Base case will provide the initial NPV to calculate *VoTmax* for each implementation, as well as, will permit comparing the production forecasts to identify the benefits from the application of the technologies.

Due to RM9-S9 was optimized using a standalone approach; an optimization of the platform capacities using IAM was required. It was done to fairly compare the base case and the cases with installation, and to guarantee that neither production results nor economic indicators were influenced by platform restrictions for liquid or water production.

Table 5.7 shows the optimized platform capacities to handle liquid, CPL; oil, CPO; water, CPW, and the injection platform capacity, CPIW. This base case, OPT PLAT, obtained NPV of 3.105 USD billion, which was used to calculate the *VoTmax* of subsequent implementations.

Table 5.7: Platform specifications of the base case - Model OPT PLAT

FEATURE	VALUE	UNITS
CPL	21,700	m^3/day
CPO	21,700	m^3/day
CPW	14,996.25	m^3/day
CPIW	28,752.5	m^3/day

Case Study 1: Revitalization of field

It shows the installation in fields at later production stages to revitalize oil production and as an anticipated solution to mitigate the problem of water management. Installation is at the beginning of declining oil production. Additional benefits from implementation are also discussed.

Case Study 2: New field

This case shows installation in new fields (green fields). It assumes that the systems are implemented at the beginning of well production. The potential of including subsea technologies in production strategies is also discussed.

6 RESULTS AND DISCUSSION

6.1 Identification of well-pairs

The influence of injectors was identified using allocations and calculating the cumulative injected water (Wi_p) to each producer. By this way, curves shown in Figure 6.1 to 6.6 were generated. Table 6.1 summarizes these results. The injector-producer influence is the same for both cases: revitalization and new field.

We considered the identification of well-pairs as the best way to propose the wells to be included in the arrangements of subsea technologies. Nevertheless, the disposition of subsea separators and pumps is a free choice of the engineer in charge of the analysis. According to his criteria, other scenarios can be evaluated and other values of maximum-theoretical value of technology (*VoTmax)* can be obtained. Because of this activity is a first approach to evaluate the economic attractiveness of installation, an optimization process is required in next steps to find the optimal configuration of the systems in the network, but this is not the focus of this work.

Notice that the same injector can influence several producers, so some subsea pumps can be shared when modeling the systems. Well INJ023 does not appear in the table because the influenced wells (PROD010 and PROD012) are already linked to another injector with a greater value of allocation.

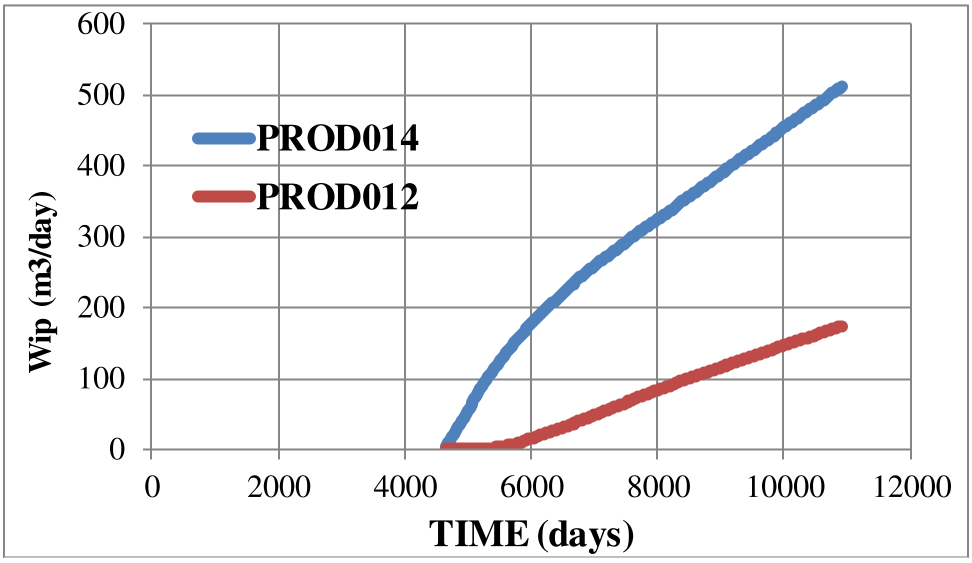

Figure 6.1: Distribution of Wi_p from well INJ006 to wells PROD014 and PROD012

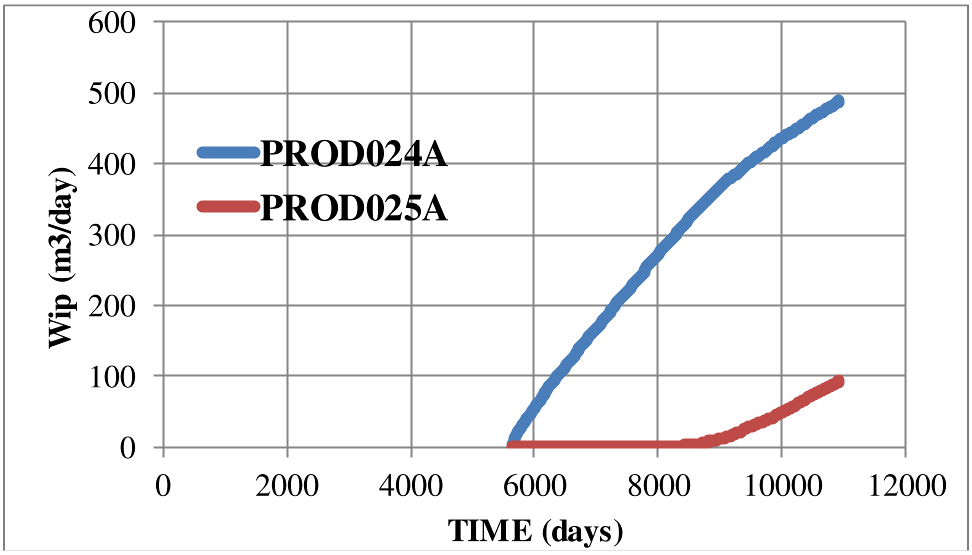

Figure 6.2: Distribution of Wi_p from well INJ010 to wells PROD024A and PROD025A

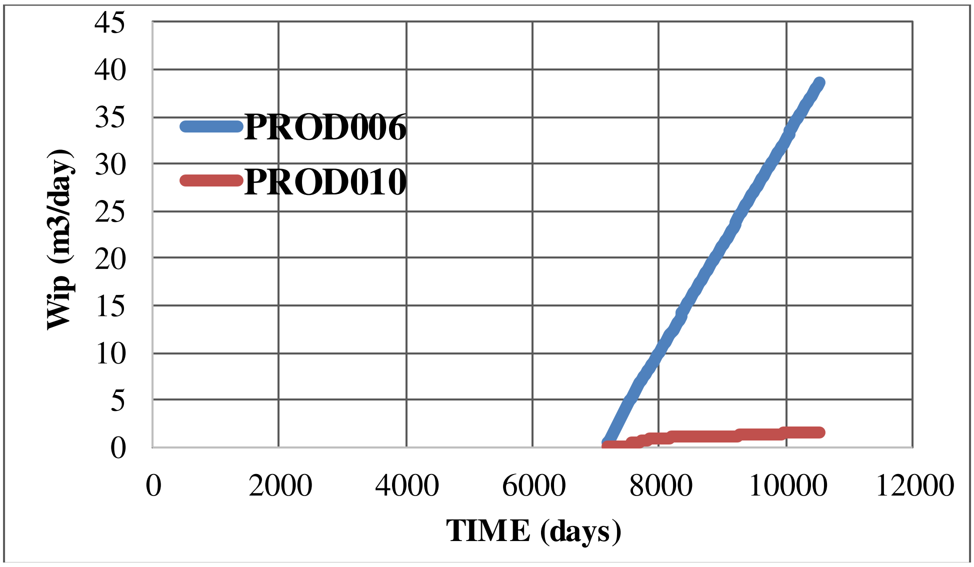

Figure 6.3: Distribution of Wi_p from well INJ017 to wells PROD006 and PROD010

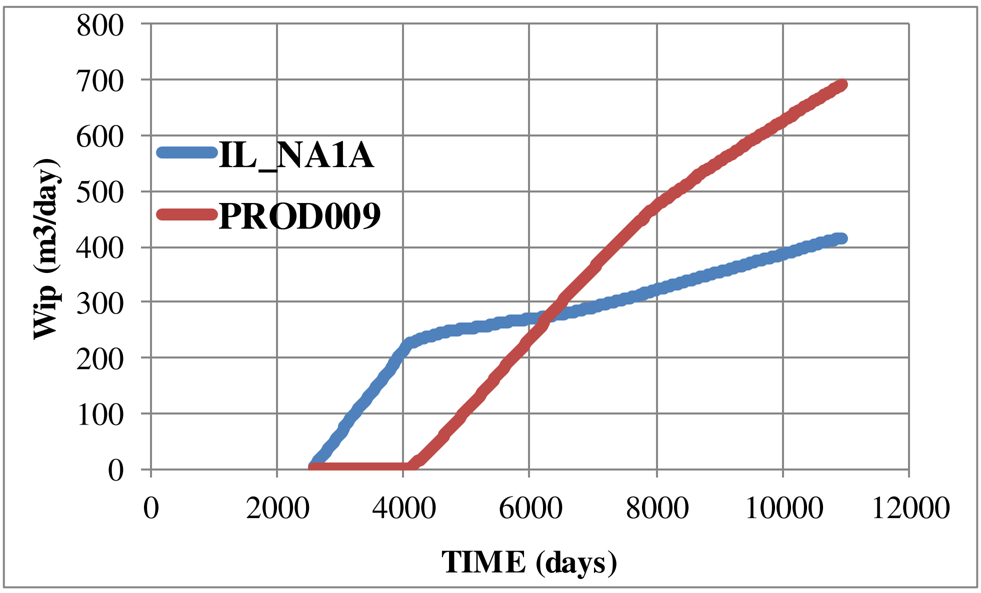

Figure 6.4: Distribution of Wi_p from well INJ019 to wells IL_NA1A and PROD009

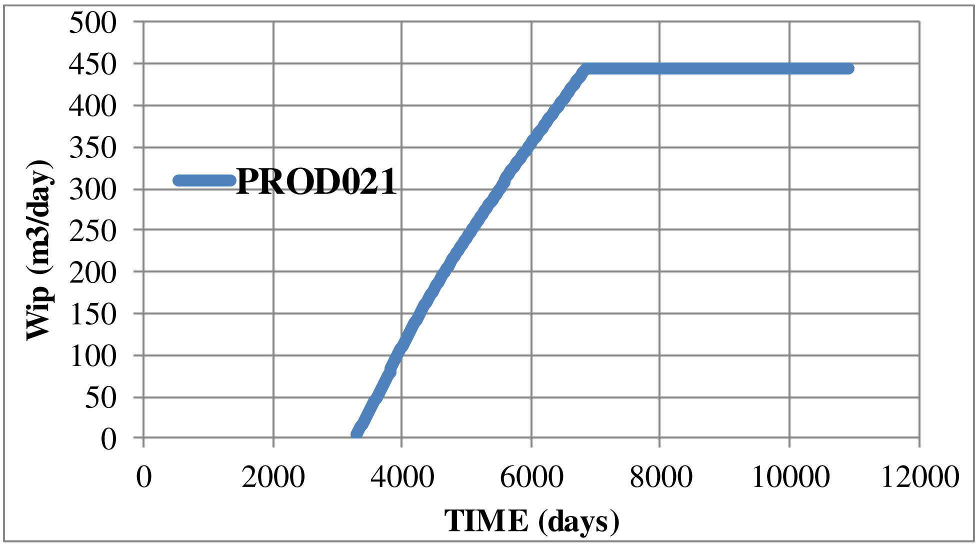

Figure 6.5: Distribution of Wi_p from well INJ021 to well PROD021

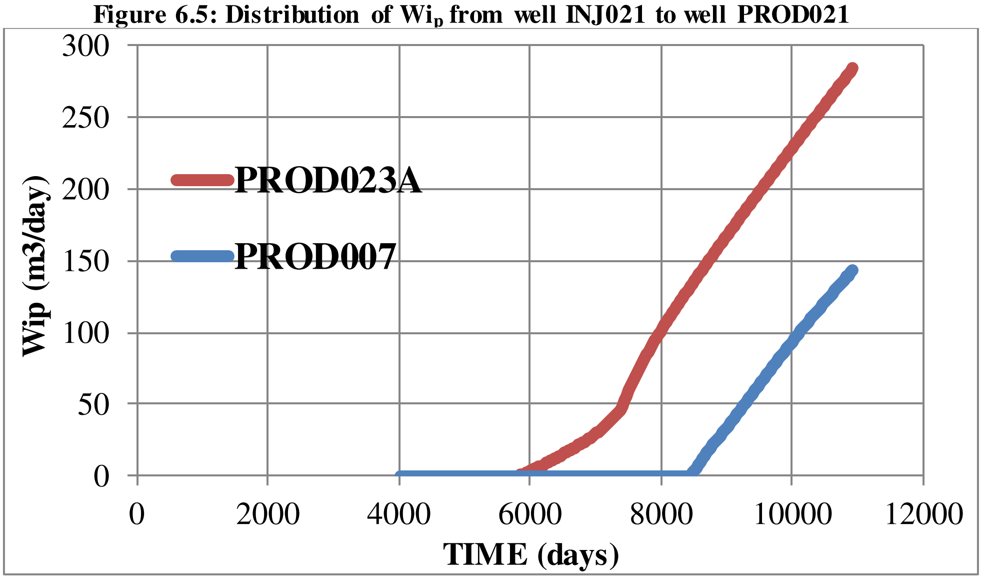

Figure 6.6: Distribution of Wi_p from well INJ022 to wells PROD023A and PROD007

Table 6.1: Producers in OPT PLAT and their most influential injectors

PRODUCER	INJECTOR	Wi_p (m^3 thousands) TO THE PRODUCER	RANKING (well candidates)
IL_NA1A	INJ019	416.15	13
PROD005	INJ021	236.02	9
PROD006	INJ017	38.54	12
PROD007	INJ022	143.18	4
PROD009	INJ019	691.51	6
PROD010	INJ017	1.58	11
PROD012	INJ006	174.40	3
PROD014	INJ006	512.31	1
PROD021	INJ021	444.99	8
PROD023A	INJ022	284.00	2
PROD024A	INJ010	489.10	5
PROD025A	INJ010	94.06	7
PROD026	INJ006	189.31	10

6.2 Selection of Candidates for Implementation

The statistical analysis was performed for production parameters of representative models (RMs) and S9 of benchmark case UNISIM-I-D and showed that net present value (NPV) was influenced by cumulative produced water (Wp) and time of breakthrough (TB).

In this work, only optimized S9 was considered as input data and to make the statistical analysis easier. By this way, the analysis has the same wells, location, completions and schedule; which permitted compare the production parameters and obtain the expressions to forecast NPV for each case and presented below.

The linear multivariable regressions obtained obey the following equation:

$$NPV = \beta_0 + \beta_1 * Wp + \beta_2 * TB \qquad \textbf{(6.1)}$$

where β_0, β_1, β_2 are coefficients that depend on the input data. NPV can be predicted through only these production parameters (from the base case). For further information about the value of coefficients for each RM analyzed, see Appendix A.

For practical purposes, an expression considering the average values of RMs from UNISIM-I-D was obtained. The relative error in forecast NPV was low (about 4.5% on average), so it was a good first approach to identify potential wells. The equation to rank wells is:

$$NPV = 3.605E + 09 - 8.460E + 01 * Wp - 1.754E + 05 * TB \qquad \textbf{(6.2)}$$

Although the methodology showed good results in the identification of the general position of each well, it was more accurate when prioritizing the first three. It is noteworthy that the obtained expressions depend on analyzed production data of this specific case.

The results of forecast NPV for single-well application in model RM9-S9 are summarized in Table 6.2. This table shows the production parameters of base case (Wp and TB), NPV calculated using the regression, NPV obtained with simulation and relative error (Er %) in the forecast.

This methodology was a parallel activity developed during researching, being only a guideline when there is lack of information about production parameters of the base case that permit the selection of best candidates for installation.

Table 6.2: NPV forecast due to installation of subsea technologies. RM9-S9

WELL	Wp (millions m^3)	TB (time)	NPV CALCULATED (USD billions)	NPV SIMULATED (USD billions)	Er (%)
IL_NA1A	3.788	3348	3.524	3.506	0.51%
PROD005	4.199	5724	3.543	3.532	0.31%
PROD006	2.911	5358	3.520	3.519	0.03%
PROD007	3.716	5113	3.532	3.536	0.12%
PROD009	4.386	4597	3.540	3.539	0.05%
PROD010	4.461	4444	3.541	3.527	0.40%
PROD012	3.480	4505	3.525	3.537	0.35%
PROD014	4.433	4322	3.540	3.547	0.20%
PROD021	5.327	3532	3.551	3.570	0.55%
PROD023A	4.342	5021	3.542	3.539	0.07%
PROD024A	2.887	5632	3.521	3.532	0.33%
PROD025A	5.406	3805	3.553	3.550	0.11%
PROD026	3.328	5905	3.529	3.527	0.08%

6.3 Case Study 1: Revitalization of Field

Figure 6.7 shows the *VoTmax* for a single-well installation in each producer well and the base case, OPT PLAT. As observed, the best single-well application was for PROD014 and the worst, for IL_NA1A. Notice that using the correlations obtained from the statistical analysis, it is possible to forecast the wells that will provide the best values of *VoTmax* due to the application of the subsea technologies. The best values were observed in wells with an upper position in the ranking showed in Table 6.1. Table 6.3 summarizes NPV and *VoTmax* for each single-well application.

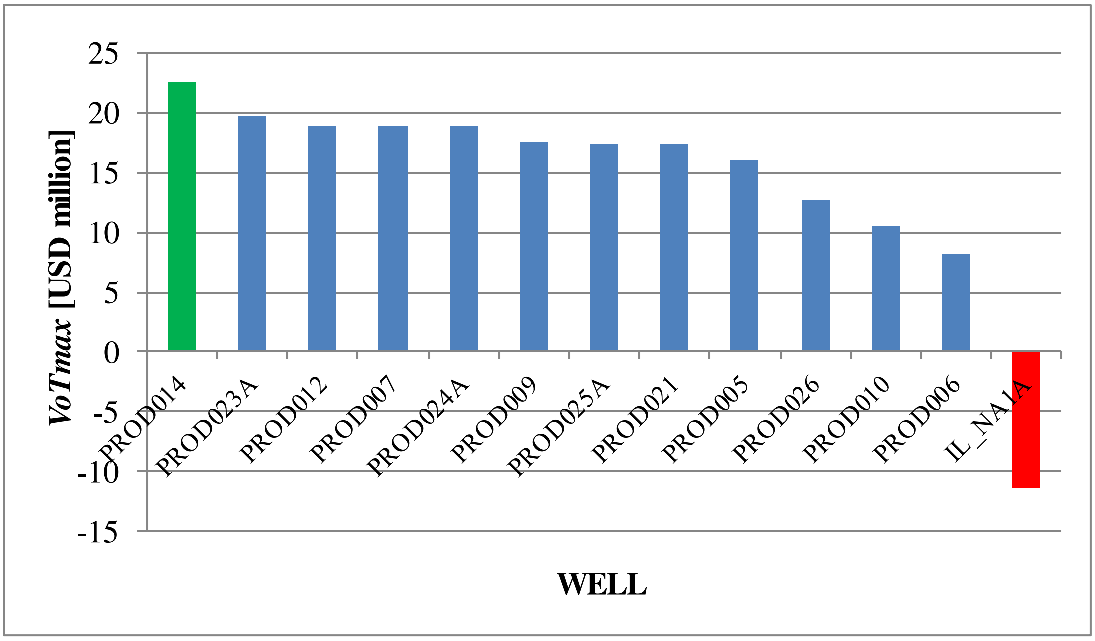

Figure 6.7: Difference between single-well applications and the base case OPT PLAT

Table 6.3: NPV and *VoTmax* values for single-well applications

WELL	NPV (USD billions)	*VoTmax* (USD millions)
PROD014	3.127	23
PROD023A	3.125	20
PROD025A	3.124	19
PROD012	3.124	19
PROD021	3.124	19
PROD009	3.122	17
PROD007	3.122	17
PROD024A	3.122	17
PROD005	3.121	16
PROD026	3.118	13
PROD010	3.115	11
PROD006	3.113	8
IL_NA1A	3.094	-11

Figure 6.8 shows the *VoTmax* for multi-well installations. Notice the change of this indicator when each producer well is added to the arrangement. New wells included in the final configuration positively impacted *VoTmax* until reaching the highest value for 12 producer wells and respective influencing injectors, excluding well IL_NA1A. This scenario includes (specifying the ranking in the well candidate criteria and showing the linking injector): PROD014 (1), PROD012 (3), and PROD026 (10) linked to INJ006; PROD023A (2) and PROD007 (4) linked to INJ022; PROD024A (5) and PROD025A (7) linked to INJ010; PROD009 (6) linked to INJ019; PROD021 (8) and PROD005 (9) linked to INJ021;

PROD010 (11) and PROD006 (12) linked to INJ017. Nevertheless, this value for 12 producer wells requires a further analysis taking into account the required investment for installation in each well.

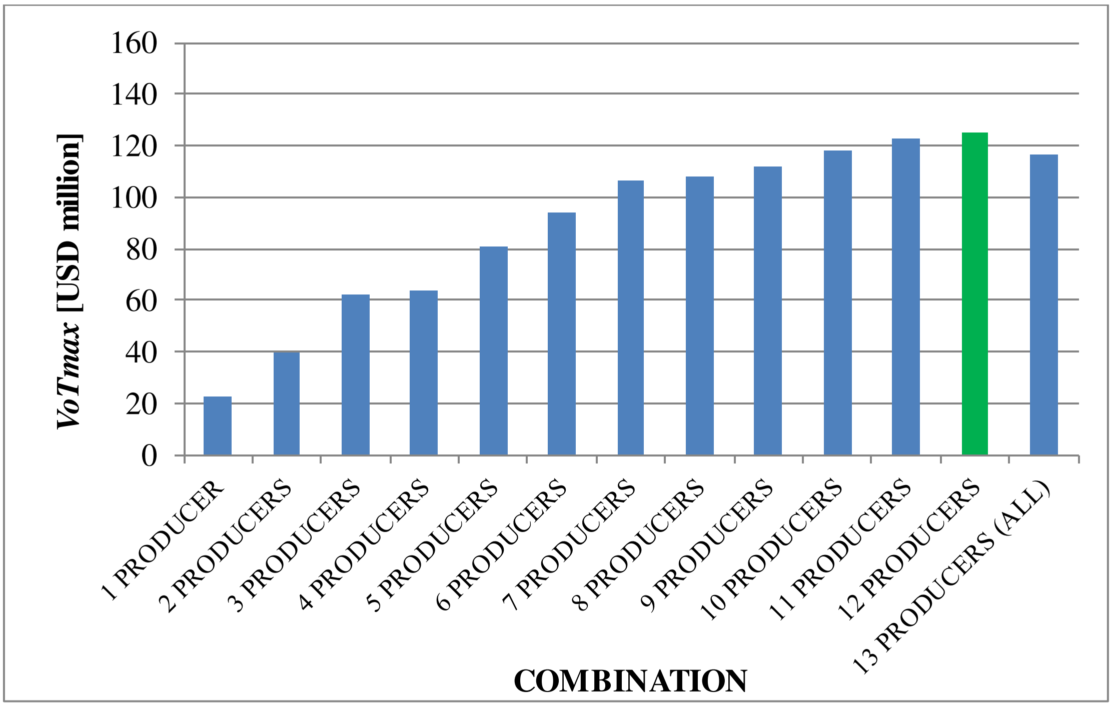

Figure 6.8: Difference between multi-well applications and the base case OPT PLAT

Table 6.4 shows the evolution of NPV and *VoTmax* for multi-well installations.

Table 6.5 compares the values of the best application for the single-well installation (PROD014) and the multi-well installation considering 12 producer wells linked. *VoTmax* raised from 23 USD million in the best single-well installation to 125 USD million for multi-well installations.

The best economic values were for multi-well installations. However, installation for only PROD014 could be more financially attractive than a full-shared production and injection scheme for 12 producers linked. That is because of *VoTmax* for multi-well scenarios could leave less investment available for equipment per well compared with single-well scenarios. The total value has to be divided by 12 producer wells and respective injectors linked to the systems.

Note that even the worst cases of multi-well installations positively influenced the economic results. The reasons for this positive effect are explained below by analyzing the behavior of production curves before and after installation and by expanding the cash flow due to implementation.

Table 6.4: NPV and *VoTmax* values for multi-well applications

COMBINATION	NPV (USD billions)	*VoTmax* (USD millions)
1 PRODUCER (PROD014)	3.127	23
2 PRODUCERS	3.145	40
3 PRODUCERS	3.167	62
4 PRODUCERS	3.169	64
5 PRODUCERS	3.185	81
6 PRODUCERS	3.199	94
7 PRODUCERS	3.212	107
8 PRODUCERS	3.211	108
9 PRODUCERS	3.217	112
10 PRODUCERS	3.223	119
11 PRODUCERS	3.227	122
12 PRODUCERS	3.230	125
13 PRODUCERS (ALL)	3.222	117

Table 6.5: Comparison between the best single-well and multi-well installations considering 12 producers linked

APPLICATION	*VoTmax* [USD millions]
SINGLE-WELL	23
MULTI-WELL	125

Table 6.6 shows the cash flow for the best multi-well case (12 producers linked) compared to the base case (OPT PLAT), specifying CAPEX, revenues obtained by oil and gas sales, OPEX associated to production and injection, and royalties (ROY). As noticed, the main contribution (besides the increasing of oil production and ORF) of applying the subsea technologies in the field, considering a 12-producer arrangement is decreased OPEX, and specifically, decreased costs related to water production and treatment, and also the amount of water required for injection from the surface. These facts are going to be observed along the comparisons of production, injection and re-injection curves of base case and cases with application (single and multi-well). It is noteworthy that these economic results are optimistic because they represent the maximum affordable investment for the installation in the field. As well as, because of the assumptions made during the calculation of NPV and *VoTmax*, and the lack of explicit information about CAPEX and OPEX related to the installation of the systems.

Table 6.7 compares the oil recovery factor (ORF) for best single-well installation (PROD014), the multi-well application with 12 producers linked, and the base case. The differential ORF is also shown. Note that increase in ORF is small due to the exploitation of the field was performed considering an already-optimized production strategy and implementing the installation of the technologies as a solution for revitalization and production anticipation, rather than a strategy for increasing the water flooding sweep efficiency or for improving the oil recovery process. Nevertheless, these obtained values in ORF positively influenced the value of *VoTmax* because of revenues from oil and gas sales. There are other factors also affecting this economic indicator and are going to be assessed later by analyzing other production curves.

Figure 6.9 compares the difference in oil flow rate (Q_o) for the base case against the best single-well installation (PROD014) and the base case against multi-well installations considering 12 producers linked. The vertical solid line shows the time of implementation. Analysis of the curves and production data before and after installation highlights added advantages of installation: (1) anticipation of oil production in later stages and (2) increase in ORF.

Table 6.6: Comparison of cash flows. Base case (OPT PLAT) and multi-well case

ATTRIBUTE		OPT PLAT [USD millions]	MULTI-WELL [USD millions]	DIFFERENCE [USD millions]
CAPEX		-1709	-6553	-4844
REVENUES		21455	26202	4747
TOTAL EXPENDITURES	OPEX	-6885	-6335	550
	ROY1	-4986	-5044	-58
	TOTAL	-11871	-11379	492
ROY2		-4770	-5040	-270
NPV		3105	3230	125

Table 6.7: Comparison of the best single-well and the multi-well installations considering 12 producers linked in terms of ORF

MODEL	ORF [%]	DIFF ORF [%]
OPT PLAT	60.2	-
SINGLE-WELL	60.6	0.4
MULTI-WELL	60.9	0.7

As previously noted, ORF improves with the installation. For both single-well and multi-well installations, oil production increased before declines in oil production began (mid-2020, time 2618) compared with the base case.

The biggest difference in oil production was observed between the base case and single-well and multi-well installations in later production stages (early 2031, time 6423). The overall difference in ORF between the base case and installation cases were largely due to this period.

Note that due the anticipation of oil production for both single and multi-well cases, the oil flow rate decreased at later stages of field production. That is the reason why the difference showed in Figure 6.9 is negative from approximately the year 2033 for single-well application and from the year 2040 until the end of simulation (year 2043) for multi-well case.

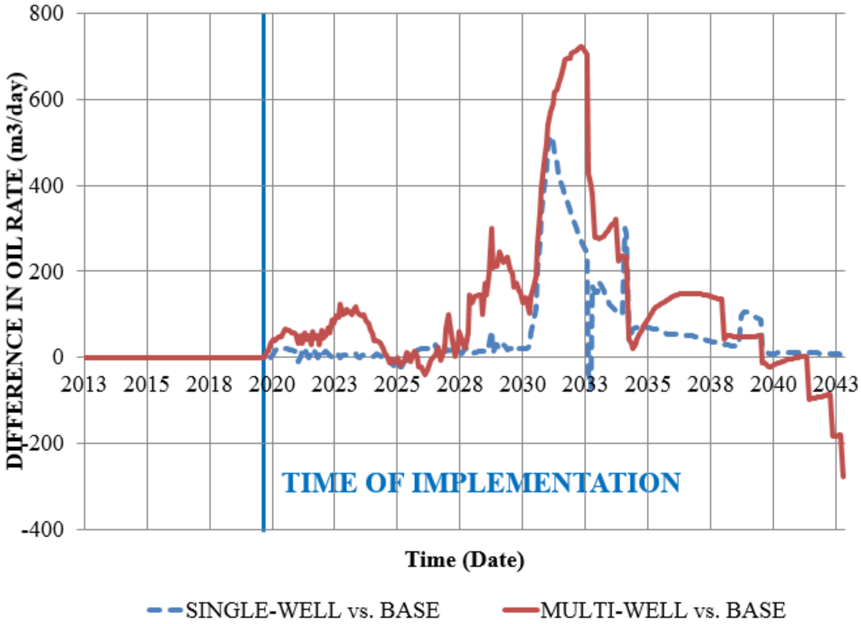

Figure 6.9: Differences of Q_o between the applications

Figure 6.10 compares re-injected water rate (Q_{wir}) before and after installations. The vertical solid line shows the time of implementation. Consider the established value of water handling capacity (CPW) obtained with optimization, as the maximum amount of water produced at the surface. In the multi-well case, the amount of water that was re-injected was greater compared with the single-well case due to the installation of several oil-water (O-W) subsea separators sending water to shared subsea pumps. The base case did not have produced water re-injection (PWRI).

Table 6.8 demonstrates mitigated water production from the reservoir (Wp_{RES}) for installation cases. Wp_{RES} is compared for the best single-well (PROD014) and the multi-well installation with 12 producers linked. As well as, avoiding sending that amount of water to the surface, installations increased oil production. To increase ORF in 0.4-0.7% without installation, much greater amounts of water (10.1-17.7% beyond the base case) would be produced and treated.

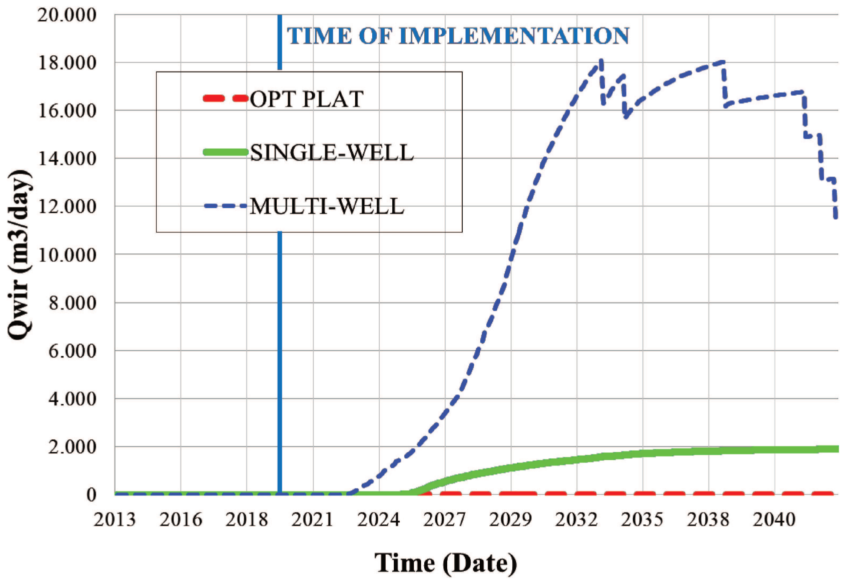

Figure 6.10: Differences of Q_{wir} between the applications

Table 6.8: Comparison of Wp_{RES} for the best single-well application and the multi-well installation for 12 producers linked

MODEL	Wp_{RES} [m^3 millions]
OPT PLAT	77.1
SINGLE-WELL	84.9
MULTI-WELL	90.8

Figure 6.11 shows liquid production rates, Q_l. The solid horizontal line marks the optimized value of liquid handling capacity (CPL) and the vertical, the time of implementation. The increased forecast liquid production around the year 2031 for installations is due to oil production anticipation.

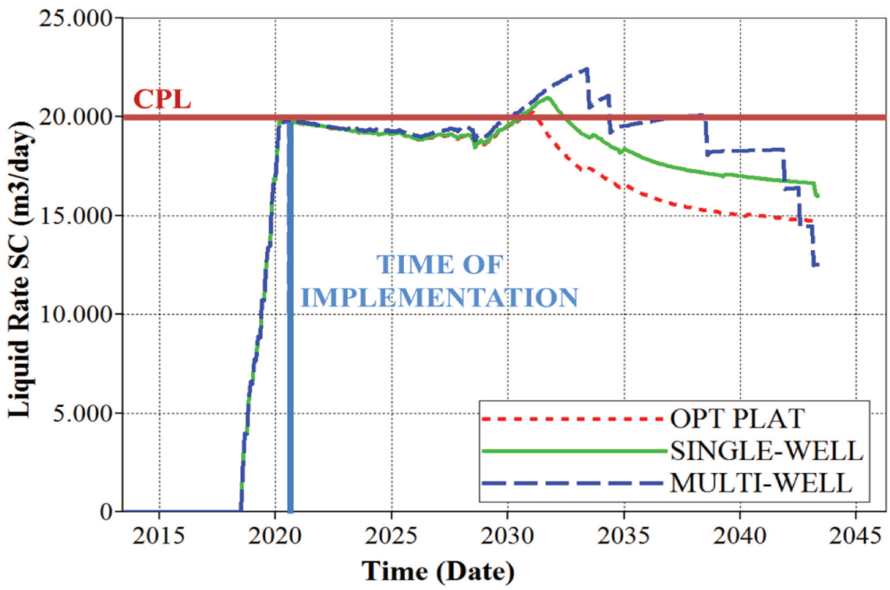

Figure 6.11: Differences of Q_l between the applications

Figure 6.12 shows the results of water injection rate (Q_{wi}). This shows the water injected into the reservoir and not water injected from the platform. The solid vertical line is the time of implementation. Notice that the amount of injected water was greater for installation cases than for the base case because of the reuse of produced water.

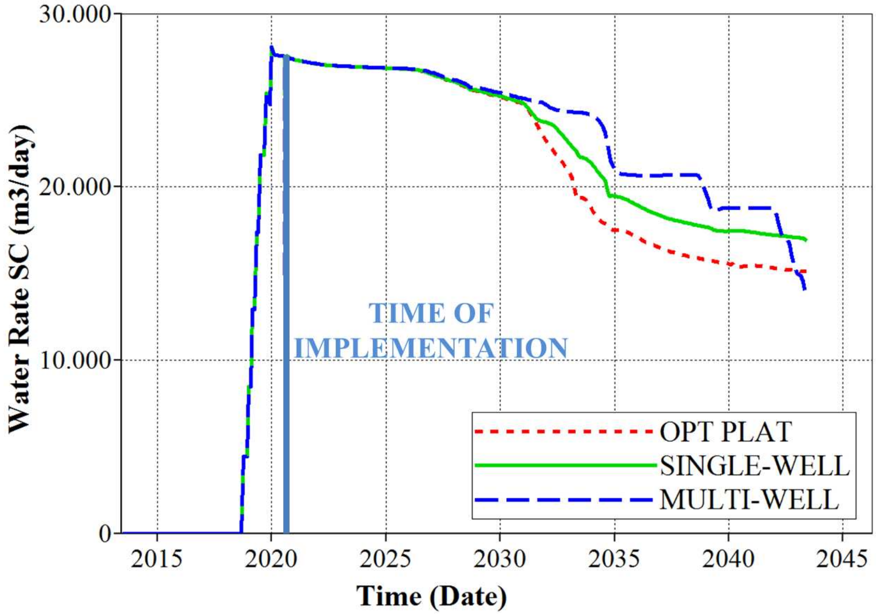

Figure 6.12: Differences of Q_{wi} between the applications

Figure 6.13 presents water injected from the platform. For installation cases, the separated and re-injected water was discounted from the injected water from the platform. This discount was bigger for the multi-well installations.

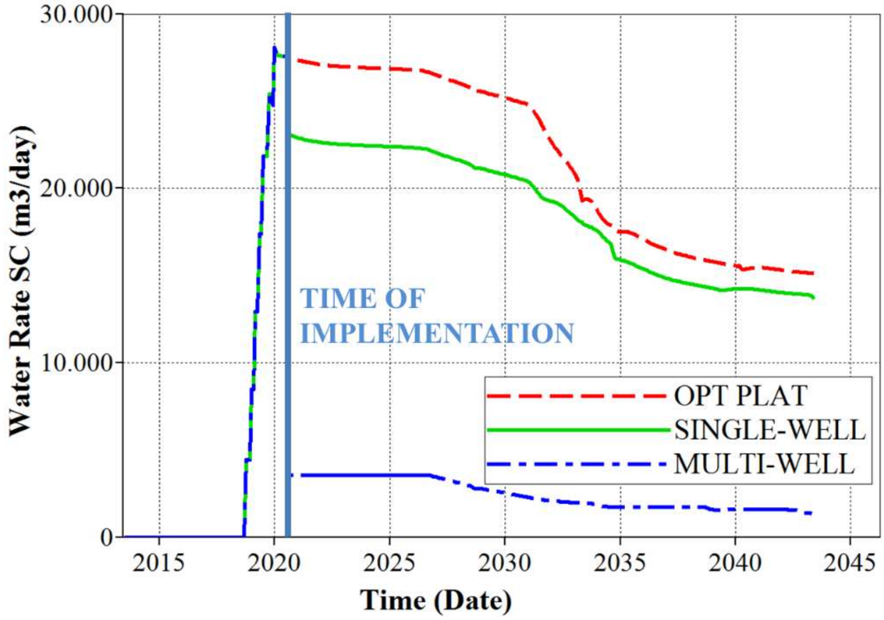

Figure 6.13: Water injected from the platform for all cases

Figure 6.14 presents bottom-hole pressure (BHP) of producers with subsea technologies. Two wells were selected according to economic attractiveness, (as shown in Figure 6.7) to represent BHP curves before and after installation.

Contrary to the literature, decrease in BHP was not fully demonstrated in the case of revitalization. For application in well PROD014, BHP showed increases when the subsea technologies were implemented. The rise in PROD014 for single-well installation averaged 48.6 kgf/cm^2 (+20%) and for multi-well, this value decreased to 12.8 kgf/cm^2 (-5%).

For the rest of wells, BHP decreased in both kinds of installations. One case exemplifying this was PROD023A. For this well, the decrease in single-well installation was about 6.1 kgf/cm^2 (-2%) on average while for the multi-well, this value decreased to 13.0 kgf/cm^2 (-5%) on average. The behavior of BHP depends on production and the response of each producer to the water separation and subsequent PWRI.

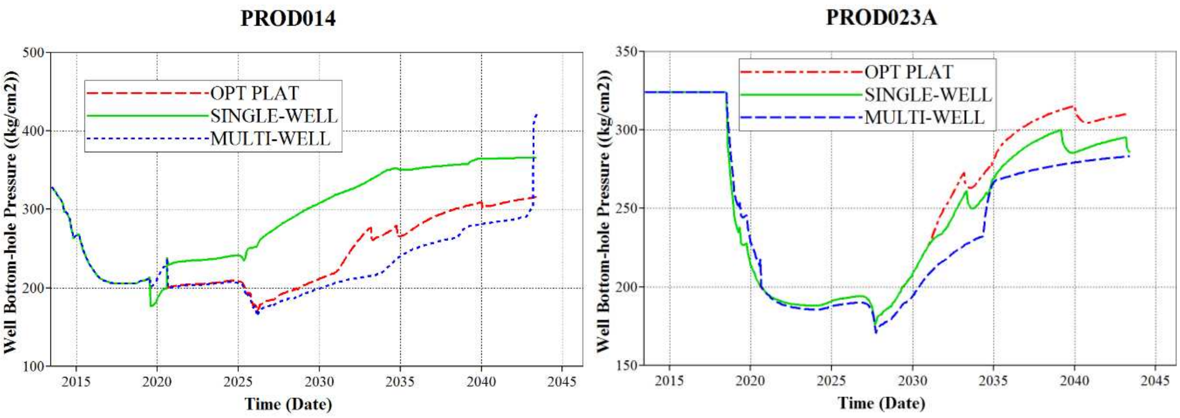

Figure 6.14: BHP of producers PROD014 and PROD023A

In Table 6.9 is exhibited the behavior of BHP for producers in the revitalization case.

Table 6.9: Behavior of BHP for revitalization case

WELL	SINGLE-WELL		MULTI-WELL	
	AVERAGE PRESSURE DIFFERENCE (kgf/cm^2)	% DIFFERENCE	AVERAGE PRESSURE DIFFERENCE (kgf/cm^2)	% DIFFERENCE
IL_NA1A	-3.4	-1%	-5.6	-2%
PROD005	-5.4	-2%	-17.7	-8%
PROD006	-4.6	-2%	-14.9	-8%
PROD007	-5.8	-2%	-13.6	-5%
PROD009	-4.4	-2%	-6.6	-2%
PROD010	-5.3	-2%	-10.5	-4%
PROD012	-7.9	-4%	-12.9	-6%
PROD014	48.6	+20%	-12.8	-5%
PROD021	-3.2	-1%	-7.5	-2%
PROD023A	-6.1	-2%	-13.0	-5%
PROD024A	-8.1	-3%	-16.2	-7%
PROD025A	-3.0	-1%	-8.2	-3%
PROD026	-4.3	-2%	-14.9	-8%

6.4 Case Study 2: New Field

Figure 6.15 shows the *VoTmax* of single-well installation for each producer and the base case (OPT PLAT). Analogously to the revitalization case, the best single-well installation was for PROD014 and the worst was for IL_NA1A. Table 6.10 summarizes NPV and *VoTmax* for each single-well application.

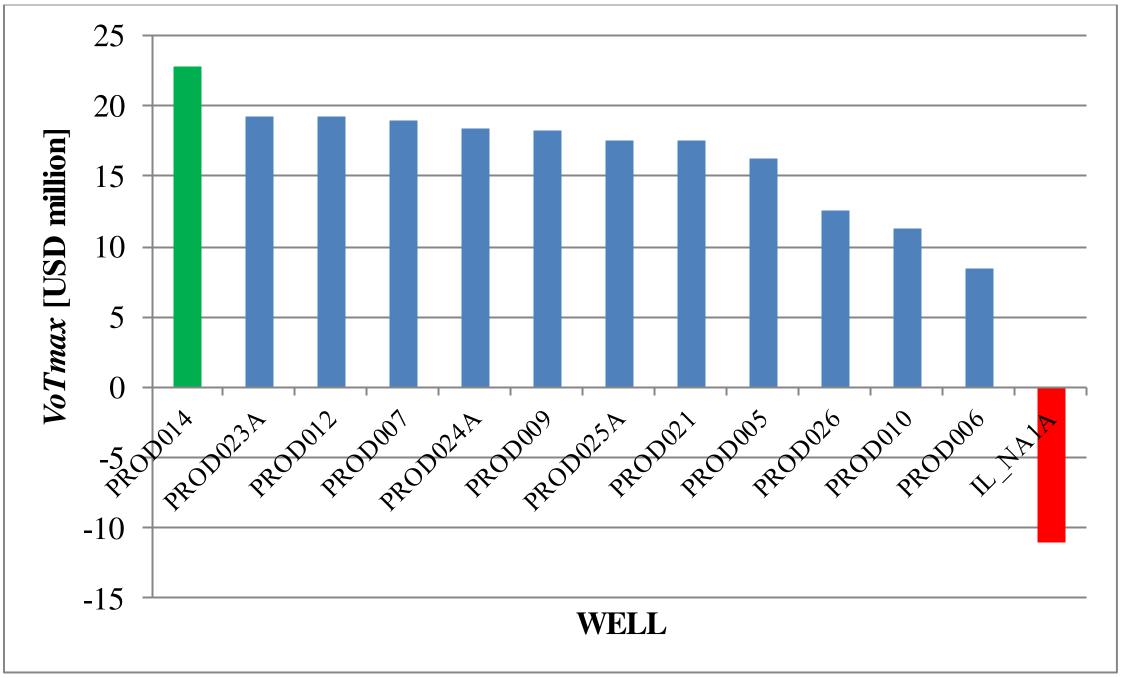

Figure 6.15: Difference between single-well applications and the base case OPT PLAT

Table 6.10: NPV and *VoTmax* values for single-well applications

WELL	NPV (USD billions)	*VoTmax* (USD millions)
PROD014	3.128	23
PROD023A	3.124	19
PROD012	3.124	19
PROD007	3.124	19
PROD024A	3.123	18
PROD009	3.123	18
PROD025A	3.122	18
PROD021	3.122	17
PROD005	3.121	16
PROD026	3.117	13
PROD010	3.116	11
PROD006	3.113	8
IL_NA1A	3.094	-11

Figure 6.16 shows the *VoTmax* of multi-well installations and the base case (OPT PLAT). *VoTmax* behaved similarly to the revitalization case. As each producer well was added in the final arrangement, the value steadily increased until the highest value for all 12 producers and respective injectors, excluding also well IL_NA1A. By this way: PROD014 (1), PROD012 (3), and PROD026 (10) linked to INJ006; PROD023A (2) and PROD007 (4) linked to INJ022; PROD024A (5) and PROD025A (7) linked to INJ010; PROD009 (6) linked to INJ019; PROD021 (8) and PROD005 (9) linked to INJ021; PROD010 (11) and PROD006 (12) linked to INJ017.

Table 6.11 shows the evolution of NPV and *VoTmax* for multi-well installations.

Table 6.12 compares the *VoTmax* of the best single-well (PROD014) and the multi-well installation (considering 12 producers linked).

Remembering that *VoTmax* represents the maximum affordable investment to implement the subsea technologies in the total number of wells, the highest values of *VoTmax* do not mean the highest financial return.

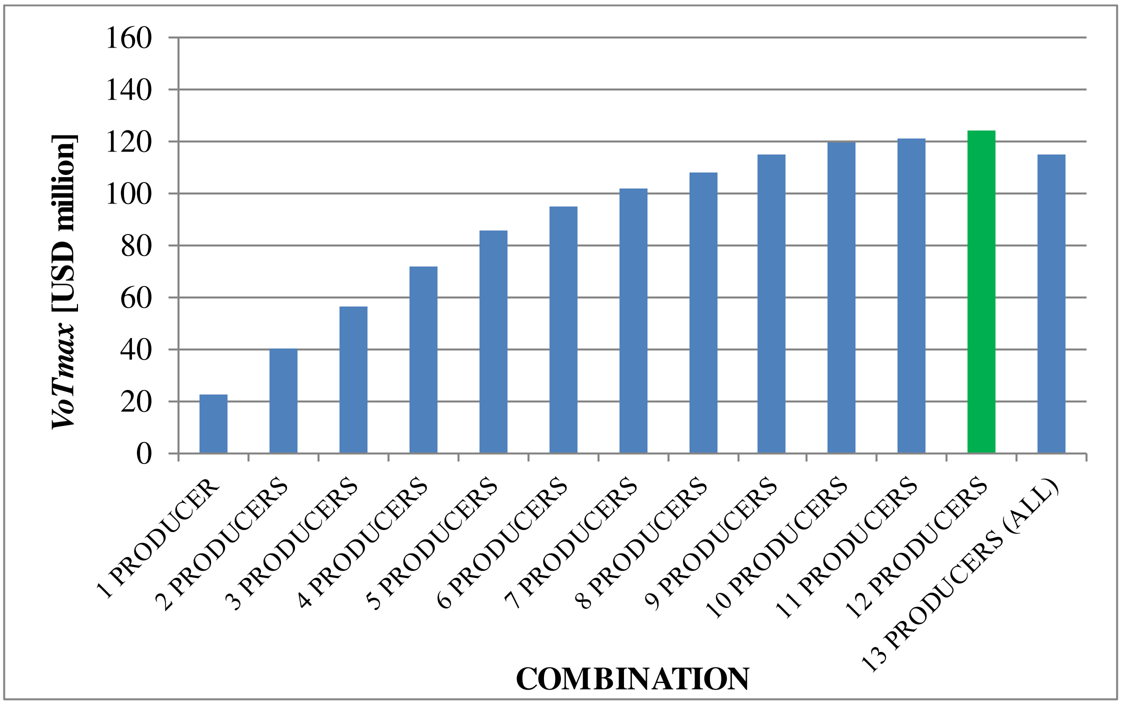

Figure 6.16: Difference between multi-well applications and the base case OPT PLAT

Table 6.11: NPV and *VoTmax* values for multi-well applications

COMBINATION	NPV (USD billions)	*VoTmax* (USD millions)
1 PRODUCER (PROD014)	3.128	23
2 PRODUCERS	3.145	40
3 PRODUCERS	3.161	57
4 PRODUCERS	3.177	72
5 PRODUCERS	3.190	85
6 PRODUCERS	3.200	95
7 PRODUCERS	3.206	102
8 PRODUCERS	3.213	108
9 PRODUCERS	3.220	115
10 PRODUCERS	3.224	119
11 PRODUCERS	3.226	121
12 PRODUCERS	3.229	124
13 PRODUCERS (ALL)	3.220	115

Table 6.12: Comparison between the best single-well and multi-well installations considering 12 producers linked

APPLICATION	*VoTmax* [USD millions]
SINGLE-WELL	23
MULTI-WELL	124

The results of *VoTmax* for installation in the new field were very similar to those of revitalization. The value of the best case in the multi-well installations was greater than the best case in single-well; however, a further analysis is required. In fact, despite a higher *VoTmax* in the multi-well case, due to the number of wells where the subsea technologies would be allocated, the available value per unit has to be smaller to compete with the single-well installations. The cost of investment for one single-well system is less than for full installation for 12 producers and is, therefore, more financially attractive.

For the new field, the best single-well installation achieved a further 23 USD million over OPT PLAT. Even though the increase of *VoTmax* was bigger for the best multi-well installation, which achieved 124 USD million more than the base case, when compared to the best single-well installation, this 101 USD million difference would not justify the investment in 12 producers and respective injectors.

Table 6.13 specifies the cash flow for the multi-well case considering 12 producer linked and the base case (OPT PLAT). Analogously to the revitalization case, the values of CAPEX, revenues, OPEX, and ROY are shown. The implementation of the subsea technologies influenced in increasing the oil production by decreasing OPEX related to water production and injection from the platform. The explanation of these results can be observed by comparing the production, injection and re-injection curves before and after the applications (single and multi-well cases). Same statement about the obtained optimistic results applies for this case because of assumptions considered in the economic submodel and uncertainty in required investments in the subsea technologies.

Table 6.14 compares ORF of the best single-well (PROD014) and the multi-well (including 12 producers linked) installations with the base case (OPT PLAT), as well as showing the values of differential ORF. Similar increases in ORF were observed (about 0.0374% for single-well application and 0.2026% for multi-well) when comparing the revitalization case with the implementation in new field. These increases were also expected for new field because technologies were installed as an acceleration and production anticipation strategy, rather than for increasing the efficiency of the oil recovery method. Even that, increases in ORF influenced positively the value of *VoTmax*. Explanation of other benefits due to the implementation of the technologies can be analyzed using production curves.

Table 6.13: Comparison of cash flows. Base case (OPT PLAT) and multi-well case

ATTRIBUTE		OPT PLAT [USD millions]	MULTI-WELL [USD millions]	DIFFERENCE [USD millions]
CAPEX		-1709	-6541	-4832
REVENUES		21455	26203	-4748
TOTAL EXPENDITURES	OPEX	-6885	-6356	529
	ROY1	-4986	-5044	-58
	TOTAL	-11871	-11400	471
ROY2		-4770	-5033	-263
NPV		3105	3229	124

Table 6.14: Comparison of the best single-well and the multi-well installations considering 12 producers linked in terms of ORF

MODEL	ORF [%]	DIFF ORF [%]
OPT PLAT	60.2	-
SINGLE-WELL	60.6	0.4
MULTI-WELL	60.9	0.7

Figure 6.17 presents oil production behavior, which was similar to the case of revitalization. At later production stages, the difference in oil production peaked around the year 2031 (time 6423) for both single and multi-well installations. As well as, the behavior of the difference in flow rate is negative due to production anticipation from approximately the year 2033 for the single-well application and from the year 2040 until the end of simulation (year 2043).

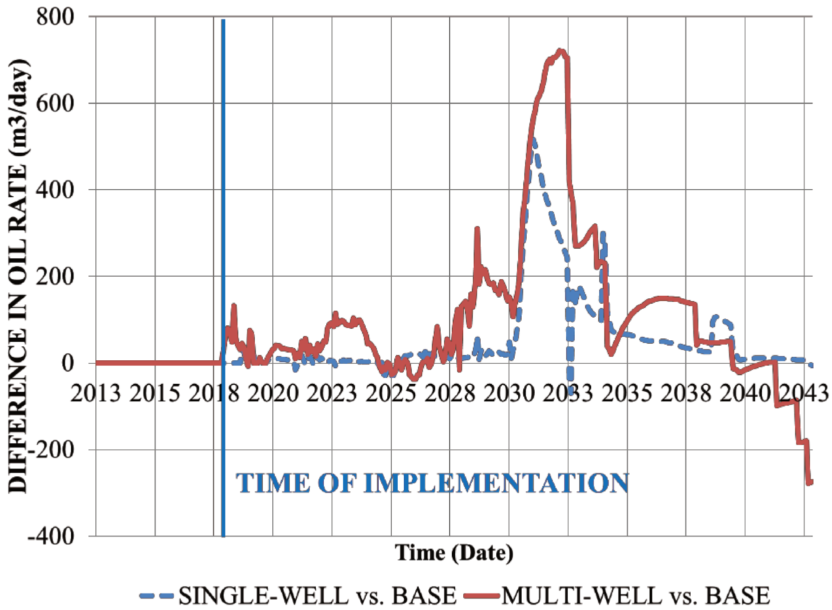

Figure 6.17: Differences of Q_o between the applications

Figure 6.18 shows the behavior of Q_{wir}. As explained before, water production is restricted to the established value of optimized CPW. Single and multi-well installations used the produced water to support the injection and a greater amount of water was re-injected in the multi-well case.

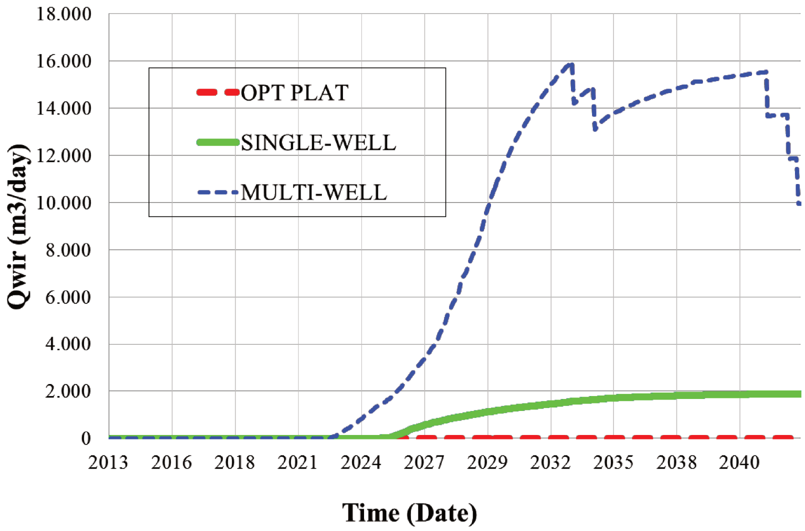

Figure 6.18: Differences of Q_{wir} between the applications

Table 6.15 gives the Wp_{RES} for each case. To recover the additional oil for the base case, shown in Table 6.14, would produce significantly more water 10.1-17.8% additional to the base case. Managing water production while increasing oil production is the key benefit of these technologies.

Table 6.15: Comparison of Wp_{RES} for the best single-well and multi-well installations

MODEL	Wp_{RES} [m^3 millions]
OPT PLAT	77.1
SINGLE-WELL	84.9
MULTI-WELL	90.8

Figure 6.19 shows Q_l for all cases. The solid horizontal line marks the optimized value of CPL. The amount of liquid beyond this value in the single and multi-well curves was because of the capacity liberation of the platform and reception of anticipated oil production.

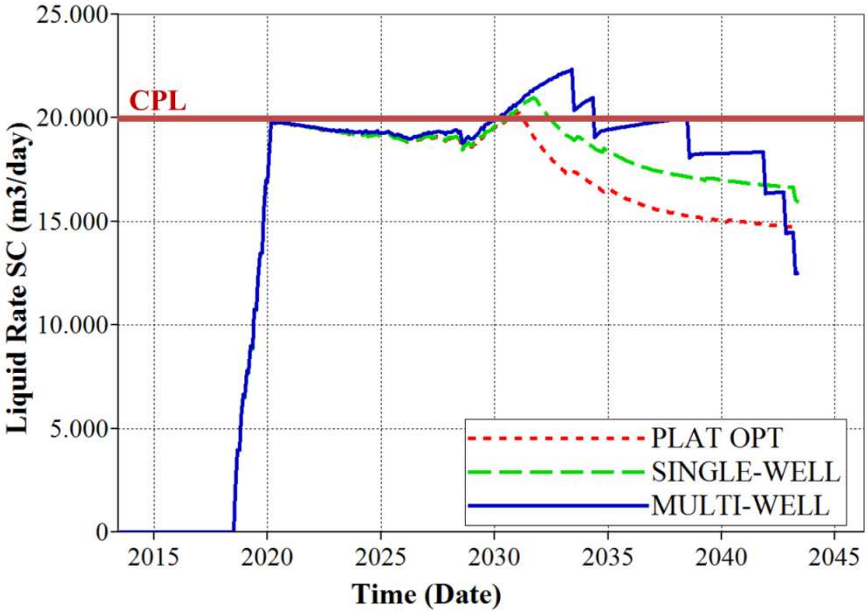

Figure 6.19: Differences of Q_l between the applications

Figure 6.20 shows the Q_{wi} for all cases. The amount of injected water in single and multi-well cases was greater than the base case because of PWRI, as observed later in Figure 6.21.

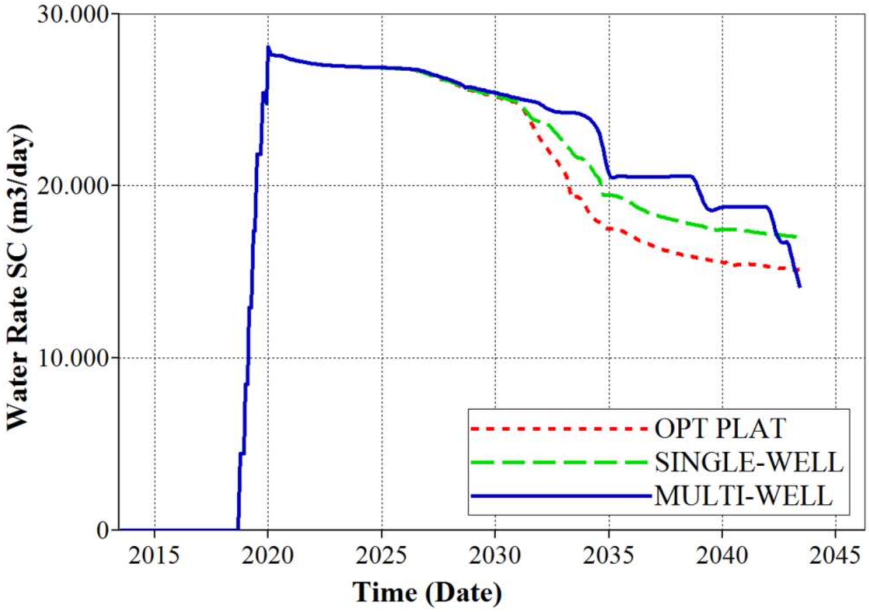

Figure 6.20: Differences of Q_{wi} between the applications

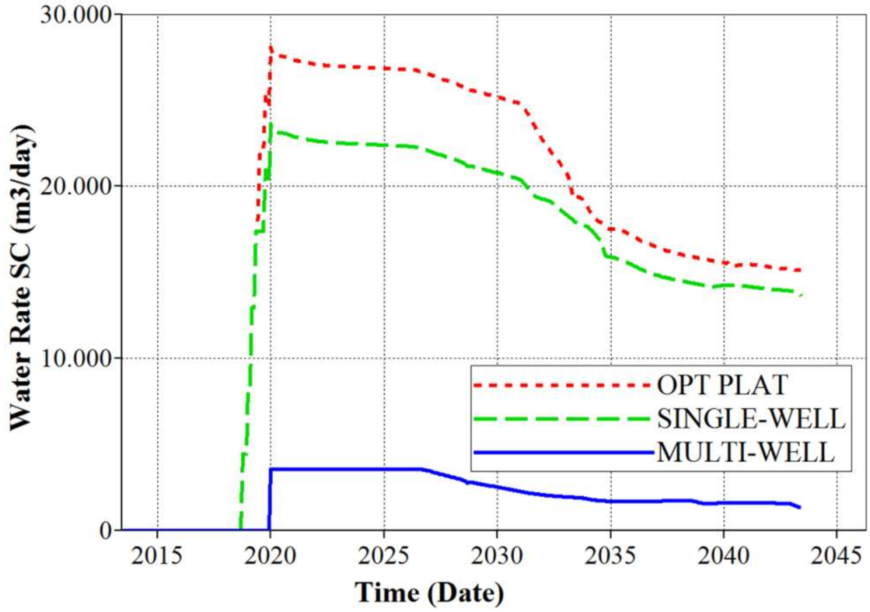

Figure 6.21: Water injected from the platform for all cases

Figure 6.22 shows BHP of producers with installed subsea technologies. The criteria to select candidates for installation were the same as for revitalization case. Table 6.16 exhibits the behavior of BHP for producers in the new field case.

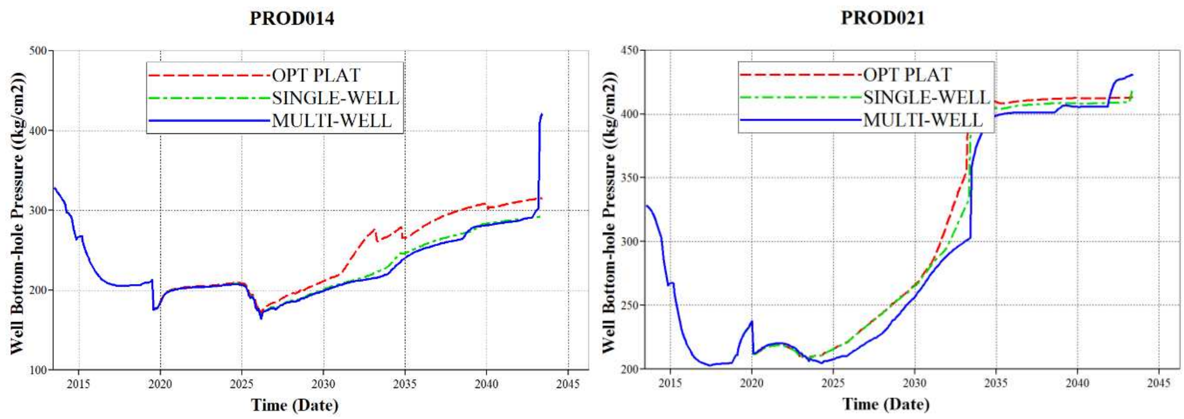

Figure 6.22: BHP of producers PROD014 and PROD021

Following installation, BHP decreased for all producers independently of the application, as the curves below show. These decreases depend on production behavior and the response of each producer to the water separation. For well PROD014, the average decrease for single-well was about 13.2 kgf/cm^2 (-5%) and for multi-well, 13.9 kgf/cm^2 (-6%) on average.

PROD021 presented an average decrease of about 3.2 kgf/cm^2 (-1%) for single-well installation and 7.8 kgf/cm^2 (-3%) for multi-well.

Table 6.16: Behavior of BHP for new field case

WELL	SINGLE-WELL		MULTI-WELL	
	AVERAGE PRESSURE DIFFERENCE (kgf/cm^2)	% DIFFERENCE	AVERAGE PRESSURE DIFFERENCE (kgf/cm^2)	% DIFFERENCE
IL_NA1A	-3.5	-1%	-5.6	-2%
PROD005	-5.4	-2%	-17.8	-8%
PROD006	-4.7	-2%	-15.1	-8%
PROD007	-7.1	-3%	-16.1	-6%
PROD009	-4.7	-2%	-6.7	-2%
PROD010	-5.3	-2%	-10.7	-4%
PROD012	-8.0	-4%	-14.8	-7%
PROD014	-13.2	-5%	-13.9	-6%
PROD021	-3.2	-1%	-7.8	-3%
PROD023A	-6.1	-2%	-14.0	-5%
PROD024A	-8.2	-3%	-19.5	-8%
PROD025A	-3.0	-1%	-8.5	-3%
PROD026	-4.4	-2%	-15.0	-8%

Other evaluation we performed was the difference in simulation times between the different approaches: Decoupled and Integrated (Explicit). We obtained similar results when the subsea systems were included in the production network. Table 6.17 summarizes the spent time by the reservoir simulator and the generation of VLP (Vertical Lift Performance) curves. As noticed, the proposed integrated model permitted to analyze the installation of the technologies in a reasonable computation time and with a better quality of results compared with the Decoupled approach.

Table 6.17: Comparison of simulation times between approaches: Decoupled and Integrated (Explicit)

APPROACH	RESERVOIR SIMULATOR TIME [s]	VLP GENERATION TIME [s]	TOTAL TIME [s]
Decoupled	488	87	575
Integraded (Explicit)	513	121	634

6.5 Discussion

The presented methodology was successfully used to calculate economic attractiveness of subsea technologies in an oil offshore field and is suitable for application in other fields considering the implementation of these types of technologies.

Each submodel comprising the integrated model can be robust and have detailed information but this will increase computational time. There must be a balance between time and computational cost against the quality of the results or the level of support when making decisions. This work proposed a simplified integrated model for economic evaluation within reasonable computational time.

The subsea technologies seem to be a good solution to mitigate the production of increased amounts of water associated with oil production. According to the *VoTmax* values, the subsea technologies achieved significant increases for both single-well and multi-well installations. Besides mitigating the excessive water production, the technologies permitted the relieving of platform capacities, enhanced oil production, and ORF, positively influencing NPV.

The increase of oil production achieved with installations could cover the investment required for equipment, depending on the capital expenditures (CAPEX) and operating expenditures (OPEX) related to installation and operation.

The time of implementation influenced *VoTmax* as seen in the cases for revitalization and new fields. The amount of water re-injected into the reservoir was the key factor affecting the economic indicators. Early implementations took better advantage of water production to support the injection process and increase the oil production, ORF and, thus, positively influenced economic results.

The literature notes reduced BHP to be a benefit of subsea installations. This was not demonstrated fully in this work although reductions were evident in the new field case for both single and multi-well installations. However, for the revitalization case, when the systems were implemented at the decline of oil production, the response was the opposite in well PROD014. This was probably due to BHP is depending on the response of each producer to the production, injection, and subsequent subsea separation and PWRI. Furthermore, other factors influencing the maximization of *VoTmax* will be studied in detail in future works.

7 CONCLUSIONS

A methodology for evaluating the economic attractiveness of installing technologies for oil-water (O-W) subsea separation and produced water re-injection (PWRI) in offshore fields as a solution for water production management was presented and tested using two study cases, showing gains in economic indicators. The conclusions obtained from the application of this methodology are the following:

- This work demonstrated the importance of integrated asset modeling (IAM) to evaluate subsea installations. The integrated models generated more appropriate production forecasts for several scenarios and economic results, which were used to assess project attractiveness.
- The results of the installation cases showed promising values of maximum theoretical value of technology ($VoTmax$) and additional benefits such as relieving platform capacities, increased oil production and oil recovery factor (ORF). These benefits increased the $VoTmax$.
- The results of the economic submodel demonstrated the potential of including subsea technologies in new fields to increase ORF.
- This work was the first approach to evaluate the economic attractiveness of these technologies. Further studies using the 12-step methodology for field development and management established by Schiozer D.J et al. (2015) are recommended. These studies could identify the most influential factors for $VoTmax$, such as project variables (G1), control and monitoring (G2), and field revitalization (G3).

Additional suggestions to guide future works are presented to improve the level of certainty in the results and in the representation of reservoir production when dealing with the subsea technologies. They are:

- Better modeling of components of the subsea systems for more realistic production forecasts and economic scenarios. This includes the location of the separator and the pump, representation of operating conditions, and phenomena occurring in each device. This would be possible by including to the integrated model a software for simulation of facilities and processes.

- To improve the economic submodel by including in calculations of economic indicators the values of CAPEX for each installation in well and OPEX related to production pauses, operating failure, requirement of maintenance and energy supply.
- A more robust optimization process is required to optimize the production network configurations, well arrangements, times of implementation, and control and monitoring rules of wells. The objective function will be net to present value (NPV) once included CAPEX and OPEX in the economic calculations.

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APPENDIX A

I. Well-Selection Methodology

Based on the work developed by De Figueiredo (2005) about the selection of candidates for installation of subsea systems, an analogous methodology using tools of multivariable statistical analysis was created. The selection of the most attractive wells to implementation can be done by knowing the cumulative water production (Wp) and time of breakthrough (TB) of the base case. This methodology is only a guideline because obtained expressions depend on the input data in the reservoir submodel. Nevertheless, it can be used as a good starting point to identify potential wells to implement the systems.

Initially, an idea about key production parameters with the greatest impact on the selection of wells was obtained by analyzing raw field data. In the beginning, it was thought that the best implementations would be in wells with the greatest water production (as stated in De Figueiredo, 2005). The technologies were considered to be used in wells with early water production. In fact, a primary approach was developed based on Wp and TB, by attributing to each parameter the same weight and ranking the wells accordingly. Unfortunately, this criterion was not good enough to rank the wells by net present value (NPV) when later TB and lower Wp were observed. Therefore, we decided to use other tools for better supporting the methodology.

By this way, using linear multivariable regressions and combining several production parameters of the representative models (RMs) and production strategy 9 (S9) of benchmark case UNISIM-I-D, we concluded that in fact, net present value with implementation (NPV_{with}) was directly correlated to Wp and TB, but with a difference in weight. This was identified and proved considering statistical indicators of correlation.

Using the regressions obtained from the statistical analysis was possible to forecast expected NPV_{with} as a function those production parameters. Wells were decreasingly ranked by Maximum-Theoretical Value of Technology ($VoTmax$) from the most attractive to the least.

The obtained regressions obey the following equation:

$$NPV_{with} = \beta_0 + \beta_1 * Wp + \beta_2 * TB \quad \textbf{(A.1)}$$

Where parameters β_0 , β_1 and β_2 are coefficients dependent on the input data. For each RM-S9 was obtained a relationship between the production parameters and expected NPV_{with}. The regression coefficients are tabulated in Table A.1.

Table A. 1: Coefficients of regressions for RMs-S9 of UNISIM-I-D

MODEL	$\boldsymbol{\beta_0}$**(E+03)**	$\boldsymbol{\beta_1}$**(E+00)**	$\boldsymbol{\beta_2}$**(E+03)**
RM1-S9	2.415	2.71	7.470
RM2-S9	2.345	4.981	1.946
RM3-S9	1.486	1.303	2.052
RM4-S9	2.707	6.474	-3.355
RM5-S9	2.435	5.801	2.132
RM6-S9	2.041	0.497	-3.023
RM7-S9	1.467	0.019	-0.501
RM8-S9	2.408	6.135	-0.846
RM9-S9	3.445	16.58	5.018

As seen, the coefficients highly depend on RM analyzed, so for practical purposes, a expression considering the average values was developed. The relative error in the forecast is low (about 4.5% on average), being a good first approach to the identification of potential wells. The equation is the following:

$$NPV_{with} = 3.605E + 09 - 8.460E + 01 * Wp - 1.754E + 05 * TB \qquad \textbf{(A.2)}$$

Although the methodology shows good results in the identification of the general position of each well, it shows better results when prioritizing the first-three ones. Obviously, it is more advisable using the results of the integrated model and performing the well-selection considering the economic submodel. However, the expressions above can be used when there is not plenty of field data or to perform a fast analysis.