CRANFIELD UNIVERSITY

NIMI INKO ABILI

SUBSEA FLUID SAMPLING TO MAXIMISE PRODUCTION ASSET IN OFFSHORE FIELD DEVELOPMENT

SCHOOL OF ENERGY, ENVIRONMENT & AGRIFOOD
Subsea Engineering

PhD
Academic Year: 2011 - 2015

Supervisor: Dr Kolios Athanasios
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ABSTRACT

The acquisition of representative subsea fluid sampling from offshore field development asset is crucial for the correct evaluation of oil reserves and for the design of subsea production facilities. Due to rising operational expenditures, operators and manufacturers have been working hard to provide systems to enable cost effective subsea fluid sampling solutions. To achieve this, any system has to collect sufficient sample volumes to ensure statistically valid characterisation of the sampled fluids. In executing the research project, various subsea sampling methods used in the offshore industry were examined and ranked using multi criteria decision making; a solution using a remote operated vehicle was selected as the preferred method, to compliment the subsea multiphase flowmeter capability, used to provide well diagnostics to measure individual phases – oil, gas, and water.

A mechanistic (compositional fluid tracking) model is employed, using the fluid properties that are equivalent to the production flow stream being measured, to predict reliable reservoir fluid characteristics on the subsea production system. This is applicable even under conditions where significant variations in the reservoir fluid composition occur in transient production operations. The model also adds value in the decision to employ subsea processing in managing water breakthrough as the field matures. This can be achieved through efficient processing of the fluid with separation and boosting delivered to the topside facilities or for water re-injection to the reservoir.

The combination of multiphase flowmeter, remote operated vehicle deployed fluid sampling and the mechanistic model provides a balanced approach to reservoir performance monitoring. Therefore, regular and systematic field tailored application of subsea fluid sampling should provide detailed understanding on formation fluid, a basis for accurate prediction of reservoir fluid characteristic, to maximize well production in offshore field development.

Keywords:

MPFM, ROV, Numerical simulation, Enhance oil recovery, transient flow model, Subsea processing, Synergy, OPEX

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Indeed my most heartily thanks go to my faithful companion, Ena Juliet Abili. Also to my daughters, Belema Vanessa Abili, Boma Zina Abili and son, Ibi-Dumo Andre Abili for the sacrifices, understanding and loving support during this research project. To my mother, and family members, I say thank you for the emotional support.

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Table 1: Notations

Symbols	Descriptions	Units
A	Pipe cross-sectional area	m^2
E	Internal energy per unit mass	J/kg
E	Bulk modulus fluid elasticity	N/m^2
E_1	Liquid hold-up prediction	
E_2	Pressure drop prediction	barg
F_D	Drag force	N/m^3
g	Acceleration due to gravity	m/s^2
G	Mass source	$kg/\ s{-}m^2$
h	Height	m
H	Enthalpy	J/kg
H_S	Enthalpy from mass sources	J/kg
L	Length	m
m_D	Liquid volume droplet fraction and density of liquid ($V_D \rho_L$)	kg/m^3
m_g	Gas volume and density of gas ($V_g \rho_g$)	kg/m^3
m_L	Liquid-film volume and density of liquid ($V_L \rho_L$)	kg/m^3
p	Pressure	N/m^2
R_s	Gas/oil mass ratio	
R_L	Liquid hold-up expressed in volume fractions	m^3/m^3
S	Perimeter	m
t	Time	seconds
T	Temperature (t_0-initial, t_0-finial)	ºC
U	Heat transfer per unit volume	J/m^3
U_G	Superficial velocity of gas	m/s
U_L	Superficial velocity of liquid	m/s
Δu	Relative Uncertainty	
v	Velocity	m/s
V_f	Volumetric fractions (F=g, L,D)	m^3/m^3
$V_i f$	Fluid volume in section number i	m^3
V_g	Real velocity of gas	m/s
V_L	Real velocity of liquid	m/s
V_M	Mixture velocity	m/s
X_m	Measured pressure value	barg
X_c	Predicted pressure value	barg
z	Length coordinate	m
Greek Symbol		
α	Angle with gravity vector	rad
β	Volumetric temperature expansion coefficient	(m^3/m^3 ºC)
ρ	Density (ρ_0 – initial, ρ_1–final)	kg/m^3
λ	Friction coefficient	
ψ	Mass transfer term	$kg/m^3 - s$

Table 2: Subscripts

Symbols	Descriptions
b	Bubble
d	Droplet deposition
D	Droplet
e	Droplet entrainment
f	Phase f(g, L, D)
F	Friction
g	Gas
i	Interfacial
L	Liquid
r	Relative
n	Number of data sets
s	Superficial

Table 3: Acronyms

Abbreviations	Descriptions
AHP	Analytical Hierarchy Process
API	American Petroleum Institutes
bbl	Oil Barrel
BPD	Barrels Per Day
BWPD	Barrels of Water Per Day
CAPEX	Capital Expenditure
CFD	Computational Fluid Dynamics
CMS	Connectivity Modelling System
DPR	Department of Petroleum Resources
EOR	Enhanced Oil Recovery
EOS	Equation of State
FCM	Flow Control Module
FEED	Front End Engineering Design
FEL	Front End Loading
GOM	Gulf of Mexico
GOR	Gas Oil Ratio
GVF	Gas Volume Fraction
IOR	Increased Oil Recovery
JIP	Joint Industrial Project
KPI	Key Performance Indicator
MPFM	Multiphase Flow Meter
MPM	Multiphase Meter
NDDC	Niger Delta Development Commission
NE	North East
OPEX	Operating Expenditure
ONGC	Oil and Natural Gas Corporation
PVT	Pressure Volume Temperature
ROV	Remote Operated Vehicle
RSSDA	Rivers State Sustainable Development Agency
SFS	Subsea Fluid Sampling
SMPFM	Subsea MPFM
SNEPCO	Shell Nigeria Exploration and Production Company
SPS	Subsea Production Systems
SPT	Subsea Production Technology
SW	South West
SOFA	Subsea On-line multiphase Fluid sampling and Analysis
SSI	Subsea Sampling Interface
SSM	Subsea Sampling Module
VFM	Virtual Flow Model

1 INTRODUCTION

1.1 Context

The acquisition of representative reservoir fluid samples plays a key role in the design and optimization of production facilities. Inaccurate and unreliable fluid characterization leads to incorrect production rates due to inadequate processing of production fluid with injection of methanol and Ethylene glycol (Meg), etc., thus negatively impacting reservoir production recoveries. Retrieving reliable pressure, volume and temperature (PVT) properties of reservoir fluids starts with the acquisition of adequate volumes of representative fluid samples, followed by PVT data measurement and phase behaviour modelling. Subsequent laboratory analysis must be monitored through established quality control procedures to provide high quality data (Sbordone et al. 2012; Nagarajan et al., 2007; Joshi and Joshi, 2007). The reservoir fluid characterization methodology must employ best practice to model fluid behaviour as functions of pressure, temperature, and fluid composition.

With current research and development (R&D) innovation in the offshore industry on subsea sampling intervention operations, a 'fluid sampling model' is used to integrate a capacity for multiphase flow measurement in each subsea tree for fluid sampling. The model employs compositional fluid tracking, which combines the multiphase capabilities in transient multiphase flow with customised calculations for fluid properties and mass transfer. However, this does not in any way eliminate the importance of retrieving physical fluid samples for analysis of the production rate, and for separate check of MPFM measurement, key in acquiring accurate data in the sampling program (Abili et al., 2013; Sbordone et al. 2012; Jaco, 2012; Joshi and Joshi, 2007). Thus, the fluid sampling model integrates capability for fluid sampling system upstream of the MPFM to capture representative subsea samples before going into phases downstream of the MPFM.

Due to current development trend, there is increased pressure on deep offshore operators to manage CAPEX and OPEX, increase efficiencies, guarantee flow assurance and increased production. The deepwater market requires higher capital expenditure expected to likely rise from a 38% share in 2012 to a 53% share by 2017 (Gene, 2013). This implies that operators active in deepwater operations must increase production and recovery, by pushing maximum production of their operating wells in order to future proof return on investment (ROI). To this end, multiphase flowmeter plays an important role in realising this ROI. However, these must be configured to determine the optimal recoverable reserves of each production well in the life of field for ultimate recovery. Therefore, subsea fluid sampling plays a key role in the validation of meter performance to guarantee production volume is sustained in the life of field (Al-kadem et al., 2014; Geneti et al., 2003; Denney, 2000a).

Furthermore, with subsea fluid sampling capability to check and validate MPFM, operators are able to retrieve information proactively without the need to shut down production wells in order to deliver a sustainable return. The conventional methods of well testing of separate oil, gas and water phase, which result in production losses, are undesirable given the volatility of the oil price, to increase revenue (Jernsletten and Scheers 2009; Ageh et al., 2009). Thus, acquiring representative fluid samples from the subsea production systems is crucial to sustaining production and generating revenues, which provides an opportunity for optimisation of production facilities without shut-in of producing wells (Pinguet et al., 2014; Sbordone et al., 2012). The fluid sampling does provide the right snap shot of the reservoir and well conditions in order to enable operators to proactively manage asset recovery.

1.2 Evolution of Subsea Fluid Sampling

The development of modern electronic flow metering allows flow rate data to be collected and recorded rapidly. The use of modern electronic flow metering and computer equipment, such as MPFM and virtual flow meter sensors for fluid sampling does not mean that wells can be conditioned any more quickly or that gas and liquid flow rate data will automatically become more representative of reservoir fluid, without physical manipulation and control of wellhead pressure and temperature changes (Jernsletten and Scheers 2009; Letton and Webb, 2012). Thus, obtaining accurate physical fluid samples is required for proper characterisation of hydrocarbon reservoirs and the prime factor for the design and advancement of processing facilities (Pinguet et al., 2014; Sbordone et al., 2012). This will enable operators to prepare for operational challenges as the field matures with depleting reserves.

For proper reservoir management, obtaining fluid samples from actual flow streams is one of the operational requirements for the adjustment and correction of MPFM range measurements (Sherief et al., 2010). Samples collected from topside facilities do not represent the fluid being measured on the seabed. The injections of chemicals such as methanol, corrosion, asphaltene, ethylene glycol (Meg) inhibitors and emulsion breaker, etc., downstream of the meter, and possible liquid separation or hold-up, are typical issues. This is currently a challenge due to multiphase flow commingling on the seabed. However, from the operators' perspective, the ability to collect information quickly and accurately through the additional metering sensors, such as MPFM, downhole pressure and temperature transmitters (DHPTT), pressure transmitter (PT) and temperature transmitter (TT), etc., without the requirement to shutdown wells is the essential to the drive to maintain production (Jernsletten and Scheers 2009; Letton and Webb, 2012; Haldipur and Metcalf, 2008). Therefore, collecting direct and representative fluid samples from the subsea production system will provide benefits to the reservoir and production operation activities to maximise recovery. This will enhance reservoir performance management and help optimise the design of production facilities (Pinguet et al., 2014; Sbordone et al., 2012).

The reliability of the measurement obtained from subsea MPFM is dependent on configuration inputs of fluid properties and analysis of subsea fluid sampling. Also critical is the fact that lack of downhole water sample is not taken on the exploration phase of each production well. Thus, such samples can then be acquired when the well attain a certain maturity on the production profile.

However, the output from other producing wells in the flow-loop or clusters, commingled into the manifold have to be shut-down to purge the flowline, in order to collect water samples for a particular production well (Joshi et.al, 2007; Sbordone et al., 2012; Ageh et al., 2009). This approach would not be economically viable at a time of oil price fluctuations, for continuous production wells for operators of offshore assets.

In addition to subsea MPFM accuracies, obtaining direct fluid samples from the subsea tree will offer significant benefit to the subsurface team, to enable better reservoir performance management. Subsea sampling systems design to retrieve representative fluid sampling, using ROVs, have been developed for comparison with the conventional topside fluid sampling acquisition (Pinguet et al., 2014; Sbordone et al., 2012; Letton and Webb, 2012; Mancini, 2011; Letton et al., 2015). A key element of a subsea production system identified here for fluid sample extraction is the subsea tree. Evaluations of the technology choices available for fluid sample retrieval subsea are developed in chapter 2.

1.3 Research Aim and Objectives

The aim is to develop a balance approach for subsea fluid sampling, to enable accurate flow measurement. This would be achieved through screening of selected sampling methods and then the application of a mechanistic model for prediction of fluid characteristic on the production facility.

Specifically, the objectives of the project are to:

- Evaluate subsea fluid sampling technology concepts from a developed literature reviews, and to consider key selection criteria (Safety and Risk, Provision of Representative Sample, Sample Verification, Operation, Economics and Equipment Technology Readiness), with application of multi criteria decision making (MCDM) to select the most suitable concept to support subsea metering requirements (based on reference deployment condition).

- Develop a numerical fluid sampling approach with application of a mechanistic model (compositional fluid tracking) to enable accurate flow measurement to manage well production.

- Perform a study applying the mechanistic model with experimental and numerical data from field case studies for validation purpose, to enable return on production asset.

- Carry out sensitivity analysis on the mechanistic model to illustrate its applicability range to support subsea processing, in order to highlight potential benefits to deepwater development projects.

1.4 Research Methodology

The research methodology provides a guide to fulfil the objectives stated above. The methods outlined below have been carefully selected to facilitate the research aim:

- *Literature reviews.* An extensive literature reviews was carried out from journals and conferences publications. This explored the knowledge gap on subsea fluid sampling. The review covered subsea fluid sampling techniques, subsea hardware interfaces, reservoir production management, numerical modelling, sensitivity analysis and applicability to subsea processing.

- *Industrial survey to capture subsea sampling requirements.* A structured industrial survey was carried out in the subsea oil and gas industry, with focus on industrial experts in IOCs, NOCs and EPC service companies (86 of the correspondence responded); see Appendix III. The survey was aimed at specifying the subsea sampling requirement, using multi criteria decision making MCDM for concept selection to rank the selected options and understanding industry perceptions in employing subsea fluid sampling on deepwater developments. It also highlighted the industrial requirements for multiphase flowmeters capable of supporting subsea fluid sampling.

- *Data collection and MCDM analysis.* The acquisition of field data for analysis was obtained from Shell Nigeria under the approved authorization of Nigerian Regulator (department of petroleum resources (DPR)), and from SPE 77502 published papers (Rydah, 2002; Shoup et al., 1998). Other specific sampling design requirements were obtained from industrial experts in the survey conducted, using MCDM analysis to rank and select a candidate fluid sampling option. Also training received from multiphase flow vendors (SPT, and Framo, etc.) on compositional fluid modeling, aided the applicability of the numerical simulation model.

- *Subsea Fluid Sampling Numerical Modelling.* A compositional fluid tracking model was used to demonstrate the validity of the numerical simulations, after research on current subsea sampling technologies and metering measurement capability. In order to develop the fluid sampling model, a transient multiphase flow program was used as the numerical simulation platform to specify, develop and document the results for sensitivity analysis.

- *Numerical Model Testing and Validation.* The testing and validation of the numerical compositional fluid sampling model was carried out, using a field development case study provided by the Shell and other published field case studies (Rydah, 2002; Shoup et al., 1998). The case studies provided real field data, such as company specific field requirements, reservoir compositional data, subsea system design data and other data relevant to the research study. These data are provided in Appendix II and Chapter 3. A simulation environment was designed using a transient multiphase flow program for the purpose of testing the numerical compositional fluid sampling model.

- *Discussion and Sensitivity Analysis of Numerical Model Applications.* A review of series of case studies on numerical simulation model with sensitivity analysis to illustrate subsea fluid sampling applicability range, to support subsea processing for deepwater field development were carried out. It also discusses where and how the research has contributed to knowledge on subsea fluid sampling applicability in deepwater development projects.

- *Conclusion:* After execution of the thesis objectives, a conclusion is presented to provide answers to the objectives with contributions to knowledge on subsea fluid sampling. Further recommendation is provided to progress the research for future studies, in maturing the contributions added from the present research study.

A workflow structure describing a systematic approach in the execution of this research work is shown in Figure 1. However, chapter 2 presents the research literatures from journals and conferences publications, with evaluations on the different technology and model for subsea fluid sampling. Chapter 3 presents the MCDM, key selection criteria, and analysis to rank and select the most suitable concept to support subsea metering requirements. And Chapter 4 presents a mechanistic model, employing compositional fluid tracking, to provide accurate flow measurement for production facility. Furthermore, chapter 4 presents a case study to validate the model with experimental and numerical data from the field to guarantee return on production asset. Chapter 5 presents series of case studies with sensitivity analysis on the mechanistic model to illustrate its applicability range to support subsea processing on deepwater development projects. Finally, chapter 6 which is the conclusion presents a summary and contribution to knowledge of the research work executed, which therefore provide answers to the objectives on subsea fluid sampling. A recommendation to further progress the research for future studies is also presented in maturing the contributions added on subsea fluid sampling.

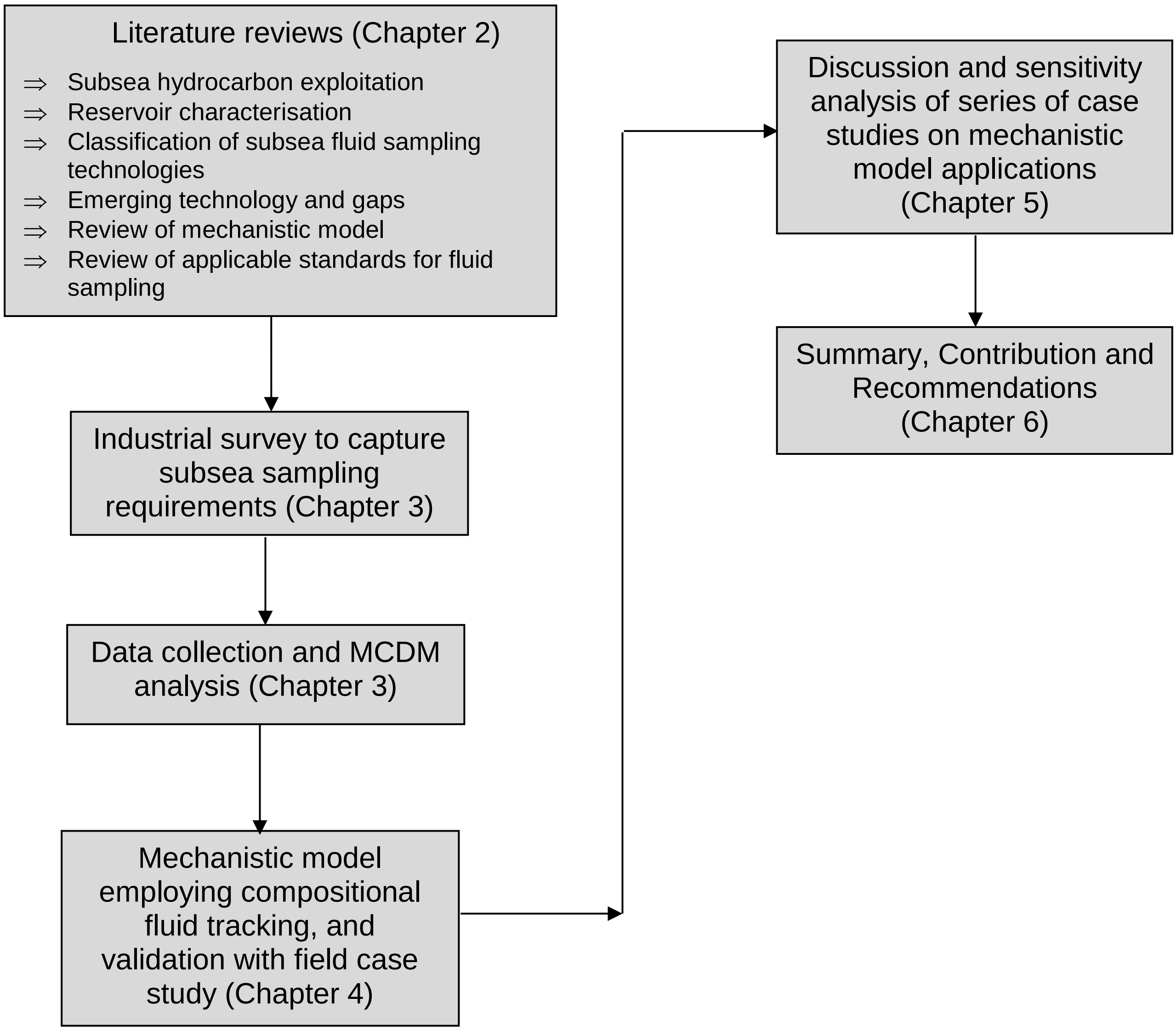

Figure 1 Research Workflow Structure

Furthermore, following the research outcome, a series of journal, conference and magazine publications on subsea fluid sampling and related studies on subsea engineering were published, which includes:

Journal Publications:

1. Abili et al., (2012), "Subsea Processing – A Holistic Approach To Marginal Field Development", International Journal of the Society for Underwater Technology, doi:10.3723/ut.30.167, Vol 30, No 3, pp 167–176;

2. Abili et al., (2013) “A mechanistic model development to overcome the challenges of subsea fluid sampling”, Int. J. Modelling in Operations Management, Vol. 3, Nos. 3/4, pp.267–281;
3. Abili et al., (2013), “Reassessment of Multiphase Pump on Field Case Studies for Marginal Deepwater Field Developments”, SPE Oil and Gas Facilities Journal (SPE 165587), doi.org/10.2118/165587-PA;
4. Abili et al., (2013), “Subsea Controls Future Proofing – A Systems Strategy Embracing Obsolescence Management”, International Journal of the Society for Underwater Technology, doi:10.3723/ut.31.187, Vol. 31, No. 4, pp. 187–201;
5. Abili et al., (2014) ‘Compositional fluid tracking: an optimised approach to subsea fluid sampling’, *Int. J. Oil, Gas and Coal Technology*, Vol. 8, No. 1, pp.1–15;
6. Abili et al., (2015) “Integrated approach to maximise deepwater asset value with subsea fluid samplings”, International Journal of the Society for Underwater Technology, doi:10.3723/ut.32.000, Vol. 32, No. 4, pp. 1–9;

Conference Publications:

7. Abili et al., (2011), “Novel Approach to Cost Effective Subsea Reservoir Fluid Sampling Method”, published and presented at the Deep Offshore Technology (DOT) International conference proceeding, ID no. 59, New Orleans, USA, 9 – 11 October 2011;
8. Abili et al., (2014), “Synergy in Maximizing Value on Deepwater Development: Employing Fluid Sampling and Subsea Processing” published and presented at the Deep Offshore Technology (DOT) International Conference, Aberdeen, UK, October 14 – 16, 2014;
9. Abili et al., (2013), “Subsea Processing Technology, an Innovative Approach to Offshore Marginal Field Developments”, published and presented at the Offshore West Africa conference proceeding, ID no. 1, Accra Ghana, 19 – 21 March 2013;
10. Abili et al., (2014), “Maximising Deepwater Asset Value with Subsea Processing: Employing Synergy on Subsea Fluid Sampling”, IPTC 17760, Kuala Lumpur, Malaysia, 10-12 December 2014;

11. Abili et al., (2015), "Subsea Processing, a Strategic Approach to Realize Value on Offshore Marginal Field Development", published and presented at the Offshore West Africa conference proceeding, ID no. 57, Lagos Nigeria, 20 – 22 January 2015;

Magazine Publications:

12. Abili N., (2013), "Revolutionising Offshore Development with Subsea Processing", spring edition of the EIC's magazine, Energy Focus, page 152, UK;
13. Abili et al., (2014), "Fluid Sampling, Subsea Processing Help Maximise Deepwater development". Offshore Magazine, International Edition Volume 74, Number 12, December, 2014.

Appendix VII present the front pages of some of the journal and conference papers.

2 LITERATURE REVIEWS

2.1 Subsea Hydrocarbon Exploitation

With the increasing number of offshore field developments, advanced technologies are enabling reliable, flexible, high performance subsea production systems (SPS) to remote deepwater field that requires constant monitoring of reservoir fluid compositions and characterisations. The last two decades have seen a significant rise in the deployment of subsea systems, incorporating sampling interfaces in the SPS (Douglas-Westwood, 2009; Douglas Westwood, 2015; Pinguet et al., 2014).

The term “Subsea Systems” is used here to refer to equipment, technology and methods employed to explore, drill, and develop oil and gas fields that exist below the sea surface. This can be in either "shallow" or "deepwater", where the term deepwater is used for subsea projects located in water depths greater than 300m. This may include floating drilling vessels, semi-submersible rigs or platforms and floating production storage and offloading vessels (FPSO) (Barton, 2015; Yong and Qiang, 2010; Fenton, 2015; Umofia and Kolios, 2014).

The offshore industry extended its boundaries beyond land based rigs, wellheads and pipelines to tap into the rich hydrocarbon reserves below the ocean. The deepest subsea installation has achieved the world record water depth of 9,627ft (2,934m) in the Gulf of Mexico (GOM), the Tobago field operated by Shell. Furthermore, the deepest drilling water depth of 10,411ft (3,174m) has been achieved in offshore India, drilled by Transocean's Dhirubhai Deepwater KG1 rig and operated by Oil and Natural Gas Corporation (ONGC) (Barton et al., 2015). Figure 2.1, shows the worldwide progression of water depth capabilities for offshore drilling and production.

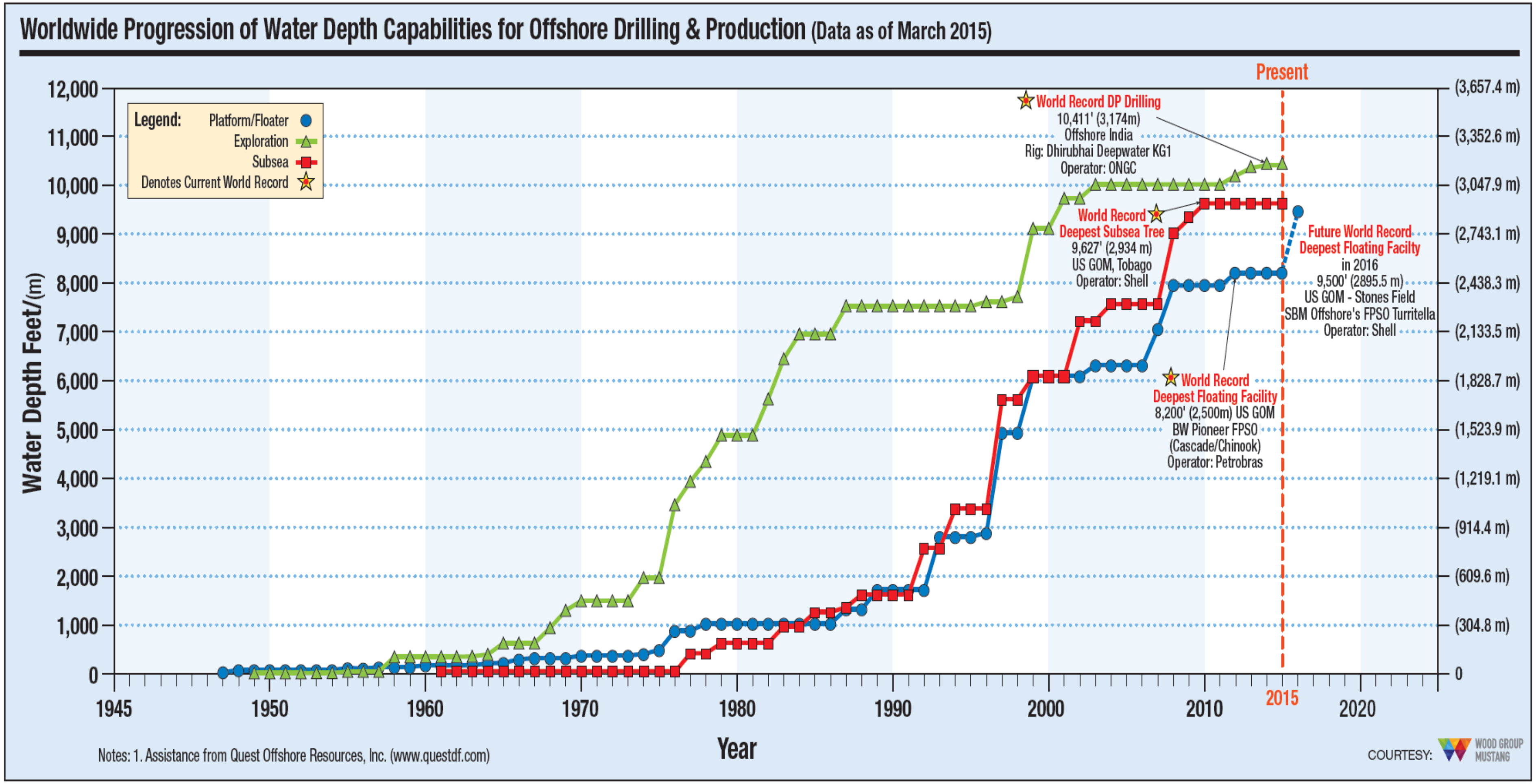

Figure 2-1 Worldwide Progression of Water Depth Capabilities for Offshore Drilling and Production (Source: Offshore Magazine, May 2015)

However, the decision making process behind choosing one deepwater development strategy over another, attempt to maximize asset value and minimize costs without compromising safety and reliability (Tveit et al., 2014; Broadbent, 2010). The decision making process also take into consideration, capital expenditure and operating expenses, risk, and the potential costs of unforeseen events.

2.2 Reservoir Characterisation

This section presents the various reservoir characterisations with inter-play in the execution of subsea fluid sampling on the SPS. The flow chart in Figure 2.2 presents an iterative process to the characterisations of components in tuning the pressure, volume and temperature (PVT), equation of state (EoS) model, for the reservoir production fluid.

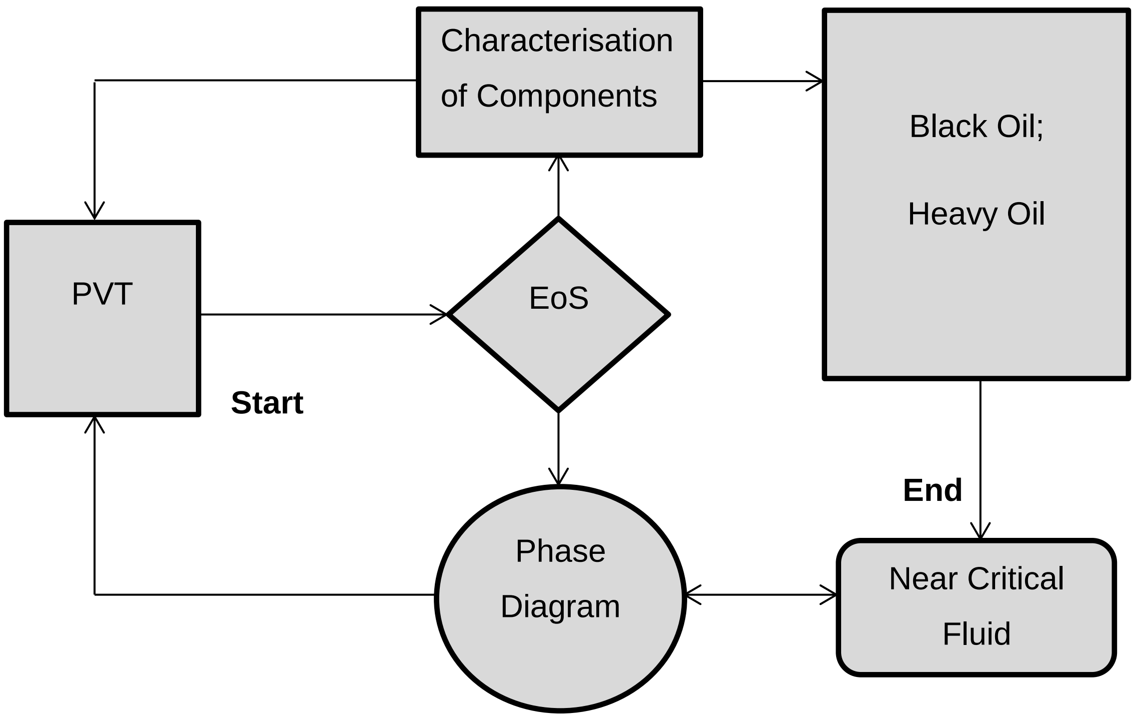

Figure 2-2 Iterative Process for Reservoir Characterisation

The process of acquiring fluid samples must take into consideration the various characterisations to check and validate the measurement results for representative fluid sampling. Failure to test the fluid sampling with these characterisations process would lead to errors in the sampling campaign. However, the iterative process provides the opportunities to optimise sample test results in order to improve the accuracy of data capture for execution of field development projects during and after conceptual studies.

2.2.1 **Pressure, Volume, Temperature (PVT)**

The PVT analysis has been defined as the “volumetric changes caused by the shrinkage factors, expansion factor, and densities for all three phases present at different stages in a multiphase stream of oil, water, and gas” (Nagarajan, et al 1991; Pinguet et al., 2012). The PVT can also be described as the fluid behaviour path through which the fluid flow from one condition to another. Therefore, it is important to highlight that the hydrocarbon mass will remain the same through the journey from a production flowline to standard conditions, but the volumetric proportion of oil and gas will change with the different stages in the fluid behaviour path (Nagarajan, et al 1991; Pinguet et al., 2014; Feria, 2010).

The PVT modelling of CO_2+ oil mixtures is quite challenging due to the complex nature of the phase equilibrium exhibited by these mixtures including near-critical behaviour at high CO_2 concentrations. In modelling Salt Creek CO_2 process, it was necessary to split the C_7+ fraction into several pseudo components using a detailed C_7+ characterization. The pseudo components (transformed values or variables used to simplify design and reduce the correlation of the component bounds) were selected by lumping components with smaller range of carbon numbers (e. g., C_7-C_9, C_{10}- C_{13}, C_{14}-C_{16}+). This type of detailed description was necessary to capture the vaporization of intermediate components as high as C_2 to C_{25} by the dense CO_2 rich phase. An energy minimization procedure was used to identify the correct solution avoiding trivial solutions most commonly encountered in near critical regions (Geneti et al., 2003; Pinguet et al., 2004; Kanu and Ikiensikimama, 2014).

2.2.2 **Equation of State (EoS)**

The fluid models used for this experiment is Pseudo-compositional black oil correlations and fully-compositional EoS methods. Although black oil correlations (PVT properties for pressures at or below the bubble-point pressure) may be adequate in some cases, EoS compositional modelling is preferred as it is based on sound thermodynamic principles and provides reliable predictions even outside the range of data to which it is measured (Stalkup, 1984; Ceragioli, 2008).

Even when using black oil properties in reservoir engineering calculations, it may be preferable to derive black oil properties using an EoS fluid model. EoS-based reservoir fluid modelling involves several key factors including:

- Appropriate component selection to describe the fluid with proper heavy end (C_7+) characterization;
- Incorporation of robust energy minimization and solution techniques for ensuring convergence and avoiding false solutions;
- Developing a regression methodology using optimization software to accurately match the model to laboratory data (Nagarajan, et al 1991; Ceragioli, 2008).

The regression methodology is a powerful tool used to predict one variable from one or more other variables with the aid of transient multiphase programs, which allows the predictions about past, present or future events, made with information about past or present events.

EoS based fluid models suffer from their deficiency in mimicking near-critical behaviour, a limitation where singularities are encountered and steep changes in fluid properties occur. Therefore, special methods such as Gibbs energy minimization and robust solution techniques are needed to predict near-critical behaviour and miscible processes that occur via a critical point (Nagarajan, et al 1991; Ceragioli, 2008). Another critical step in fluid modelling is optimization of model parameters (C_7+ properties such as critical pressures, temperatures, volumes, acentric factor, and binary interaction coefficients with pure components) to match the data. Generally, an EoS fluid model consists of 6 to 10 components of which 4 to 5 can be C_7+ pseudo components and the remaining pure components, resulting in several tens of model parameters to be optimized. Special techniques are employed to overcome these difficulties by grouping similar properties of C_7+ pseudo components and regressing on them consistently (Nagarajan, et al 1991; Ceragioli, 2008; Al-Marhoun, 2015).

2.2.3 **Phase Diagram**

A phase diagram is a "plot that shows the equilibrium temperature-pressure relationships for different phases of a multicomponent mixture" (Schindler, 2007). The phase diagram is a useful tool to assess the behaviour of the fluid properties as they move from the reservoir to the well. It is important to understand the fluid behaviour path or fluid properties, in relations to pressure and temperature, in order to attain high accuracy of flow rate measurement (Pinguet et al., 2012; Foster et al., 2006; Schindler, 2007). The diagram always shows the envelope on how the fluid behaves as two phase liquid and gas.

The area in the diagram is defined by the dew line and the bubble line as shown in Figure 2.3 in red and blue respectively for the reservoir fluid. The red line demonstrates how the temperature is decreasing at a given pressure, which results to the first liquid droplet formed out of the gas. The blue line demonstrates how the first bubble of gas comes out of the oil when the temperature is increasing at a given pressure (Pinguet et al., 2012; Kanu and Ikiensikimama, 2014). The "critical point", shown as a green diamond point in the phase diagram is the point where the two phases (oil and gas) become indistinguishable or impossible to differentiate the gas from the oil. Also, the measured bubble point as a black diamond in the bubble line following, demonstrate the type of well, and in this case, is a typical black oil well. This is the point where the production demonstrates fluid properties of multiphase liquid and gas which generally occurs within the well bore (Foster et al., 2006; Pinguet et al., 2004).

Furthermore, we can deduct from the phase diagram in Figure 2.3 that the reservoir is at a given pressure and temperature outside of the multiphase envelope. It is recommended to avoid producing the reservoir below the bubble point for a long period, for better reservoir management to maintain high recovery (Pinguet et al., 2012). Consideration should be given to the reservoir requirements, well constraints, flowing temperatures and pressure in a subsea production facility before the fluids cross other phase boundaries on their path to the surface. A typical example is where hydrate or asphaltene solids could form on lower pressure and temperature, resulting to change affecting the performance of the well and hence the subsea production flowlines (Foster et al., 2006; Pinguet et al., 2004).

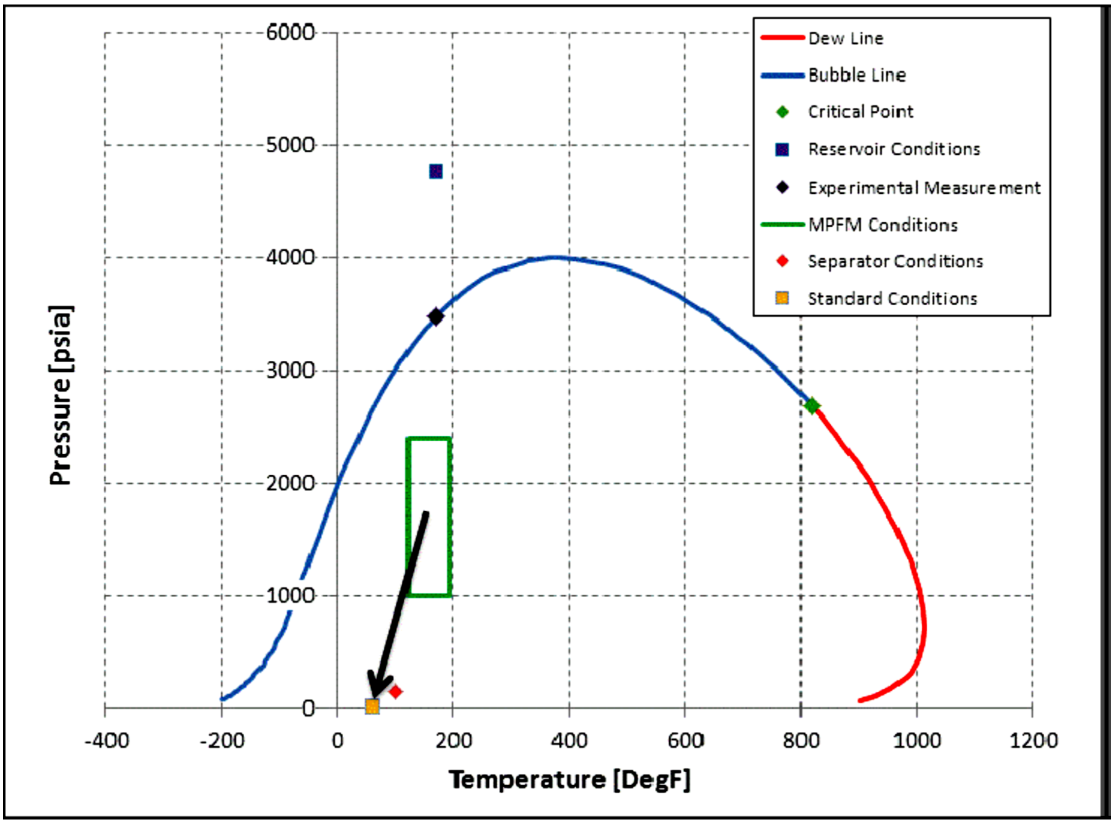

Figure 2-3: Representation of the fluid behaviour path from line to standard conditions (Pinguet et al., 2004)

The green square represents the subsea multiphase flowmeter which is at subsea line conditions and in most applications it is in multiphase conditions. A range of pressure from 1000 to 2400psia is selected for the subsea meter as shown from the phase diagram, to test the reservoir pressure conditions. The range shows that in these conditions the operating point of the subsea meter is much higher than that of the usual operating range of a surface separator. It should be noted that the square box could cross the bubble line. This only indicates that in some conditions the flow is not diphasic but monophasic, and thus such condition could occur for high pressure reservoirs or possibly where the subsea meter is installed upstream of the production choke (Foster et al., 2006; Pinguet et al., 2004). The production separator condition is shown with a red diamond in Figure 2.3 of the phase diagram (150 psia and 100 degF).

Finally, the orange square as shown in the phase diagram represents the standard conditions at 14.7psia and 60degF**,** with anticipated water also being produced at some point in this field case example (Pinguet et al., 2014). Therefore, whatever type of MPFM used in the reservoir production well, there is a fluid specific correction from the line conditions to standard conditions measurement. This PVT correction means that fluid behaviour needs to be modelled in order to estimate the amount of gas that is dissolved inside the oil, and the result will be presented in pressure over temperature (Pinguet et al., 2012; Foster et al., 2006).

For field cases where correlations are applied to a measurement that is performed by a separator, the correlations are considerable as the pressures and temperatures are low, which is not challenged by their validity range (Turna et al., 2003; Pinguet et al., 2012). We can also see the change of pressure and temperature in the Figure 2.3, showing the arrow going from line conditions with subsea multiphase flowmeter, to standard conditions. This conversion is made by introducing some “well known” parameters listed as follows:

- **bo** Oil shrinkage
- **bw** Water shrinkage
- **bg** Gas expansion
- **Rst** Stock tank gas oil ratio
- **Rwst** Stock tank gas water ratio
- **rgmp** Gas phase condensate ratio

Details of these parameters inside the different equations can be found in published papers (Pinguet et al., 2004; Foster, et al., 2006; Pinguet et al., 2012).

2.2.4 **Characterization of Components**

Characterization and component selection of the reservoir fluid contains numerous compounds of different kinds (paraffinic, naphthenic, and aromatic) which play a dominant role in determining the PVT behaviour of the fluid. An example is in a gas-condensate fluid, where the dew point pressure is a strong function of C_7+ components and their relative amount in the fluid. In heavy oils, these components dictate the viscosity behaviour and control the asphalting and wax deposition characteristics. The most widely used method is due to Whitson in which the C_7+ distribution is represented by a continuous gamma function that is optimally discretized into a few fractions (pseudo components) (Whitson, C. H., 1993; Lawrence et al., 2008; Bargas, et al., 1992; Nagarajan, et al 1991; Ceragioli, 2008).

However, many of these black oil reservoirs with high remaining oil saturation after primary depletion and secondary water-flood, could become prime candidates for enhanced oil recovery (EOR) by non-hydrocarbon gas injection such as CO_2. Significant solubility of CO_2 in the oil enhances the recovery through oil swelling and viscosity reduction CO_2 can also vaporize intermediate components in the oil with carbon numbers as high as CO_2+ due to its super critical behaviour at reservoir conditions leading to miscibility development and high recoveries (Whitson, C. H., 1993; Lawrence et al., 2008; Nagarajan, et al 1991; Nagarajan, et al 2006; Al-Marhoun, 2015).

A typical phase behaviour exhibited by CO_2+ oil mixtures at both low (<120 °F) and high (>120 °F) temperatures is displayed in Figures 2.4 and 2.5 through a pressure-composition (P-X) and a ternary diagram. Depending on the pressure, the temperature, and the mixture composition, CO_2+ oil mixtures can exhibit near-critical behaviour including multiphase equilibrium ranging from simple two-phase liquid-vapour as seen in Figure 2.4a and 2.4b to more complex two or three-phase liquid-liquid or liquid-liquid-vapour equilibrium in Figure 2.5a and 2.5b. As shown in Figure 2.4a, the CO_2+ oil phase boundary in the neighbourhood of the critical point is steep. The fluid properties vary significantly in this region with small changes in operating conditions or fluid composition. PVT tests for evaluating CO_2 injection processes should be customized so that appropriate compositional and PVT data are acquired to model the complex phase behaviour exhibited by CO_2+ oil system. These data were essential for tuning EoS model parameters to replicate miscibility development under field conditions (Lawrence et al., 2008; Bargas, et al., 1992; Nagarajan, et al 1991; Ceragioli, 2008; Al-Marhoun, 2015).

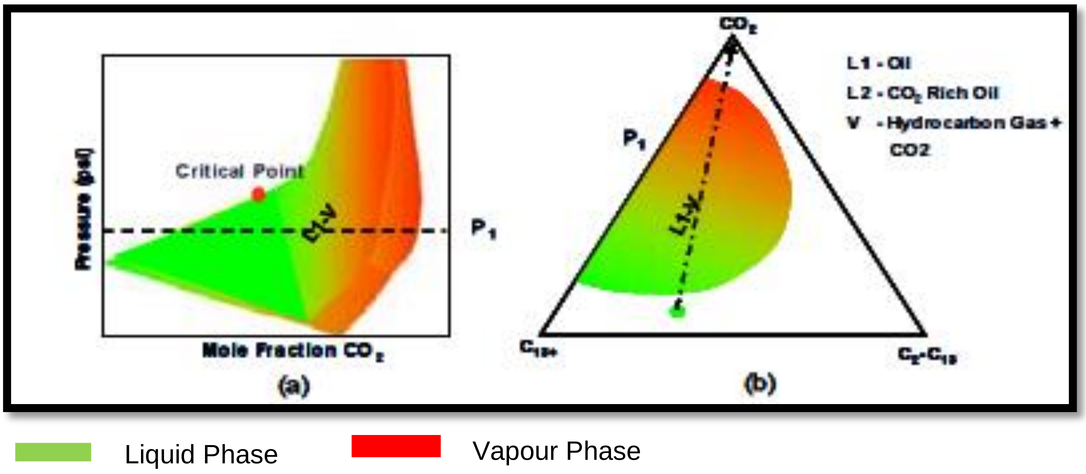

Figure 2-4: CO_2+ Oil Pressure Composition and Ternary Diagrams at T>120 °F **(**Lawrence et al., 2008)

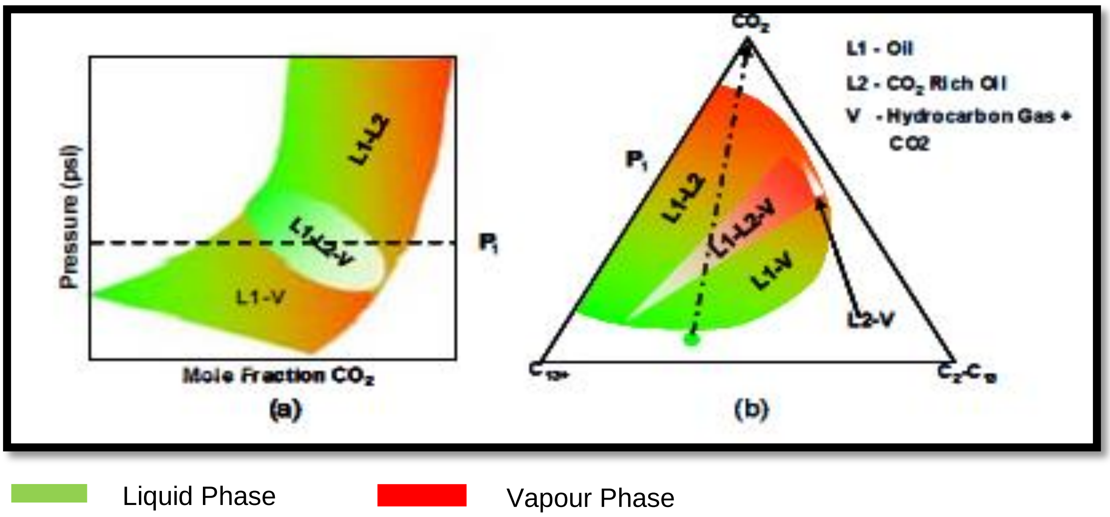

Figure 2-5: CO_2 + Oil Pressure Composition and Ternary Diagrams at T<120 °F **(**Lawrence et al., 2008)

2.2.5 **Black oil**

Reservoir fluid properties are useful in numerical reservoir simulations to determine estimation of reserves, well testing, and design of fluid handling equipment. Black oil reservoirs are characterised by large and heavy non-volatile hydrocarbon molecules, and reservoir conditions the fluid is in a liquid state. It can be identified as having, initial solution gas oil ratio, very dark brown to black colour, stock-tank oil gravity at or less than 45 degree API, and possess C_7+ compositions which is greater than 20 mole (Al-Marhoun, 2015; Schindler, 2007; Kanu and Ikiensikimama, 2014).

The physical properties are bubble point pressure, solution gas-oil ratio, oil formation volume factor (FVF), oil viscosity, oil compressibility and relative density. The bubble pressure is the first gas that comes out of solution, which could be used as the saturation pressure. In under saturated black oil reservoir, the gas oil ratio is equal to the gas-oil solution ratio for pressure equivalent or above the bubble point pressure. The ratio of gas-oil solution is estimated at an accuracy of 10%. It was highlighted that the typical embedded PVT package based on black oil correlation and direct flash assumption is a drastic simplification of the PVT process from subsea line to standard conditions (Al-Marhoun, 2015, Ceragioli, 2008).

2.2.6 **Heavy Oil**

Most fields in the industry contain extra-heavy oil in highly unconsolidated sands. The high oil viscosity in the oil impedes the separation of solution gas from the oil below its true bubble point pressure, resulting in micro bubbles of gas dispersed in the oil. Diffusion forces eventually help gas bubbles to slowly coalesce into a distinct gas phase (Ceragioli, 2008; Al-Marhoun, 2015). This unique behaviour poses several challenges in fluid sampling and PVT measurement requiring careful choice of tools and procedures.

The objective of the heavy oil sampling program is to obtain adequate volumes of representative single-phase oil samples for laboratory analysis. The following sampling challenges deserve consideration (Ceragioli, 2008; Al-Marhoun, 2015):

- Adequate near-wellbore cleanup to minimize sample contamination by drilling mud filtrate
- Controlled drawdown to minimize sand production and avoid two-phase flow, while mobilizing the oil from the reservoir into the sample chamber

- Producing GOR surface sampling, presents measurement uncertainty due to large drawdown and incomplete gas separation from the oil.
- Another challenge with surface samples was the slow dissolution of gas while recombining them to prepare reservoir fluid.

Many of these sampling problems if well tackled can be eliminated through bottomhole sampling (BHS) by wireline formation tester (WFT) without the need to experience bubble point uncertainty of the fluid before it get to the surface, realisable with appropriate tool selection and procedures.

2.2.7 **Near Critical Fluid**

In recent times most of the oil and gas fields contain highly under-saturated near-critical fluid. The high relief of the reservoir and the near-critical nature of the fluid contribute to substantial fluid gradients with depth. Early on in the field development planning, hydrocarbon gas injection was seen as one of the necessary production schemes for pressure maintenance and improved recovery through near-miscible processes (API RP 44, 2003; Ceragioli, 2008; Al-Marhoun, 2015).

Today sampling reservoir fluid posed significant challenges on near-critical fluid. The near-critical nature of the fluid required careful design and execution of the sampling program. Small variations in the fluid pressure and temperature can cause significant changes in fluid composition, particularly near the saturation pressure. Representative fluid sampling required strict isolation of sampling intervals as the fluid properties vary over depth. On the seabed surface sampling operation, low pressure complete phase separation in the surface equipment, and accurate measurement of oil and gas rates are critical for obtaining representative GOR for laboratory recombination. As a result, several reservoir fluid samples from different deepwater are now been collected by both bottomhole WFT and seabed surface sampling (Ceragioli, 2008; Al-Marhoun, 2015).

2.3 Reasons for Subsea Fluid Sampling

In the present offshore industry, several large oil and gas fields are being developed with metering systems such as multiphase meters and wet-gas meters. These instruments provide essential data for optimizing production, measuring oil, gas and water fractions and also flow rates (API MPMS, 2013; Neol, 2001; Jasco, 2012; Jernsletten and Scheers, 2009). The key goal now in the offshore industry is to perform and verify in-situ measurements using the redundant measurements done by the flowmeters various sensors, to reduce the need for direct fluid sampling capture for meter performance monitoring purposes. However, collecting samples from the subsea production system (SPS) for analysis may still be needed to verify the performance of the meter and its calibration. This is to ensure continuity of accurate data measurements of the reservoir and production facilities (Jernsletten and Scheers, 2009; Sbordone et al. 2012).

The development of modern electronic flow metering allows flowrate data to be collected and recorded very rapidly in real time. This has become a common practice in subsea applications, providing the opportunities for surface and sub-surface engineers to understand and optimise well performance (Hall and Gordon, 2011; Sbordone et al. 2012). However, the use of modern electronic flow metering and computer equipment for fluid sampling does not mean that wells can be conditioned any more quickly or that gas and liquid flowrate data will automatically become more representative of reservoir fluid. This is why taking direct fluid sampling from the SPS became pertinent for production operations management. Thus, recent R&D championed by major operators in the offshore industry has been focused on improving the performance of the metering systems. An example is the use of a MPFM with the deployment of subsea fluid sampling technology at mid-life of the field to check and calibrate MPFM PVT input data (Eric, 2012; Hall and Gordon, 2011; Letton and Webb, 2012; Pinguet et al., 2012).

Furthermore, the reason for subsea fluid sampling is not limited to multiphase meter verification and calibration. Other applications include (Kelner et al., 2015; Letton et al., 2015; Pinguet et al., 2014; Letton et al., 2015):

- Determination of API Gravity, Sulphur content, etc.;
- Detection of contaminants;
- Detection of Fluid properties (density, oil permittivity and water conductivity or salinity and mass attenuation);
- Regulatory issues relating to revenue allocations from government authorities and join venture partners, to verify information provided by the operator;
- Industrial shift from conventional well testing to transient multiphase flow model and metering sensors, requiring adjustment of meter reading with life fluid samples;
- Configuration of subsea MPFM to match changing operational conditions;
- Snapshot for insight into reservoir conditions at the time of sample collection, for correct evaluation of oil reserves;
- Design optimization of subsea production facilities;
- Enable early detection to manage water breakthrough with subsea processing.

These reasons have created opportunities to improve understanding of the well flow stream for reservoir monitoring, using available transient multiphase flow model and redundant metering sensors (Pinguet et al., 2012; Sbordone et al. 2012; Jasco, 2012). Therefore, obtaining accurate fluid samples for compositional analysis is vital to understanding the reservoir characteristics. This provides opportunities for the design and advancement of subsea facilities (Eric, 2012; Erik et al., 2010; Letton and Webb, 2009).

A set of parameters is measured from subsea fluid sampling, such as PVT, gas oil ratio (GOR), fluid compositions, viscosity, density, change in vaporization, and secondary measurement such as multistage separation test. The sample also provides the necessary data needed to update the configuration of multiphase flowmeters. This includes well fluid composition data for well scale squeeze inhibitor operations for blocking flow caused by clogging perforations in the well tubing. This also help with planning special treatments required for production, such as hydrogen sulphide removal, waxing tendencies, hydrate formation, asphaltene content, metallurgy and refining trials (Christie et al., 1999; Hall, 2011; Letton et al., 2015).

To optimize growth in production volume, operators must identify and manage any changes that might affect the reservoir fluid as it moves through the production system to the processing facilities. Some of these changes are counter-intuitive, and are only recognised through analysis of representative subsea fluid samples and modelling of fluid behaviour between the reservoir and the processing facility. The information derived from analysis and modelling of fluid behaviour serves as a basis for developing an overall production strategy (Christie et al., 1999; Hall, 2011; Pinguet et al., 2012).

2.4 Fluid Property Measurement and Modelling Techniques

There are various techniques available on how to generate fluid properties in production sampling operations. The following approach describes the techniques to perform fluid property measurements:

Black oil Correlations (BOC): This approach uses the BOC to estimate oil, water and gas fluid properties from a production stock tank measurement (to measure produced oil and gas volume initially in place at standard condition). The fluid behaviour may differ from the correlations with stock tank measurements. In such conditions therefore, the use of data collected from experiments or simulations using the PVT EoS model simulator are preferable (Pinguet et al., 2012; Ceragioli, 2008; Al-Marhoun, 2015).

Wellsite Fluid Property Measurement (WSPM): The wellsite measurement of fluid properties can be dedicated, such that it can produce with PVT to deliver an equivalent or accurate PVT laboratory measurement. The measure can produce a full PVT report with relevant fluid properties for multiphase meter input from a representative recombined sample. Due to vitality of the produced fluid, the wellsite fluid property measurement becomes subjected to high uncertainty in the multiphase meter pressure and temperature measurement (Ceragioli, 2008; Al-Marhoun, 2015; Kanu et al., 2014).

Equation of State (EoS): Fluid property inputs can be generated using the EoS tuned data from full PVT report packaged in the PVT simulator. The PVT report is generated during explorations and appraisal of well formation samples. PVT expertise is required to conduct this EoS simulation to ensure quality controls of the PVT data capture. In some cases, the EoS tuning is required to run the multiphase meter in volatile oil and gas condensate. If validated, the turnaround time is shorter to acquire a representative PVT data (Pinguet et al., 2004; Kanu et al., 2014; Ceragioli, 2008; Al-Marhoun, 2015).

Laboratory Measurement (LM): Samples acquired from multiphase meter PVT laboratory measurements, take longer turnaround time compare to other techniques. However, this approach would offer the most accurate measurements on PVT sample data. The need for this accuracy is applicable in production when the cost of deferment in running a PVT sample is occasioned by delays in producing the fluid property inputs (Pinguet et al., 2014; Ceragioli, 2008; Al-Marhoun, 2015).

The Table 2.1 presents the advantages and limitations of the techniques to perform fluid property measurements.

Table 2-1 Advantages and Limitations of Fluid Property Measurement Techniques

Measurement Techniques	Advantages	Limitations
Black oil Correlations (BOC)	• Fast and efficient tuning of oil, water and gas fluid properties; • Take into consideration the effect of surface separator configuration; • Saves considerable amount of computation.	• Deviation of fluid correlations when using stock tank measurement; • Rely on experimental data for validation.
Wellsite Fluid Property Measurement	• It can be tailored or dedicated to PVT measurement; • Can generate full PVT report; • Enable evaluation of fluid properties; • Thermal stability in well testing.	• Subjected to high uncertainty T & P measurements; • Difficult to flush by mud; • High initial cost of oil fraction of mud for flushing; • Oil mud cutting have to be clean up before dumping.
Equation of State	• Can be used for a wide range of temperature and pressure; • Thermal properties can be computed with minimal amount of components data; • Suitable for modelling hydrocarbon systems.	• Requires binary interaction parameters; • Not capable of representing highly non ideal chemical systems; • PVT expertise is required to conduct EoS simulations for quality controls of PVT data.
Laboratory Measurement	• Reliable for accurate measurement of PVT data; • It can be replicated easily in the laboratory; • Allow for control of extraneous variables with well-established cause and effect.	• Takes longer turnaround time; • Experimenter effect can bias the results; • Requires costly resources to perform laboratory measurements.

2.5 Process for Planning and Executing Subsea Fluid Sampling Program

The keys to a successful fluid sampling program are proper planning and careful implementation of the steps in a subsea production facility. This can be achieved by setting objectives, design, procedures, execution, data capture, laboratory analysis, and tracking or stewardship. These steps are illustrated on a flowchart in Figure 2.6.

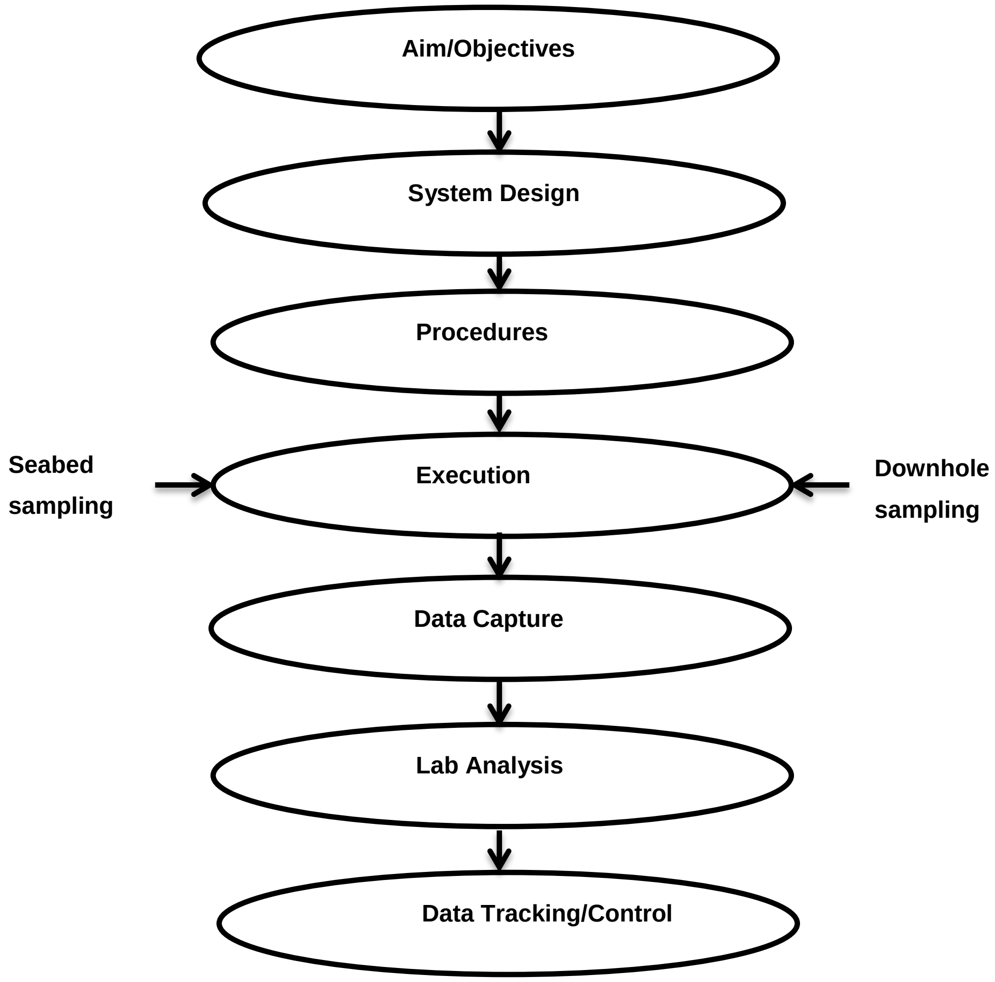

Figure 2-6 Conceptual Processes for Planning and Executing a Sampling Program (Lawrence et al., 2008)

The design stage of the sampling program consists of all the factors that will be necessary to meet the objectives. A firm definition of the objective of the sampling program is essential to begin the design, and this is the primary reason for obtaining a fluid sample to inform reservoir management system and facilities design. Each of these purposes will lead the fluid sampling project in different directions due to requirements, different types and volumes of samples. Once the objectives, and thus the sample type (bottom hole or surface) and volume are determined, the specifics of the sampling program or protocol must be resolved (Pinguet et al., 2012; Pinguet et al., 2014; Ceragioli, 2008; Al-Marhoun, 2015).

In an ideal situation, the objective is to obtain samples of the original reservoir fluid before the bottom hole flowing pressure has dropped below the reservoir fluid saturation pressure. The fluid entering the well bore under such conditions will be representative of the original reservoir fluid, since the fluid has not been subjected to pressures below the saturation pressure at any point in the near-well region. When the pressure in the near-well region is reduced below the saturation pressure of the original reservoir fluid, the fluid separates into two phases (gas and liquid), having different compositions (API RP 44, 2003; Dybdahl and Hjermstad, 2001; Nagarajan et al., 2006; Pinguet et al., 2014). This gives rise to flowrate of gas and liquid due to the changes in velocity that result in different fluid composition, in the wellbore which differs from that of the original reservoir fluid, at least during the initial period after flow is established.

A frequent occurrence in sampling operations is that the pressure at the producing well’s wellbore is reduced (drawn down) below the fluid saturation pressure, while the static (shut-in) reservoir pressure is still above the saturation pressure. Under such circumstances, it is still possible to collect representative samples of the original reservoir fluid, but considerably more effort is required to properly “condition” the well prior to sampling (API MPMS., 2013; API RP 44, 2003; Nagarajan et al., 2006; Sbordone et al. 2012). The methods to do this are described in this section. If sampling is delayed until the static reservoir pressure drops below the saturation pressure of the original reservoir fluid, representative samples of the original fluid can no longer be obtained. This provides strong motivation for sampling early in the life of a reservoir, especially since the actual saturation pressure will not be known conclusively until samples have been taken and studied in the laboratory. This is very important in sampling for PVT analysis. For multiphase flow metering, samples obtained any time above saturation pressure during the field life is adequate for meter measurement re-adjustment (Pinguet et al., 2014; Ceragioli, 2008; Al-Marhoun, 2015).

2.6 Preparing the Well for Sampling

Preparing the well for sampling requires considerations which includes an understanding of the type of fluid that is being produced and of the current status of the production operation. An example is the difficulties experienced in obtaining samples from a production well, with highly under saturated oil and producing at a near-critical fluid close to its saturation pressure. Also, the production history of the well can have a significant impact on conditioning (i.e., samples taken during pre-production [sampling during the drilling/completion process]), those taken at the conclusion of a well testing program, and those taken after a well has been placed on pump, may involve considerably different conditioning (Dybdahl and Hjermstad, 2001; Nagarajan et al., 2007; Pinguet et al., 2014; Foster et al., 2006).

2.6.1 **Sampling Procedures**

The well should be conditioned (stabilised in flowrate) by producing it until the non-representative oil has been completely displaced with fresh unaltered oil. And so in essence oil well conditioning is the process for eliminating any gas coning and for flushing from the vicinity of the wellbore any reservoir oil which has been altered in composition by being subjected to pressure less than its saturation pressure (Pinguet et al., 2014; Pinguet et al., 2012; Ceragioli, 2008). The non-representative oil is replaced by representative oil from beyond the immediate wellbore area by producing the well in series of step-wise flowrate reductions. The stabilized gas-oil ratio is measured after each reduction in flowrate. The well is considered to be conditioned when further reductions in rate of flow have no effect on the stabilized gas-oil ratio. Adequate time must be allowed after each flowrate reduction to ensure that the gas-oil ratio has completely stabilized. This is applicable for all cases of fluid sampling process including for MPFM configuration (Pinguet et al., 2014;

Foster et al., 2006; Sbordone et al. 2012). The rock prosperities too can be used with correlations of the reservoir fluid properties to make a preliminary estimate of the volume of the non-representative oil in the vicinity of the well (Lawrence et al., 2011; Nagarajan et al., 2007; Pinguet et al., 2014; Foster et al., 2006).

However the length of time that a fluid sample from a particular field should be held in storage before disposal is case specific. Each case depends upon many factors including the properties and composition of the sample, the recovery process being employed in the field, the location of the reservoir, and the long-term plans for the field. Ultimately, the decision can be reduced to a question of storage cost and sample quality. The cost of storing a high quality fluid sample must be weighed against the cost of retrieving another representative fluid sample from the field (Joshi and Joshi, 2007; Hollaender et al., 2007). In some regions of the world, obtaining any type of representative fluid sample is extremely expensive and difficult due to the remoteness of the location.

2.6.2 **Personnel Responsibility**

Another critical factor in the fluid sampling program is the personnel attending to the job during the execution phase and the safety of both the personal and the environment. These personnel must be properly trained with the commitment to obtaining representative samples. Though much thought and time is given to planning the job, many decisions such as flushing of sample bottle before final sample capture, taking required volume in a stable well condition, manipulation of valves during sampling operations, storage and preservation of sample temperature, and prevention of sample contamination, must be made by personnel onsite; therefore all decision-making personnel should have a clear understanding of the sampling objectives and procedures. Most often the information used during the design phase has some amount of error inherent in the measurements and so small deviations in sample depth and fluid behaviour are expected (Pinguet et al., 2012; Pinguet et al., 2014). Experienced people are required to monitor the operation and troubleshoot any problems that may arise.

The onsite experienced personnel can perform quality control and quality assurance (QA/QC) of sampling methods and ensuring representative fluid samples is captured, since it can be costly to return to a well to resample subsea. This will involve visual observations amongst which include checking for leaks, examining fittings and connections during tool disassembly from the subsea production trees for traces of oil, verifying that clocks and rupture disks functioned according to design, ensuring that opening pressures and temperatures are consistent with expectations, and the integrity of the storage system on the sampling skid is to specification (Pinguet et al., 2012; Pinguet et al., 2014).

2.7 Classification of Subsea Sampling Technologies

This section provides a review of available sampling technologies which will be screened for application in chapter 3. The review provides in detail the classification of surface (seabed) and subsurface (downhole) sampling technologies for deepwater field application. However, the research predominantly focuses on seabed sampling operations, to enable sample capture without the need to interrupt production. The potential location from which to retrieve representative fluid samples spans the entire section 2.7. Figure 2.7 gives a schematic view of the various sampling options applicable to field development.

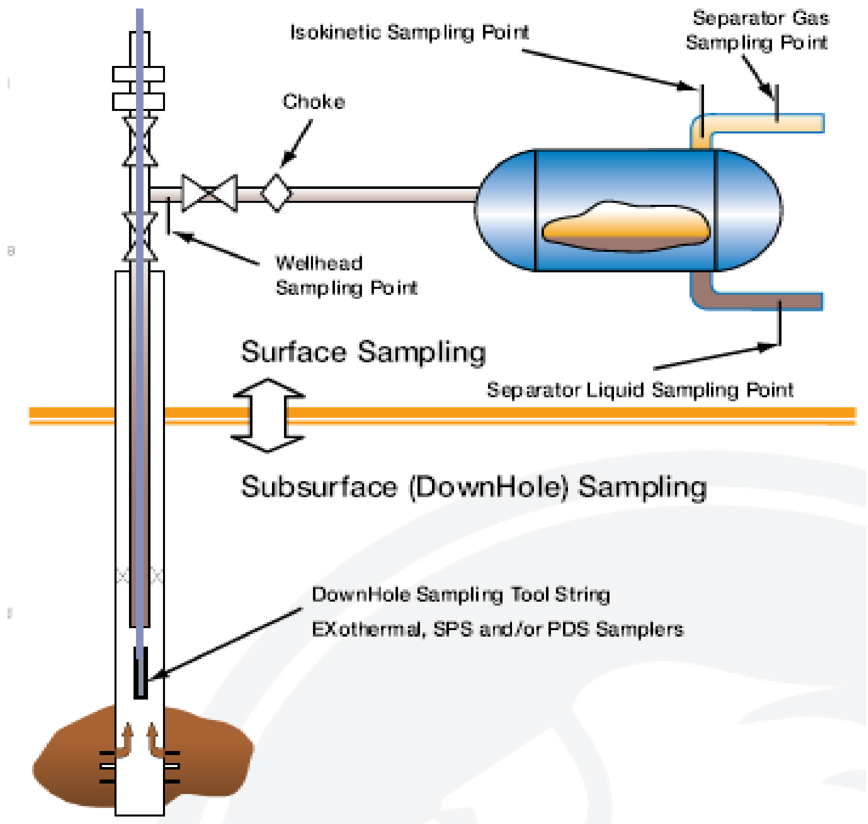

Figure 2-7 Schematic of Sampling Reservoir Fluids options (Source: Expro)

Fluid samples provide the first look at a well's production, and operators need to be confident that the few litres of fluid retrieved from their wells are representative of the reservoir (Sbordone et al. 2012; Jernsletten and Scheers, 2009; Pinguet et al., 2012; Alastair et al., 1998; Pop et al., 2014). Therefore, developments of subsea sampling technology could add value in helping operators to make informed decisions on production.

This has re-enforced the strategy in sampling fluids from a subsea wellbore, subsea MPFM or a flow control module (FCM), etc. with an ROV sampling skid. Therefore, samples may be recovered directly from the seabed and subsequently analysed to determine the characteristics of the oil produced from separate wells. To fully justify this sampling strategy, an ROV interface with the seabed sampling system has been developed and qualified. The ROV interface is compatible with the technical integrity of the sampling process (Mancini, 2011; Sbordone et al. 2012). An examination of the available sampling systems in the market, will determine the process of integrating this strategy in the subsea environment.

There are other strategies today for obtaining representative samples, such as downhole and seabed sampling technologies. These strategies have the potential to provide the best possible quality data for reservoir management and well diagnostics, making sampling and fluid characterisation a fundamental element for well testing (API RP 44, 2003; Nagarajan et al., 2006). Retrofitting subsea sampling technologies to optimise production from a Greenfield asset usually involves strategic decision making during concept selection. Applying this sampling solution would reduce the high cost of intervention on subsea field operations (Zijderveld, et al., 2012). This has necessitated a holistic methodology in the technology development. The following review of seabed sampling technologies demonstrates how ultimate recovery from the field can be achieved with real time monitoring of reserves. To appreciate the full value impact of subsea sampling technology, an examination of the relevant subsea sampling methods are discussed in section 2.7.1 and 2.7.2, to assess a candidate system for integration into the SPS.

2.7.1 **Downhole Sampling**

2.7.1.1 **Downhole Sampling Techniques**

An advanced downhole sampling technology has been developed over 10 years ago, that allows a wireline formation tester (WFT) to sample reservoir fluids in open hole with levels of filtrate contamination that are, in many cases, below measurable limits. Downhole fluid sampling techniques capture the fluid at reservoir conditions before reaching the surface, thus providing an opportunity to acquire life fluid sampling for accurate measurement. This can be achieved via three methods. Firstly, the wireline formation tester is lowered into the open-hole with a probe inside a packer that is mechanically pushed into the formation for extracting samples. Examples are Repeat Formation Tester (RFT) single probe, Modular Formation Dynamics Tester (MDT) as shown in Figure 2.8, Reservoir Characterization Instrument (RCI), and Reservoir Description Tool (RDT). The second is a sample chambers that can also be lowered in cased hole on wireline through a lubricator and wellhead into the tubing. These sample chambers have ports that open and capture a sample of the wellbore fluid. One example is the Single-phase

Reservoir Sampler (SRS). The third method is a sample chambers that is part of the Drill Stem Test (DST) string and have ports that open and capture samples of wellbore fluid (Vick et al., 1995; Dybdahl and Hjermstad, 2001; Lawrence et al., 2008).

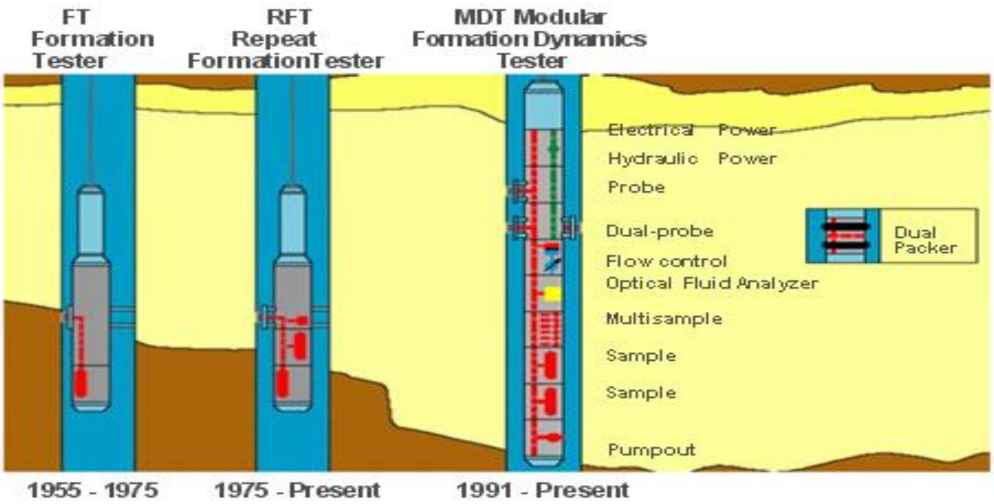

Figure 2-8 Modular Formation Dynamics Tester (Lawrence et al., 2008)

One of the benefits of sampling with wireline formation testers is that the reservoir fluids can be captured at native conditions before any fluid properties losses and the sample is taken directly from the reservoir over a narrow depth interval on production. However, the wireline formation sampling method has a lot of challenges that include capturing representative samples of the reservoir fluid, maintaining the sample at reservoir conditions, and small sample size. A major issue with wireline formation sampling is achieving a representative reservoir sample (Dybdahl and Hjermstad, 2001; Lawrence et al., 2008; Alastair et al., 1998; Pop et al., 2014).

Two reasons for non-representative samples are contamination and uncontrolled drawdown. Drilling muds and mud filtrates infiltrate the near wellbore region during drilling, which then flow back into the wellbore when flow is started on production. When this occurs, the captured sample will contain fluids other than the intended reservoir fluid. Many times contaminated samples are obtained and the true reservoir fluid compositions are calculated when the compositions of the contamination are known. Drawdown must be controlled to ensure a representative reservoir fluid sample is attained. If the drawdown is too large the fluid could split into multiple phases at the wellbore and the sampling vessel may not retain both phases effectively (Michaels et al., 1995; Lawrence et al., 2008; Alastair et al., 1998; Dybdahl and Hjermstad, 2001). Figure 2.9 shows the sample compositional analysis for a typical reservoir fluid mud filtrate.

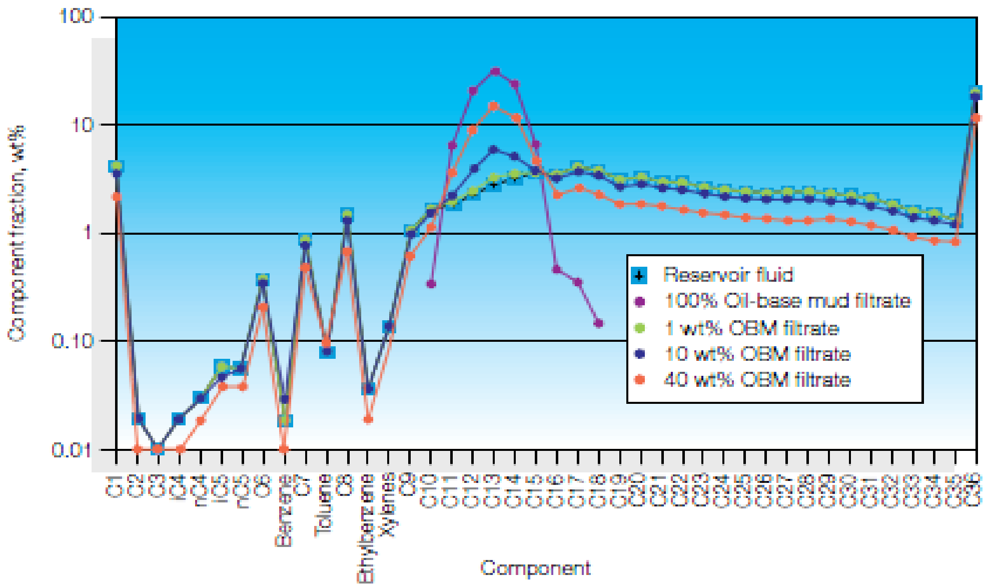

Figure 2-9 Sample Compositional Analysis of Mud Filtrate (Alastair et al., 1998)

In Figure 2.9, weight concentrations are shown on the Y-axis for a typical formation hydrocarbon sample contamination with varying concentrations of oil base mud (OBM) filtrate. Each component on the X-axis represents the number of carbon atoms in the principal hydrocarbon type. Crude oils obtained from different reservoirs have widely different characteristics (Alastair et al., 1998). Some could be black, heavy and thick like tar, and others are brown or nearly clear with low viscosity and low specific gravity.

DST (drill stem test) samplers are useful as backup to subsea surface separator samples. The samplers are run in a carrier as part of the DST string. Common activation methods (opening the sample chamber) include annulus pressure and acoustic signals. The incremental cost is small as the sample chambers are a minor component of a typical DST string. However, both cased-hole subsurface and DST samplers do not have the same quality control capabilities as samplers associated with wireline formation testers (Lawrence et al., 2008; Del Campo et al., 2006; Jackson et al., 2009). A more focused sampling will provide high quality samples that are economically viable to subsea sampling process.

2.7.1.2 **Downhole Focused Sampling**

In all stages of sampling operations accurate description of reservoir fluid properties is critical in the life of an oil or gas field. It is therefore required to carry out exploration to ascertain the true nature of a discovery and to assist in defining reserves to value the economic potential. This is used to determine layer connectivity and field structure as well as the optimization of well completion and production tests during appraisal phase. In development of the field, fluid composition is crucial for material selection of well completion and surface flowlines, flow assurance, design of process control, and production facilities (Jackson et al., 2009; Lawrence et al., 2008; Nagarajan et al., 2007; Williams, 1998). Thus, during the exploitation of the reserves, it is necessary to understand fluid behaviour during the production and life of the asset.

Fluid sampling operations are continuously under pressure from cost control, operational limitations, and sometimes, the lack of understanding of their true value in downstream processes. In addition the risk of financial loss attached to poor fluid characterization, although difficult to quantify, can be enormous. This risk is indeed magnified in deepwater projects, where the development can be extremely expensive and decisions on facility design must be made early in the project. It is no wonder that reservoir engineering and production strategies are crucially dependent on knowledge of these fluid sample phase behaviour with multiphase fluid flow on production, and they so much rely on numerical simulators tuned to PVT laboratory measurements. (Alastair et al., 1998; Nagarajan et al., 2007; Jackson et al., 2009; Khan et al., 2006; Lawrence et al., 2008).

The concept of “focusing” wireline log measurements to measure true formation characteristics has been around since the pioneering days of the early electrical resistivity probes. In this third generation of wireline sampling tools, a similar ability to focus formation fluids to achieve uncontaminated samples within a finite time is introduced. The operation of focused sampling probe draws fluid from two production zones at the interface between the formation and the downhole tool (O'Keefe et al., 2008; Seth et al., 2007; Jackson et al., 2009). The first zone is the sampling zone, which is at the centre of the formation interface. The second zone is the guard zone, which is an annular production zone surrounding the sampling zone, separated by a packer seal. This can be seen in Figures 2.10a and 2.10b that show the frontal view of a conventional single probe and the new focused sampling probe, respectively.

Figure 2-10 Frontal views of (a) conventional probe, and (b) focused sampling probe (O'Keefe et al., 2008)

Description of the cross-sectional view of the focused sampling probe is shown in Figure 2.11 and this illustrates how the improved design can separate efficiently filtrate contamination from the virgin (pure) reservoir fluid. Here the flow being divided directly in front of the packer and mud filtrate is captured in the guard zone, allowing uncontaminated reservoir fluid to flow into the sample probe.

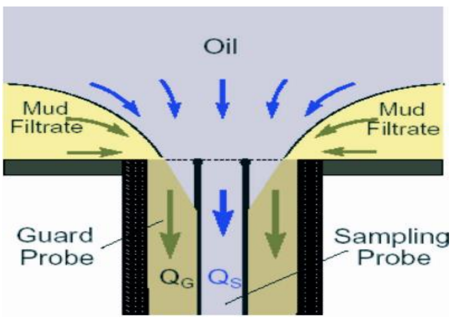

Figure 2-11 Cross-sectional schematic of focused sampling probe (O'Keefe et al., 2008)

Again, a similar schematic which is illustrated in Figure 2.12a shows why conventional sampling with a single probe is not able to reach zero contamination, due to the filtrate continually feeding into the sampling zone. This filtrate is trapped by the guard zone as shown in Figure 2.12b, leaving uncontaminated reservoir fluid to flow into the sample probe (O'Keefe et al., 2008; Seth et al., 2007; Jackson et al., 2009).

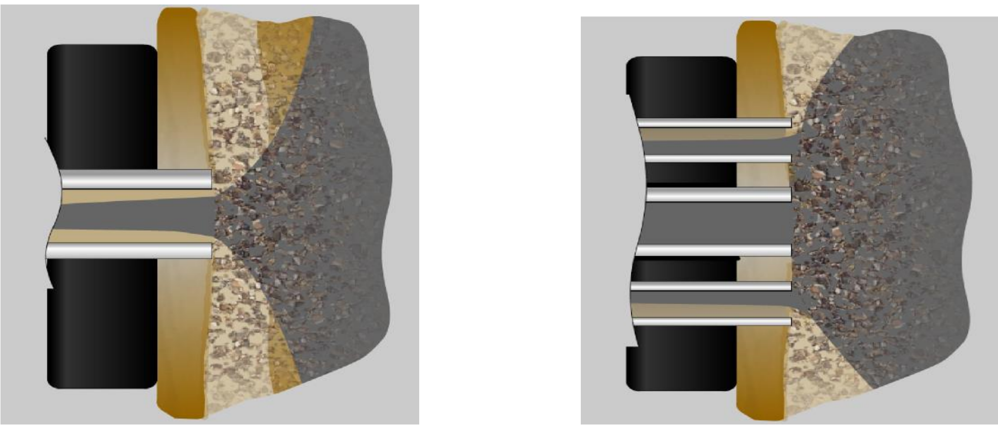

Figure 2-12 (a) Conventional Probe and (b) Focused Sampling Probe (O'Keefe et al., 2008)

A snapshot of the clean-up profile which was recorded for a conventional single probe is shown in Figure 2.13a and it illustrates the expected conical flow regime, the width of which was dependent on flowrate for this homogeneous example. Figure 2.13b shows the setup with the focused sampling technique, where the green arrow represents the sample probe and the two black arrows represent the surrounding guard probe. The results showed that it was possible to achieve a virtually clean fluid through the sample probe, while the contamination measured in the guard area was about 30% for the given parameter set (O'Keefe et al., 2008; Seth et al., 2007; Jackson et al., 2009). Furthermore, the time taken to reduce contamination was considerably less than the conventional approach in Figure 2.13a.

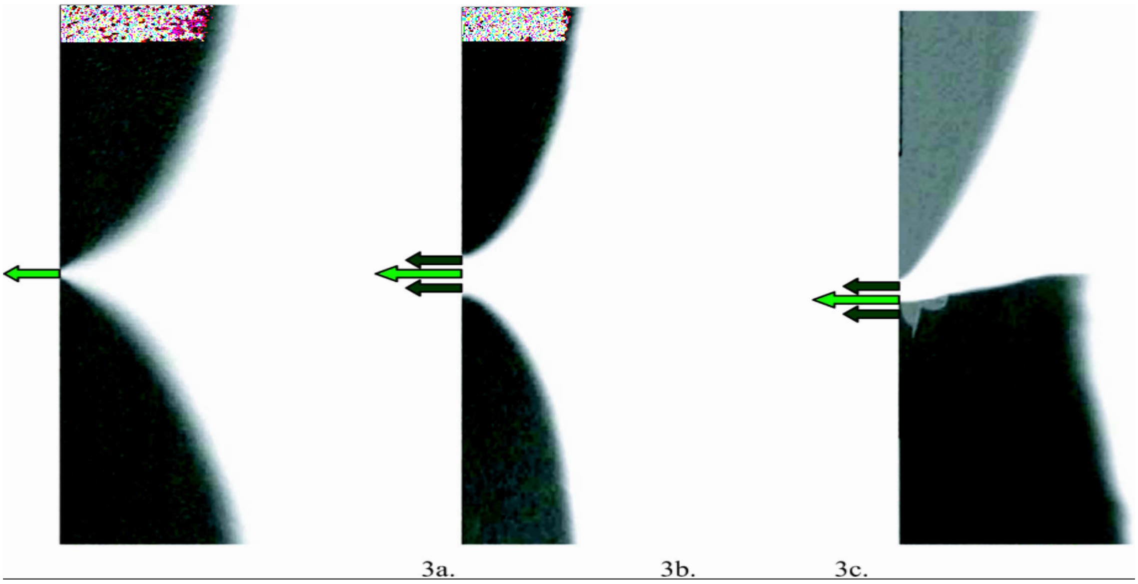

Figure 2-13 Laboratory experiments showing clean-up profile of invaded mud in: (a) Single Probe, (b) Focused Sampling Probe, and (c) Permeability layering (O'Keefe et al., 2008)

In imitating a non-homogeneous formation, Figure 2.13c illustrates what would happen if the probe were set directly across a permeability barrier. For this experiment, the photograph shows that filtrate is cleaned up much more quickly in the upper zone of high permeability, while the lower, tighter zone requires more time for invaded fluid to be cleaned. Results show that an uncontaminated sample is still achievable; however, the clean-up time is longer than in the ideal case. It should be noted here that this is a worst case scenario and that if the probe had been set just above or below the permeability barrier the clean-up actually would have been faster than in the homogeneous case (O'Keefe et al., 2008; Seth et al., 2007; Jackson et al., 2009; Weinheber et al., 2009).

The difference between focused sampling operation and conventional sampling operation is in the equipment, technique, and results. Unlike conventional sampling, which utilizes a single flowline and pump, focused sampling requires dual flowlines for the sample and the guard, with an addition of a pressure gauge on each flowline and separate pumps controlling sample and guard drawdown individually (Weinheber et al., 2009; O'Keefe et al., 2008). Also these pumps are operated in a synchronized manner, to prevent any contaminant entry during the stroke reversing directions on the guard pump. Additional fluid analyzers are required to monitor filtrate contamination on the guard as well as the sample flowlines (Dong et al., 2008; Weinheber et al., 2009; Seth et al., 2007). A flowline schematic of the minimum functionality needed for a focused sampling operation is illustrated in Figure 2.14.

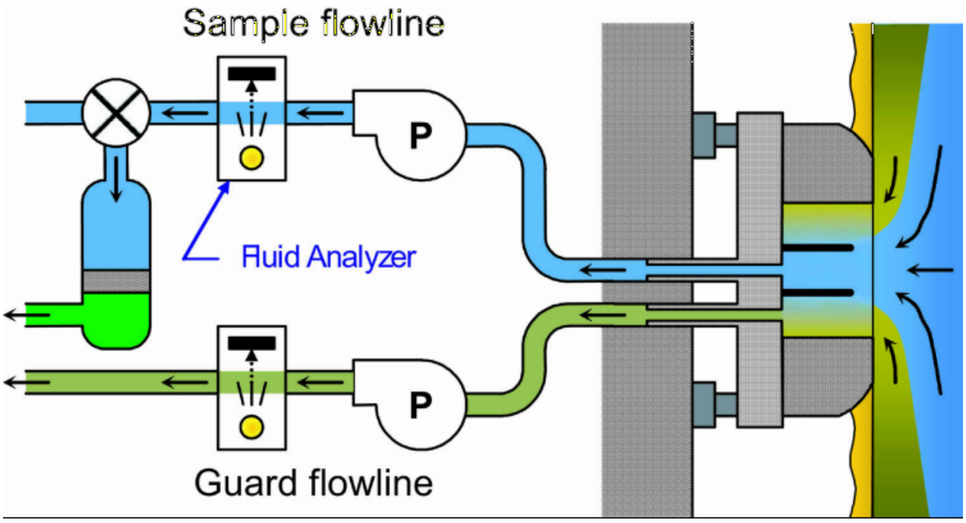

Figure 2-14 Flowline Schematic of a Focused Sampling System (O'Keefe et al., 2008)

Figure 2.15 shows an example of WFT modules configuration in an actual tool string, where the sample area is connected to the upper pump and fluid from the guard area is pumped down by the lower pump, past the fluid analyzers and out to the borehole. The sample chambers are connected to the sample flowline above the upper pump (Weinheber et al., 2009; O'Keefe et al., 2008).

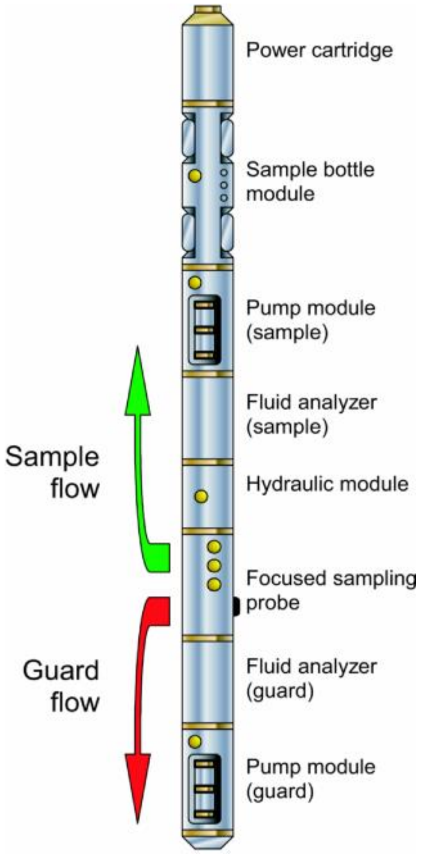

Figure 2-15 Focused sampling tool string (O'Keefe et al., 2008)

This configuration has the advantage that the reservoir fluids do not pass through any pump on their way to the sample chamber and, hence, avoid potential segregation of fluid going into phases. In addition, the flowline can be guarded while pumping; the production ratio can be adjusted during the station to focus the flow regime in the most efficient manner to maximize the reduction of filtrate contamination (Weinheber et al., 2009; O'Keefe et al., 2008).

2.7.2 **Seabed Sampling Measurement Technology**

2.7.2.1 **Multiphase Meter**

Multiphase flow meter is an advance technology developed over 30 years ago by researchers and has become an essential technology in well testing applications. It has evolved into a consolidated solution accepted worldwide by operators and regulators. The MPFM can perform well testing without the need of separation or shut-in of production as in conventional well testing applications. It has the capability to constantly monitor well performance in surpassing reservoir characterization. The MPFM requires less measurement time compared to the conventional well testing which takes hours using a test separator. Also the footprint of the MPFM is significantly reduced on well construction and mobilisation where the separator would need to be moved from one location to the other (Al-Kadem et al., 2014; Al-Khamis et al., 2008; Eivind, 2005). Another driving factor for the adaptation of the MPFM technology is as a result of the complexity of the multiphase flow from the well, which is difficult to predict the flow regimes numerically (Al-Kadem et al., 2014). Figure 2.16 illustrates the MPFM separation process in the sample line of a multiphase flow.

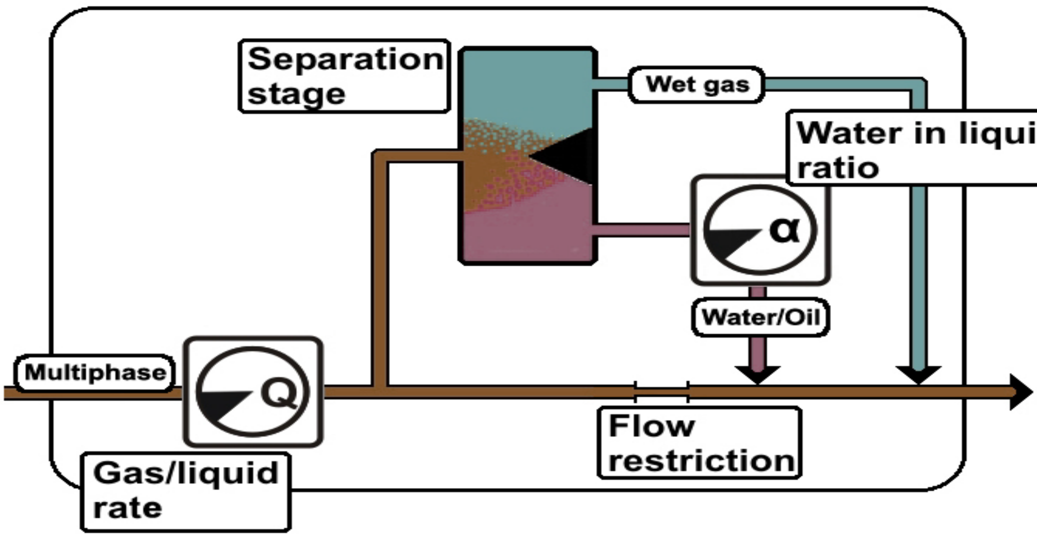

Figure 2-16 Principle of a MPFM with Separation in Sample line (Eivind, 2005)

The MPFM employs several measurement principles, the phase fraction of different fluids (oil, gas and water) with PVT model correlations, utilising pressure, temperature, and differential pressure measurements. It also employs nuclear source, such as gamma rays to determine the fluid properties measurements. This could be low energy gamma rays for water-oil ratio measurement and high energy gamma rays for density mixture measurement (Al-Kadem et al., 2014; Al-Khamis et al., 2008; Eivind, 2005; Erik et al., 2010; Thorn et al., 1997; Stephen and Hoi, 2008).

The MPFM configuration is made up of the following components:

- **Radioactive Densitometer**
  The MPFM consist of the radioactive chemical source that emits gamma ray of photons and detector, which detects the gamma rays that have not been absorbed by the mixture flowing through the Venturi section, all encapsulated in an assembly. The gamma rays attenuation in the MPFM is used to measure the oil, gas and water ratio in the fluid composition with the corresponding density (Al-Kadem et al., 2014; Jayawardane and Theuveny, 2002).
- **Venturi Meter**
  The Venturi is a non-intrusive tube encapsulated in the MPFM assembly. It measures the total flowrate by differential pressure across the upstream and the throat section of the apparatus, where the densitometer calculates the mixture density (Al-Kadem et al., 2014).
- **Pressure and Temperature Transmitter**
  Measurement of the pressure and temperature are done at the operating surface condition of the process fluid. They convert the calculated flow rates drivable from PVT models correlations (Al-Kadem et al., 2014). This provides the calculations for standard condition of the MPFM flowrate allocation.

- **Data Acquisition Unit**
  All process data from the radioactive densitometer assembly, venture meter and pressure and temperature transmitters are received by the data acquisition unit and processed to calculate standard flowrates per phase, including water cuts and gas oil ratio for the MPFM outputs measurements (Al-Kadem et al., 2014). A display screen and battery power is provided to interface with the meter and control system program for data streaming.

However, the MPFM still surfer some limitations with uncertainty in the measurement due to complexity and variations of the multiphase flow. One challenging problem that the oil and gas industry has been dealing with for several years is the need for accurate and reliable multiphase flowrate measurement. Subsea multiphase meters have faced a growing number of challenges linked to the issues of robustness, accuracy and safety in the last 8 years. The remoteness and deepwater depths has proved a significant challenge to meters' robustness and ability to measure flowrates of oil, water and gas in all reservoir conditions (API 17S, 2015; Al-Kadem et al., 2014; Eivind, 2005; Brill, 1987).

In addition, the reservoir fluid properties flowing through the meter changes in particular at commingled multiple producing zones, which results to measurement bias as this change in fluid properties are not updated in the meter configuration. The MPFM is also affected by the limitation to provide representative sample of targeted fluid, as it cannot continuously rejuvenate the reservoir fluid parameters and PVT models over time in responding to the dynamic changes occurring from the reservoir fluid compositions (Al-Kadem et al., 2014; Al-Khamis et al., 2008; Eivind, 2005).

Furthermore, in the case where samples can be captured for different fluid, e.g., from single-phase outlets of a test separator, no standard or method for multiphase fluid sampling with MPFM is yet available. In as much as the MPFM requires prior information of the target fluid properties to be measured (oil, gas and water, density, oil permittivity and water conductivity or salinity and mass attenuation), this information is crucial to update the MPFM on a regular basis (Toskey and Hunt, 2015; Al-Kadem et al., 2014; Eivind, 2005). These fluid properties may change throughout the life of the well with considerable impact on the accuracy of the MPFM measurement. Also coupled with the fact that MPFM are to be relied upon for over 20 years life of field for deepwater development, the need for a method to check and verify the meter performance cannot be over emphasized. Therefore, in-situ verification using ROV deployed sampling measurement system, can be accomplished on permanently installed trend verification or temporarily for periodic measurement verification (Kelner et al., 2015; Letton et al., 2015; Pinguet et al., 2014; Mancini, 2011). This will improve the meter accuracy, allocation process, well diagnostic capability and ultimately the reservoir management.

A typical example of the MPFM from field experience is the MPM flow meter. Its key capability is that the physical measurement principle is less dependent on changing fluid properties than the existing MPFM concept. This reduces the need for sampling and minimizes systematic errors due to changing fluid parameters. The meter is also able to detect produced water earlier, and quantify it more precisely. When installed on the wellhead/subsea tree, return of investment will be paid back many times over, through reduction in both capital and operating costs, improved production optimization and a better understanding of reservoir behavior (Wee, 2010; Kelner et al., 2015; Letton et al., 2015; Pinguet et al., 2014).

The unique methodologies adopted in MPM meters for in-situ measurement of fluid properties (that represent further increased robustness against uncertainties of the PVT properties) are (Wee, 2010; Letton et al., 2015):

- Measurement of salinity of the water phase. This is an in-line continuous measurement, which is performed while the well is flowing. Separate methods are used for water continuous conditions, for multiphase flow conditions, and for wet gas flow conditions.
- Measurement of gas density and permittivity by utilizing the droplet count method to detect periods with pure gas within the pipe. During these periods, the permittivity and density measurement is used to measure,

verify and correct the PVT calculated values for permittivity and density. This method can also be used to measure the permittivity and density of oil.

- In wet gas, the MPM meter incorporates three different methods for measurement of the fractions and flow rates of the wet gas, which can be used to determine PVT properties. This uses in-line continuous measurement which is performed while the well is flowing, based on recalculation of the following measurement modes:
    I. two-phase mode with GOR Input
    II. three-phase mode
    III. three-phase mode with droplet count

These three methods behave differently when changes are introduced in the PVT configuration data, and this different behaviour can be used to estimate the correct PVT configuration data (Wee, 2010; Kelner et al., 2015; Letton et al., 2015; Pinguet et al., 2014). Figure 2.17 shows the MPM subsea meter and Table 2.1 in (a) of Appendix I contain the specific parameters for subsea meter.

Figure 2-17 MPM Subsea Meter (Source: MPM)

2.7.2.2 **Red Eye Water Cut Meter**

The ‘Red Eye’ subsea meter designed by Weatherford (now Proserv), has been qualified with high affinity for water-cut and GVF as shown in Figure 2.18. Due to its advanced technology the Red Eye subsea water-cut meter is unaffected by changes in water chemistry (salinity, H_2S, CO_2, etc.) and does not have to correct for these changes unlike other technologies. Additionally, the hardware is ruggedized and marinized to accommodate the stringent requirements of subsea applications (Weatherford, 2010). This subsea meter has high reliability and can provide a redundant water-cut measurement to multiphase meters or to trend water behaviour in the reservoir, and is thus suitable for validation of fluid sample measurements.

Figure 2-18 Red Eye Subsea Water-cut Meter (Source: Weatherford)

2.7.2.3 **ROV Deployed Sampling System**

Offshore intervention vendors have developed ROV capabilities for the offshore industry. These have provided a breakthrough in subsea intervention operations, as the most reasonable alternative for fluid sampling from subsea installations. The ability to acquire subsea samples from well production systems without the need for static platform is the key benefit of an ROV deployment. This increases the availability of subsea fluid sampling as it does not require a fixed platform to acquire subsea samples (Mancini, 2011; Zijderveld et al., 2012).

The new generation of subsea fluid sampling technologies comprise the use of an ROV, sample collection device, known as sampling skid and a storage facility for the collected fluid. The collecting device recovers samples of the fluid from the subsea tree that are representative of the well flow stream. The sample is then taken to the vehicle's storage facility housing the sample bottles via a pump driven sampling skid with circulation of the sample fluid back to the subsea production system. The captured sample is stored by closing the valve in the sample skid and the samples are carried in the vehicle's storage facility to a second location as demanded by the operation (Mancini, 2011; Sbordone et al., 2012; Eric, 2012). This storage facility has the capability of maintaining the integrity of the sample temperature and pressure even above the well operating range. This ensures representative samples are maintained in good condition during their transfer subsea and that they are safely delivered for laboratory analysis.

Furthermore, the ROV is used in deepwater for various other maintenance and intervention on subsea operations. With the evolution of subsea processing, new applications of ROV deployed subsea measurement will provide access and retrievability of important measured data from the wellhead. This has been applied in the Eastern Trough Area Project (ETAP) that is an integrated development of nine different reservoirs; located 240km east of Aberdeen, UK, in the Central North Sea, where ROV assisted liquid sampling was successfully carried out. ROV deployed sampling has the potential be the vanguard method for accurate data acquisition (representative sampling) for verification of subsea metering (Denney, 2000; Joshi and Joshi, 2007; Mancini, 2011; Kelner et al., 2015).

2.7.2.4 **Production Sampling System**

The subsea sampling Interface has been developed by one of the major EPC contractors as an integral part of the subsea production systems. This includes:

Subsea Sampling Module (SSM)

This is an ROV operated tool that connects to the subsea sampling interface (SSI). It operates the SSI pressure barriers, and captures the required fluid samples by pumping the fluids from the production flow loop or sample point into the sample bottles. The SSM is designed to capture representative samples of the 3 phases (oil, water and gas) in isobaric and isothermal conditions. It can be operated to meet different requirements in terms of single, two or three phase samples, in quantity and from many wells in one subsea deployment as shown in Figure 2.19. The SSM can be used for a wide range of applications. From a single to multiphase phase flow measurement of one or more physical properties, PVT analysis can be used to acquire high quality samples (Sbordone et al., 2012; Pinguet et al., 2014).

Furthermore, the module design philosophy takes into consideration, safety, and efficiency, sample representativeness. The SSM is compatible with ROV interface with flexibility for different sampling applications. The sample can be taken at a wide range of flow rates, water cuts, GVF and viscosities.

Subsea Sampling Interface (SSI)

This equipment is installed in the subsea tree or manifold to provide access to the production flow stream. The SSI can be installed as a permanent hardware structure in the subsea production system, or can be included in a retrievable flow control module (subsea multiphase meter and choke module). The SSI can also be integrated into the subsea multiphase flowmeter, or can be provided as a standalone device. The SSI is designed to capture representative samples of oil, water and gas in a wide range of flow conditions, in terms of flow rates, phase distribution and physical properties of each phase (Sbordone et al., 2012; Pinguet et al., 2014).

The SSI includes the sampling lines that tap into the production flow, and the remotely activated valves (2 or 4 on each sampling line, depending on project specific requirements, all of which fail-safe in the close position). The ROV interface with the connections between the SSI and the sampling tool is shown in Figure 2.20 (Sbordone et al., 2012; Pinguet et al., 2014). The SSI can be configured for vertical access sampling, as is normally required for manifolds, or for horizontal access as the preferred option for integration into production subsea tree, shown in Figure 2.21. Figure 2.22 shows the subsea sampling interface architecture for subsea production system.

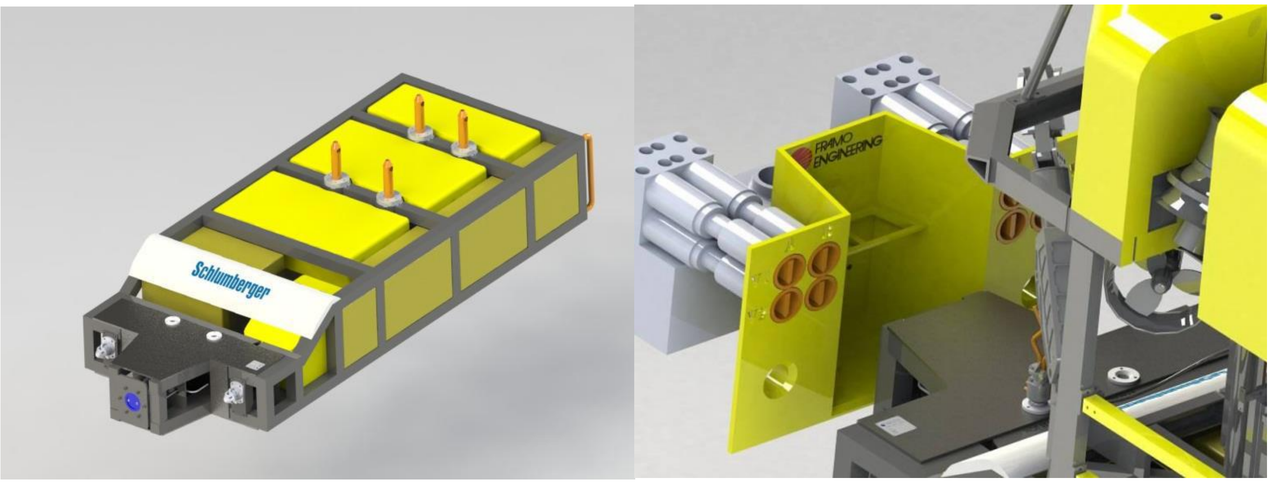

Figure 2-19 Subsea Sampling Modules (Source: Framo)

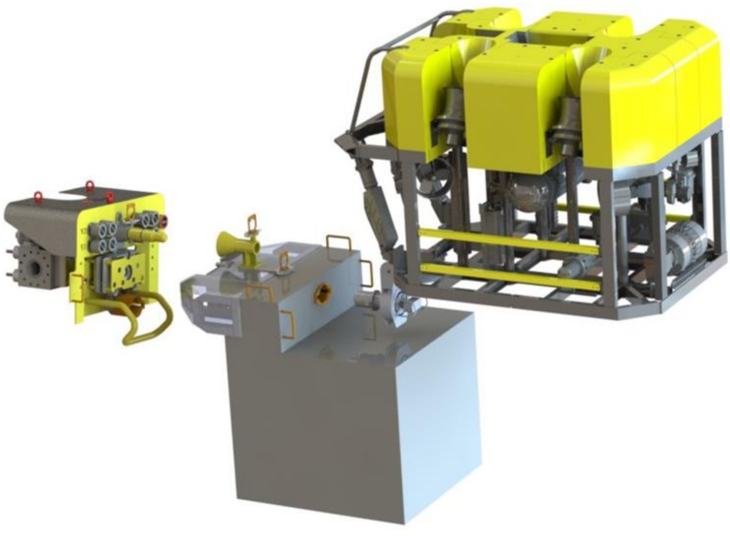

Figure 2-20 Subsea Sampling Interface (Source: Framo)

Figure 2-21 Subsea Fluid Sampling System Configurations (Source: Framo)

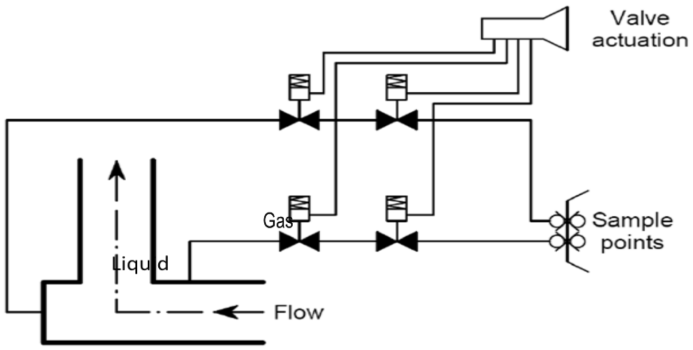

Figure 2-22 Subsea Sampling Interface Architectures (Source: Framo)

The SSM can house up to 9 to12 sample bottles based on project specific requirements, providing adequate sample volumes. Table 2.2 and 2.3 in (b) and (c) respectively of Appendix I, provides the specifications and operating parameters for the ROV deployed sampling skid. Depending on the operator data requirements, it is necessary to collect representative proportions of oil, gas and water. The sample bottles can be configured to be biased towards sampling liquid or gas depending on the application requirements. The sample bottles are designed to aid effective flushing of both the bottle itself and associated pipework (Pinguet et al., 2014; Hall, 2011).

Before the sample bottle is isolated from the flow stream, the sampling system can be allowed to circulate for a considerable period of time. This process allows the pipework to heat up, for thermal equilibrium to be attained. By design the flow-through sampling method captures the sample over 15 to 30 minutes, rather than grabbing what happens to be passing through the production bore at a given instance (Pinguet et al., 2014; Hall, 2011).

2.7.2.5 **Subsea Sampling System**

Subsea sampling system also designed and available in the offshore industry is believed to provide accurate data and detailed knowledge about the reservoir. For fields that have been in production for more than ten years, the need for accurate data is critical. This fact represents a problem that is connected to the uncertainty of the accuracy of the data currently available.

The subsea sampling System provides the operator with the capability to collect individual well test samples, via the subsea sampling module installed on the ROV (Proserv, 2013). Figure 2.23, shows the subsea fluid sampling system, Figure 2.24, the sampling cylinder module, and Figure 2.25, the piston cylinder for retrieving samples. The sampling system capabilities are given in Table 2.2.

Table 2-2 Fluid Sampling Capability (Proserv, 2013)

List	Sampling Capability
1.	Liquid and gas samples – for well fluid composition
2.	Water cut analysis, salinity – important for subsea meter verification and calibration
3.	Barium monitoring – well plugging requirement for scale squeeze
4.	Pressure, Volume and Temperature (PVT) analysis
5.	Well souring later in life due to water injection
6.	Tracer detection – for understanding the reservoir structure

The sampling module is designed with functional specifications in Table 2.3.

Table 2-3 Sampling Functional Specifications (Proserv, 2013)

List	Module Functional Specifications
1.	Manufactured and tested to API 6A, API 17D
2.	Modular construction
3.	Cathodic protection designed to DNV RP B 401
4.	Deployable from a vessel of opportunity
5.	Interface via hot stab (Industry Standard)
6.	NACE compliant material (HH trim)
7.	Rated to 2500m water depth

Figure 2-23 Subsea Fluid Sampling System (Source: Proserv)

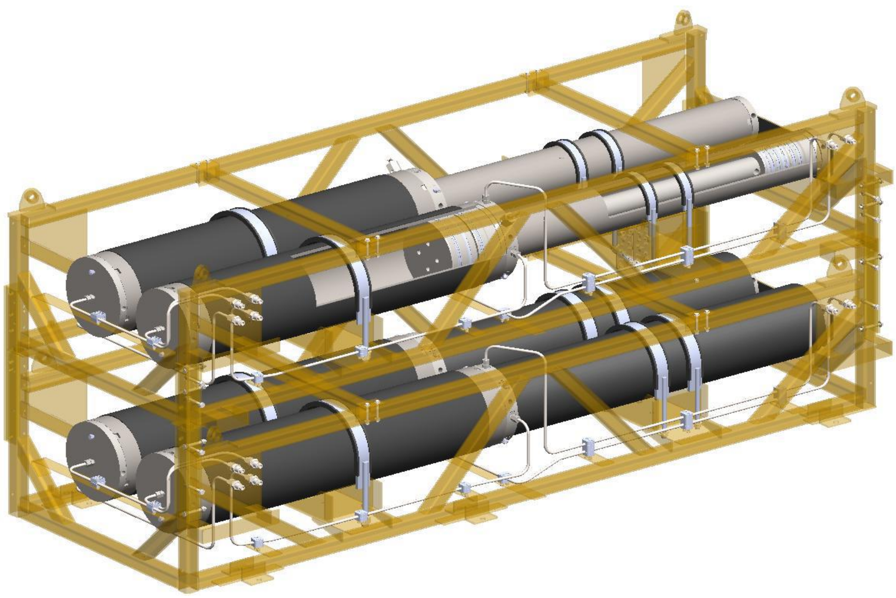

Figure 2-24 Sample Cylinder Module (Source: Proserv)

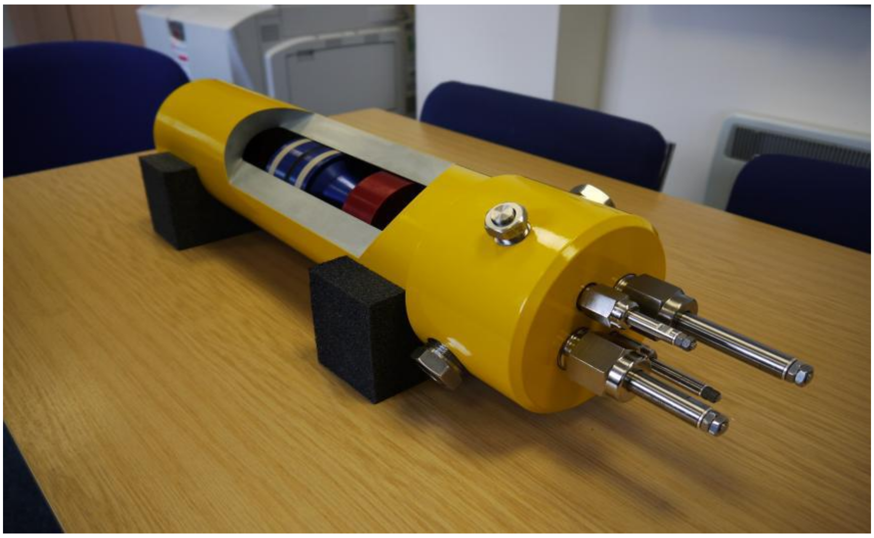

Figure 2-25 Piston Cylinder (Source: Proserv)

Thus, an efficient sampling strategy is required for sampling each individual production well, during early, mid and late life of subsea field operations. The integration and benefits of applying this strategy in the field are further analysed in chapter 5, with a numerical compositional fluid sampling model employed to add value to the sampling operations.

2.8 Benefits of Fluid Sampling

Subsea fluid sampling leads to significant cost savings in operational management on deepwater development. This is applicable even under conditions where significant variations in the reservoir fluid composition occur in transient production operations (Abili et al., 2014; Pinguet et al., 2012; Pinguet et al., 2014). The failure to obtain representative samples can have considerable impact on the Operational Expenditure (OPEX) and consequently the asset value to sustain production volume or enhance financial returns over the life of the field. The list in Table 2.4 provides a summary of the benefits accurate fluid sampling can bring to production operations.

Table 2-4 Benefits of Accurate Fluid Sampling

List	Benefits of Accurate Sampling
1.	Enhancement of oil recovery by securing detailed knowledge about individual well for content analysis
2.	Accurate fluid samples work to maintain lifetime accuracy and value of multiphase measurement systems by providing a source of verification and calibration
3.	Allocation and fiscal data points are provided through component analysis of hydrocarbons to determine the quality from each well
4.	Mitigate flow assurance issues by use of chemical and salinity analysis, for effective dosage of chemical injection strategy
5.	Optimized subsea processing and reducing environmental hazards through sampling efficiency of separation and waste water purity
6.	Acquiring accurate fluid properties from representative subsea samples reduce uncertainties in reservoir management which thus lead to increased oil recovery (IOR) and improved economics
7.	Subsea fluid sampling leads to significant cost savings in operational management on deepwater development

2.9 Emerging Technology

2.9.1 **Subsea On-line Multiphase Fluid Sampling and Analysis (SOFA)**

The Subsea On-line multiphase Fluid sampling and Analysis (SOFA) system designed by Christian Michelsen Research in cooperation with the University of Bergen, is an autonomous metering station for permanent installation subsea. The SOFA project was planned to carryout representative fluid analysis. As can be seen in the Figure 2.26, the SOFA device is installed in the flow line and will be able to take a sample of the flow which then is stored for the time necessary to permit the separation of the different phases. The small gravitational separator tank in the SOFA device allows for multiple measurements designed to characterise the fluid. After the measurements are achieved, the sample is released into the flow, followed by the capture of a new sample intake (Erik et al., 2010).

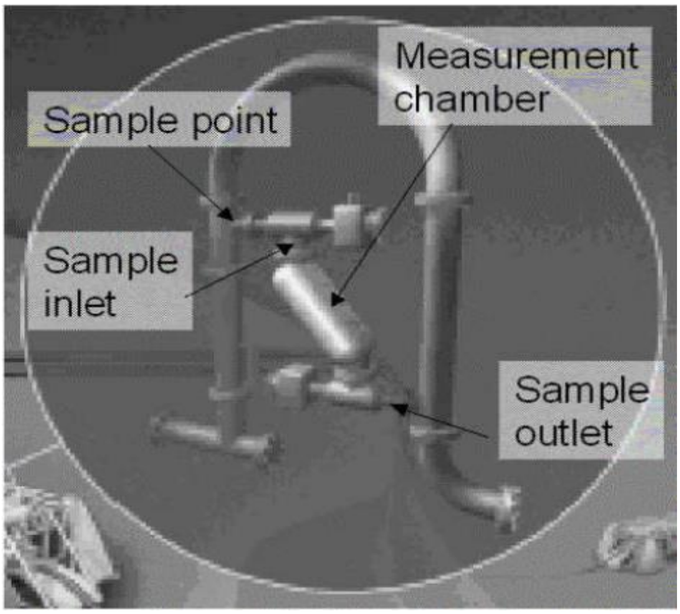

Figure 2-26 Sketch of SOFA Design for Continuous Sampling and Analysis of Multiphase Flow (Erik et al., 2010; Taylor and France, 2009)

Although fluid characterization is and has been the main focus for this subsea fluid sampling research, representative sampling of the flow can give valuable additional information. This information is however, available also from commercially available multiphase flow meters which have a requirement for periodic configuration and calibration. CFD modeling was used in the first design of the sampling probe on the SOFA, and such simulations will also be useful in the further developments of the fluid sampling system (Erik et al., 2010; Stephane et al., 2010). This may provide an integrated fluid sampling approach in providing solutions on challenges faced by the subsea industry.

2.9.2 **Miniature Mass Spectrometer Applied to Subsea Sampling**

The University of Liverpool had made a breakthrough in the miniaturisation of the mass spectrometer which is used mainly to identify sample compositions. It can detect and quantify the trace levels of oil recovery and production to be maximised, and discharge of hydrocarbons, as well as other unwanted contaminants which need to be minimised (Taylor and France, 2009). A Quadrapole retrofitted section of this spectrometer can be seen in Figure 2.27.

The subsea industry could profit from this technology, as it could provide alternative method for the accurate characterisation of reservoir fluids.

Figure 2-27 Quadrapole (Taylor and France, 2009)

With the joint industrial project (JIP) support from BP, BG Group, Chevron, ConocoPhillips, and ENI, a full matrix of field trials were carried out in 2009 at Opus Plus Limited, in Orkney (ITF, 2009). Thus, the continued progress of this innovative technology could bring about viable alternative solutions for representative fluid analysis in future for the subsea industry.

2.10 Innovative Dedicated Fluid Sampling

The subsea flow control module has been on development in the past 5 years. But the cost of integration is high on CAPEX with increased OPEX on intervention operations. A major contribution to knowledge from this research is on the innovative application of this flow control module to the subsea production system (SPS). A new solution with sampling points (all related ROV interfaces, barriers etc.) packaged in a ‘Dedicated Fluid Sampling – Flow Control Module (FCM)’, was ‘conceptualised’ from this research studies to provide the benefit of ‘interchangeability’ with the standard production FCM (MPFM and Choke), captured as an optimised fluid sampling solution during concept selection phase of a deepwater project in West Africa. The FCM on the SPS is retrievable, so designing a ‘dedicated fluid sampling FCM’ was conceived in this research as a novel application to make subsea fluid sampling adaptable to the specific design of a production XT, which thus provide a suitable interface on ROV deployed sampling operations (Pinguet et al., 2014; Sbordone et al., 2012).

The principal for the FCM is to install components which may be retrieved several times during the life of the equipment. The design of the FCM is based on a vertical deepwater Xmas Trees which is now available as 'Enhanced Horizontal Xmas Trees' (EHXT). The EHXT lower frame is designed in such a way as to support the addition of a FCM. The FCM design supports the ready removal and replacement of key EHXT equipment (chokes, MPFM, acoustic sand detector) as a single entity. It can be installed and retrieved on its own, or when fitted to the XT (Fenton, 2009; Bradley et al., 2006; Vick and James, 1995; Sbordone et al., 2012).

The Figure 2.28 presents the 'dedicated fluid sampling FCM' hardware with sampling hub or stab plate, developed with one of the EPC contractors on a deepwater project FEED. In the architecture, two sampling tubes with multiple quick connect (MQC) plates is designed to allow fluid sampling access to the production flowstream. This provides the possibility for retrofit into existing XT system on Brownfield, or Greenfield conceptual design with retrievability of the FCM technology. However, this solution could also be applied to other applications such as acid stimulation on the wellhead, etc. (Hall, 2011; Pinguet et al., 2014).

Figure 2-28 Dedicated Fluid Sampling FCM with Sampling Stab Plate (Source: Deepwater project)

The new conceptualised 'dedicated fluid sampling FCM' is significant, as it would enable improved representative sample capture, with tailored ROV interface valves for fluid sampling in the SPS. Therefore this novel approach provides the right operational access for production fluid sampling to maximise MPFM accuracy without need for conventional shut-in or introduction of external components to interrupt the process flowstream and hence production (Hall, 2011; Sbordone et al., 2012; Pinguet et al., 2014). With this sampling solution, the offshore industry would be able to adapt subsea fluid sampling operations interchangeably to different production XTs, to retrieve representative samples for meter measurements verification and thus, for proper assessment of fluid properties on production facilities.

2.11 Resources Gaps

The subsea MPFM is an interesting solution in achieving production measurement as field development is moving toward deep and ultra-deepwater, with increasing tie-back distance, challenging the conventional method of well testing. Also allowing for future tie-in developments to existing facilities and royalty payment requirements further makes the acquisition process complex. This necessitates the need for accuracy of the data acquired at the wellhead, which can be met with the deployment of subsea MPFM for offshore field application (Ageh et al., 2010; Al-Kadem et al., 2014; Al-Khamis et al., 2008; Eivind, 2005).

Employing subsea MPFM measurements in the underwater environment presents some significant challenges. Due to the fact that MPFM is not 'fit-and-forget' subsea instrumentation hardware (that requires fluid properties data as input), changes in the inputs from the flow stream's actual properties can lead to errors in data capture. While it is possible to monitor the fluid properties at the MPFM with real time data input, the subsea industry is yet to achieve this milestone (Bringedal and Phillips, 2006; Eivind, 2005; Toskey and Hunt, 2015).

Moreover, the MPFM has a limited life span as most electronic could barely survive up to 5 years with the field life demands of over 20 years due to obsolescence, coupled with upset of the data capture on deviation of inputs data measurement from the evolving flow stream fluid properties changes (Abili et al., 2013; Ward and Sohns, 2011; Beedle and Stansfield, 2010; Cretenet, 2004; Solomon et al., 2000; Tester, 2010). Subsea sensors equally suffer same limitations as they are all made of electronic chips, occasioned by failure related to interconnections, which may be solder connections between components, circuit-boards, induced by vibrations or during installation on poor handing. Also early failure could be due to shorter life span and requirement for frequent adjustment of input data, which does complicate the reliability and available of these electronic sensor components during life of field (Danney, 2002; Denney, 2012; Ward and Sohns, 2011; Broadbent, 2012).

This inevitable reality calls for a sustainable proactive approach to mitigate and thus guarantee sampling data accuracy for the long term benefits of field development. This is crucial as most green field would become candidate for brownfield optimization with life of field extension prone to metering sensor obsolescence (Abili et al., 2013; Bartels et al., 2012; Tester, 2010; BSI, 2007; Cretenet, 2004; Solomon et al., 2000). Therefore subsea fluid sampling becomes more attractive to bridge the gaps in metering sensor verifications and calibrations of the MPFM to match reservoir changing dynamics in fluid properties measurements (Kelner et al., 2015; Pinguet et al., 2014; Joshi and Joshi, 2007).

However, current conventional sampling operations that require shutting down the production well are not economically viable for production sustainability. The option to install subsea MPFM, would enable testing, calibration, and post-installation tuning of the meter, which are often problematic. Further, once the meter is been installed, it is not economically viable to remove these meters for any type of maintenance in the life of field. Thus, operators are increasingly turning to virtual multiphase flow model based solutions to estimate the well flowrates in real time (Kelner et al., 2015; Haldipur and Metcalf, 2008).

Therefore, it is important to have separate checks to ensure that the subsea multiphase flowmeter measurements are realistic and accurate. At present in the subsea industry, current applications use redundant instrumentation to provide multiple measurements by difference, but independent separate check measurements for verification are not available (Kelner et al., 2015; Letton et al., 2015; Joshi and Joshi, 2007). Thus retrieving representative fluid samples directly from the subsea tree to continuously verify the meter measurements, is one of the most reliable solutions for data acquisitions. This would provide improved accuracy of the reservoir properties throughout the life of field. Without this solution, subsea reservoirs will be depleted in ways that may leave behind recoverable hydrocarbons, with the resulting loss of revenues. However, this solution has its own challenges in fluid sampling intervention operation that could be counter intuitive to accurate data measurement on non-representative fluid sampling, and with high OPEX if not properly managed in the field operational philosophy (Lawrence et al., 2008; Pinguet et al., 2014).

Furthermore, this solution provides flowmeter measurement of single and multiphase flow rates on merging and injection networks. While this present the traditional solution to flow measurement, powerful numerical simulation model based solutions are available, but not well explored as a complimentary virtual metering solution on multiphase flow in field developments (Haldipur and Metcalf, 2008; Kelner et al., 2015; Cramer et al., 2011; Amin, 2015). A review of numerical simulation model to complimentarily bridge identified gaps in subsea fluid sampling is discussed in section 2.12. A summary of the identified resources gaps on subsea fluid sampling include:

- Limitations of MPFM to provide real time data;
- No reliable separate check measurements exist to validate MPFM;
- No standards available for subsea fluid sampling;
- Comingled flow impact on retrieved fluid samples topside;
- Limitations to ROV deployment, recovery and power source.

2.12 Review on Numerical Modelling

Numerical modelling is employed in the offshore industry to track fluid compositions in transient multiphase flow at wellbores and pipeline systems, that can be analysed using a dynamic two or three-fluid modelling technique (Mantecon and Hollams, 2009; Abili and Kara, 2013; Abili and Kara, 2014). The numerical model developed essentially solves conservation equations for mass, momentum and energy for the gas and liquid phase, or phases, as a function of time. Also, for water breakthrough, the model can handle water either as an integral part of the hydrocarbon phase or as a separate liquid phase (Nagarajan et al., 2006; Bendiksen et al., 1991; Moreno et al., 2014).

The numerical fluid tracking model improves estimation of the reservoir fluid properties for facility design optimisation and operations of a subsea production facility. This model can offer significant benefits to the reservoir performance monitoring and for calibration of subsea metering instruments, which are vital elements for subsea production (Letton et al., 2015; Amin, 2015).

Numerical simulations of the fluid properties that correlate with the measured data can be used to predict reliable reservoir performance even under conditions where significant variations in the reservoir fluid composition occur. Hence, a transient multiphase flow model, when properly applied, provides detailed fluid descriptions, keeps track of local compositions and reduces uncertainty in transient flow conditions. The numerical model tracked individual fluid components and parameters of the well, which gives confidence in transient multiphase flow model (Mantecon and Hollams, 2009; Abili and Kara, 2013; Nagarajan et al., 2006). The studies provide further applications of numerical modelling, as discussed in this section, to show the reliability and potential benefits of employing these numerical modelling techniques in field developments.

2.13 Virtual Flow Model

The term virtual refers to a software based package which can replicate an environment that simulates a physical property in a network or flowstream. Thus, virtual flow metering (VFM) is a category of numerical tools that provides reliable and accurate flow rate predictions over a variety of well configurations and reservoir characteristics. This method determines the flow rates of wells by modelling the flow. The model acquires its data from sensors insertion at various measurement nodes or points in the well, including at the downhole tubing (Kelner et al., 2015; Amin, 2015; Denney, 2012; Vedachalam et al., 2015) Hence with temperature, pressures and other measurement parameter sensors, the VFM model is able to retrieve essential data from each node as inputs, to compute the flow rate of the well. The model can be tuned periodically with the available input pressure and temperature nodal data to determine the flow rate. This is built on first principles (where the model calculates the conservation equations for mass and momentum with the support of closure laws that are dependent on the flow pattern) and derivable from statistical analysis of nodal measurement acquired from the production system (Letton et al., 2015; Amin, 2015; Moreno et al., 2014).

The deviations are useful to assess the range of conditions to predict the model behaviour and dependency of quality input data tuning (to run database application more quickly). The deviations measure the difference between the actual field measurements parameters (pressure, temperature, flowrates, total mass, GVF, WLR) to the predicted data of the VFM at actual subsea conditions (Kelner et al., 2015; Amin, 2015).

The VFM model is not required to be installed with the MPFM, as the sensors need to be installed and functionally commissioned with tested data from various nodes at proper locations in the SPS. At present this VFM models are used as backup to physical measurements should primary metering fails or to compliment the physical metering to reduce uncertainties in measurements, which is maturing rapidly in utilisation on field developments. The growing and complex subsea developments with commingling production have necessitated the need for VFM as a complimentary cost effective measurement system (Amin, 2015; Moreno et al., 2014). However, it is not generally accepted by the industry as the industry is quiet conservative in embracing new technology especially with software capability. Another reason to this is the non-consistent converging results from different modelling approach using field production data. A common problem in simulating infield subsea flowlines between the wells to topsides is the lack of real time 3 phase flowrates from the wells (Amin, 2015; Moreno et al., 2014; Haldipur and Metcalf, 2008). This does not instil confidence on the effectiveness of the VFM system to provide viable solutions to flow measurement.

Irrespective of these limitations, the VFM simulator provide real time information on temperature profiles, pressure, flowrate, pipeline holdup, slug size, proximity to hydrate or wax formation and pig tracking. The VFM applications can combine field data and online model predictions to run forecast simulation. It explores the use of existing pressure and temperature measurements within the well to estimate the well flowrate (Haldipur and Metcalf, 2008; Bringedal and Phillips, 2006; Kelner et al., 2015; Denney, 2012; Letton et al., 2015; Amin, 2015).

Thus, the main purpose of the VFM is to provide real time well flowrate estimates, in order to enable reconciliation of daily/monthly production of the wells. It also serves to optimize methanol injection rates and to provide information on sand production well with sand monitoring. The VFM has been developed into a robust technology that can be used to overcome real-life installation issues such as unavailability of data, data degradation and operational maintenance over the life of field. This is achieved through combine multiple methods to enable robust data estimate with minimal uncertainties. In turn, the uncertainties can be used for verification to back-allocate the reconciled production volume data to the wells. The VFM is equipped with smart logic to enable detection of instrument or sensor failures resulting to sudden changes in field conditions which provides early warning signal on field operations (Haldipur and Metcalf, 2008; Cramer et al., 2011; Moreno et al., 2014; Amin, 2015). This VFM numerical tool has been used by many operators and in managing field operations, which can equally be employed to monitor changes in fluid composition parameters. Table 2.5 provides a list of VFM numerical tools and their suppliers in the market.

Table 2-5 VFM Numerical Tools and Suppliers

VFM Numerical Tools	Suppliers
Ledaflow	Kongsberg
FlowManager	FMC
Prosper	Petroleum Experts (Petex)
OLGA	Schlumberger
ValiPerformance	Belsim

The need to limit the number of expensive well tests and operating expenses (OPEX) reduction cannot be over stated as more Greenfields are becoming marginal. Most of the new field discoveries are deepwater. As a consequence, more production networks leads to complex long tiebacks. Hence the need for reliable production monitoring of each well in the network is crucial for continuous optimisation of field operations. Another application where VFM could be very useful is on ownership of different reservoirs commingling into a pipeline network of same infrastructure and production facilities. The VFM thus provides the capability to monitor the production from each respective well for allocation (Letton et al., 2015; Amin, 2015; Moreno et al., 2014).

The VFM numerical tool is relatively cheaper than installing a hardware metering instrument such as the MPFM and can be used very easily in well production sampling and monitoring purposes. The VFM numerical tool can be maintained and supervised remotely, in contrast to multiphase flowmeter hardware that requires on-site maintenance. Furthermore, the VFM numerical simulation can be tuned without performing physical well tests that would require shutdown of well in order to re-tune the production rate estimator. This is advantageous in field development with long tiebacks where VFM can be utilised effectively in well testing but would be impossible with conventional physical well testing (Haldipur and Metcalf, 2008; Letton et al., 2015; Amin, 2015).

The VFM provides flexibility in real-time reconciliation of data from existing instrument measurement such as the MPFM. The data reconciliation philosophy provides a redundant level of instrumentation measurement. This level of measurement can be used to make the existing hardware more reliable by verifying the validity of data measured. This VFM software technology could be used to permanently replace installed MPFM measurement hardware in events of failure (van der Geest 2001; Haldipur and Metcalf, 2008). Furthermore, it is not cost effective to repair or replace downhole hardware sensor in subsea wells. Software sensors, unlike hardware sensors do not break down. In as much as, software sensor depends on the availability of hardware measurements that fail or give error in measurement, it does not necessarily depend on the availability of a particular piece of hardware. A VFM numerical tool will continue work as long as the total set of available sensor data contains considerable information for the system to update its data measurement estimates (Haldipur and Metcalf, 2008; Letton et al., 2015; Amin, 2015).

However, research carried out by the subsea sampling task Working Group (WG) of the Research Partner to Secure Energy for America (RPSEA), defined technical requirements and selected a concept to design a sampling system. Prototype testing of the system was carried out at the Southwest Research (SwRI) multiphase flow facility and at the Oceaneering Morgan city subsea test facility that began in mid-2010 (Letton and Webb, 2012).

One of the objectives of RPSEA is to address the gap in documented studies of current VFM techniques by critically evaluating the performance of existing VFMs. This was done by comparing the predictions of the VFMs with actual field data from flow meters. Other measurement sources and simulated field data constructed from industry standard flow models were used. The intention of such evaluations was to document the performance of VFMs in order to identify areas of strengths and weakness in the utilization of the VFM technique in monitoring and allocation of production wells (Letton et al., 2015; Letton and Webb, 2012).

This VFM was used to evaluate the identified gaps in subsea fluid sampling to provide a separate check method for fluid sampling from the subsea tree, to enable reservoir production analysis with an in-situ measurement capability.

The model was used to validate multiphase flow meter that is a compromise to subsea fluid sampling. Also, application of the fluid sampling numerical model could reduce the frequency of retrieving subsea samples (Letton et al., 2015; Letton and Webb, 2012; Abili et al, 2013; Moreno et al., 2014; Abili et al, 2014; Mantecon and Hollams, 2009).

Furthermore, the VFM employs data reconciliation as a part of the instrumentation philosophy for redundant level to increase the existing hardware reliability. Hence, greater reliability (consistency of a measure condition) is a key performance indicator of the VFM for greater system uptime (van der Geest et al., 2001; Melbø et al., 2003; Bringedal and Phillips, 2006). The VFM model process is tuned to production data to match field-specific parameters. This enables the software sensors to depend on hardware sensors for the collection of measurement data; however, the software sensor does not necessarily depend on the availability of a particular hardware over a period in time. So the software sensor could be tuned provided the available data set is rich enough or convenient for collection during well tests. The VFM software sensor technology has been tested against production data from BP Troika field in the Gulf of Mexico (Bringedal and Phillips, 2006).

Therefore, the VFM is used as a reliable robust technology to overcome real-life operations issues including data unavailability, communications breakdown, data degradation, and system maintainability over the entire life of field. This is achieved through a combination of multiple measurement methods to provide robust estimate with minimal overall uncertainty. The VFM also employs smart logic to detect instrument failures and sudden deviation in measured field process conditions, to provide an early warning signal to the operator. With the VFM capability, it can be integrated with real time pipeline simulators to track changes on flowlines. VFM can also serve as standard forecasting tools for flow assurance guidance on issues relating to cool-downs, warmups, hydrate blockage and leak detection. In as much as the VFM is tuned or calibrated to the actual field condition, this virtual model solution can be relied on to provide results with high degree of accuracy

(Picart and Llave, 2004; Haldipur and Metcalf, 2008; Bringedal and Phillips, 2006; Denney 2012; Amin, 2015).

Thus, studies conducted in the offshore industry have demonstrated that the integrated measurement capability has strategic link between a VFM installation and a subsea MPFM. The VFM provides the complimentary measurement that is cost effective to verify and enhance the accuracy of the physical measurements, including sensors acting as a partially subsea MPFM to validate the integrity of flow measurement system in a deepwater development (Kelner et al., 2015; Amin, 2015). The VFM has also demonstrated to be a redundant and robust complimentary measurement model with water-cuts, fluid densities and mass flow rates capabilities.

2.14 Transient Multiphase Flow Base Model

The objective of the numerical model deployment is to provide a capability for compositional fluid tracking at the wellhead/subsea tree, flowlines or external subsea components. This would enable fluid sampling to provide detailed knowledge of subsurface and surface condition of the production well, thus setting a standard for subsea fluid sampling, as no standards currently exist in the offshore industry (Hall, 2011).

2.14.1.1 **Physical Models**

The transient multiphase flow model employs a continuity equation for gas, bulk liquid and liquid droplets, which can be coupled through interfacial mass transfer. The model uses two momentum equations. However, a combination of an equation for gas, possible liquid droplets and a separate one for the liquid film is also employed in the dynamic multiphase flow simulation (Danielson et al., 2005; Goldszal et al., 2007; Bendiksen et al., 1991). A selection of energy conservation equations applied in the model is presented in (d) of Appendix I. The development of the equations based on fundamental principles in the dynamic multiphase flow model is provided in (d) of Appendix I.

Thermal Calculations

The dynamic multiphase flow model has the capability to simulate a pipeline with an insulated wall or with a wall composed of layers of different thicknesses, heat transfer capacities, and conductivities. The wall description may change along the pipeline to simulate, for instance, a production well surrounded by rock of a certain vertical temperature profile connected to a flowline with insulating materials and concrete coating and an un-insulated riser (Danielson et al., 2005; Goldszal et al., 2007; Bendiksen et al., 1991).

This model computes the heat transfer coefficient from the flowing fluid to the internal pipe wall, where the user specifies the heat transfer coefficient on the outside. Circumferential symmetry is assumed in this case, and if this is broken, for example with a partly buried pipe on the seabed, an average heat transfer coefficient for the buried and exposed section must be specified (Danielson et al., 2005; Goldszal et al., 2007; Bendiksen et al., 1991).

The rate of heat transfer between the bulk of the fluid inside the pipe and the pipe external surface is defined as:

$$q = \left(\frac{1}{\frac{1}{h}+\frac{t}{k}}\right).A.\Delta T \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(1)}$$

Where q is heat transfer rate (W), h is heat transfer coefficient (W/(m^2·K)), t is wall thickness (m), k is wall thermal conductivity (W/m·K), A is area (m^2) and ΔT is difference in temperature (Danielson et al., 2005; Bendiksen et al., 1991).

Fluid Properties and Phase Transfer

The fluid properties in the dynamic multiphase flow model i.e., densities, compressibilities, viscosities, surface tension, enthalpies, heat capacities, and thermal conductivities, are given in the fluid properties in Table 2.6. The actual values at a given point in time and space are found by interpolating in the data tables.

Table 2-6 Fluid Properties Table

Test	**3 phase Compositional**		**EOS = SRK Peneloux**			
			PT Flash at			
			800	psia		
			80	°F		
		Total	Vapor	Liquid		
Mole%		100	97.97	2.03		
Weight%		100	92.56	7.44		
Volume		6.06	6.15	1.87	ft³/lb-mol	
Volume%		100	99.37	0.63		
Density		56.21	52.36	668.37	kg/m³	
Z Factor		0.84	0.849	0.26		
Molecular Weight		21.27	20.1	77.95		
Enthalpy		-377.6	-169.7	-10410	BTU/lb-mol	
Entropy		-6.59	-6.44	-13.55	BTU/lb-mol	
Heat Capacity (Cp)		12.83	12.26	40.34	BTU/lb-mol	
Heat Capacity (Cv)		8.46	7.94	33.4	BTU/lb-mol	
Kappa (Cp/Cv)		1.52	1.54	1.21		
JT Coefficient			0.07	-0.01	psia	
Velocity of Sound			1225.3	2469.8	ft/s	
Viscosity			0.01	0.32	cP	
Thermal Conductivity			0.02	0.09	BTU/hr ft	
Surface Tension			9.93	9.93	mN/m	

These tables are generated before dynamic multiphase flow simulation is run, by use of any fluid properties package. EoS is used which comply with the specified table format (Danielson et al., 2005; Goldszal et al., 2007; Bendiksen et al., 1991; Williams, 1998).

The total mixture composition is assumed to be constant with time along the pipeline, while the gas and liquid compositions change with pressure and temperature as a result of interfacial mass transfer. However, in real systems, the velocity difference between the oil and gas phases may cause changes in the total composition of the mixture. This can be fully accounted for only in a compositional model (Danielson et al., 2005; Goldszal et al., 2007; Bendiksen et al., 1991).

Interfacial Mass Transfer

Applying an interfacial mass transfer model can treat both normal condensation or evaporation and retrograde condensation, in which a dense phase condenses from the gas phase as the pressure drop (Danielson et al., 2005; Goldszal et al., 2007; Bendiksen et al., 1991). The gas mass fraction at equilibrium conditions can be defined as:

$$R_s = m_g/m_g + m_L + m_D \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2)$$

We can also compute the mass transfer rate as:

$$\psi_g = [(\frac{\delta R_s}{\delta p})_T \frac{\delta p}{\delta t} + (\frac{\delta R_s}{\delta p})_T \frac{\delta p}{\delta z}\frac{\delta z}{\delta t} + (\frac{\delta R_s}{\delta T})_p \frac{\delta T}{\delta t} + (\frac{\delta R_s}{\delta T})_p \frac{\delta T}{\delta z}\frac{\delta z}{\delta t}](m_g + m_L + m_D) \text{ (3)}$$

The term (δRs/δp)T (δp/δt) in equation 3 represents the phase transfer from a mass present in a section due to the pressure change in that section. The term (δRs/δp)T (δp/δz)(δz/δt), represents the mass transfer caused by mass flowing from one section to the other. Because only derivatives of Rs appear in equation 3, errors resulting from the assumption of constant composition are minimized (Dhulesia and Lopez, 1996; Bendiksen et al., 1991; Danielson et al., 2005; Goldszal et al., 2007).

2.14.1.2 **Main Steps in Transient Multiphase Flow Model Development**

The main steps of a transient multiphase flow simulation employed in the model, are outlined in Figure 2.29. The transient multiphase model equations required in this model development are presented in (d) of Appendix I.

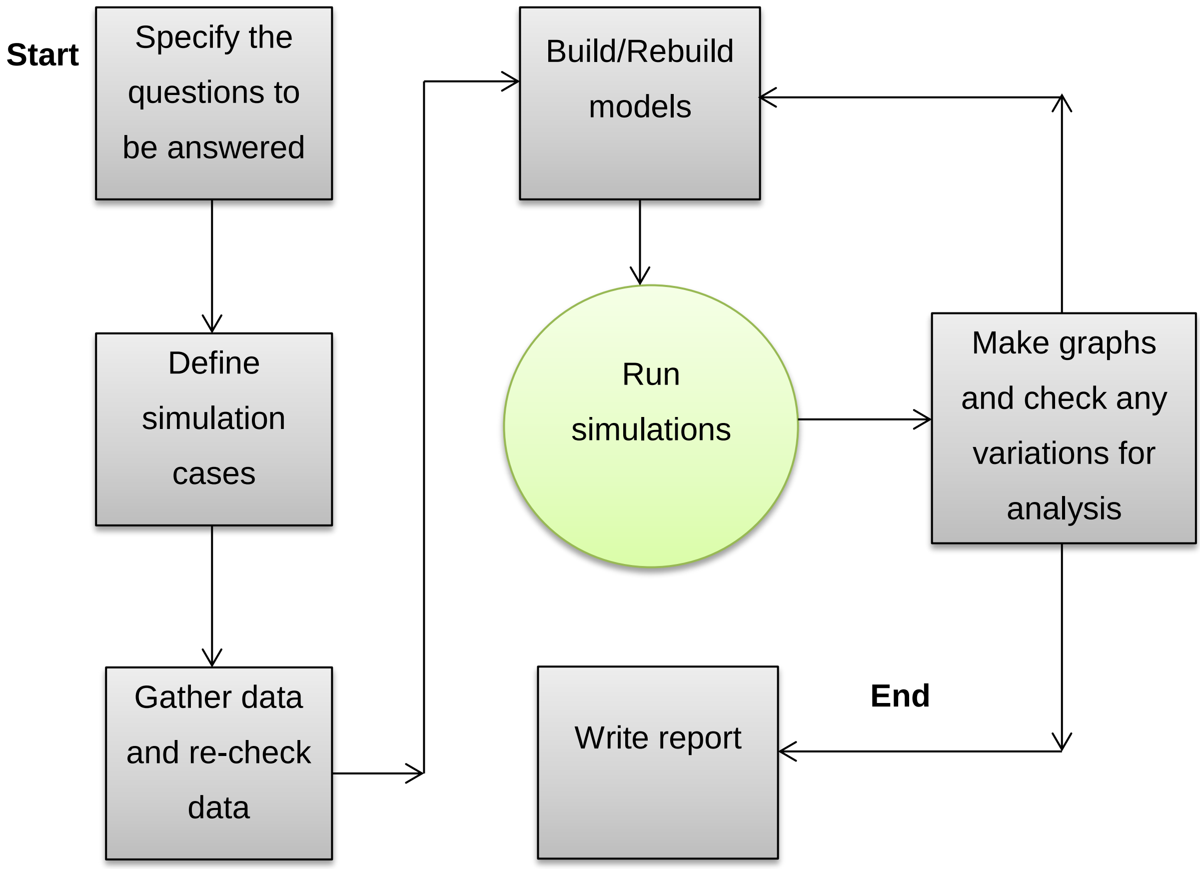

Figure 2-29 Main Steps to Execute Transient Multiphase Flow Simulations

2.14.1.3 **Density and change in Temperature and Pressure**

If there is a change in temperature the density of a fluid can be expressed as:

$\rho_1=\rho_0/(1+\beta\ (t_1-t_0))$.. (4)

If the pressure is changed the density of a fluid can be expressed as

$\rho_1=\rho_0/\ (1-(p_1-p_0)/E)$.. (5)

2.14.1.4 **Density of a fluid changing both Temperature and Pressure**

The density of a fluid when changing both temperature and pressure can be expressed using equations 4 and 5 by substituting ρ_0 in equation 6 with the expression for ρ_1 in equation 4.

Therefore from equation 5,

$\rho_1 = \rho_1/\ (1 - (p_1 - p_0) / E)$

Where the substituted ρ_1 is taken from equation 4 and this combination then give equation 6.

$\rho_1 = [\rho_0 / (1 + \beta (t_1 - t_0))] / [1 - (p_1 - p_0) / E]$.. (6)

These equations also guide the validation of the reservoir fluid sampling by providing the pressure and temperature matching with density of fluid at the wellhead or subsea tree to enable prediction of representative fluid samples (McMordie et al., 1982; Mantecon and Hollams, 2009).

2.15 Limitations of Transient Multiphase Flow Model

The transient model exhibits a level of numerical error when the fluid volume is different from the pipe volume. This is due to the model scale-up behaviour with pipe diameter to match the fluid volume. Therefore, this is essential in order to reduce uncertainty associated with fluid properties and pipeline sizes that differ greatly from available experimental data. An error of 10 – 15% is within acceptable limits, but above 15% is not acceptable (Mantecon and Hollams, 2009; SPT Group, 2011). Though it minimizes volume over a number of time steps, it does not force it to zero in order to avoid initiating new numerical instabilities. This error is expressed as:

$VOL_i = 1- \Sigma V_i f / Vsection_i f$.. (7)

Where,

$V_i f = m_i f / \rho_i f$, is calculated fluid volume in section number i

$m_i f$ = calculated mass in pipe section number i

$\rho_i f$ = density of fluid in section number i from fluid table

f = indicates liquid, gas, and droplets.

2.15.1.1 **Sources of Numerical Error**

- Linearization of a nonlinear model, where iterations are not performed serially;

- Thermal expansion with time-step, where the pressure is calculated with the old volume temperature to give a predictive fluid volume error on simulation;
- Local changes of total composition, which are neglected in standard simulation program, could be a source of predicting fluid volume error, etc. (Mantecon and Hollams, 2009; SPT Group, 2011; Goldszal et al., 2007; Danielson et al., 2005).

2.16 Compositional Tracking Model

Compositional fluid tracking allows improved estimation of the actual fluid properties from the well and pipelines by enabling computation of the thermodynamic equilibrium. A consideration of results between the compositional modelling approach and results obtained using the pre-calculated table-based fluid property approach are examined. The analysis is based on the dynamic two-fluid theory commonly used to simulate transient multiphase flow in wells and flowlines. The results illustrate possible applications of the compositional fluid tracking approach as applied to production allocation problems which can be used to test similar simulated numerical results. In this case more than two components are used to describe the two-phase flow mixture (Rydah, 2002; Mantecon and Hollams, 2009).

The multiphase flow in a well and flowline is analysed using a dynamic multiphase fluid modelling technique. To solve for pressure drop, temperature changes and flow regime, the model typically solves conservation equations for mass, momentum and energy for the gas and liquid phase or phases as a function of time. For fluid characteristics in a multiphase flow with water breakthrough, the model identifies water as a separate liquid phase. The compositional tracking model also has the capability to detect different fluid properties or compositions such as density, viscosity, etc., (Rydah, 2002; Mantecon and Hollams, 2009; Goldszal et al., 2007; Danielson et al., 2005).

Local representation of the fluid properties is achieved through pre-calculated tabular values with an upper and lower boundary for pressure and temperature. Considering the fluid compositions, the properties are tabulated numerically at pressure and temperature points. Recent advances in the numerical simulation of flash calculations for multiphase flow have enabled a more rigorous simulation approach to be developed. Thus, compositional fluid tracking model accurately predicts the fluid composition changes in space and time, and then calculates physical properties continuously for the in-situ hydrocarbon and aqueous fractions. Compositional fluid tracking does not display such limitations as in the tubular pre-calculated approach (Rydah, 2002; Mantecon and Hollams, 2009; Goldszal et al., 2007; Danielson et al., 2005).

Compositional tracking is required in practical applications during a shut-in, start-up and transient flow, where fluid re-distribution causes local composition changes (Mantecon and Hollams, 2009). This is applicable in steady state flow conditions where the gas phase is at its dew point and oil phase at its bubble point. On shutdown, for example oil and gas segregation causes local pressure and temperature changes. Component properties for compositional tracking include phase densities, gas mass fractions, conductivities, viscosities, surface tension, specific heat, specific enthalpy and specific entropy.

Furthermore, the compositional tracking model combines the powerful multiphase capabilities with customised calculations for fluid properties and mass transfer. Part of this compositional tracking model is a software package for fluid characterisation developed by Calsep (Calsep, 2011). With the compositional tracking model, every single fluid component is accounted for throughout the calculation, enabling simulation of scenarios such as start-up and blowdown, with a high level of detail and accuracy (Rydah, 2002; Mantecon and Hollams, 2009; Goldszal et al., 2007; Danielson et al., 2005).

Due to the limitations that exist in the fluid properties table, oil and gas segregate under steady state flow condition during shutdown. The actual composition at the well changes with pressure and temperature. However, the compositional tracking model can be used to track all composition components under 3 phase transient flow conditions (Rydah, 2002; Goldszal et al., 2007; Danielson et al., 2005). Typical cases where compositional tracking effects may have influence are populated in Table 2.7.

Table 2-7 Typical Compositional Tracking Cases

List	Typical Cases
1.	Networks with different fluids
2.	Changes in composition at boundaries
3.	Blowdown
4.	Gas injection / gas lift
5.	Start-up
6.	Shut-in and restart

2.16.1.1 **Methods and Assumptions**

The standard dynamic multiphase flow model uses a table of fluid properties calculated for a predefined composition, and this composition is assumed to be constant throughout the whole simulation. Different compositions can be used for each branch in a system, but with compositions that are constant with time.

In reality the composition may vary along the pipeline due to slip effects (velocity differences between phases), interfacial mass transfer, merging network with different fluids from other parts of the network and changes in fluid composition at the inlet. In the compositional tracking model the mass equations are solved for each component (e.g. H_2O, C_1, C_{14}- C_{22}), in each phase (e.g. gas, liquid droplets, bulk hydrocarbon liquid and bulk water). Thus, the model keeps track of the changes in composition in both time and space, and ensures a more accurate fluid description compared to using the standard dynamic multiphase flow model (Mantecon and Hollams, 2009; SPT Group, 2011; Goldszal et al., 2007; Danielson et al., 2005).

Instead of using a table with pre-calculated fluid properties, a FEED file must be generated by PVTsim and given as input to simulation program. The FEED file contains information about the fluid composition used in a source or well and as boundary or initial conditions that the user wants to use in the simulation. In addition, the user may define additional feeds through the FEED keyword. These feeds may only contain a set of the components defined in the FEED file. It is not possible to define additional components outside the

FEED file (Goldszal et al., 2007; Danielson et al., 2005; SPT Group, 2011; Mantecon and Hollams, 2009).

2.17 Numerical Model Validation Methodology

The numerical model employed to construct and run the field simulation, comprise of four building blocks in Figure 2.30, to enable the validation of the model:

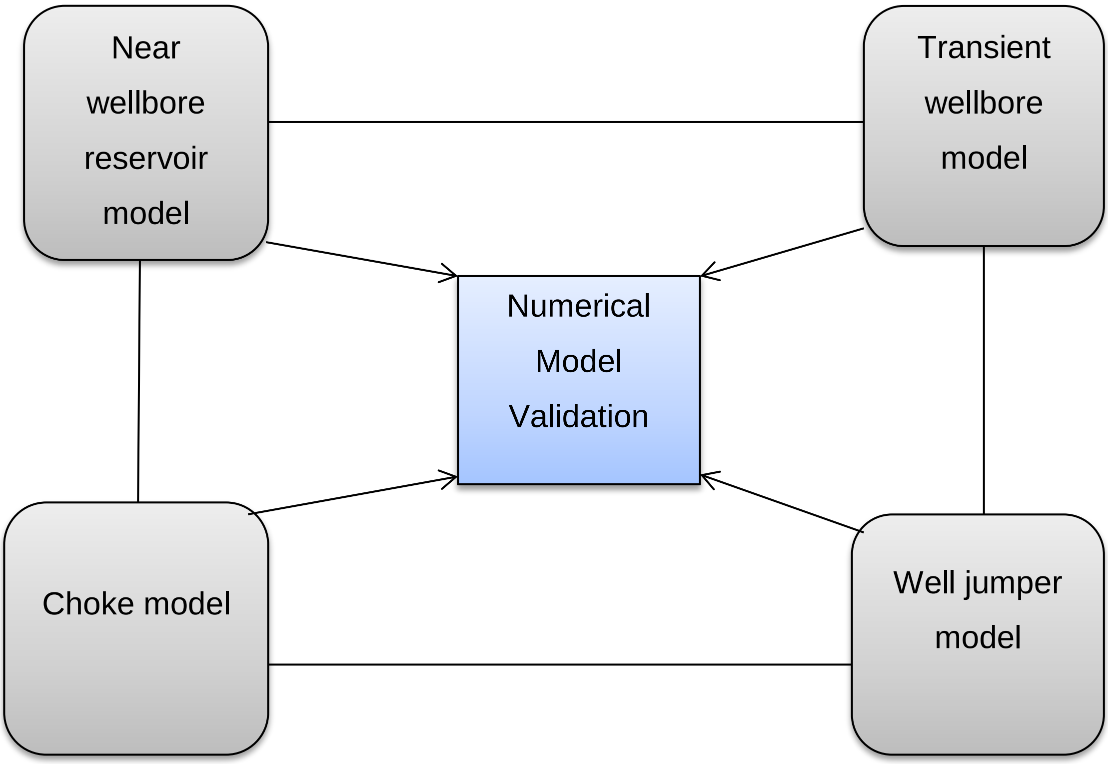

Figure 2-30 Building Blocks for Numerical Model Validation

The near wellbore reservoir model provides the pressure boundary with the well inflow performance characteristics employed to estimate the flowrate across the well perforations. In some cases, the near wellbore reservoir model is replaced with a constant reservoir pressure boundary condition, where the VFM is able to calculate in real time the cumulative production depletion from the reservoir (Haldipur and Metcalf, 2008; Denney, 2012; Moreno et al., 2014; Picart and Llave, 2004; Cramer et al., 2011).

The flowstream fluid composition, wellbore profile, tubing diameters and roughness, and the geothermal gradient are used in the transient simulation to fine tune the wellbore model, to enable predictions of transient of single to three-phase flow in the well. The VFM model utilise the mass conservation equation, energy-balance equations, and momentum balance equations combined with closure laws which is depended on the flow regime, to calculate for the flowrate in the wellbore using all the available pressure and temperature data (Haldipur and Metcalf, 2008; Denney, 2012; Moreno et al., 2014; Picart and Llave, 2004; Cramer et al., 2011).

The choke model utilise the choke Cv relationship with pressure and temperature measurements across the choke to determine an estimate of the flowrate. The VFM is capable to use several methods in estimation of the flowrate. These methods are derived from different combinations of the four building blocks, which utilise real time measurements for their boundary condition. The various methods are described below. However, the current study does focus on methods 1 to 3 applications (Haldipur and Metcalf, 2008; Denney, 2012; Moreno et al., 2014).

- Method 1 – extends from near-wellbore reservoir to manifold (at end of well jumper)
- Method 2 – extends from near-wellbore reservoir to downstream of choke
- Method 3 – extends from near-wellbore reservoir to upstream of choke
- Method 4 – extends from bottom-hole to manifold (at end of well jumper)
- Method 5 – extends from bottom-hole to downstream of choke
- Method 6 – extends from bottom-hole to upstream of choke
- Method 7 – extends from near-wellbore reservoir to bottom-hole
- Method 8 – extends across choke
- Method 9 – extends across the well jumper

To define and achieve a model validation methodology for subsea fluid sampling, it is very important to better understand the field architecture in view of the flowline simulation comprising three distinct parts: hydrodynamic point model, flowline simulation algorithm and physical properties generator.

2.17.1 **Hydrodynamic Point Model**

This point model has the basic hydrodynamic equations which describe the gas and liquid phase momentum equation and the closure laws. This model can be applied on flowline to acquire the pressure gradient (δp/δx), liquid hold-up and flow regime (Bendiksen et al., 1991; Goldszal et al., 2007; Danielson et al., 2005). The physical properties of the fluid samples such as density and viscosity, along the flowline geometry and in thermodynamic equilibrium, are assumed to be consistent at all points along the flowline. This is called the ‘point model’ as it makes predictions for single point of the flowline.

2.17.2 **Flowline Simulation Algorithm**

The way the simulation algorithm works is to divide the flowline into suitable segments as a function of pipeline configuration, and then performs heat, mass and pressure balances for each segment along the flowline (Mantecon and Hollams, 2009; Bendiksen et al., 1991; Goldszal et al., 2007; Danielson et al., 2005). This requires the use of the point model and a physical properties generator for each segment to obtain the hydrodynamic parameters (flow regime, pressure gradient, liquid hold-up etc.) as defined earlier.

2.17.3 **Physical Properties Generator**

The generator provides the physical properties for the point model and for the mass computation at the local pressure and temperature. The physical properties involved in this model are the density, viscosity and enthalpy of gas and liquid phases, and the surface tension of the liquid phase. The properties, taking into consideration temperature, can be obtained from following three methods:

- Use of an internal thermodynamic vapour-liquid-equilibrium (VLE) module with EoS.
- Interpolation of fluid characteristics and gas volume fraction tables generated by an external thermodynamic VLE module.
- Use of correlations for internal fluid characteristics (black oil) (Bendiksen et al., 1991).

Due to the outline structure of the flowline model validation is done using the following two steps:

Step 1: Validation of Hydrodynamic Point Model

Hydrodynamic validation by pressure gradient prediction, liquid hold-up and flow regime is carried out using test loop data. The physical properties of fluid samples are generally measured with good accuracy from the test loop data (Mantecon and Hollams, 2009; Bendiksen et al., 1991; Goldszal et al., 2007; Danielson et al., 2005).

Step 2: Validation of over-all Flowline Simulation Model

The model described earlier involves a simulation algorithm coupled with a hydrodynamic point model and a physical property generator. The validation of the overall flowline simulation model requires data from real flowlines and wells (Bendiksen et al., 1991). However, for the purpose of subsea sampling at the wellhead/subsea tree, attention is given to the hydrodynamic point model validation of well fluid.

2.17.4 **Experimental Analysis on Fluid Modelling**

The fluid models developed for an oil field experiment was Pseudo-compositional black oil correlations and fully-compositional EoS (equation of state) methods. Although black oil correlations may be adequate in some cases, EoS compositional modelling is preferred. This is based on sound thermodynamic principles and provides reliable predictions even outside the range of data for which it is designed (Nagarajan et al., 2007; Holm, 1986).

In using black oil properties in reservoir engineering calculations, it would be preferable to derive these properties using an EoS fluid model. EoS-based reservoir fluid modelling involves several key factors. These include appropriate component selection to describe the fluid with proper heavy end (C_{7+}) characterization, incorporation of robust energy minimization and solution techniques for ensuring convergence and avoiding false solutions. Thus, the developed regression methodology using optimised transient model, such as Calsep PVTsim, can accurately match laboratory data (Nagarajan et al., 2007; Avansi and Schiozer, 2015).

However, the PVT modelling of oil mixtures with CO_2+ is quite challenging, due to the complex nature of the phase equilibrium exhibited by these mixtures. This includes near-critical behaviour at high CO_2 concentrations. In modelling the Salt Creek CO_2 process, it was necessary to split the C_{7+} fraction into several pseudo components using detailed C_{7+} characterization results (Genetti et al., 2003). The pseudo components were selected by linking components with smaller range of carbon numbers (e. g., C_7-C_9, C_{10}-$C_{13,}$ and C_{14}-C_{16}). This type of detailed description was necessary to capture the vaporization of intermediate components as high as C_{20} to $C_{25,}$ from the dense CO_2 rich phase. An energy minimization procedure was used to identify the correct solution avoiding trivial solutions most commonly encountered in near critical regions. The minimization algorithm used Helmholtz free energy in terms of component molar densities instead of mole numbers and molar volumes (Geneti et al., 2003; Pinguet et al., 2004; Kanu and Ikiensikimama, 2014). This formulation ensures correct solutions by avoiding many of the singularities encountered while minimizing Gibbs energy as a function of mole numbers and molar volume. This numerical model is adapted and applied for subsea fluid sampling on the present study.

2.18 Mechanistic Model

A mechanistic model is where the basic elements of the model have a direct correspondence to the underlying mechanisms in the system being modeled. Hence, the mechanistic model can further be described as a physical system that obeys certain fundamental laws in providing a more realistic prediction, for multiphase flow analyses. The model offers the opportunity to test the sensitivities of process flow stream to determine the heat transfer coefficients, mass flow and momentum equations, etc. Furthermore, the mechanistic model can be used to design a new process, trouble-shoot a process and for fundamental improvements of process operability. Mechanistic model makes use of fundamental laws such as continuity equations to build a description of a process model. These equations are known as the balance equations which provide the description of conservation of mass, and conservation of energy (Bendiksen et al., 1991; Moreno et al., 2014).

The objectives of this mechanistic model study is to assess the performance of flow model predictions with field data acquired from sensor nodes (pressure, temperature, choke, etc.,) in the subsea well that is integrated with an MPFM on multiphase flow. Aligned to this research, the offshore oil and gas industry has employed mechanistic numerical modelling to simulate single-phase and two-phase flow scenarios in pipelines and wells (Amin, 2015; Moreno et al., 2014). The mechanistic transient multiphase flow model was employed in the present study.

A mechanistic model usually first identifies the flow regime, and then solves a set of mass and momentum conservation equations with the help of closure laws which are flow regime dependent. These closure laws provide additional equations to the basic mass and momentum conservation equations necessary for their resolution (Bendiksen et al., 1991). The main closure laws concern the interfacial friction between the phases, the wall friction for each phase in the case of separated flow (i.e. the stratified and the annular flow regimes). Also the bubble velocity in the case of dispersed flow, the Taylor bubble velocity and the void fraction in the liquid slug, in the case of intermittent flow (Dhulesia and Lopez, 1996; Bendiksen et al., 1991). The main predictions obtained from such a mechanistic model are to define the flow regime, the pressure drop and the liquid hold-up, including the fluid compositional properties.

In line with this mechanistic model, the transient multiphase flow model development is based on a two-fluid concept. It solves three separate continuity equations for gas, liquid bulk and liquid droplets and two momentum equations, i.e. one for the liquid film and another combined for the gas and possible liquid droplets.

An experiment carried out with a transient multiphase flow model has been tested against data acquired on the SINTEF two-phase flow loop (with 200mm in diameter and 450m in Length) operated with nitrogen/gasoil system at a pressure up to 90bar. The transient multiphase flow model can choose the flow pattern from among two basic flow regime classes, i.e. the separated flow class including stratified and annular-mist flows and the distributed flow class, which include bubble flow and slug flow regimes (Dhulesia and Lopez, 1996; Bendiksen et al., 1991; Falcone Gioia et al., 2008). The mechanistic transient multiphase flow model is a useful application tool in the prediction of multiphase flow on subsea wellhead and production flowlines (Joshi and Joshi, 2007). The conservation of mass and momentum equations that are provided in (d) of Appendix I, describe the theory and application of the mechanistic flow models.

Therefore, the mechanistic model is key in the development of case studies in the present thesis. The results generated and validated from the model demonstrated that changes in variables such as pressure, temperature, density, flow rate and volume would have varying effects on compositional properties of the fluid sample collected. A sensitivity analysis was performed in chapter 4 and 5 to confirm the validity and reliability of the mechanistic model development from industrial case studies and from published experimental data (Amin, 2015; Moreno et al., 2014).

2.19 Review of Applicable Standards for Fluid Sampling

The Table 2.10 presents the relevant standards applicable to support subsea fluid sampling, as no tailored standard specification exist currently in the offshore industry.

Table 2-8 Applicable Standards for Fluid Sampling

Applicable Standards for Fluid Sampling	Descriptions
API RP 44	The API RP 44 focus on reservoir fluid sampling to collect representative reservoir samples from the flow stream at the time of sampling. Issues that relates to incorrect sampling collected from an improperly conditioned production well, is elaborated (API RP 44, 2003).
API RP 17S	The API RP 17S standard provides details for the sizing, specification, system integration, and testing of subsea MPFM for measurement of full stream and multiphase flow. This is valuable in applications such as, well testing, allocation measurement, fiscal measurement, well management, and flow assurance (API RP 17S, 2015; API MPMS, 2013). This standard recommendation is also applicable to wet gas flow meters as a subset of MPFMs, due to the fact that in-line MPFMs are typically used in subsea applications
API MPMS	The API MPMS standard, Chapter 20.3 addresses the requirements for multiphase flow measurement point in a production system, in onshore, offshore (subsea) operations. The standard serves as a reference for well tests and flow assurance, in multiphase flow measurement to optimise reservoir management (API MPMS, 2013; API RP 44, 2003; API MPMS, 2010).
API RP 85	The API RP 85 addresses allocation methodology technically and mathematically optimized meter application, with variations in uncertainty level between metering system. The standard also considers marinization techniques and meter testing used in the allocation of total production from difference commingled flow streams (API RP 85, 2003; API RP 86, 2005).
ASTM D4177– 95	The ASTM D4177 – 95 standard addresses the requirement for representative samples to determine the chemical and physical properties used to establish standard volumes based on regulatory requirements. The standard also covers requirements for the design, installation, testing, and operation of automated equipment for the acquisition of representative samples from a flow stream (ASTM D4177 – 95, 2010).
ISO 3171	The main focus of ISO 3171 is for collection of a fluid sample flowing through a flowline to determine the compositions and quality of sampling. The bulk

	quantity of samples are analysed to determine composition, water, density, viscosity, pressure and temperature (API MPMS, 2010; ISO 3170; ISO 3171, 1988).
ISO 3170	The ISO 3170 provides the specification on manual methods of sampling to obtain liquid or semi-liquid samples from pipelines on petroleum products, crude oils stored in tanks at or near atmospheric pressure (BS 2000-476, 2002; ISO 3170, 2004).
ISO 3165	The ISO 3165 standard is designed to assist personnel on sampling operational activities, to ensure safe sampling operation is carried out. General recommendations are provided in this standard for operations the various properties being sampled (ISO 3165, 2011).
ISO 11631	The ISO 11631 is used for specifying the design of flowmeters and for providing resolution to issues faced by manufacturers. This standard provides methods of describing the performance of any flowmeter, for use either in closed conduits or open channels (ISO 11631, 2014).

3 SUBSEA FLUID SAMPLING TECHNOLOGY CONCEPT SELECTION ASSESSMENT FOR FIELD DEVELOPMENT

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Abstract

The key to a successful subsea field development lies in the proper assessment of technologies to be used in the field. Hence, the concept selection assessment suitable for screening and ranking of subsea fluid sampling technologies available in the offshore industry have been developed, as an attractive technical and economic method employed for field development. This will enable operators to make an initial quick decision during the concept studies, to determine the most economic and effective technology given the field parameters, thus reducing ambiguity and much expenditures in the design life of deepwater project development.

The paper presents ‘remote operated vehicle’ deployment for sampling system subsea, safely connecting to subsea production systems, capturing a representative sample of the produced fluid, and then delivers the collected sample to the laboratory for analysis. To achieve the best optimal subsea sampling solution, an Analytic Hierarchy Process was chosen as the method of selection, and the conditions for the subsea sampling technology were defined that eventually became the governing criteria for selection of the candidate subsea fluid sampling system.

Keywords: Subsea fluid sampling, Subsea technology selection, Analytic hierarchy process, MPFM, Deepwater development

3.1 Introduction

One of the key challenges of offshore development is to address the expected poor primary recovery of subsea well (Tester, 2010). A key solution to this challenge is subsea fluid sampling (SFS), which Mancini and Turnbull defined as, “the act of retrieving a measure of production fluid from a subsea installation such as a production tree, manifold or other access point for the purpose of testing and recording information about the said fluid" (Mancini and Turnbull, 2011). Subsea fluid sampling and processing play a key system engineering role in generating the fractional data on oil, gas, water, salinity, PVT (Pressure, Volume, Temperatures) and other information that current multiphase flowmeters (MPFM) need, to be calibrated regularly with these data (Gransaether, 2011; Yasseri, 2014; Yasseri, 2015b).

The aim of the present paper is to use governing criteria suitable for screening or ranking subsea sampling technologies available in the industry, to help give operators a systematic decision-making chart, during a field's initial design phase. The objective is to consider key selection criteria, with application of multi criteria decision making (MCDM) to select the most suitable concept to support subsea metering requirements. However, selection process consists of eliminating concepts that can be quickly determined as fundamentally unfeasible from a technical or economic perspective with good interface management (Yasseri, 2012; Yasseri, 2015a). To achieve this aim, the paper does consider the SFS technologies currently available. Then it also reviewed the parameters and standards that guide Subsea Technology Concept Selection (STCS) to develop a technology assessment, and the selection method which is then used for ranking or screening the SFS technology concepts. The selection of a concept is field specific, and must be first conceived and detailed before an optimal choice can be made through selection assessment process; hence the developed method is applied to a case study (Yasseri, 2012; Patton, 2002).

In the execution of the selected subsea sampling technology, Analytic Hierarchy Process (AHP), Pairwise and Grid analysis amongst the multi criteria decision making (MCDM) were applied in evaluating the optimal sampling concept solution. However, before carrying out the technology assessment, it is important to understand the value of system design life cycle and its impact in the selection of a candidate subsea fluid sampling system. The MCDM selection assessment considered in the paper is presented in Figure 3.1

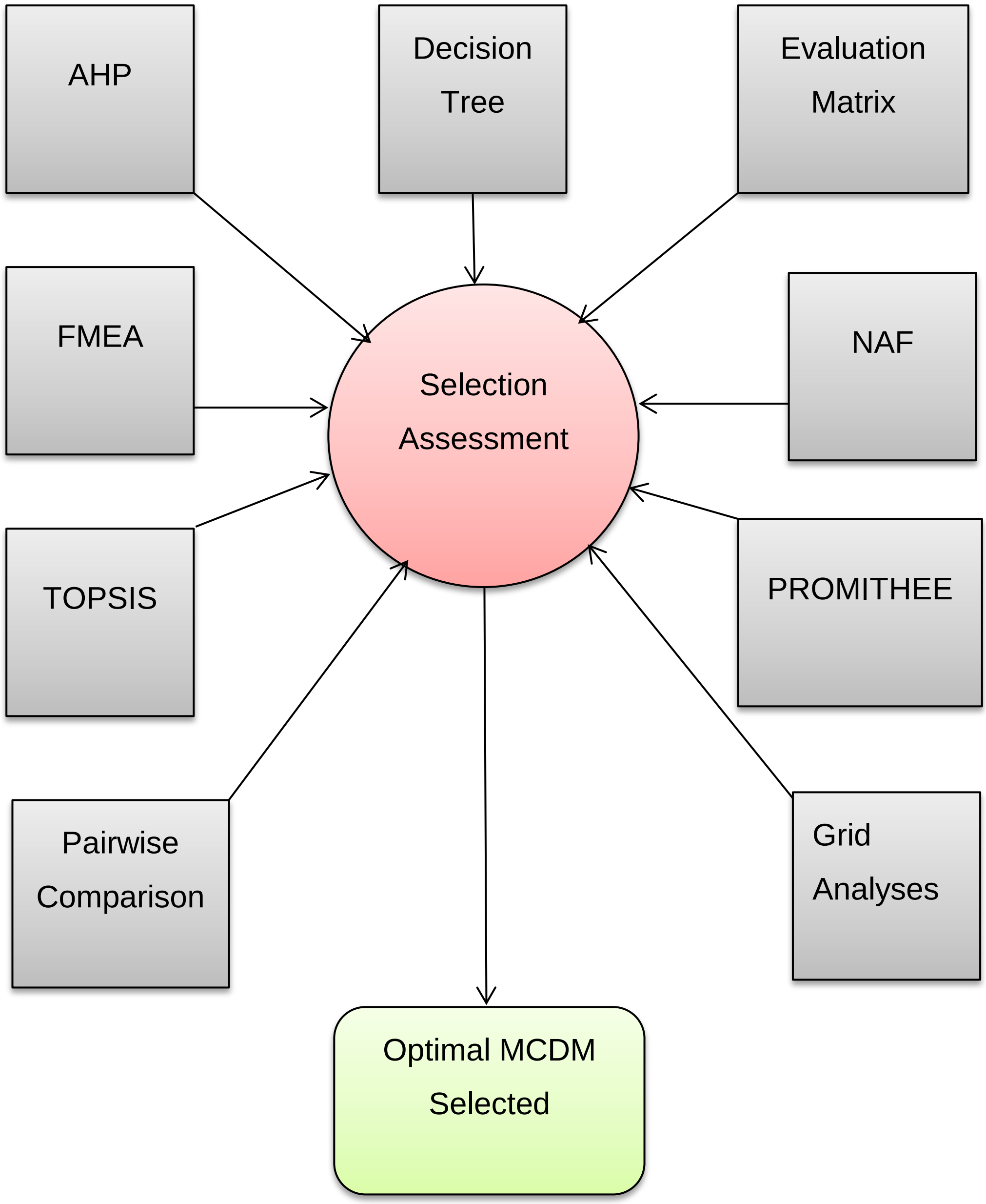

Figure 3-1 MCDM Selection Assessment

3.2 Subsea Systems Design Life Cycle

In the offshore industry, the life cycle design for subsea engineering development requires six distinct project phases: Explore, Appraisal/Select, FEED, Execute, Operate and Abandonment. A known rule of thumb, which is supported by industry data, justifies the conclusion that "the ability to influence the value of the design as it progresses from the appraisal/selection phase of a project to abandonment, follows a logarithmic curve" shown in Figure 3.2

(Neol, 2001). It is apparent from the curve, that the Front-End-Loading (FEL) region of the engineering design (Appraisal/Select through FEED) predominantly determines the actual value of the design factor (Time, Availability and Life Cycle Cost). The FEL provides the right opportunity to influence value for subsea system development, as 80% value of the project life cycle is realised at this phase of early engineering development, which account for about 20% on the entire project schedule.

Therefore, sufficient time and efforts must be invested during early engineering to get the design right at the conceptual phase of a specific project development. This is crucial to captured and align the design for fluid sampling amongst other system design components in the conceptual phase of field development, with reliability and availability fully evaluated to realise project value.

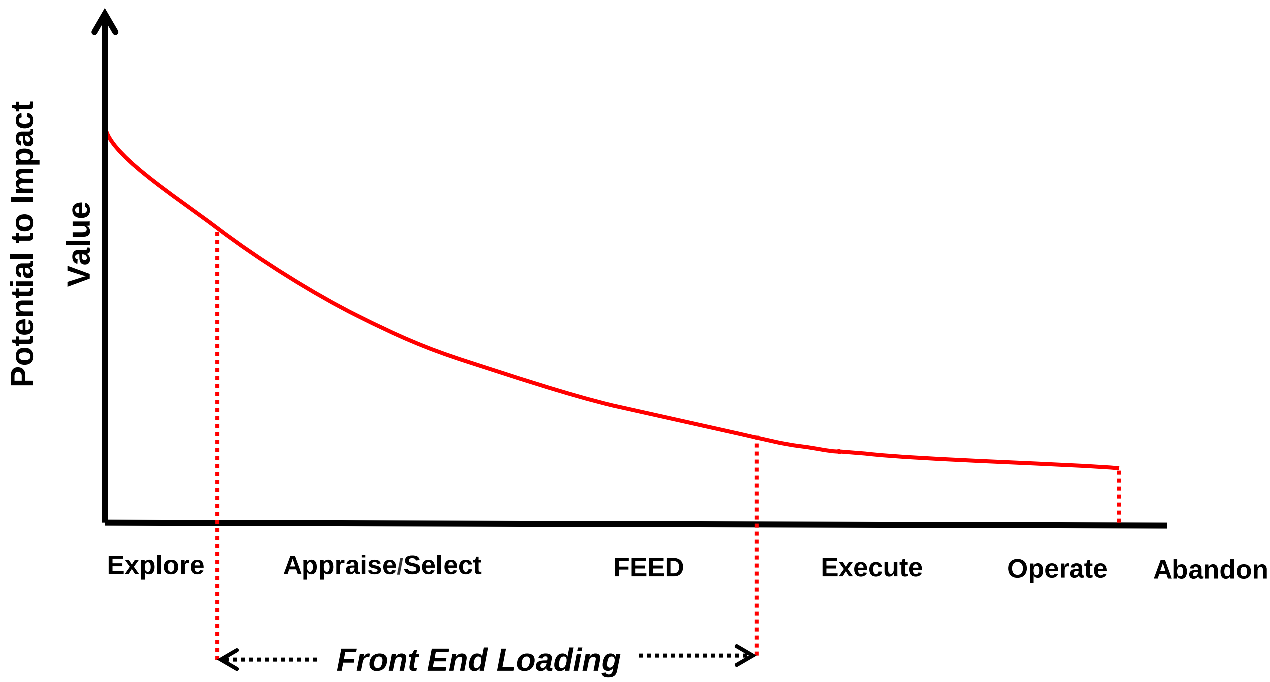

Figure 3-2 Design Life Cycle Influence Curve of a Typical Project (Neol, 2001)

3.2.1 **Design Selection**

Design selection consists of an iterative process occurring without a conscious decision that influences the selection of the optimum design. Figure 3.3 is the product design selection process that captures the product design process which begins by selecting an initial set of contending design options for a particular field development from a global database. Then appropriate design options are selected using readily available knowledge of the field development (location, water depth, step-out distance, size of reserves, shape of reservoir, composition of reservoir fluid, etc.,) and the readiness of the technology (Neol, 2001; Yasseri, 2013). An evaluation of the selected designs is then carried out to assess the fitness for purpose for project development and then undergo a further selection process to remove the least fit design selection from further consideration. This iterative process is repeated over successive cycles until we arrive at 2 – 3 design options for the optimum solution.

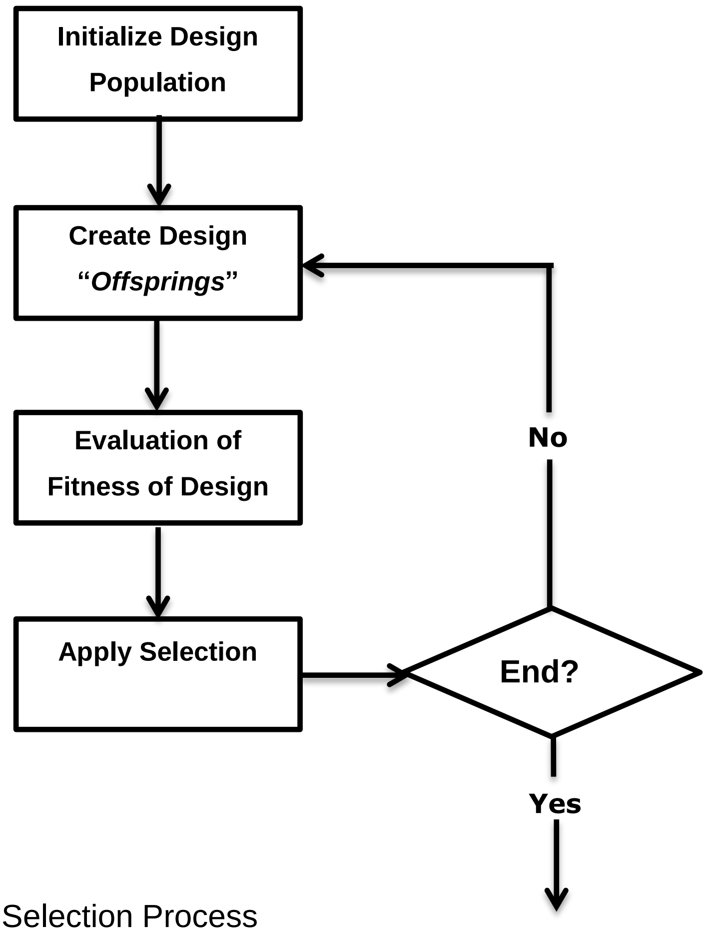

Figure 3-3 Product Design Selection Process

3.3 Subsea Sampling Technology Assessment Methodology

The application of subsea technology concept selection and assessment during the design phase of field development projects is critical to the economic sustainability of the life of the field (Yasseri, 2012). A standardised

Subsea Fluid Sampling (SFS) concept selection method uses an assessment and criticality ranking of key subsea sampling technology life-of-field criteria. This determines the most suitable option for each field. The method aims to select the most suitable subsea sampling technology for the field developments, given the field parameters.

It is therefore appropriate to use the most appropriate selection methods for decision making in subsea sampling technology assessment (Saaty, 1990; Rebernik and Bradac, 2015). A lot of factors affect the choice of selection method; the ideal method of selection in the context of the present paper should have the following features or characteristics:

- Ability to perform analysis to produce results of a decision making process;
- Appropriate for early phases in technology selection processes;
- Compares alternatives, efficient in ranking and screening ideas;
- Enables objective decisions with processing of input date statistically;
- Can consider correlation of criteria applied to subsea technology selection processes.

In view of the above, the following MCDM assessment methods are examined but briefly presented in this paper to select the most suitable method for application in the subsea sampling technology selection.

3.3.1 **Analytical Hierarchy Process (AHP)**

AHP is an assessment method, which uses hierarchical approach to idea evaluation and decision making. This method assesses one idea on multiple criteria and structures them according to their relative importance. Hence it uses these scales to measure intangibles idea in relative terms. The comparisons are made using a scale of absolute judgements to assess how much one element dominates another with respect to a given attribute (Saaty, 2000; Rebernik and Bradac, 2015).

AHP have been employed in various sectors, like in General Services Administration (GSA) of the USA, where they used AHP to support their annual Information Technology Council (ITC) and Council of Controllers (COC), in order to priorities their major information technology initiatives. They used the process to refine their analytical framework, priorities their criteria and then rate each IT initiative against them. It has also been used in the offshore industry (Saaty, 2000; Yasseri S, 2012).

3.3.2 **Decision Trees**

A decision tree is used for calculating conditional probabilities. A decision tree describes graphically the decisions to be made, the events that may occur, and the outcomes associated with combinations of decisions and events. Probabilities are assigned to the events, and values are determined for each outcome (Freitas et al., 2015; Rebernik and Bradac, 2015). The objective is to determine the best decisions.

Decision trees are useful tools which help to choose between several courses of action, which have been created manually. Decision tree models include such concepts as nodes, branches, terminal values, strategy, payoff distribution, certain equivalent, and the rollback method (Rebernik and Bradac, 2015).

3.3.3 **Evaluation Matrix**

Evaluation matrices are used to evaluate a number of options against prioritised criteria. This process is relatively simple to apply and aids the team in making objective decisions. The use of an evaluation matrix is one method of objectively evaluating a number of options against a number of criteria. Hence, these criteria are prioritised before the evaluation is made with greater weighting to those items of most importance (Wang et al., 2015; Rebernik and Bradac, 2015).

Thus, the main aim of evaluation matrix is to evaluate an idea in accordance to several factors or criteria. This is applicable when considering more characteristics or criteria of an idea. Evaluation matrix has many application possibilities in different areas.

3.3.4 **Failure Mode and Effect Analysis (FMEA)**

FMEA is used for the risk and failure analysis which is well known as a qualitative reliability method in the area of reliability methodology. It is a dynamic preventive reliability method used in the modification of subsea systems and accompanies the design cycle for modification of components. The overall aim is to analyse and modify components in the light of experience to achieve an optimum criterion of reliability assessment (Rebernik and Bradac, 2015).

The method is mainly used to identify potential failure modes, determine their effect on the operation of the product, and identify actions to mitigate the failures. A crucial step is anticipating what might go wrong with a product. While anticipating every failure mode is not possible, the development team should formulate as extensive a list of potential failure modes as possible (Rebernik and Bradac, 2015).

3.3.5 **Novelty Attractiveness Feasibility (NAF)**

The (NAF) method is a quick and easy way of assessing new ideas which involves novelty, appeal and practicality. The method is especially appropriate in assessment before further development of idea. The method can be applied individually or in a group and in many different areas. As it is simple to use, is appropriate for early phases in idea selection process, and in ranking of ideas for value analysis (Rebernik and Bradac, 2015).

3.3.6 **Technique for Order of Preference by Similarity to Ideal Solution (TOPSIS)**

TOPSIS is a practical and useful technique for ranking and selection of a number of externally determined alternatives through distance measures. It is a useful technique in dealing with multi-attribute or multi-criteria decision making (MADM/MCDM) problems in the real world. It helps decision makers (DMs) organize the problems to be solved, and carry out analysis, comparisons and rankings of the alternatives (Lai, 1994; Srdjevic et al., 2004; Hwang and Yoon, 1981). However, many decision making problems within organizations will be a collaborative effort.

TOPSIS has been successfully applied to the areas of human resources management, transportation, product design, manufacturing, water management, quality control and location analysis. In addition, the concept of TOPSIS has also been connected to multi-objective decision making and group decision making. The high flexibility of this concept is able to accommodate further extension to make better choices in various situations (Deng et al., 2000; Rebernik and Bradac, 2015).

3.3.7 **Preference Ranking Organization Method for Enrichment of Evaluations (PROMITHEE)**

PROMETHEE approach is based on extensions of the notion of criterion. These extensions can easily be identified by the decision-maker because the parameters have an economic significance. A valued outranking graph is constructed by using a preference index. Two possibilities are considered to solve the ranking problem by using this valued graph. PROMETHEE I provide a partial preorder and PROMETHEE II a total preorder on the set of the possible actions (Brans and Vincke, 1985).

The PROMETHEE I method provides a partial ranking of the actions. If needed, a complete ranking can be acquired by PROMETHEE II. The PROMETHEE methods were very easily accepted and understood by the practitioners. These methods could be an easier approach for solving a multi-criteria problem by considering simultaneously extended criteria and outranking relations (Brans and Vincke, 1985).

3.3.8 **Pairwise Comparison**

A range of options in the pairwise comparison are compared to find an overall score. Each option is compared against each of the other options, to determine the preferred option. Thus, the results correlated and the option with the highest score is selected. The pairwise comparison can be conducted individually or in groups. It may include criteria to guide the comparisons in an open group discussion. A paired comparison matrix can be developed to assist in the pairwise analysis (Rebernik and Bradac, 2015).

3.3.9 **Grid Analysis**

The grid analysis is a similar method to evaluation matrix. It can be employed for consideration of many different factors and alternatives assessment. A group or individually can use this selection method in many applications or different areas. The grid analysis employs identical table as evaluation matrix. Options are written on a row and the factors on the columns for analysis.

Then each factor is scored, weighted and summed up to get the overall score for each option (Rebernik and Bradac, 2015). It is suitable for comparison of options and alternative to get the optimal option in a selection assessment.

3.4 MCDM Selection

After reviewing a list of MCDM for SFS technology selection, 9 were selected which has the ideal features listed above. The Table 3.1 shows these 9 and their additional comments that enabled the selection of the best method for this paper, having in mind that ranking and comparison of technologies are also part of the objectives to justify the SFS technology to be eventually selected (Saaty, 1990; Rebernik and Bradac, 1989).

Table 3-1: MCDM Selection

Selection Methods	***Comments***
AHP	Suitable in pairwise comparison
Decision Trees	Strictly an individual technique, and for solving complex problems
Evaluation Matrix	Its governing selection criteria must be carefully reviewed
FMEA	Like FMECA, it is not appropriate in selecting just one idea
NAF	Restricted to just Novelty, Attractiveness and Feasibility of the technology, which is less than the requirements for a SFS selection.
TOPSIS	Requires collaborative effforts with its MADM/MCDM decision making to solve problems within organizations
PROMITHEE	Is based on extensions of the notion of criterion
Pairwise Comparison	Is based on a range of plausible options
Grid Analysis	Applicable in evaluting many different factors and alternatives

After considering the 4 optimal selection methods that made it through the selection process, the AHP emerged as one of the most optimal method among other competing methods for technology selection. The AHP allows complex decision problems to be structured in a hierarchical form; "it has been identified as an important approach to multi-criteria decision-making problems of choice and prioritization"(Lai et al. 2002). It performs two main kinds of measurement; relative and absolute. In relative measurement, paired comparisons are formed throughout the hierarchy including the alternatives in the lowest level of the hierarchy with respect to the criteria in the level above them (Saaty, 1990). This is one of the reasons for selecting AHP as the method for SFS technology selection. "The comparisons are made using a scale of absolute judgments that represents how much more, one element dominates another with respect to a given attribute" (Saaty, 2008).

The second reason for selecting AHP is its ability to be used by both an individual and by a group of decision makers. In reality, the AHP steps have been adapted in projects for the oil and gas industry. Selecting any technology for a system development subsea is usually carried out by a team of expert system engineers, who come together to deliberate and eventually agree on one concept. Thus in a similar fashion in the oil and gas industry, AHP was used in a selection process for choosing subsea Xmas tree in a deployment project of 500m water depth. Though one assessor used this tool in the cited literature, a later assessment by nine experts yielded a similar result, where a South American Company used AHP to select an oil pipeline route (Yasseri 2012; Dyer and Forman, 1992; Fakier et al., 1992). Furthermore, AHP was adopted from the RPSEA's report on improvements of deepwater sampling, where criteria were considered when selecting the best subsea sampling system. They are used in combination to certain subsea system requirements from Xmas tree selection process (Letton and Webb, 2012; Yasseri, 2012).

The third and most important reason for using the AHP methodology is its ability to accommodate both tangible and intangible individual and group values. It is claimed that AHP help to structure group decision so that the decision centers on objectives rather than the alternatives, thus will eliminate biased judgments which is usually the case in simple decision making tools. It is argued that AHP can help group decision makers' structure complex decisions, discuss extensively all relevant factors related to the decision to be taken, and measuring both tangible and intangibles with respect to numerous objectives common in group decision, and finally arriving at a choice of alternative most likely to achieve the organization's set goal (Dyer and Forman; 1992; Lai et al. 2002).

However, other methods such as TOPSIS can equally be used for decision making, in meeting stated objectives. Furthermore, pairwise comparison and Grid analysis are employed in a selection process in section 3.6.1 and 3.6.2 to select the optimal sampling option in the SPS to acquired representative sampling. Figure 3.4 presents the basic steps adopted for AHP. It performs two kinds of measurement; relative and absolute, which is the main reason why it was the preferred selection method. The comparisons are made using a scale of absolute judgments that represents how much one element dominates another with respect to a given attribute (Saaty, 2008; Saaty, 1990).

Figure 3-4: Basic AHP steps

AHP's 3 basic functions or steps are presented in the following sections.

3.4.1 **Step 1 Set goals, and Define Variables**

This is stating goals and criterias for selection. As mentioned in this chapter, the functional requirements can be broken down to become criterias and sub criterias, and the different methods of sampling will become the alternatives to be ranked (Saaty, 2008).

3.4.2 **Step 2 Assign weights based on relative importance**

This step compares and assigns a scale to the different variables or criterias on each level, which is achieved through extensive literature review and consultation with the industry experts, and is about the relative importance of the elements (criteria) with respect to the overall goal. Here the questions such as "which criterion is more important than the other" is asked and weighed accordingly (Saaty, 1990; Yasseri, 2012).

3.4.3 **Step 3 Synthesizing**

This step compares the alternatives or methods by using AHP's hierarchical model as shown in Figure 3.5 (Saaty, 1990; Saaty, 1977). The alternatives at the bottom are calculated, and the one with the highest scale becomes the best option, while the second highest becomes the second best and so on.

Furthermore, AHP breaks down a complex system into levels of hierarchy, identified from the highest level, (main objective), to the second or intermediate level, (criteria, sub-criteria or attributes) and finally the lowest level (alternatives), as shown in Figure 3.5. The variables on each level are compared with each other, and weighed; afterwards, the relative weighs are calculated, the priority vectors are also determined. The priority vectors are then summed up to determine the composite weight of the alternatives, where the alternative with the highest value becomes the most desirable (Saaty, 2008, Yaseri, 2012).

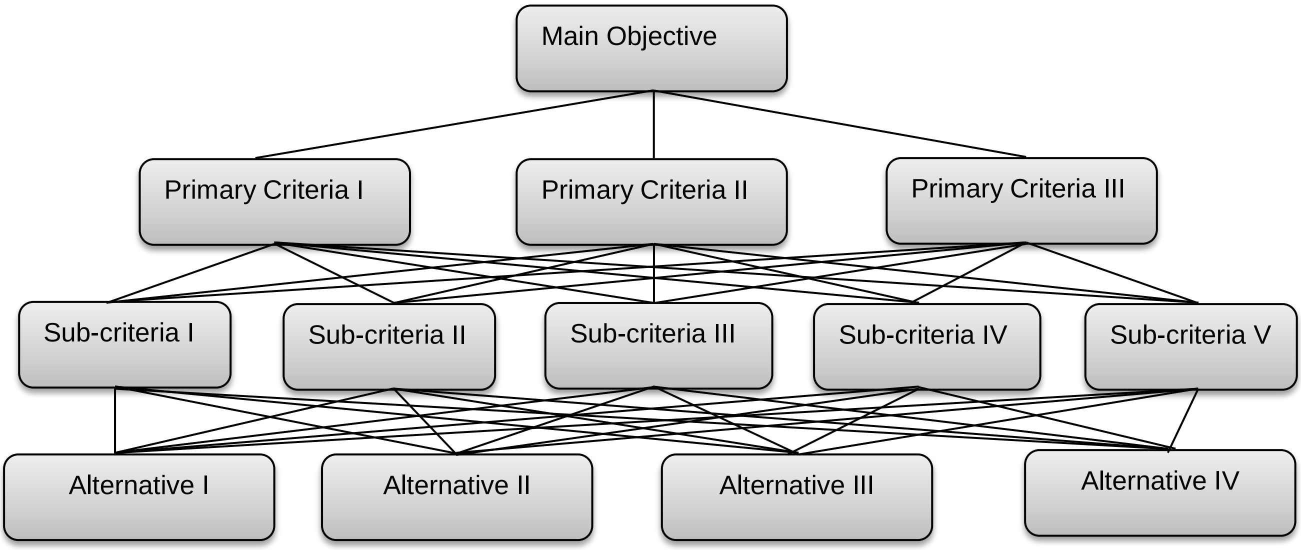

Figure 3-5: Structure of AHP

Figure 3.6 is a structured methodology with an AHP model adopted in the selection process (Saaty, 2008).

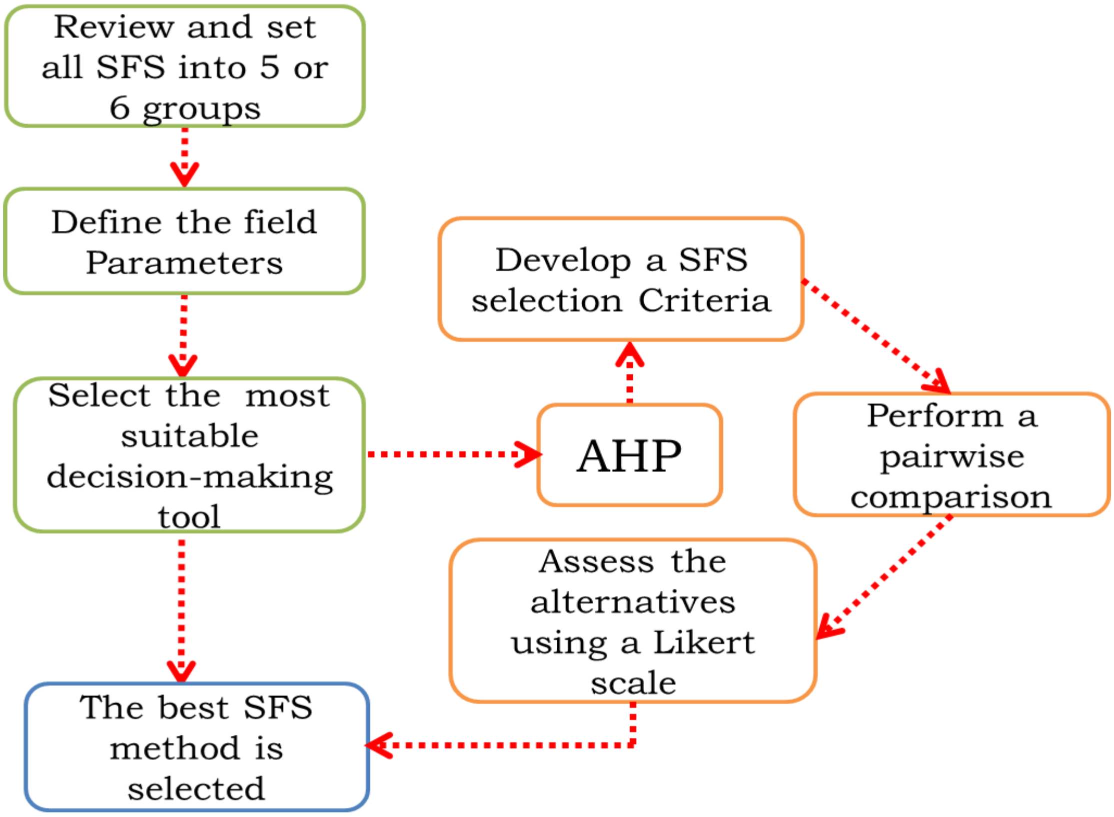

Figure 3-6 Selection Assessment Methodology Employing AHP

3.5 Case Study on Technology Selection

The deepwater Greenfield development in offshore West Africa has an 18km subsea tie-back to the FPSO with 4 production drill centers and 3 water injection drill centers. There is a total of 17 production and 15 water injection wells including dual zone completions (smart wells). The water depth in the area is between 1100m (3609ft) and 1200m (3937ft), as can be seen from the field architecture in Figure 3.7 (Ageh et al., 2010; Sathyamoorthy et al., 2009). The field parameters are also a major influencing factor for SFS which forms part of the selection criteria needed to perform the first initial screening of technologies, ensuring that the old methods of sampling (such as hot stab and topside sampling) are eliminated. The deepwater field reservoir data required for the design selection is provided in (a), (b), and (c) of Appendix II. Thus, AHP is used in selecting and ranking the SFS technology methods that are listed in section 3.5.1.

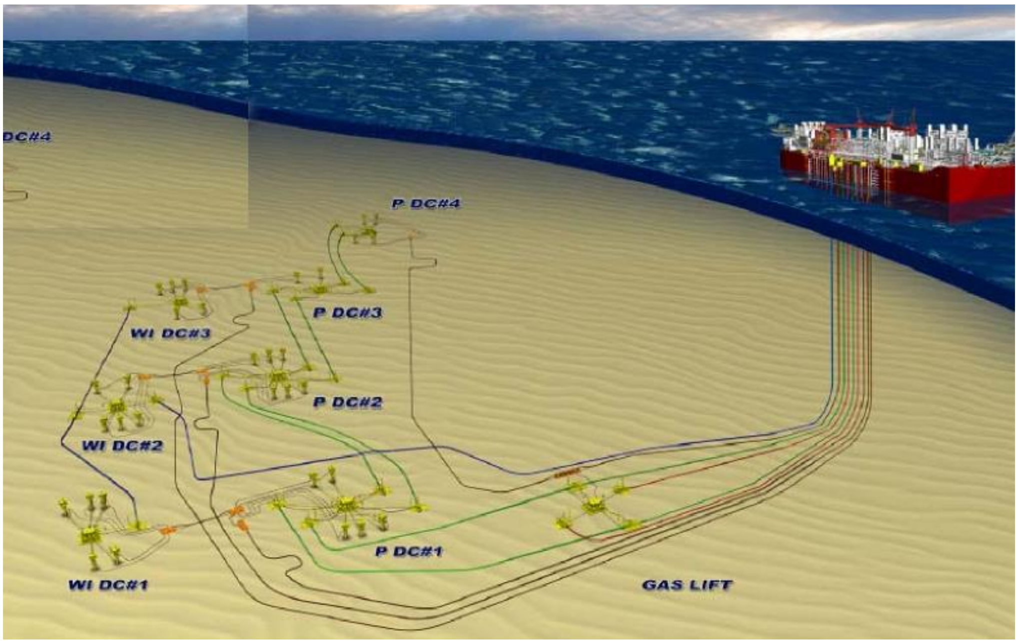

Figure 3-7 Subsea Architecture for Greenfield Development (Ageh et al., 2010)

Furthermore, attempts are made to first develop a checklist for the screening of subsea sampling technologies for deepwater applications. The subsea sampling technologies available in the subsea industries are then further analyzed. The analysis enables us to identify for each technology, the governing criteria which has favored the selection of the applied technology amidst other competing subsea solutions.

For a 'Greenfield' development, the subsea sampling method identified in section 3.5.1 would apply, depending on hydrocarbon data driven by operator demand on the subsea production systems. However, from the survey conducted, 100 e-mail questionnaires were circulated to the subsea oil and gas project population. Table 3.2 provides the summary of the demographic profile in the industrial survey conducted. Out of the 100 questionnaires emailed, 86 responded on time, which represents 86% of respondents for the analysis process. Majority of the respondents are between the age range of 44 to 48 which represents 41.9%, and from 49 years above represents 33.7%. Furthermore, 43.0% of respondents were senior project engineers, 20.9% were project engineers, and 12.8% were project managers and 11.6% accounting for the rest others. About 57.4% majority of the respondents work with the oil and gas operator companies and 54.7% of the respondents have a master's degree, followed by 40.7% of respondents with bachelor degree, while 5.0% hold a PhD degree. 48.8% of the respondents have over 10 years of working experience, and 8.1% possess less than 6 years working experience. The 87% of the respondents were male, while 13% were female.

The analysis demonstrate that the average work experience in the deepwater oil and gas industrial survey is 12 to 16 years (48.8%), and majority of the respondents were at the time of this survey, worked for 5 to 21 years in their present companies. The majority of the respondents, about 82% were from the major deepwater oil and gas industry such as, TOTAL, Chevron, ExxonMobil, DPR, Shell, Schlumberger, Cameron, FMC, Proserv and Framo. About 92% of these companies have been in operations in Nigeria for more than 21 years. Only DPR is the state owned company of Nigeria, as the regulator arm of the offshore exploration blocks, under the oversight of Nigerian National Petroleum Company (NNPC). Thus, the finding gives credence to the expected reliability of responses gotten from the industrial survey.

Table 3-2 – Demographic Profile of Respondents

Age Group	**Frequency**	**Percent**	**Cumulative Percent**
32 - 38 years	5	5.8	
39 - 43 years	16	18.6	5.8
44 - 48 years	36	41.9	24.4
49 years and above	29	33.7	66.3
Total	86	100.0	100.0
Education			
Bachelor degree	35	40.7	
Master	47	54.7	40.7
PhD	4	5.0	95.4
Total	86	100.0	100.0
Job Role			
Project Director	3	3.5	
Project engineer	18	20.9	3.5
Senior Project engineer	37	43.0	24.4
Project manager	11	12.8	67.4
Project Coordinator	7	8.1	75.5
Other	10	11.6	87.1
Total	86	100.0	100.0
Years of Industrial working experience in company			
Less than 6 years	7	8.1	
7 - 11 years	18	20.9	8.1
12 - 16 years	42	48.8	29
17 - 21 years	16	18.6	77.8
More than 21 years	3	3.9	96.4
Total	86	100.0	100.0

3.5.1 **Subsea Sampling Technology Method**

The following subsea sampling technologies presented are summary of the selected methods, after application of the AHP methodology.

I. ***Production sampling system***: The subsea sampling Interface has been developed by one of the major EPC contractors as an integral part of the subsea production systems. This includes a ‘subsea sampling module’ (SSM) that is ROV operated, which connects to the subsea sampling interface (SSI), to provide representative sampling from a production flow stream, without interruption of hydrocarbon production (Sbordone et al., 2012; Pinguet et al., 2014). For fields that have been in production for more than ten years, the need for accurate data is critical. The Production sampling system provides the operator with the capability to collect individual well test samples, via the subsea sampling module installed on the ROV (Proserv, 2013).

II. ***Red eye water-cut meter:*** The 'Red Eye' subsea meter has high affinity for water-cut and GVF. Due to its advanced technology the Red Eye subsea water-cut meter is unaffected by changes in water chemistry (salinity, H_2S, CO_2, etc.) and does not have to correct for these changes unlike other technologies. This subsea meter has high reliability and can provide a redundant water-cut measurement to multiphase meters or to trend water behaviour in the reservoir (Weatherford, 2010).

III. ***Virtual flow model***: The virtual flow metering (VFM) is a category of numerical tools that provides reliable and accurate flow rate predictions over a variety of well configurations and reservoir characteristics. The model acquires its data from sensors insertion at various measurement nodes or points in the well, including at the downhole tubing (Kelner et al., 2015; Amin, 2015; Denney, 2012; Vedachalam et al., 2015).

IV. ***ROV deployed sampling system***: The ability to acquire subsea samples from well production systems without the need for static platform is the key benefit of an ROV deployment. This increases the availability of subsea fluid sampling as it does not require a fixed platform to acquire subsea samples (Mancini, 2011). The ROV deployment makes fluid sampling possible for subsea interventions.

V. ***MPFM In-situ sampling***: The MPFM can perform well testing without the need of separation or shut-in of production as in conventional well testing applications. It has the capability to constantly monitor well performance in surpassing reservoir characterization. The MPFM requires less measurement time compared to the conventional well testing which take hours using a test separator. (Al-Kadem et al., 2014; Al-Khamis et al., 2008; Eivind, 2005).

3.5.2 **Key Influencing Factors**

First, it is important to identify the key influencing factors to determine success in the system selection. Economic return on investment for offshore operators and stakeholders, is the most considered ‘performance indicator’ for the subsea sampling system. However, a wide set of indicators is necessary for optimal engineering design concept selection. Once established, the process to measure the performance of the subsea sampling system, with the possibility to compare with other viable options can be achieved (Dorgant et al., 2001; Yasseri, 2012). The Key influencing factors correlated with RPSEA’s report on improvements of deepwater sampling and selected amongst others based on an assessment carried out in the survey conducted in Appendix III, are described as follows (Letton and Webb, 2012):

I. ***Safety and Risk:*** Freedom from potential damage (leaks) of sampling system to the subsea environment, employing double isolation valves in the system and operational procedure during sampling operation.

II. ***Provision of Representative Sample***: System availability to capture small quantity of fluid that is a true representation of the reservoir fluid, both having the same characteristics.

III. ***Sample Verification***: A means of measuring the quantity of acquired fluid to know it has enough samples for its operation.

IV. ***Operations***: Availability and reliability of operational sampling systems and to ensure safe storage kit for the collected sample and transportation unit.

V. ***Economics***: Guarantee production volume on system availability with proactive sampling.

VI. ***Equipment Technology Readiness***: Maturity of equipment, hardware designed to withstand the environmental impact, field tested, technology feasibility, good proven record of robustness, availability of all system technologies.

Thus, the aim is to select the best and most appropriate method for performing a SFS in overall deepwater field development, given its parameters. Identification of key influencing factors is perhaps the most important aspect of system selection (Dorgant et al., 2001; Yasseri, 2012). Extracting a representative sample is paramount in any sampling operation, hence the ideal sample would be taken directly from the reservoir well isobarically, isothermally and instantaneously (Mancini and Turnbull, 2011). The sampling system is therefore a critical part of any fiscal quality measurement system. Any errors introduced through sampling error will generally have a direct, linear effect on the overall measurement (Letton and Webb, 2012; API RP 44, 2003). Therefore, obtaining the sample from the wellhead is the best option, it is only through sampling at or near the wellhead that samples that are representative of the fluid flowing through the meter can be generated (Gransaether, 2011).

Moreover, temperature could be lost during sample’s transit to the topside, it is expected that the extracted sample is stored isobarically and heated to maintain the temperature, if these are not maintained, the integrity of the sample will be highly jeopardized and accuracy of the final result would become unreliable, thus, defeating the essence of the sampling operation (Letton and Webb, 2012; API RP 44, 2003). The continuum of sampling technology complexity is proportional to how close to an ideal sample is required (Mancini and Turnbull, 2011). Figure 3.8 is the schematic representation of the ideal sampling extraction point or location in the SPS to be selected.

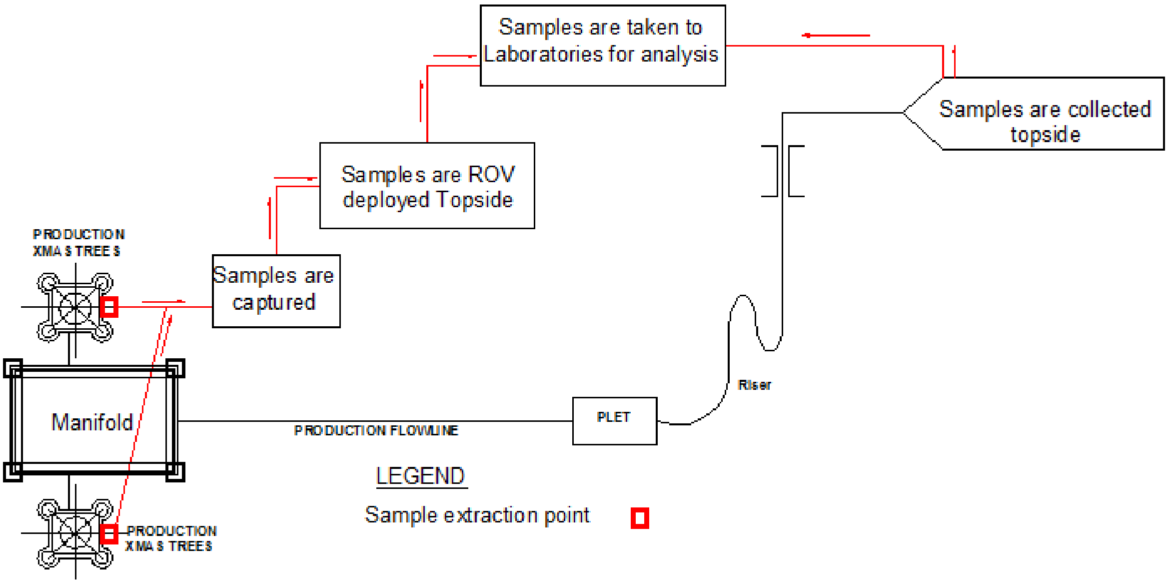

Figure 3-8 Subsea Fluid Sampling Schematic

3.5.3 **Development of Selection Criteria**

The suitable SFS selection criteria are adopted from the RPSEA's report on improvements of deepwater sampling, where criteria were considered when selecting the best subsea sampling system. They were used in combination to ascertain subsea system requirements for Xmas tree selection process. In order to aid the decision making and sure that all the influencing factors affecting the selection process are captured in detail, the criteria is then broken down to levels of the same magnitude to form the sub-criteria, so that these homogeneous variables can be compared accurately (Yasseri, 2012). The criteria and sub-criteria are developed and shown in Table 3.3 from the SFS influencing factors as discussed in 3.5.2. Finally, the five different SFS methods in secton 3.5.1 become the alternatives which are at the lowest level of the hierarchy.

The decision-maker must ensure all major influencing factors are adequately represented and thus separate the basic requirements, which will not be a selection criteria, but a standard for all technologies, and of great importance to the operator, or of minor importance, or can be left out entirely, some may even be captured under a different heading, hence the sub-criteria. Adopting the style used in literature, the criteria are represented with [1] to [6], while the sub-criteria are [1A] to [6D] as seen in Table 3.3, to prevent cluster in the matrix table (Saaty, 2008). Appendix IV further present definition of the sub-criterias.

Table 3-3 Selection Criteria and Sub-criteria (Saaty, 2008)

Symbol	Criteria	Sub Criteria
[1]	Safety and Risk	[A] Minimize leak and emission
		[B] Minimize exposure to high pressure fluids
		[C] Minimize risk to asset
		[D] Versatility of Design
[2]	Provision of Representative Sample	[A] Is sample Isobaric
		[B] Is sample Isothermal
		[C] Prevents Hydrate formation
		[D] Is sample free of contaminants
		[E] Is sample in a single phase
[3]	Sample Verification	[A] Confirm sample acquired
		[B] Confirm phases in the sample
[4]	Operation	[A] Acquire multiple sample from a single connection
		[B] Doesn't interrupt production

		[C] Simple to operate
		[D] Ability to clean and prepare for next sample
[5]	Economics	[A] Operational Expenditure
		[B] Capital Expenditure
		[C] Lead time
		[D] Integration
[6]	Equipment Technology Readiness	[A] Technology Readiness Level (TRL)
		[B] Size and weight
		[C] Survivability
		[D] Maintainability

3.5.4 **Assign Weights to the Criteria and Sub-criteria**

This step compares and assigns a scale to the different variables or criterias on each level, which is achieved through consultation with the industry experts (Yasseri, 2012). It is also about the relative importance of the criteria with respect to the overall goal. Here questions such as “which criteria is more important than the other” is asked and weighed accordingly (Saaty, 1990). The first thing to do is to establish a fundamental weighing scale as presented in Table 3.4 and Figure 3.10. This will then be used to assign weights to compare the criteria listed above.

Table 3-4: Fundamental Scale of Relative Importance (Yasseri, 2012)

Scale Factor	Definition	Notes
1	Equal importance	The two activities contribute equally to the objective.
3	Moderate importance of one over another	Experience and judgment slightly favours one activity over another.
5	Strong importance	Experience and judgment strongly favours one activity over another.
7	Very strong importance	An activity is strongly favoured and its dominance demonstrated in practice.
9	Extreme importance	The evidence favouring one activity over another is of the highest possible order of affirmation.
2,4,6,8	Intermediate values for the above value	Used when a compromise judgment is the only option.
Reciprocals	If activity ***i*** has one of the above numbers assigned to it when compared with activity ***j***, then ***j*** has the reciprocal value when compared with ***i***.	
Rationals’	Ratios arising from the scale	If consistency were needed by obtaining ***n*** numerical values to span the matrix.

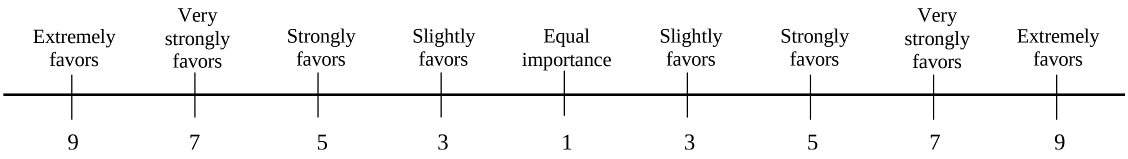

Figure 3-9: Format for Pairwise Comparisons (Yasseri, 2012)

The criteria are then arranged in a square matrix for a pairwise comparison, assigned by the judgments from expert's inputs about the relative importance of the elements in respect to the overall goal of collecting a "representative sample". The diagonal elements of the matrix are all weighed as 1 (i.e. comparing a criterion with itself) because they are of equal importance. The criterion in the *i*th row is more important than criterion in the *j*th column if the value of element (*i, j*) is less than 1; otherwise the criterion in the *j*th column is more important than that in the *i*th row. The (*j, i*) element of the matrix is the reciprocal of the (*i, j*) element. For example, in the first row and column [2] of the Table 3.5, 2 is the assigned weight, this means that criteria [1] slightly favours criteria [2], (see Table 3.4) and in the second row, and column [1], ½ is the assigned weigh which is the reciprocal of 2, it still means that criteria [1] is slightly favours [2]. After the weights are assigned the relative weights are calculated, and so are the weights of each Criteria. This will help determine the operators' most influencing factor in the selection of a SFS method, amidst others.

Table 3-5: Pairwise Comparison Matrix for the Criteria in the Second Level in the Hierarchy

	[1]	**[2]**	**[3]**	**[4]**	**[5]**	**[6]**
[1]	1	2	3	3	5	3
[2]	1/2	1	1	2	3	3
[3]	1/3	1	1	1	2	2
[4]	1/3	1/2	1	1	3	1/2
[5]	1/5	1/3	1/2	1/3	1	2
[6]	1/3	1/3	1/2	2	1/2	1
Sum	**2.70**	**5.17**	**7.00**	**9.33**	**14.50**	**11.50**

Table 3-6 : An Aggregation for Table 3.5 to determine the Relative Weights of the Variables

	[1]	[2]	[3]	[4]	[5]	[6]	Weight
[1]	0.370	0.387	0.429	0.321	0.345	0.261	**0.352**
[2]	0.185	0.194	0.143	0.214	0.207	0.261	**0.201**
[3]	0.123	0.194	0.143	0.107	0.138	0.174	**0.146**
[4]	0.123	0.097	0.143	0.107	0.207	0.043	**0.120**
[5]	0.074	0.065	0.071	0.036	0.069	0.174	**0.081**
[6]	0.123	0.065	0.071	0.214	0.034	0.087	**0.099**
CR = 0.07282							

Table 3.6 is the average of the scales of the expert judgement. The weights are determined by calculating the relative weights and then determining the mean relative weights. For example, the value in row 1 and column 3 is calculated to present the relative weights as seen in same row and column 5 as follows:

$$\frac{3}{3+1+1+1+\frac{1}{2}+\frac{1}{2}} = 0.429 \qquad \text{...............................} (8)$$

When this has been calculated for all the rows columns, the weight of [1] are determined (Table 3.6) by calculating the average weights:

$$\frac{0.370+0.387+0.429+0.321+0.345+0.261}{6} \qquad \text{..............}(9)$$

$$= 0.352$$

From the weights on the 8th column of Table 3.6, the criterion with the highest weight is [1], which is the Safety and Risk management of the asset with 0.352. This is an indication that Safety and Risk management of the asset is of primary importance to the operator even at the cost of acquiring a representative sample. This is followed by [2] which is Provision of a Representative Sample, with a weight of 0.201 and then [3] Sample Verification with 0.146, [4] Operation with weight 0.120, [6] Equipment Readiness Level with weight 0.099 and [5] Economics with weights 0.081. Thus, this agrees to the fact that operators are willing to invest on SFS because they know that the benefit of recoverable volume on production will be worth the investment on the sampling operation.

The pairwise comparison is also performed for the sub-criteria and their relative weights. Table 3.7 to 3.12 are the different sub-criteria represented by [A-E].

Table 3-7 Pairwise Comparison Matrix of Sub-criteria for Safety and Risk

(a)

	[1A]	**[1B]**	**[1C]**	**[1D]**
[1A]	1	3	1	3
[1B]	1/3	1	1/3	1/3
[1C]	1	3	1	3
[1D]	1/3	3	1/3	1
Sum	**2.67**	**10.00**	**2.67**	**7.33**

(b)

	[1A]	**[1B]**	**[1C]**	**[1D]**	Weight
[1A]	0.38	0.30	0.38	0.41	**0.36**
[1B]	0.13	0.10	0.13	0.05	**0.10**
[1C]	0.38	0.30	0.38	0.41	**0.36**
[1D]	0.13	0.30	0.13	0.14	**0.17**
CR = 0.07122					

Table 3-8:Pairwise Comparison Matrix of Sub-criteria for provision of Representative Sample

(a)

	[2A]	**[2B]**	**[2C]**	**2D]**	**[2E]**
[2A]	1	1	1/3	1/5	2
[2B]	1	1	1/2	1/5	3
[2C]	3	3	1	1	4
[2D]	5	5	1	1	4
[2E]	1/2	1/3	1/4	1/4	1
Sum	**10.50**	**10.33**	**3.08**	**2.65**	**14.00**

(b)

	[2A]	**[2B]**	**[2C]**	**[2D]**	**[2E]**	Weight
[2A]	0.10	0.10	0.11	0.08	0.14	**0.10**
[2B]	0.10	0.10	0.16	0.08	0.21	**0.13**
[2C]	0.29	0.29	0.32	0.38	0.29	**0.31**
[2D]	0.48	0.48	0.32	0.38	0.29	**0.39**
[2E]	0.05	0.03	0.08	0.09	0.07	**0.07**
CR = 0.074469						

Table 3-9: Pairwise Comparison Matrix of Sub-criteria for Sample Verification

(a)

	[3A]	[3B]
[3A]	1	1/2
[3B]	2	1
Sum	3.00	1.50

(b)

	[3A]	[3B]	Weight
[3A]	0.33	0.33	**0.33**
[3B]	0.67	0.67	**0.67**
CR = 0			

Table 3-10: Pairwise Comparison Matrix of Sub-criteria for Operation

(a)

	[4A]	[4B]	[4C]	[4D]
[4A]	1	1/4	3	1/3
[4B]	4	1	5	5
[4C]	1/3	1/5	1	3
[4D]	1/4	1/5	1/3	1
Sum	**5.58**	**1.65**	**9.33**	**9.33**

(b)

	[4A]	[4B]	[4C]	[4D]	Weight
[4A]	0.18	0.15	0.32	0.04	**0.17**
[4B]	0.72	0.61	0.54	0.54	**0.60**
[4C]	0.06	0.12	0.11	0.32	**0.15**
[4D]	0.04	0.12	0.04	0.11	**0.08**
CR = 0.033065					

Table 3-11: Pairwise Comparison Matrix of Sub-criteria for Economics

(a)

	[5A]	[5B]	[5C]	[5D]
[5A]	1	1	3	3
[5B]	1	1	3	2
[5C]	1/3	1/3	1	2
[5D]	1/3	1/2	1/2	1
Sum	**2.66**	**2.83**	**7.50**	**8.00**

(b)

	[5A]	[5B]	[5C]	[5D]	Weight
[5A]	0.38	0.35	0.40	0.38	**0.38**
[5B]	0.38	0.35	0.40	0.25	**0.34**
[5C]	0.12	0.12	0.13	0.25	**0.16**
[5D]	0.13	0.18	0.07	0.13	**0.12**
CR = 0.049456					

Table 3-12: Pairwise comparison matrix of sub-criteria for Equipment's Technology Readiness Level

(a)

	[6A]	[6B]	[6C]	[6D]
[6A]	1	3	1/2	1/3
[6B]	1/3	1	1/3	1/3
[6C]	2	3	1	1
[6D]	3	3	1	1
Sum	**6.33**	**10.00**	**2.83**	**2.67**

(b)

	[6A]	[6B]	[6C]	[6D]	Weight
[6A]	0.16	0.30	0.18	0.12	**0.19**
[6B]	0.05	0.10	0.12	0.12	**0.10**
[6C]	0.32	0.30	0.35	0.38	**0.34**
[6D]	0.47	0.30	0.35	0.38	**0.38**
CR = 0.052284					

3.5.5 **Accuracy of Comparison**

In a pairwise comparison, there is a high probability of inconsistency in judgment. Hence, a means of measuring the degree of consistency is proposed where the Consistency Ratio (CR) examines the consistency of the pairwise comparisons in the matrix. CR is defined as the ratio of Consistency Index (CI) to Random Index (RI) (Saaty, 2008; Yasseri, 2012). That is:

$$CR = \frac{CI}{RI} \qquad \text{.......................................} (10)$$

Where RI is Saaty's randomly generated reciprocal matrix, see Table 3.13 for an average RI. Thus CI is further defined as:

$$CI_{max} = \frac{\lambda_{max} - n}{n-1} \qquad \text{...} (11)$$

Where *n* is the number of the square matrix, and λ_{max} is the maximum value of $n \; x \; n$ pairwise comparison matrix (Yasseri, 2012; Saaty, 2008). If the matrix is perfectly consistent then λ_{max}= *n,* hence the $CI_{max} = 0$ however if it is inconsistent with so much discrepancies, then λ_{max} > *n.* The CI should not be above 0.10, if it does, the inconsistency of the weights is much and may require re-assignment of weights (Yasseri, 2012).

Table 3-13: Yaserri (2012) Random Index (RI)

N	1	2	3	4	5	6	7	8	9	10
RI	0.00	0.00	0.58	0.90	1.11	1.24	1.32	1.41	1.45	1.49

To calculate the CR of Table 3.6:

$$\lambda_{max} = \left(\frac{0.352}{0.370} + \frac{0.201}{0.194} + \frac{0.146}{0.143} + \frac{0.120}{0.107} + \frac{0.081}{0.069} + \frac{0.099}{0.087}\right) = 6.455 \quad \ldots\ldots(11)$$

$$CI = \frac{\lambda_{max} - n}{n-1} = \frac{6.455 - 6}{6-1} = 0.091024 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (12)$$

$$CR = \frac{CI}{RI} = \frac{0.091024}{1.24} = 0.07282 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (13)$$

CR is less than 0.1; therefore the comparison matrix of the Criteria is consistent.

Similarly the CR of the sub-criteria is also determined to ensure their assigned weights are consistent. And this can be seen in the last rows of Table 3.7b, 3.8b, 3.9b, 3.10b, 3.11b and 3.12b.

3.5.6 **Assess the Alternatives**

The next AHP step is to assess the alternative SFS methods which are not done by a pairwise comparison. Likert Scale is adopted as the suitable scale for ascribing quantitative value to a qualitative data to make it amenable to statistical analysis (Yasseri, 2012). A Likert Scale is a style of psychometric scale mostly used in psychology questionnaires. Developed by and named after a psychologist Rensis Likert, when properly applied, it can be a useful tool in addressing the need to consider opinions and attitudes towards potential policy decisions (McCall, 2001). Likert developed the principle of measuring attitudes by asking people to respond to a series of statements about a topic in terms of the extent to which they agree with them. As a survey questionnaire, a typical Likert will have the following format of rating; **1**-strongly unfavourable to the concept, **2**-somewhat unfavourable to the concept, **3**-undecided, **4**-somewhat favourable to the concept, **5**-strongly favourable to the concept (McCall, 2001).

Weights of 1 to 5 are assigned to the alternatives. Note that the "concepts" is referring to criteria. The values remain as stated above. This could be carried out by 3 or more experts and the final score is averaged. Without having a reliable data for the third step, the pairwise comparison may not be possible (Yasseri, 2012). Table 3.14 has the average scores assigned to the alternative SFS methods.

3.5.7 **Selection of Best Alternative**

This is not identified as a step in the AHP decision making, but it is the last process in using this method. The scores assigned to the different SFS methods are multiplied by the relative weights of each sub-criterion, which is a product of the average weights of the sub-criteria and the weight of their parent criteria. The overall sums of the alternative SFS are calculated, the SFS with the highest sum becomes the most favourable option of SFS to be use in the deepwater field. Table 3.15 shows the alternatives weights and the sum of the total weights, and the results of the entire scaling. The rank can also be deduced from the result.

From Table 3.15, the alternative with the highest weight is the ROV Deployed Sampling method at approximately 4.335. Thus, the best method after selection process is the ROV Deployed sampling system, with regards to the field parameters.

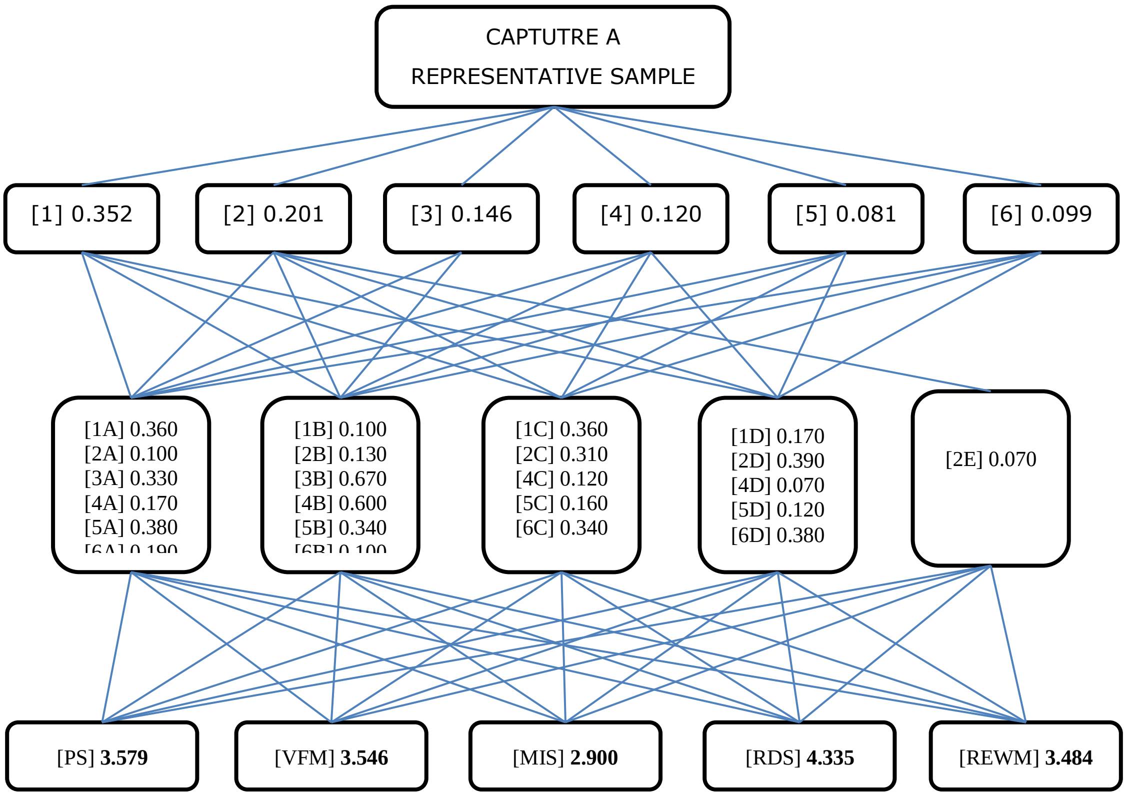

Figure 3-10: AHP Result Structure

3.5.8 **Ranking the SFS Methods**

The ranking of the SFS methods in the present paper is done with the field's parameter as an influencing factor; this rank may change in a different field. From Table 3.15 and Figure 3.11, the Table 3.14 is the ranking chart of the 5 SFS methods: The MPFM In-situ Sampling is the least favourite sampling method for the field.

Table 3-14: Ranking the SFS Methods

Rank	*Sampling Methods*	*Scales*
1	ROV Deployed Sampling (RDS)	4.335
2	Production Sampling (PS)	3.579
3	Virtual Flow Model (VFM)	3.546
4	Red Eye Water-cut Meter (REWM)	3.484
5	MPFM In-situ Sampling (REWM)	2.900

Table 3-15: Weights, Relative Weights, Likert Scale and Result

Criteria	Primary Criteria Weight	Sub Criteria	Sub-Criteria Weight	Overall Weight	[PS] Score	[VFM] Score	[REWM] Score	[RDS] Score	[REWM] Score	[PS] Weight	[VFM] Weight	[REWM] Weight	[RDS] Weight	[REWM] Weight
Safety and Risk	0.352	[A] Minimize leak and emission	0.3600	0.12672	5	4	4	4	4	0.6336	0.50688	0.50688	0.50688	0.50688
		[B]Minimize exposure to high pressure fluids	0.1000	0.0352	4	4	3	4	4	0.1408	0.1408	0.1056	0.1408	0.1408
		[C] Minimize risk to asset	0.3600	0.12672	5	5	3	4	5	0.6336	0.6336	0.38016	0.50688	0.6336
		[D] Versatility of Design	0.1700	0.05984	2	3	2	5	3	0.11968	0.17952	0.11968	0.2992	0.17952
Provision of "representative sample"	0.201	[A] Is sample Isobaric	0.1000	0.0201	4	5	2	4	5	0.0804	0.1005	0.0402	0.0804	0.1005
		[B] Is sample Isothermal	0.1300	0.02613	4	5	2	4	5	0.10452	0.13065	0.05226	0.10452	0.13065
		[C] Prevents Hydrate formation	0.3100	0.06231	3	3	1	4	3	0.18693	0.18693	0.06231	0.24924	0.18693
		[D] Is sample free of contaminants	0.3900	0.07839	5	4	5	4	4	0.39195	0.31356	0.39195	0.31356	0.31356
		[E] Is sample in a single phase	0.0700	0.01407	4	4	2	4	4	0.05628	0.05628	0.02814	0.05628	0.05628
Sample Verification	0.146	[A] Confirm sample acquired	0.3300	0.04818	1	2	2	5	2	0.04818	0.09636	0.09636	0.2409	0.09636
		[B] Confirm phases in the sample	0.6700	0.09782	1	2	2	5	2	0.09782	0.19564	0.19564	0.4891	0.19564
Operation	0.120	[A] Acquire multiple sample from a single connection	0.1700	0.0204	2	3	1	5	3	0.0408	0.0612	0.0204	0.102	0.0612
		[B] Doesn't interrupt production	0.6000	0.072	5	5	4	5	5	0.36	0.36	0.288	0.36	0.36
		[C] Simple to operate	0.1500	0.018	5	4	3	4	3	0.09	0.072	0.054	0.072	0.054
		[D] Ability to clean and prepare for next sample	0.0800	0.0096	1	1	4	5	1	0.0096	0.0096	0.0384	0.048	0.0096
Economics	0.081	[A] Operational Expenditure	0.3800	0.03078	4	4	4	3	4	0.12312	0.12312	0.12312	0.09234	0.12312
		[B] Capital Expenditure	0.3400	0.02754	4	1	4	3	1	0.11016	0.02754	0.11016	0.08262	0.02754
		[C] Lead time	0.1600	0.01296	5	4	3	4	2	0.0648	0.05184	0.03888	0.05184	0.02592
		[D] Integration	0.1200	0.00972	4	3	1	4	3	0.03888	0.02916	0.00972	0.03888	0.02916
Equipment technology readiness	0.099	[A] Technology Readiness Level (TRL)	0.1900	0.01881	4	2	5	5	1	0.07524	0.03762	0.09405	0.09405	0.01881
		[B] Size and weight	0.1000	0.0099	3	2	4	5	2	0.0297	0.0198	0.0396	0.0495	0.0198
		[C] Survivability	0.3400	0.03366	2	3	2	5	3	0.06732	0.10098	0.06732	0.1683	0.10098
		[D] Maintainability	0.3800	0.03762	2	3	1	5	3	0.07524	0.11286	0.03762	0.1881	0.11286
Total Weight										**3.57862**	**3.54644**	**2.90045**	**4.33539**	**3.48371**

3.6 Analysis of Subsea Fluid Sampling Options on the SPS

A set of possible options to effectively implement the fluid sampling at the point of sampling on the SPS, so as to acquire representative sample for Greenfield or existing Brownfield facilities is provided in section 3.6.1 and 3.6.2. Two different selection analysis approach, pairwise comparison and grid analysis is employed to independently assess and select the optimal sampling option. The flow chart in Figure 3.12 provides the process on how the optimal sampling option is achieved.

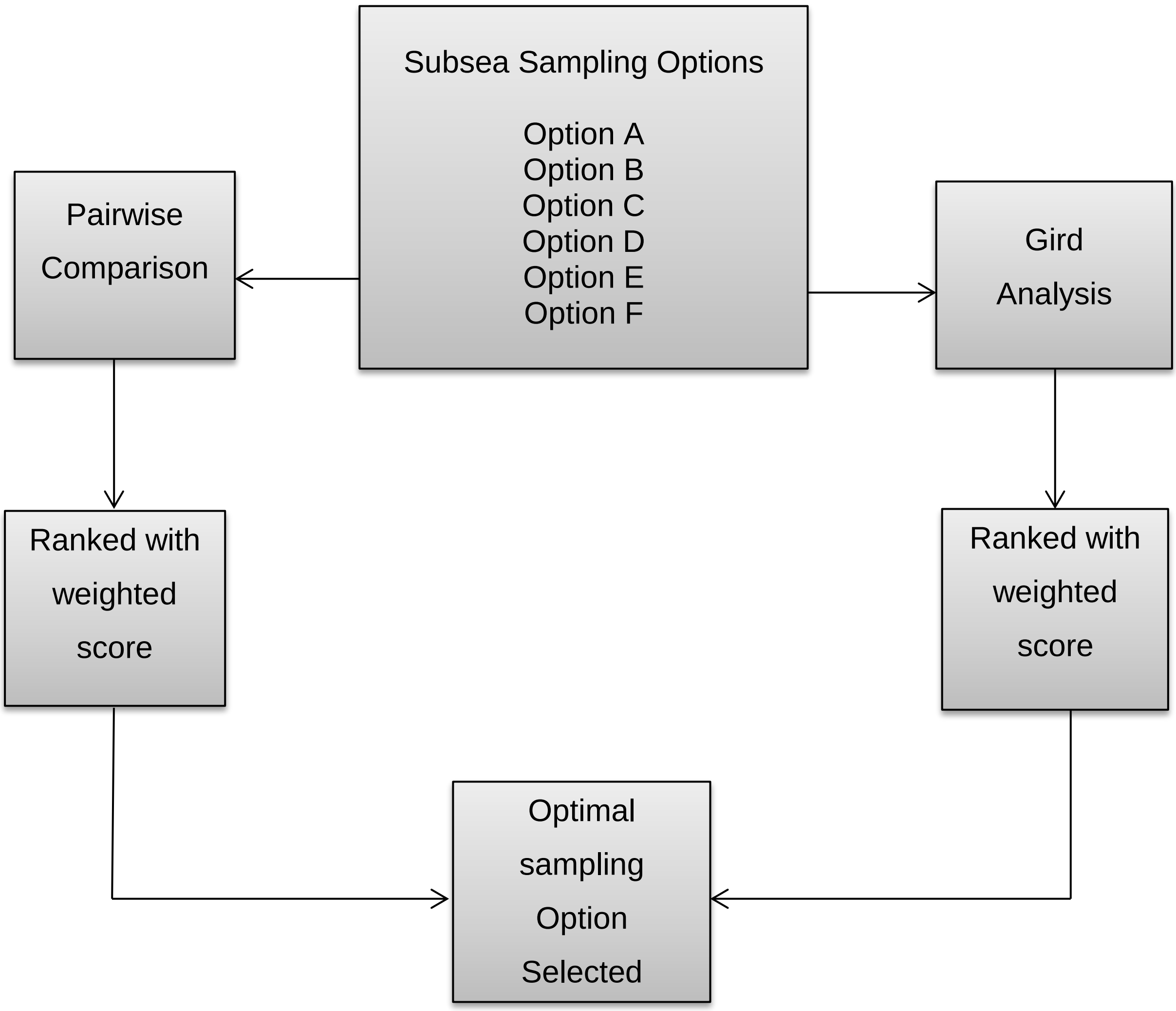

Figure 3-11 Flow chart for Subsea Sampling Option Analysis on the SPS

3.6.1 **Pairwise Analysis**

A pairwise comparison analysis was carried out to compare the options listed in Table 3.17 on the basis of five objective functions in Table 3.16.

Table 3-16 Objective Functions

List	Objective Functions
A.	Ability to sample individual well
B.	Representative sample capture
C.	Flow assurance
D.	Real time data monitoring
E.	Accuracy and Reliability

Decision Scores: 0 – 3, where 0 is no difference and 3 is much difference.

The ‘Objective Functions’ were selected based on the feedback survey carried out on engagement with Operators, vendors and experts in the subsea industry that is provided in Appendix III. The objective functions are limited to five for the pair analysis comparison with a decision score of 0 to 3. The objective functions are used to determine the selected sampling options in Table 3.17.

Table 3-17 Selected Sampling Option

List	Sampling Options
A.	Fluid Sampling on Wellhead
B.	Fluid Sampling on Manifold
C.	Fluid Sampling + MPFM on Wellhead
D.	Fluid Sampling + MPFM on Manifold
E.	Fluid Sampling on Manifold, MPFM on Wellhead
F.	Fluid Sampling on Wellhead, MPFM on Manifold

Options A and B are variants of C and D and these are described schematically as shown in Appendix V. A critical factor in the successful application of subsea sampling is to have good quality representative fluid samples taken close to the wellhead. This is applicable in field layouts with different well streams commingling in a manifold, where wide variations of fluid properties are envisaged over the life of field.

Table 3-18 Pairwise Comparison

Options	A	B	C	D	E	F
A		A3	C2	A2	A1	F1
B			C3	D1	E1	F1
C				C3	C2	C1
D					E1	F1
E						F1
F						

Table 3-19 Ranking Results of Weighted Scores

Options	Ranked Scores	Weighted Scores
A	7	**28%**
B	0	**0%**
C	11	**44%**
D	1	**4%**
E	2	**8%**
F	4	**16%**
Total Scores	25	**96%**

The analysis method compares the point of sampling option with two options in comparison at a time, based on the objective functions and then selects the option with higher rating that satisfies the objective function. However, the rating was assigned from the feedbacks on the industrial survey that is provided in Appendix III. This is done by assigning a score ranging from 0 - 3 on the degree of variation between the two options compared (Ageh et al., 2009; Thomas, 2008). The scores for each option are then summed to determine the option with the highest scores. An example for options A and C with the weighted scores is provided in Table 3.18 and 3.19. The following calculations demonstrate how the option scores are been summed.

The total ranked score (TRS) = A+B+C+D+E+F

Therefore total ranked score (TRS) = 7+11+1+2+4 = 25

For option A, the weighted score = A/TRS = 7/25 = 28%

Similarly for option F, the weighted score is F/TRS = 4/25 = 16%

From the results in Table 3.19, options C and A rank the highest with 44% and 28% respectively. Option C is the best subsea sampling option selected in this pairwise analysis. However, option A would be considered for field development where MPFM is predominantly installed on the Manifold. Thus, option C is considered the preferred approach for subsea fluid sampling. This option would ensure accurate representative fluid sample capture at the wellhead, to enable accurate calibration of the MPFM installed at the subsea tree for validation purposes.

3.6.2 **Grid Analysis**

The grid analysis attempts to grade the objective functions based on their relative importance to a subsea installation. Definitions of the objective function weighted factors are shown in Table 3.20.

The relative importance of factors and decision scores are defined in Table 3.12, with weighted scores ranked in Table 3.13.

Table 3-20 Objectives Function Weighted Factors

Objective Function		Important Factors
A	Ability to sample individual well	5
B	Representative sample capture	5
C	Flow assurance	2
D	CAPEX & OPEX	4
E	Intervention operation	3
F	Real time data monitoring	5
G	Accuracy and Reliability	4

The survey conducted in the offshore industry provided in Appendix III, was used to provide weighed factors for the objective functions.

Table 3-21 Relative Importance of factors and Decisions Scores Chart

Relative Importance of Factors		Decision Scores	
0	Absolute Unimportant	5	Very Good
1	Somewhat Unimportant	4	Good
2	Desirable	3	Adequate
3	Somewhat Important	2	Fair
4	Important	1	Poor
5	Very Important	0	Not Adequate

Table 3.21 is the grid analysis showing the factors and decision scores of how the fluid sampling option satisfies each objective function (Joshi and Joshi, 2007).

Table 3-22 Ranked Weighted Scores for Grid Analysis

Objective Functions		A	B	C	D	E	F	G		
Importance Factors		5	5	2	4	3	5	4		
	Options									
Fluid Sampling on Wellhead	A	5	5	4	3	4	4	4		
Fluid Sampling on Manifold	B	2	1	2	4	4	2	2		
Fluid Sampling + MPFM on Wellhead	C	5	5	4	2	4	5	5		
Fluid Sampling + MPFM on Manifold	D	2	1	2	5	4	3	2		
Fluid Sampling on Manifold, MPFM on W/H	E	3	2	3	3	4	3	2		
Fluid Sampling on W/H, MPFM on Manifold	F	5	5	4	4	4	3	2		
					Weighted Scores					
	Options								**Total**	
Fluid Sampling on Wellhead	A	25	25	8	12	12	20	16	118	**21%**
	B	10	5	4	16	12	10	8	65	**11%**
Fluid Sampling + MPFM on Wellhead	C	25	25	8	8	12	25	20	123	**22%**
	D	10	5	4	20	12	15	8	74	**13%**
	E	15	10	6	12	12	15	8	78	**14%**
	F	25	25	8	16	12	15	12	113	**20%**
									571	**100%**

A weighting of the selected fluid sampling option to satisfy or meet the requirements of the objective function is carried out. These weighted scores are then multiplied by the assigned scores for each objective function as shown in Table 3.22. From the result shown above, the highest overall score then becomes the preferred option and option C, “Fluid Sampling + MPFM on Wellhead” is selected. Moreover, options A and F are likely to fall within the margin of error as the second selected options for field applications, following option C as the optimal. Also it can be observed from the result that option C was the preferred option in the previous pairwise analysis.

Thus, the parameters used in the selected process are a good representation of the technical requirements which influence the choice of the subsea sampling technology option that is deployed. The selected option can then be subjected to an economic evaluation based on the field parameters. However, it must be noted that a team of different skill sets should be involved in the screening process with expert knowledge of the technology and the field development. A final decision can then be reached based on the technical and economic evaluations.

3.7 Conclusions

This paper discussed the different MCDM, SFS methods and options to implement subsea fluid sampling technology on the SPS, necessary with the innovative trend in the offshore industry. The AHP decision making emerged as the optimal selection method based on its ability to compare the criteria and alternatives in a pairwise manner, and at the same time, assigning scores on both tangible and intangible values (Saaty, 2008; Yasseri, 2012).

After the ranking of selected subsea sampling options from respondents scoring model in Figure 3.15, the ‘ROV deployed sampling system’ came up as the preferred, while on the pairwise comparisons and grid analysis in 3.6.1 and 3.6.2 respectively, the most emerged options which dominate the ranking was the ‘Fluid Sampling + MPFM on Wellhead’, to enable representative sample capture. This is essential in meeting the stated objectives, to determine the best accurate sampling solution, i.e., the best location to take fluid samples with ROV deployed system. However, one key influencing factor of interest is the 'economic value to stakeholders', and this is understood that offshore operators are now willing to spend some considerable amount to have an accurate fluid sampling, because of the eventual benefits to maximise production volume on the life of field operations (Gransaether, 2012; Mancini and Turnbull, 2011; Letton and Webb, 2012).

Thus, the ROV deployed sampling method emerged with the highest score, thereby making it the candidate method for the field sampling operations. This is in conformity with the offshore operators' response to the survey that was performed during the course of this research. It could also explain why there is more investment in R&D on the ROV operated system, for its improvement on intervention operations, especially in subsea sampling application (Yasseri, 2012; Kelner and Letton, 2012; Mancini and Turnbull, 2011).

4 INTEGRATED APPROACH TO MAXIMIZE DEEPWATER ASSET VALUE WITH SUBSEA FLUID SAMPLINGS

Abili et al., *School of Energy, Cranfield University, Bedfordshire UK* *(doi:10.3723/ut.32.245 published in Underwater Technology, Vol. 32, No. 4, pp. 245–253, 2015) Received 17 November 2013; Accepted 6 January 2015 for publication.*

Abstract

The acquisition of representative subsea fluid samples from offshore field development is crucial for the correct evaluations of oil reserves and for the design of production facilities. Employing a mechanistic compositional fluid tracking model, an integrated sampling approach was developed to capture the essential building blocks of the subsea production system. With the mechanistic model, every single fluid component was accounted for throughout the calculation, enabling simulation of scenarios such as start-up and blowdown with a high level of detail and accuracy. Therefore, the model provides a predictive tool to test and monitor subsea operational conditions for the life of field. The application of the model should reduce the frequency of subsea intervention operations required for the offshore oil and gas industry, with considerable saving on operational expenditures. The present paper explores the derivable benefits of the integrated sampling application to maximise value on deepwater field development.

Keywords: Subsea fluid sampling, Compositional tracking, Integrated sampling model, MPFM, EOS model

Acronym list	
API	American Petroleum Institutes
EOR	Enhance Oil Recovery
EOS	Equation of State
FEED	Front End Engineering Design
FPSO	Floating Production Storage and Offloading Vessel
GOR	Gas Oil Ratio
MPFM	Multiphase Flow Meter
P	Pressure
PVT	Pressure Volume Temperature
SPS	Subsea Production Systems
T	Temperature

4.1 Introduction

Acquiring representative reservoir fluid samples play a key role in the design and optimization of production facilities. Inaccurate and unreliable fluid characterization leads to incorrect production rates, thus negatively impacting reservoir production recoveries. Retrieving reliable pressure, volume and temperature (PVT) properties of reservoir fluids starts with the acquisition of adequate volumes of representative fluid samples, followed by PVT data measurement and phase behaviour modelling. Subsequent laboratory analysis must be monitored through established quality control procedures to provide high quality data (Sbordone et al. 2012; Nagarajan et al., 2007; Nagarajan, et al, 2011; Joshi and Joshi, 2007). The reservoir fluid characterization methodology must employ best practice to model fluid behaviour as functions of pressure, temperature, and fluid composition.

Arguably, the drive in the offshore industry on fluid measurement capability is to use the redundant meter sensors and transient multiphase flow models to check and validate present flow measurement methods (Bruno et al., 2012). Thus, the requirement for numerical fluid sampling to predict wellhead and flowline conditions has never being so important in the current investment trend toward offshore field development.

The mechanistic compositional fluid tracking model combines the multiphase capabilities in transient multiphase flow for fluid properties measurements. However, this does not in any way eliminate the importance of retrieving live subsea fluid samples with ROV deployed sampling for analysis of the production fluid, and for separate check of MPFM measurement, key in acquiring accurate data in the sampling program (Abili et al., 2013; Sbordone et al. 2012; Jaco, 2012; Joshi and Joshi, 2007). So the mechanistic model makes provision for a fluid sampling process upstream of the MPFM to capture subsea samples.

The integrated sampling model specifically evaluates the compositional changes from the subsea tree or manifold for representative fluid sample measurement. This adds value to subsea sampling operations with significant cost saving on intervention operations. Thus, acquiring representative fluid samples from the subsea production systems is crucial to sustaining production revenues. This provides an opportunity for optimisation of production facilities without shut-in of producing wells.

The aim of the present paper is to use the numerical compositional fluid tracking model to determine pressure and temperature, fluid compositions and flowrates of subsea production wells. The objectives are to develop a numerical fluid sampling approach with application of a mechanistic model (compositional fluid tracking) to enable accurate flow measurement to manage well production. And secondly, to perform a case study applying the model with experimental and numerical data for validation purpose, to enable return on production asset. Therefore, a deepwater field case study was selected to demonstrate the derivable benefits of employing the numerical compositional fluid tracking model. In line with the model, an evaluation of fluid compositions at the wellhead and flowline simulation is demonstrated, to efficiently monitor the reservoir fluid and well production. The Table 4.1 provides the contributions made to subsea fluid sampling.

Table 4-1 Contributions to Research

List	Contributions
1	Use of the mechanistic (numerical compositional fluid tracking) model to predict fluid characteristic, individual phases, fluid compositions and flowrates at wellhead and production flowline.
2	Use of the mechanistic model to monitor the reservoir production fluid, and to validate the well testing operations to ensure representative fluid samples data are obtained.
3	Use of compositional fluid tracking to match the experimental results for wellhead fluid measurements, to predict wellhead fluid characteristics data.
4	Use of the mechanistic model for reduce cost saving in the frequency reduction of periodic subsea interventions sampling operations, required for well production and reservoir performance monitoring.

4.2 Mechanistic Model Description

A mechanistic model is used in the offshore oil and gas industry to simulate single phase and two or three phase flow scenarios in subsea flowlines and wells. The mechanistic compositional fluid tracking model is employed to simulate this transient condition. The model first identifies the flow pattern, and then calculates the conservation equation for mass and momentum with the support of closure laws that are dependent on the flow pattern. Additional equation is provided by the closure laws for resolution of this conservation equation (Dhulesia et al., 1996; Kjell et al., 1991). This closure laws provides the interfacial friction on the phases, frictional forces for the phases on stratified and annular flow pattern, the Taylor bubble flow, and the liquid slug void fraction on periodic flow pattern. This enables the mechanistic model to predict the flow stream patterns, pressure drop, change in temperature, liquid hold up and fluid compositions (Dhulesia et al., 1996; Kjell et al., 1991).

In line with the mechanistic model, the characterised fluid model is derived from Pseudo compositional black oil correlations and equation of state (EoS) method. Although black oil correlations may be adequate in some cases, EoS compositional modelling is preferred as best practice based on sound thermodynamic principles and it provides reliable predictions even outside the range of data with incremental time steps (Mantecon and Hollams, 2009; Schindler, 2007).

Therefore when using black oil properties in reservoir engineering calculations, it is preferable to derive black oil properties using an EoS fluid model. EoS reservoir fluid modelling involves several key factors. This includes appropriate component selection to describe the fluid with proper heavy end (C_{7+}) characterization, incorporation of solution techniques for ensuring convergence and avoiding unrepresentative sampling. Finally, a methodology is developed using an optimization software package to accurately match the model to laboratory data (Schindler, 2007; Mantecon and Hollams, 2009; Avansi and Schiozer, 2015).

Validation of the mechanistic compositional fluid tracking model was done with the reservoir fluid properties in order to demonstrate the representative fluid samples acquired at the production system. Difference flow regimes were examined in this experiment and parameters such as PVT, density, viscosity, specific gravity, phase slip mode and molar compositions, were considered to determine a representative fluid sample capture at the subsea tree.

The mechanistic model is able to choose the type of flow from the stratified or annular mist flows and the bubble flow or slug flow patterns (Dhulesia et al., 1996; Kjell et al., 1991). This mechanistic compositional fluid tracking model is a useful application tool in the prediction of multiphase flow on subsea wellhead and production flowlines.

A base case model considered for this study is shown in Figure 4.1.

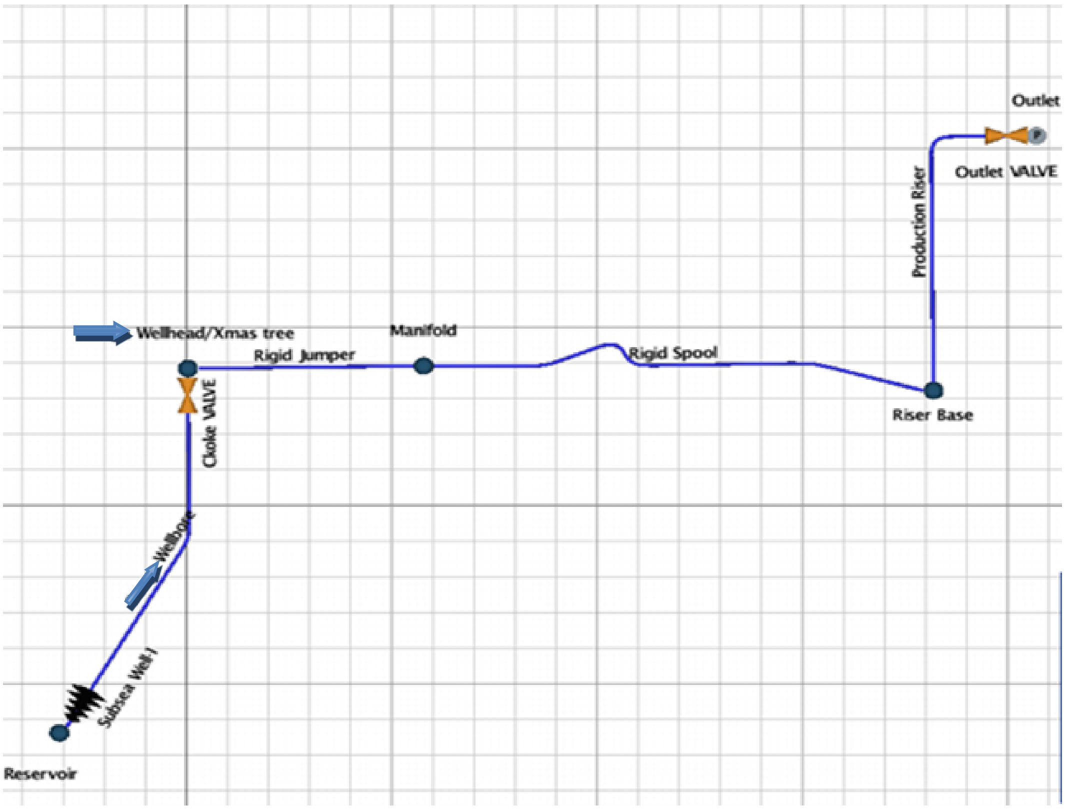

Figure 4-1 Base Case Model

4.3 PVT Data Analysis

A deepwater field is selected for this study as shown in Figure 4.2, is 18km subsea tie-back to a Floating Production Storage and Offloading (FPSO), with 4 production drill centres and 3 water injection drill centres. There is a total of 17 production and 15 water injection wells including dual zones completions (smart wells), and the water depth in the area is between 1100m to 1200m, with a seabed temperature of about 4^{o}C (Ageh et al., 2010; Ageh et al., 2009; Sathyamoorthy et al., 2009).

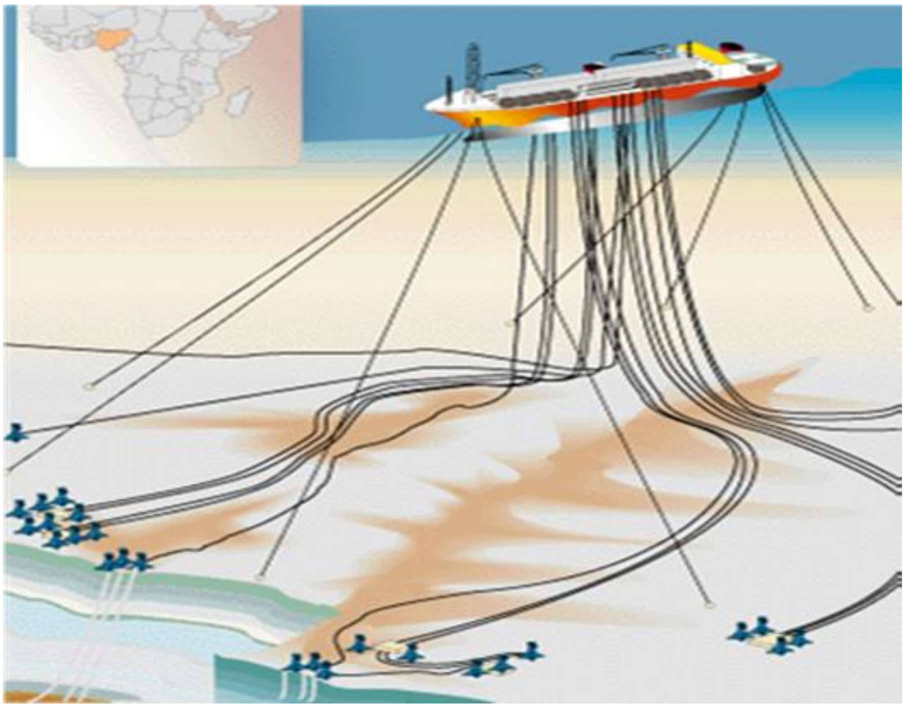

Figure 4-2 - Subsea Architecture for the Deepwater Field Development **(**Ageh et al., 2010)

The deepwater field contain a carbonate reservoir of medium gravity oil for an appraisal well of 33 °API. The initial reservoir pressure and temperature were 4601psi (317.2bar) and 70.6°C (159.08°F), respectively. The initial GOR was 1080scf/bbl, viscosity and density of oil were 0.3cP and 0.6g/cm^3 respectively. The fluid exhibited a bubble point pressure of 4190psi (288.9bar) at 70.6°C (159.08°F). The producer well is capable of delivering high liquid rate of 40mbpd, and the reservoir is produced by water injection pressure maintenance (Okoh et al., 2010). The molar composition in equilibrium at the inlet conditions is shown in Table 4.2.

In Figure 4.3, the phase diagram for characterized fluid is shown with the phase envelope. The critical temperature and pressure of this characterized fluid are 320°C (608°F) and 3046psi (210bar) respectively. The phase diagram can be used to check and verify the potential transfer of mass between phases before performing a simulation. With estimation of the fluid pressures and temperatures, it is easy to use the diagram in order to better understand likely phase mass transfer along the flowpath.

Table 4-2 Typical Input Molar Compositions of Reservoir Fluid Data

Component	Mol %	Mol wt	Liquid Density g/cm³	Crit T °C
CO2	0.5	44.01		31.05
C1	44.7	16.043		-82.55
C2	6.2	30.07		32.25
C3	8.3	44.097		96.65
iC4	1.9	58.124		134.95
nC4	3.5	58.124		152.05
iC5	1.9	72.151		187.25
nC5	1.9	72.151		196.45
C6	1.8	86.178	0.664	234.25
C7	3.327	96	0.652	257.024
C8	2.944	107	0.6659	277.62
C9	2.605	121	0.6782	301.384
C10-C11	4.345	140.103	0.6941	331.253
C12-C13	3.402	167.573	0.7123	369.403
C14-C15	2.664	197.512	0.7279	406.948
C16-C17	2.086	229.042	0.7414	443.226
C18-C20	2.312	262.024	0.7559	479.016
C21-C23	1.602	303.568	0.7712	521.27
C24-C28	1.654	355.927	0.7882	571.939
C29-C35	1.128	437.236	0.8093	645.317
C36-C80	0.83	605.056	0.8439	796.528

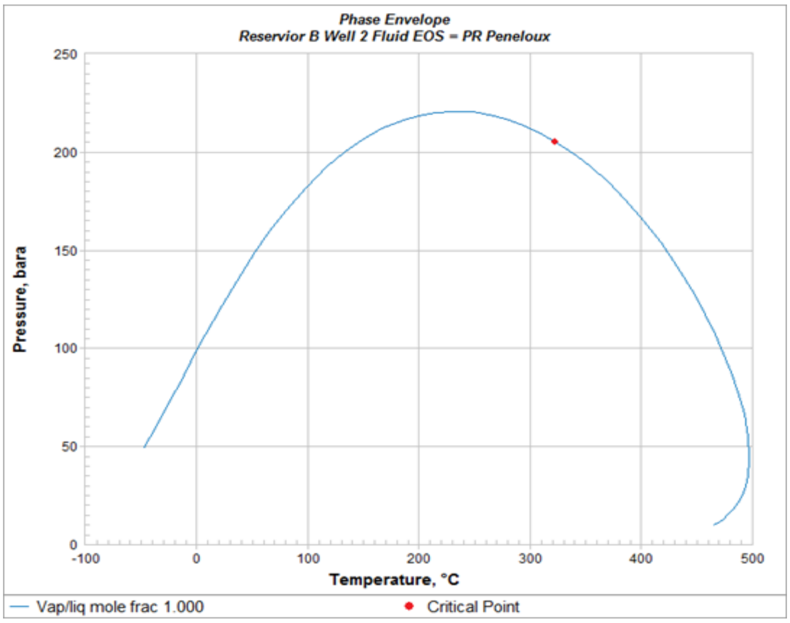

Figure 4-3 – Phase Envelope of Typical Characterized Fluid

However, it is important to recognise that medium gravity oils with the API gravity ranges from high twenties to mid-thirties and this can provide insight into the black oil fluid characteristic. These black oil reservoirs become prime candidates for EOR after primary depletion and secondary water-flood, through CO_2 injection (Bargas et al., 1992). A CO_2 component that is of lesser density could vaporize due to their super critical behaviour at reservoir conditions which can lead to high recoveries of these rich reserves (Genetti et al., 2003).

4.4 Compositional Fluid Tracking Model

The numerical compositional fluid tracking model employs the powerful multiphase capabilities in transient dynamic flow program. Part of this model is a software package for fluid characterisation developed by Calsep (Calsep, 2011). In the model, each fluid component is accounted in the calculation, with high level of accuracy in start-up and blowdown scenarios in the simulations (Rydah, 2002; Mantecon and Hollams, 2009).

However, the local composition at the well changes with pressure and temperature. Hence, the compositional tracking model can be used to track all composition components at nodes in transient flow conditions (Rydah, 2002). Typical cases where compositional fluid tracking effects may have influence are populated in Table 4.3.

Table 4-3 - Typical Compositional Tracking Cases

List	Typical Cases
1.	Networks with different fluids
2.	Changes in composition at boundaries
3.	Blowdown
4.	Water or Gas injection / Gas lift
5.	Start-up
6.	Shut-in and restart

4.5 Validation of the Mechanistic Compositional Tracking Model

The mechanistic compositional fluid tracking model is a dynamic production support system, with the capability to improve the understanding of well stream flow and so enable proactive and cost effective operation. This program could also provide information on parts of the production system that instrumentation cannot reach, and this could allow the development of advanced monitoring, as operational conditions change over the field life, with opportunity to drill new wells (Carimalo et al., 2008; Bendiksen et al., 1991).

The mechanistic compositional fluid tracking model dynamically accommodates operational changes, such as adding field components as modules without rebuilding the entire system. However, the simulator is a dynamic, first principle multiphase flow model developed and validated over 25 years (Carimalo et al., 2008; Bendiksen et al., 1991). The model has the capability to predict operational changes that could be relied on. However, typical field case study was chosen to carry out validation of the compositional fluid tracking model to confirm the accuracy of the simulation results acquired in the present study.

This case study utilise 100mm nominal pipe with a diameter of 93mm bore. The total length of the pipeline is 17,300ft (5200m) and the total volume of the line is 229bbl. An internal pipe roughness of 0.04mm was assumed.

The pipeline is buried approximately 5ft underground and is normally operated at line pressures between 800 and 1,000psi (55 and 69bar). Pressure and temperature measurement uncertainties are calculated to be 11.25psi (0.75bar) and 1.5°F (-16.9°C). The pipeline geometry model is shown in Figure 4.4.

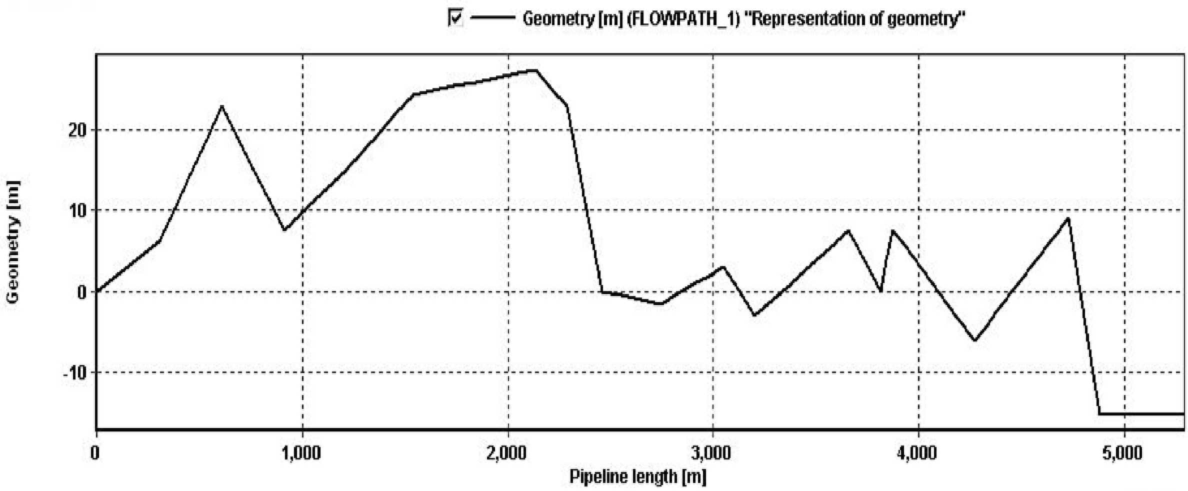

Figure 4-4 - Pipeline Geometry Model

The validation in Figure 4.5, shows a simulated pressure profile results acquired with compositional fluid tracking in the present study. This is then compared with the experimental base pressure data from a test loop facility, as shown in Figure 4.6. Appendix VI presents the raw experimental and simulated compositional tracking (CT) data for validation. The simulated pressure exhibited the same result with less than 2% slip mode effect of the fluid compositions on multiphase flow. This might be due to difference of in-situ densities of the settling liquid phase in the pipeline low spots. From expert analysis the errors obtained is negligible on the numerical results as the pressure trend cannot be 100% accurate but not more than 10 to 15% prediction error in the multiphase flow progarm. This demonstrates that both results are representative in the pressure trend profile in Figure 4.6. The ‘references marks’ are used to highlight both results, which converge at approximately 730psi (50.3bar), 715psi (49.2bar) and 700psi (48.2bar) pressure. The results acquired in this validation provide a predictive tool to tract fluid compositions changes at the well (Abili and Kara, 2013; Rydah, 2002; Shoup et al., 1998).

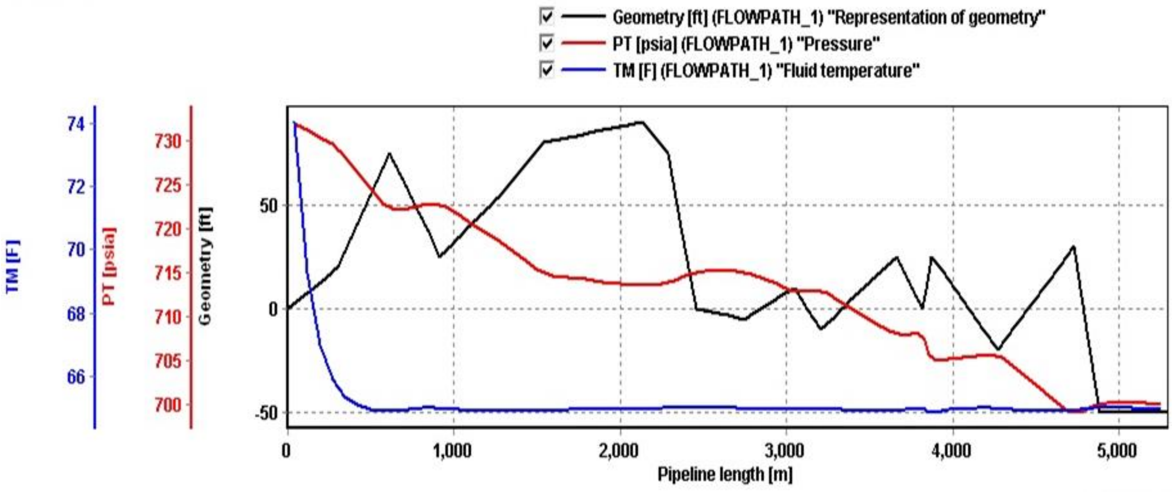

Figure 4-5- Simulated Pressure and Temperature Profile across Flow Path Geometry

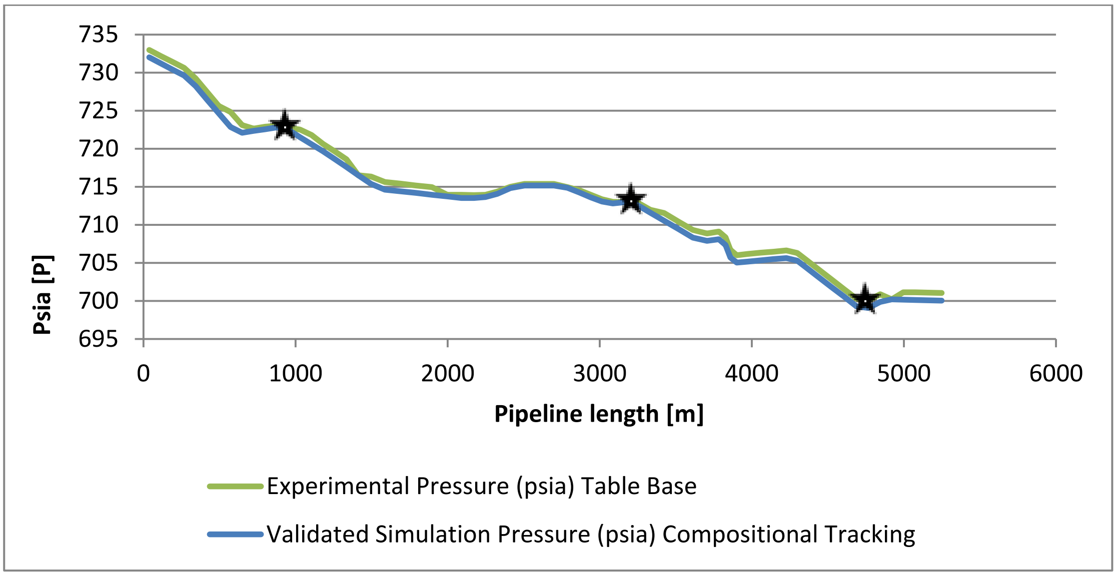

Figure 4-6- Simulated Pressure Profile (Comp Track) comparsion with Experimental Pressure Profile (Table Base)

Convergence tests on the simulated numerical pressure results at 5s, 10s and 20s time interval respectively over 6000m, are presented in Figure 4.7. One notable result from this test is the convergence of all pressure drops at 726.6psi (50bar) down to 725psi (49.9bar) over 20,000 seconds of the simulation. Hence, the simulations presented approximate numerical results at the same trend pressure taken at different time interval with less than 5% negligible convergence error.

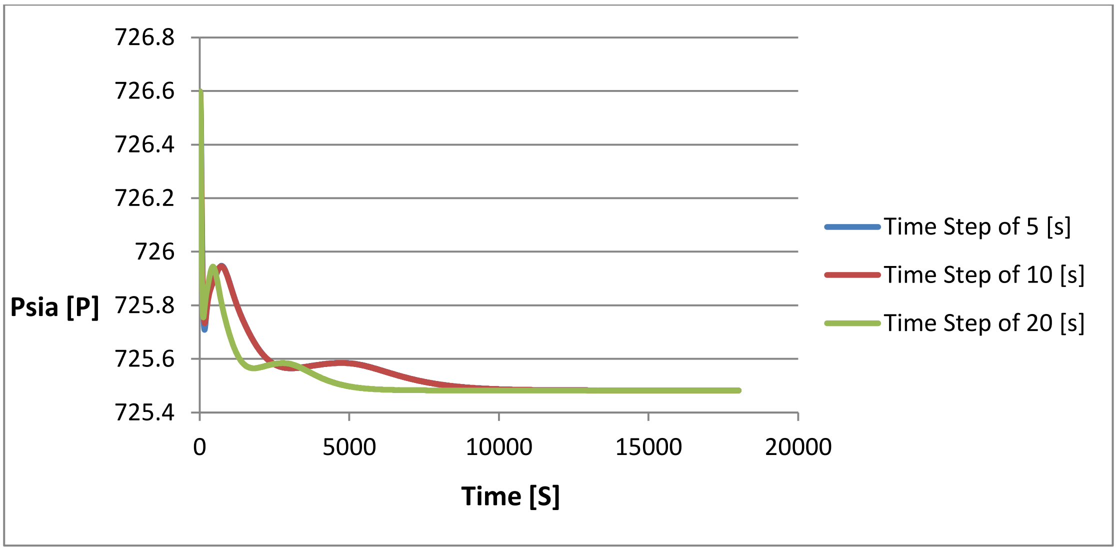

Figure 4-7 Simulated Covergence Pressure Result at 5, 10 and 20 Time Steps

The field case study demonstrates the capability of compositional fluid tracking on PVT and fluid component data to check the accuracy of subsea MPFM performance. In Figure 4.8 and 4.9, the molar compositions of C_3 components are tracked using trend and profile plots. The plot in Figure 4.8, show the difference of C_3 components between the trend and profile plot where the molar compositions at the wellhead were tracked over 7000 seconds. The C_3 component is representative of 8.3% which is equally the actual characterized input component in Table 4.2. The results for the flowline profile plot in Figure 4.9 show the predicted C_3 component values overestimate the measured values by 0.04%, with a significant drop along the flowline. The maximum deviation on the compositional tracking simulation is

1.6%. The C_3 components are more accurately simulated with compositional tracking at an error less than 0.5% from the well, which gives confidence in the tracking of each molar composition from the wellhead source. This is an indication of the accuracy of the compositional fluid tracking model to acquire representative fluid sampling data at the well. This presents a predictive tool to match the performance of subsea MPFM for accurate measurements at the wellhead in monitoring of the well fluid properties (Avansi and Schiozer, 2015).

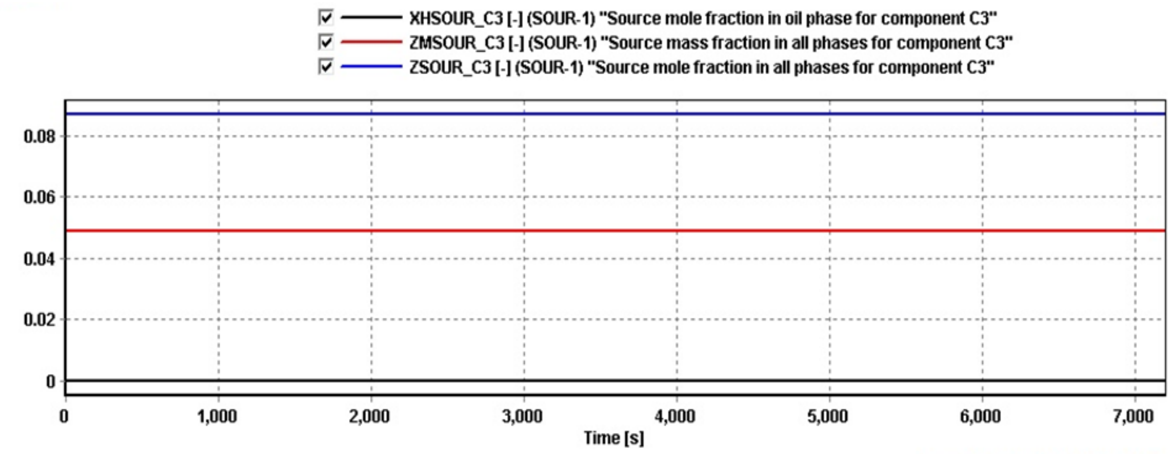

Figure 4-8 - Source Mole Fraction and Mass Fraction of C_3 Component Trend Plot

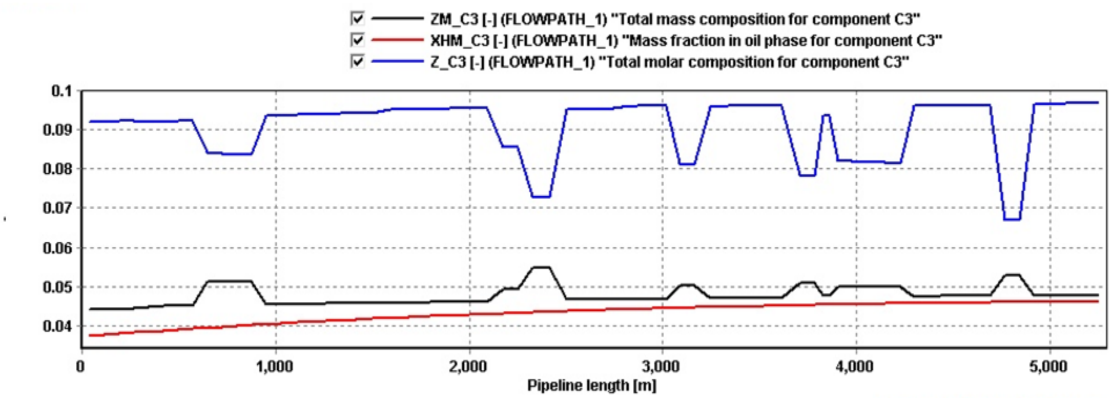

Figure 4-9 – Mass Fraction, Total Mass and Total Molar composition for C_3 Component

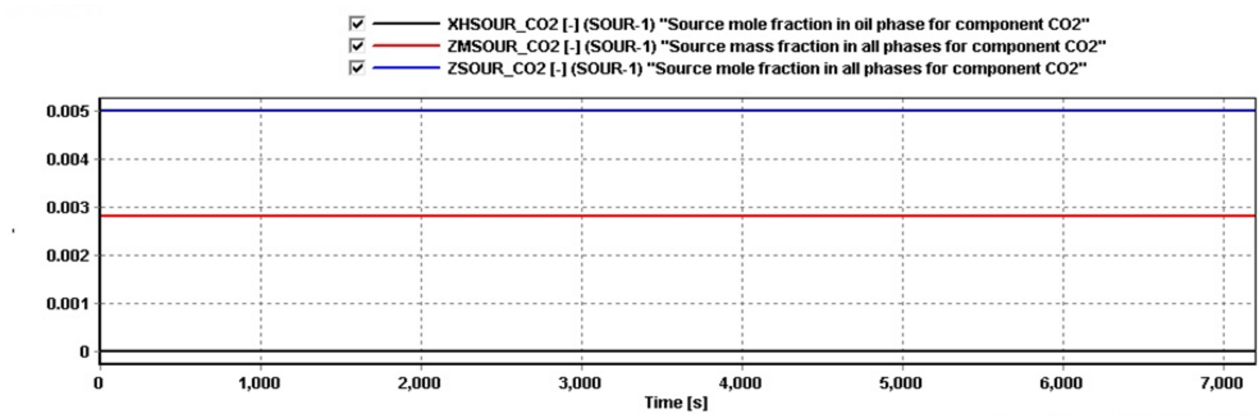

Figure 4-10 - Source Mole Fraction and Mass Fraction of CO_2 Component Trend Plot

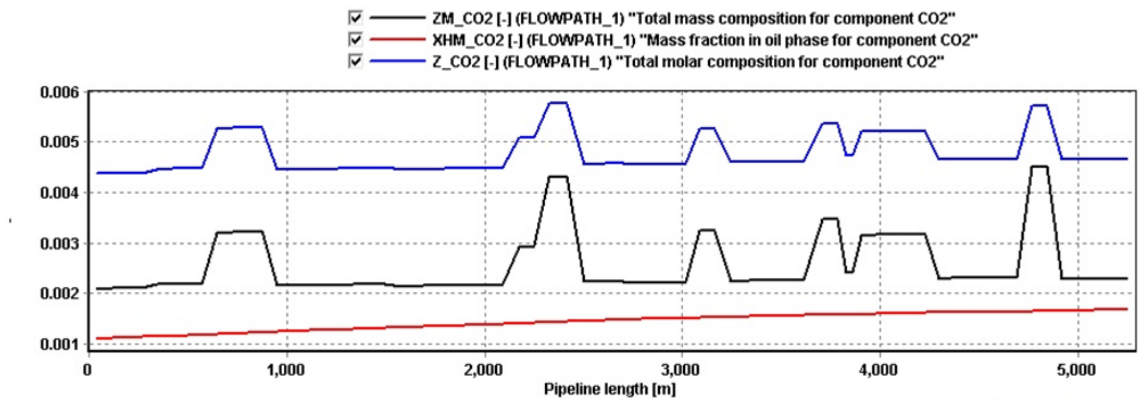

Figure 4-11 – Mass Fraction, Total Mass and Total Molar composition for CO_2 Component

In Figure 4.10 and 4.11, the predicted trends in the molar compositions of the CO_2 component at the wellhead and at the flowline profile are presented using the compositional fluid tracking model. The results show a similar trend to that for the C_3 component as described in Figure 4.8 and 4.9, but underestimate the measured values with insignificant increase in the CO_2 value along the flowline. These results establish that the transient compositional fluid tracking model, can accurately predict the fluid compositions at the well source and in production flowlines.

Therefore, even if the overall composition of the fluid changes as a function of time, the physical properties for a given phase and compositions at a given (P, T) point may remain fairly constant (Mantecon and Hollams, 2009). This demonstrates confidence that taking fluid samples at or close to the wellhead source will provide accurate representation of the fluid compositions.

4.6 Discussion on the Mechanistic Model

The mechanistic compositional fluid tracking model is used to predict well behaviour, validate the planned well test program and ensure representative fluid samples data are obtained. It is also used in real time monitoring during well testing operations (Juan et al, 2009; John et al., 2008). Obtaining representative reservoir fluid data is the main objective of any sampling operations and sometimes even the objective of drilling a well (exploratory and appraisal wells). Careful handling of this data allows for properly estimating reservoir properties that will define the technical viability of developing (or not developing) a field.

The mechanistic model is a proactive and cost effective approach to validate well samples and MPFM measurements without the need to conduct frequent and expensive intervention operations with significant OPEX reductions on field operations. Furthermore, this would go a long way to better manage chemical injections on the wellhead and part of the subsea systems on the seabed as a result of early detection of water break-through and also proactive monitoring of each wellhead flowrate, density and compositions. However, the mechanistic model is also applicable to a pre-test and post-test evaluation for field production operations as discussed in the preceding section.

4.6.1 **Pre -Test Evaluation**

The ability to predict well behaviour during initial fluid sampling test operations and being prepared to deal with potential operational conditions beyond instrument controls provides the opportunity to optimise production well testing/ sampling system design in order to reduce potential risk to operations, with variable cost saving worth millions of dollars on intervention, thus minimal impact to the subsea environment. The pre-test evaluation can proactively provide well test operations to validate test procedures to ensure planned well test on:

- Fluid sampling is done after the well is cleaned-up;
- Stable conditions of the well is attained before changes on choke size (flow after flow);
- An equilibrium condition of the reservoir profile pressure is attained at planned shut-in time;
- Analysis can be achieved as the well flow build up, where the phase segregate, redistribute, gas expands, and at flow reversal;
- Surface vs downhole shut-in can be compared and best economic option selected;
- The dynamic (versus time) fluid density of the simulator can see beyond the gauge location and reservoir to determine the actual gauge measurement– with no need to extrapolate data (Juan, 2007).

4.6.2 **Post -Test Evaluation**

The mechanistic compositional fluid tracking Model is the most useful tool to ensure accurate test data is collected accurately, and in most of the times is the “only” objective of well testing. This numerical tool is able to predict reservoir data input in cases where the simulation results cannot be analysed with actual data (as explained earlier in the field case study), however, the model can be validated by matching simulated data when actual data become available. This model could then serve as a virtual well simulator. Based on the actual data available, the model validation can be converted into (Juan et al, 2009):

- A compositional fluid sampling analysis model
- A real time subsurface gauge – with readily available surface data
- A real time subsurface gauge and multiphase flowmeter – with readily available surface and subsurface data

However, the mechanistic compositional fluid tracking model is able to calculate bottomhole flowing conditions given the surface wellhead temperature, wellhead pressure and flowrates measurements. To optimise reservoir management without the requirement for downhole gauges, the downhole flowing bottomhole pressure and bottomhole temperature can be used to compute from the readily available surface data (Juan, 2007; Juan et al, 2009). Thus, this can serve as a real time subsurface gauge and multiphase flowmeter. This enables further calculation of the subsurface flowing conditions including multiphase flowrates, liquid hold up, pressure and temperature parameters, with better fluid composition analysis for optimised well production and accurate reservoir management.

The mechanistic model development is a cost effective subsea fluid sampling approach to reduce the frequency of retrieving subsea sample. Thus, could reduce the cost of intervention operations and associated risk of exposure to the subsea environment. To achieve operational success with the model, an optimised novel sampling strategy applicable for deepwater field development on case by case bases is shown in Table 4.4. Though fluid sampling may not be required at the early life of the field however, sampling will be d as the fluid compositions changes over time to update the MPFM (Joshi and Joshi, 2007; API MPMS, Chapter 20.3: 2013; API RP 44, 2003). In as much as the MPFM requires prior information of the target fluid properties to be measured (oil, gas and water density, oil permittivity and water conductivity or salinity and mass attenuation), this information is crucial to update the MPFM on a regular basis. It is therefore recommended to carry out fluid sampling every 4 to 6 months as the field matures due to the MPFM deviation span measurement limitation, which does requires periodic adjustment of input data to match the well production fluid (Toskey and Hunt, 2015; Al-Kadem et al., 2014; Eivind, 2005).

However, the mechanistic compositional fluid tracking model would be useful for operators and regulatory authorities, in managing the challenges on fluid characteristics for accurate understanding of the reservoirs and impact on production facilities. This would provide the right opportunities for application of robust strategy with subsea processing technologies, such as subsea separators, booster pumps and operational control philosophy for EOR (Abili et al., 2013; Abili et al., 2012; Ageh et al., 2009).

Thus, with the integrated approach to subsea fluid sampling, a separate check on MPFM measurement is achievable. The validation provides accurate PVT and compositions of reservoir fluid properties at the wellhead or subsea tree. This enables representative fluid sampling that would accurately inform operational conditions of subsea production facilities, for proactive monitoring and cost efficient operations.

Table 4-4 - Innovative Fluid Sampling Strategy for Deepwater Field Developments

Parameters/ Periods	**High Pressure Well**		**Low Pressure Well**	
	Primary Testing/Sampling Method	Validation Method	Primary Testing/Sampling Method	Validation Method
Early Life	*MPFM/ Subsea Sampling*	*Numerical Compositional tracking Model*	*MPFM*	*Subsea Sampling/ Numerical Compositional tracking Model*
Early to Mid Life	*MPFM*	*Subsea Sampling/ Numerical Compositional tracking Model*	*MPFM*	*Subsea Sampling/ Numerical Compositional tracking Model*
Mid to Late Life	*MPFM*	*Subsea Sampling/ Numerical Compositional tracking Model*	*MPFM / Subsea Sampling*	*Numerical Compositional tracking Model*

4.7 Conclusions

The integrated approach to maximise value have been demonstrated with a deepwater field case study. The mechanistic compositional fluid tracking model uses the fluid properties that are equivalent to the flow stream being measured to predict reliable reservoir fluid characteristics. This is achieved through validation of simulated result data with experimental data, justify the accuracy of the mechanistic model measurement data acquired in Figure 4.6, and with further convergence to match experimental data to numerical simulated data in Figure 4.7 of section 4.5. This validation became necessary under conditions where significant variations in the reservoir fluid composition occur in transient production operations, which can affect the accuracy of

MPFM measurement in the SPS. The mechanistic model does bridges the gap in fluid sampling by providing a predictive tool to optimize individual well test proactively without expensive intervention sampling operations.

However, the mechanistic model utilise a transient multiphase flow program to simulate real life production flowstream, employing a compositional fluid tracking model to predict fluid compositions characteristics in section 4.4 and 4.5. The mechanistic model provides representative fluid sampling for the lifetime of the field, to check and adjust MPFM measurements, key in subsea reservoir performance management. Furthermore from the mechanistic model, the deepwater field case study in section 4.5 demonstrates that obtaining representative fluid samples will depend on the proximity to the wellhead source of fluid. Samples are preferably taken at the wellhead or at the subsea tree, after conditioning of the well. This provides the ability to capture fluid samples that are representative of the liquid and gas constituents passing through the MPFM during the sampling operations.

The research outcome also demonstrates that each well tested (with subsea MPFM integrated in the Xmas Tree) can be validated with a full set of fluid properties using the mechanistic compositional fluid tracking model in section 4.5. Depending on the tolerable metering error when compared with results from the compositional fluid tracking model, a proper calibration schedule should be incorporated at every 4 to 6 months for the subsea MPFM in Table 4.4 of section 4.6. As the oil and gas field asset becomes mature where reservoir pressure reaches almost stable values, time between calibrations can be extended without significant accuracy losses.

Therefore, the combination of subsea MPFM, subsea fluid sampling operations and the mechanistic compositional fluid tracking model provides a balanced approach to reservoir performance monitoring. This integrated approach provides an accurate method for testing individual production well. However, the failure to obtain representative samples could have considerable impact on the OPEX for subsea production facilities. The mechanistic compositional fluid tracking model could mitigate the risk of obtaining unrepresentative samples from measurement instruments in the life of field. Thus, the offshore industry will benefit significantly as the integrated fluid sampling approach would reduce considerably the cost of intervention on sampling operations and accurately monitor each subsea production well for fiscal allocations.

5 SYNERGY OF FLUID SAMPLING AND SUBSEA PROCESSING, KEY TO MAXIMISING OFFSHORE ASSET RECOVERY

Abili et al., School of Energy, Cranfield University, Bedfordshire UK (to be submitted and published in SPE oil and gas facility journal)

Abstracts

The acquisition of accurate fluid samples for deepwater development is crucial for the correct evaluation of oil reserves. This would enable design optimisation of subsea production and processing facilities in order to maximize asset value. A mechanistic model is employed, using the fluid properties that are equivalent to the flow stream being measured, to predict reliable reservoir fluid characteristics on the production flow stream. This is applicable even under conditions where significant variations in the reservoir fluid composition occur in transient production operations. The benefit of the mechanistic model is that it adds value in the decision to employ subsea processing in managing water breakthrough as the field matures. This can be achieved through efficient processing of the fluid with separation and boosting delivered to the topside facilities or for water re-injection to the reservoir. The failure to obtain representative samples could have considerable impact on the Operational Expenditure (OPEX) and consequently the asset value to sustain or enhance production volume for financial returns over the life of the field.

The present paper explores the synergy in successful application of subsea fluid sampling and subsea processing to maximize asset value on deepwater development.

Keywords: Synergy, MPFM, Mechanistic model, Subsea Processing, OPEX, ROV

Acronym List	
CAPEX	Capital Expenditure
EOR	Enhance Oil Recovery
FPSO	Floating Production Storage and Offloading Vessel
GOR	Gas Oil Ratio
IOR	Increased Oil Recovery
MEG	Mono Ethylene glycol
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditures
PVT	Pressure Volume Temperature
R&D	Research and Development
ROI	Return on Investment
SMPFM	Subsea Multiphase Flow Meter
SPT	Subsea Production Technology
SPS	Subsea Production System

5.1 Introduction

The increasing world energy demands for oil and gas has driven offshore operators to explore viable solutions to maximize recoverable volume on deep offshore assets with innovative technologies. Industrial forecast from subsea processing game changer report shows that expenditure on subsea processing systems is expected to exceed US$3.4 billion, with deepwater expenditures expected to increase by 130% to $260 billion by 2018 (Douglas-Westwood, 2014). A contributing factor driving this expenditure high is the demands to deploy over one thousand additional subsea multiphase flowmeters (SMPFM). This critical component is used to provide well diagnostics to measure individual phases (oil, gas, water) without the need for complex conventional well testing operations.

Responding to the increase in subsea tree orders for Greenfield developments, manufacturers are now developing more SMPFM products to meet well diagnostic demands. In addition, the industry is very optimistic on marginal fields development prospects (on average 200 to 300 million bbl. each), and growth in viable Brownfields. It is estimated that over 70% of the world's oil and gas production comes from Brownfields of over 30 years, hence a trend for application of enhanced oil recovery (EOR) technologies such as subsea processing to meet global demands (OECD/IEA, 2012; OECD/IEA, 2002). However, due to results on current development trend, there is increased pressure on deep offshore operators to manage capital expenditures (CAPEX) and operational expenditures (OPEX), increase efficiencies, guarantee flow assurance and increased production.

The current growth trends on deep and ultra-deepwater development demonstrate a greater need for ultimate recovery with increased hydrocarbon output while improving the asset's net present value (Infield, 2013). The new application of subsea fluid sampling (employing mechanistic model), and subsea processing would enabled remote long-distance assets (even with low reservoir pressure) to be developed economically (Abili et al., 2013; Sbordone et al., 2012; Jijun et al., 2013). Furthermore, the synergy of subsea fluid sampling and subsea processing have evolved into a solution for transforming potential oil and gas reserves below the seabed into economic return of investment (ROI) in the deep offshore industry.

Therefore, with the acquisition of accurate fluid samples, the potential value of subsea processing can be realized on increased production volume. The aim of this paper is to explore the mechanistic model in order to integrate the application of the numerical results in a range or series of case studies. The objectives is to carry out sensitivity analysis on the mechanistic model to illustrate its applicability range to support subsea processing, in highlighting potential benefits to deepwater development projects.

5.2 Development Scenario of Subsea Fluid Sampling

In the deep offshore industry, several large oil and gas fields are being developed with metering systems such as multiphase meters and wet-gas meters. These instruments provides essential data for optimizing production, measuring oil, gas, water fractions and flowrates (API MPMS, 2013; Jasco, 2012; Jernsletten; Neol, 2001; and Scheers, 2009).

However, the development of modern electronic flow metering does not mean that wells can be conditioned any more quickly or that gas and liquid flowrate data will automatically become more representative of reservoir fluid. Thus, recent research and development (R&D) championed by major operators and original equipment manufacturers (OEM) in the offshore industry, have been focused on improving the performance of the metering systems with subsea fluid sampling (Eric, 2012; Hall and Gordon, 2011; Letton and Webb, 2012; Pinguet et al., 2012).

This has created opportunities to improve understanding of the well flow stream for reservoir monitoring, using available Mechanistic (transient multiphase flow) model and redundant metering sensors (Jasco, 2012; Pinguet et al., 2012; Sbordone et al. 2012). Therefore, obtaining accurate fluid samples for PVT, flowrates measurements and compositional analysis is vital to understanding the reservoir characteristics. This would enable the design optimization and advancement of subsea facilities (Eric, 2012; Letton and Webb, 2012).

5.3 Description of Deepwater Field Parameters

The deepwater field is located in Offshore West Africa, at a water depth of between 1100m (3609ft) and 1200m (3937ft), seabed temperature of about 5°C. The well is modelled using a vertical profile, its 2000m below seabed and a distance of 6m from the wellhead. The length of the flowline from the well to the floating production and storage facility is 9km. The Flowline profile is uneven with areas of inclination and declination because of the seabed topography, hence slugging is expected. It’s a high pressure field with pressure in excess of 340bar and temperature of 93°C. Production is through water injection, 18km tie-back to an FPSO with 4 production drill centers (17 Production wells) and 3 water injection drill centers (15 water injection wells) as shown in Figure 5.1 (Ageh et al., 2010; Sathyamoorthy et al., 2009; Udofia et al., 2012).

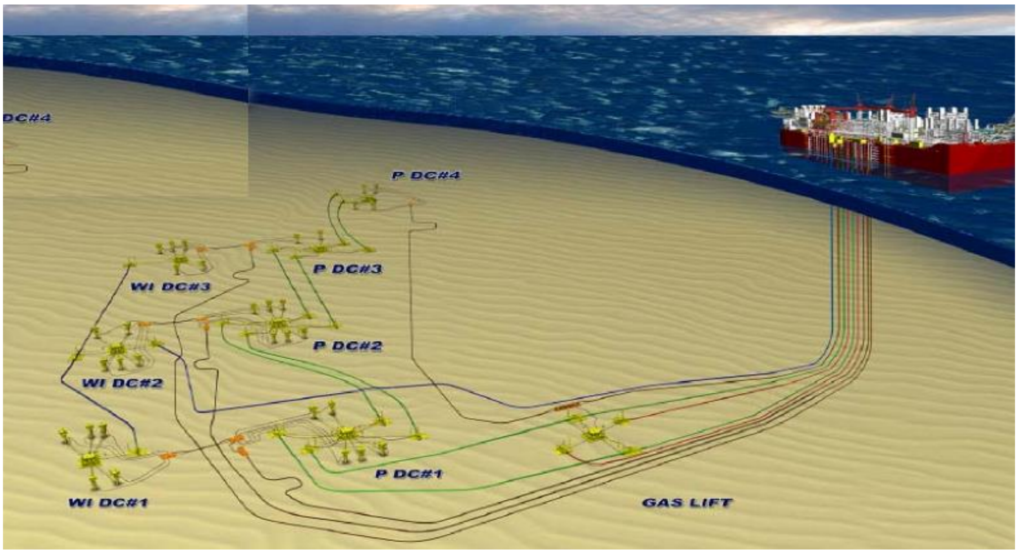

Figure 5-1 Subsea Architecture for Deepwater Field Development (Ageh et al., 2010)

The reservoir fluid properties for the deepwater field are demonstrated in a phase diagram. A phase diagram is a "plot that shows the equilibrium temperature-pressure relationships for different phases of a multicomponent mixture" (Schindler, 2007). The phase diagram in Figure 5.2 is a useful tool to assess the behaviour of the fluid properties as they move from the reservoir to the well as shown in the phase envelope lines. It is important to understand the fluid behaviour path or fluid properties, in relations to pressure and temperature, in order to attain high accuracy of flowrate measurement (Pinguet et al., 2012; Foster et al., 2006; Schindler, 2007). Immediately past the critical point, the fluid start going into phases at a pressure of 175bar and 463^{o}C with the different fluid path, due to presence of water breakthrough or presence of liquid vapour (condensate) at the wellhead down the flowline. This is also evident with decline in production rate for the same pressure drops.

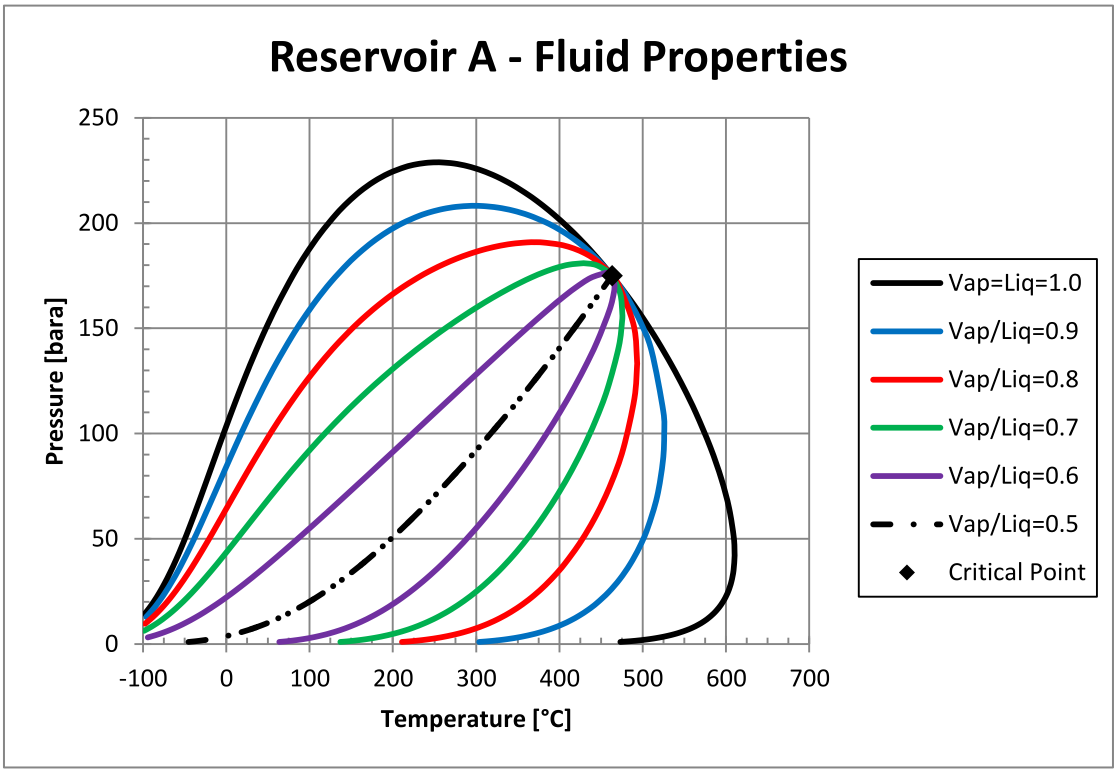

Figure 5-2 Phase Envelop of Reservoir A – Fluid Properties (Source: Deepwater Field Case Study)

Figure 5.3 presents Well 1 production rate for the life of field. The first oil schedule for 2017, reach a production rate of about 5stb/d with initial pressure of 4,000 psia, before shut-in of the well pressure. The profile trend for other productions forecast year of 2020, 2024, 2029 and 2036 shows an early decline of pressure with resulting drop in production rate to less than 1stb/d. They all started with well pressure above 4,000 psia but experience a sharp drop of pressure in the respective years. The production well then becomes a potential candidate for enhance oil recovery with aid of the mechanistic (transient multiphase flow) model to determine the level of separation and boosting systems to increase the well pressure in order to maximise the productivity rates. Further case studies in the present paper demonstrate benefits of employing subsea separation and boosting to enhance the production rates of the well for increased oil recovery.

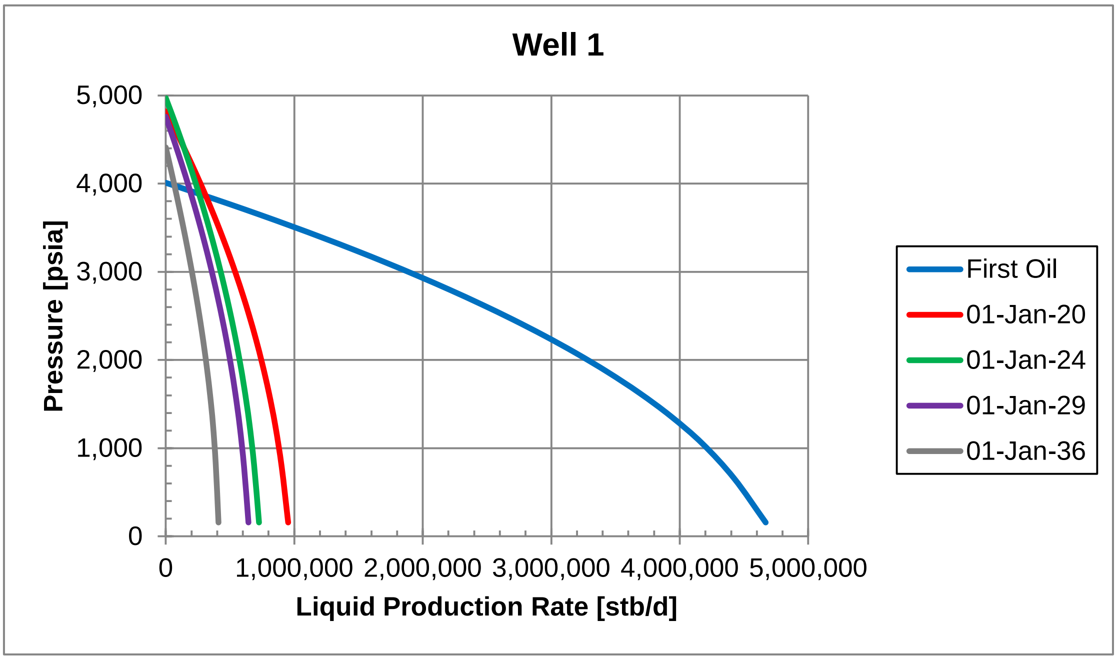

Figure 5-3 Well 1 Oil Production Rate Profile (Sources: Deepwater Field Case Study)

5.4 Deepwater Field Case Studies

Employing the mechanistic model, a series of case studies is conducted in section 5.4.1 – 5.4.5, to demonstrate the range of applications of subsea fluid sampling to maximise well production with subsea processing, taking into consideration the change in density, temperature and pressure in the subsea production system (SPS).

5.4.1 **Analysis of Field Case A – Without Separation**

The mechanistic model employed for the deepwater field case study 1 and 2 are described in Figure 5.4 and 5.5 respectively, which are deviated well with depth of over 1800 meters below seabed, at a temperature of 90°C and pressure of over 200bar, the well tubing was modelled using steel and formation which is rock in essence. The well tubing has a nominal diameter of 5.5 inches and wall thickness of 0.304 inch. The heat transfer coefficient is taken to be 12.5W/m2°C (Ageh et al., 2010; Sathyamoorthy et al., 2009). The wellhead is taken as an open node, the dimension of which is computed in the cause of running a simulation. The pipeline is modelled using 12.75 inch API 5L grade X52 line pipe with a thickness of 0.5 inch, that is insulated with two layers of insulation (5mm poly propylene and 20mm poly ethylene foam), the pipeline is neither buried or trenched on the seabed (Dhulesia and Lopez, 1996; Manabe et al., 1997; Henriot et al., 1999; Irfansyah et al., 2005; Carimalo et al., 2008). Total pipeline length from wellhead to riser base is in excess of 18km.

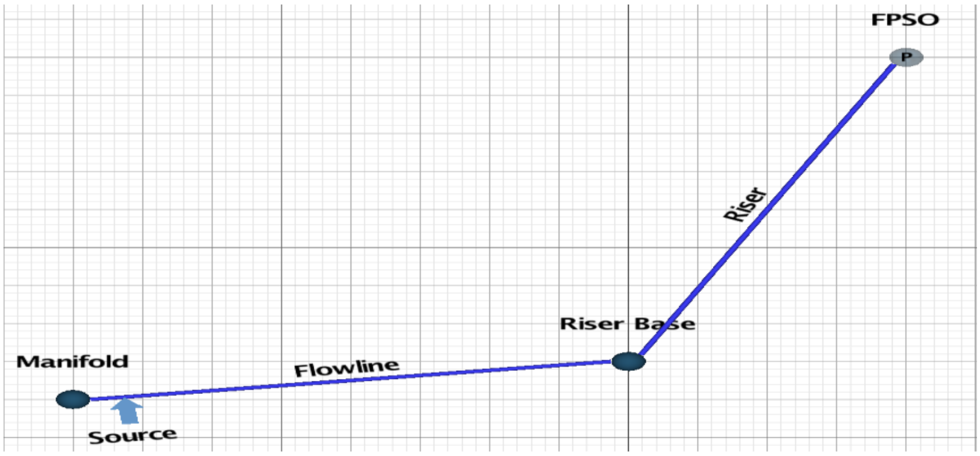

Figure 5-4 Deepwater Case Study 1 – without water production

The well was simulated using a pressure node, so there is no need to input flowrate of fluid. The output that is the riser base is also simulated using a pressure node with the arrival temperature and pressure defined. The mechanistic model using a transient multiphase simulator, modelled the flow from the well to the riser base thereby computing the flowrate, and types of production fluid (Dhulesia and Lopez, 1996; Irfansyah et al., 2005). Case 1 was simulated without water from the well and for a period of 12 hours for each varying criteria, while case 2 was simulated with water from the well over the same period.

Figure 5-5 Deepwater Case study 2 – with water production

5.4.2 **Analysis of Field Case B – With Separation**

The mechanistic model employed for case 3 and 4 for the deepwater field is described in Figure 5.6 and 5.7 respectively. The reservoir characteristics and flowline are similar to the case described for 1 and 2. However, these cases incorporate a separator along the flowline very close to the manifold, with two riser base for gas and liquid to the FPSO. Case 3 was simulated without water from the well and for a period of 18 hours for each varying criteria, while case 4 was simulated with water from the well over the same period.

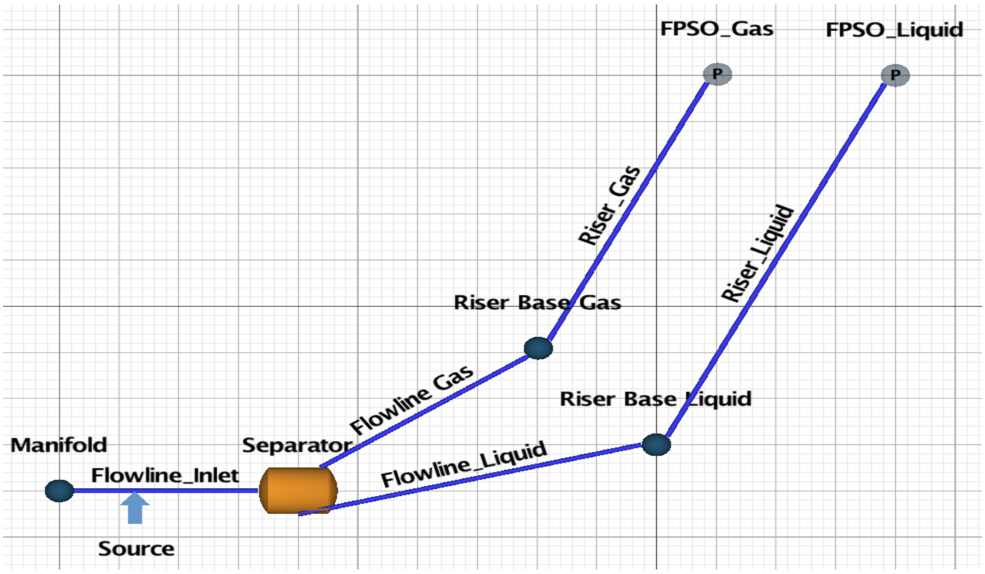

Figure 5-6 Deepwater Case Study 3 – separation without water production

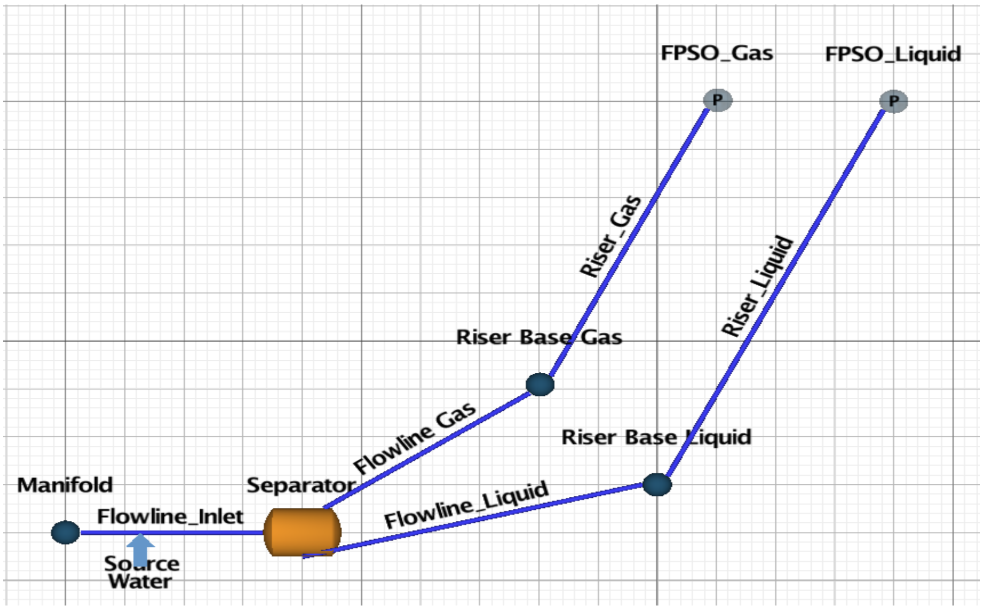

Figure 5-7 Deepwater Case Study 4 – separation with water production

5.4.3 **Comparison of Case A and B Results**

The pressure profiles in Figure 5.8 shows two scenarios of separation with and without water from the well. The separation without water (red line) increase in pressure from the well by 146bar along the liquid flowline to 81bar at 18km of the flowline end termination. But with the presence of water (green line) there is an increase of 4bar along the flowline to 85bar at the flowline termination. This increase in pressure is as a result of the increase in density (more liquid breakthrough before the critical point), but drop in density with no liquid breakthrough equally result to drop in pressure (Mantecon and Hollams, 2009; McMordie et al., 1982). Same analysis applies to the riser flowline as there is an increase in pressure by 5bar (Blue line) from the 80bar (black line) initial pressure of the well. This actually affect the production flowrate as increase in density of liquid (water) could slow down the production or causes hydrate blockage along the flowlines and risers, as the temperature drops. The water can also be detected from the increase in temperature of the liquid and gas, which show the presence of water with significant increase in the density of gas and liquid volume. Such presence of water could be detected on time with periodic physical fluid sampling (or mechanistic modelling) of the well production to mitigate loss of production flowrates with chemical (methanol etc.), injection strategies (Mantecon and Hollams, 2009; McMordie et al., 1982; Sbordone et al., 2012; Abili and Kara 2015).

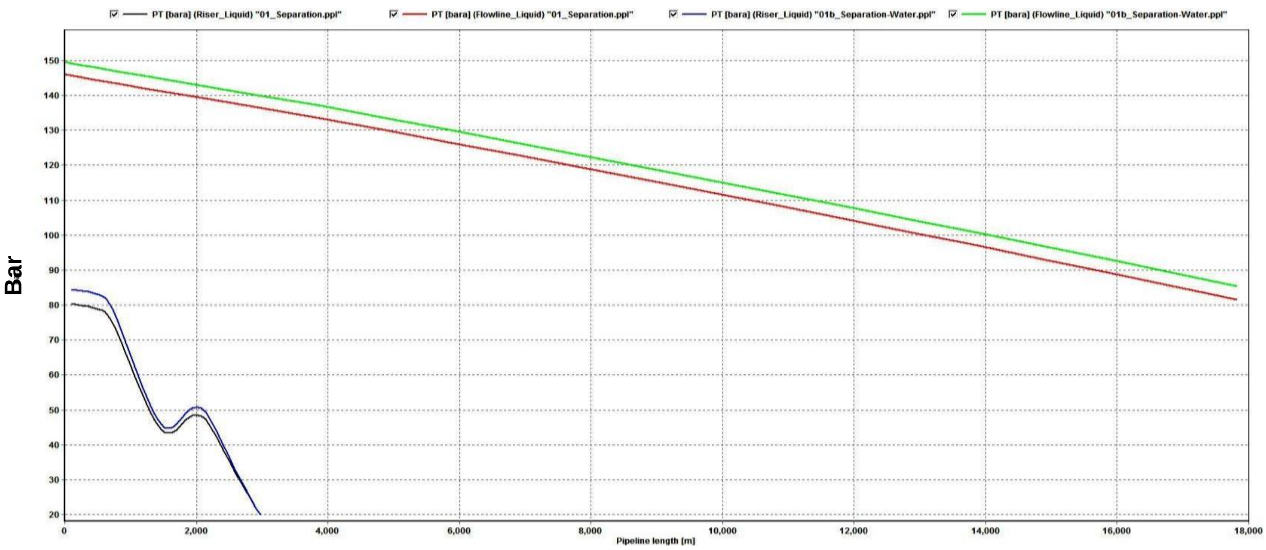

Figure 5-8 Comparison of Pressure Profiles – with and without water in liquid Stream

The field case studies in Figure 5.9 to 5.12 provide a comparison for the four different cases developed with and without water breakthrough and separations. Figure 5.9 and 5.10 is a replica of Figure 5.11 and 5.12 which exhibit similar characteristic in pressure increase as a result of increase in density of water. There is a pressure increase of 5bar from 145bar to 150bar with the presence of water and separation in Figure 5.9. But the flowline inlet density of water remains stable. Figure 5.10 shows similar trend of 5bar increase from 80bar to 85bar but with a drop in pressure along the riser as a result of drop in liquid density and temperature at the receiving outlet. The pressure and temperature will increase if the GOR decreases (less gas, more hydrocarbon liquid). However, the constant drop in pressure and temperature is another evidence to show that no water breakthrough or increase is present. If we have water, the pressure and temperature would either remain stable or increase (McMordie et al., 1982; Mantecon and Hollams, 2009; Abili and Kara, 2015).

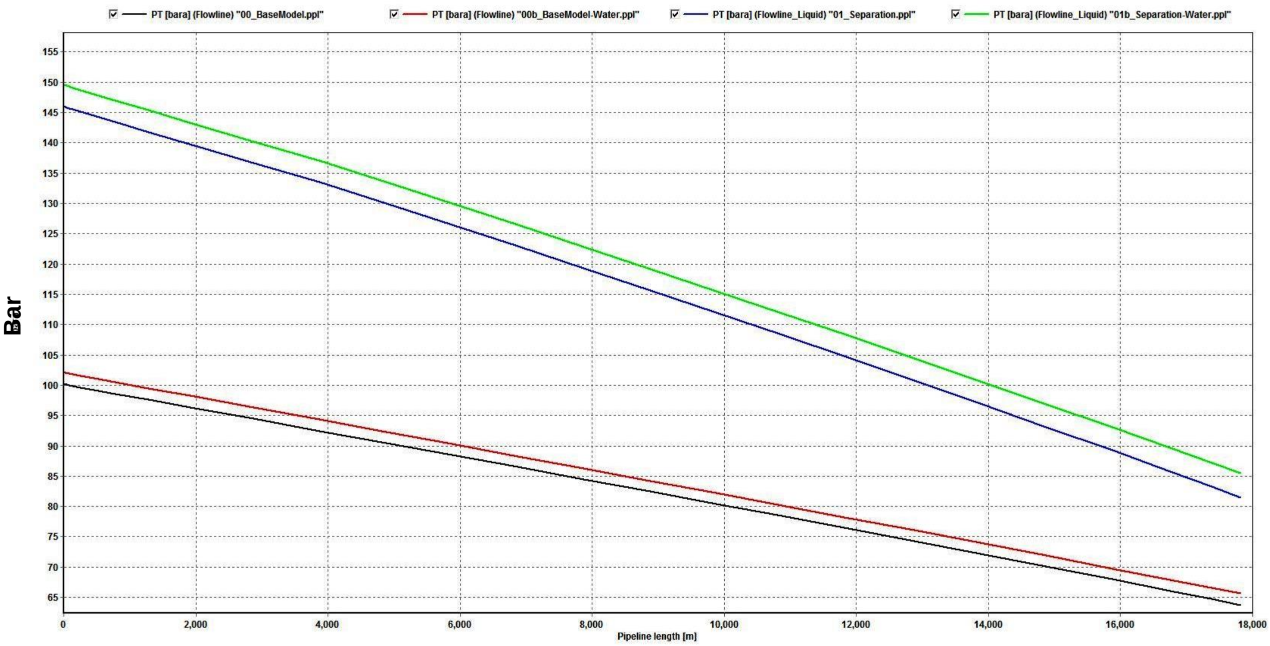

Figure 5-9 Comparison of Pressure Profiles in Flowline – 4 Cases

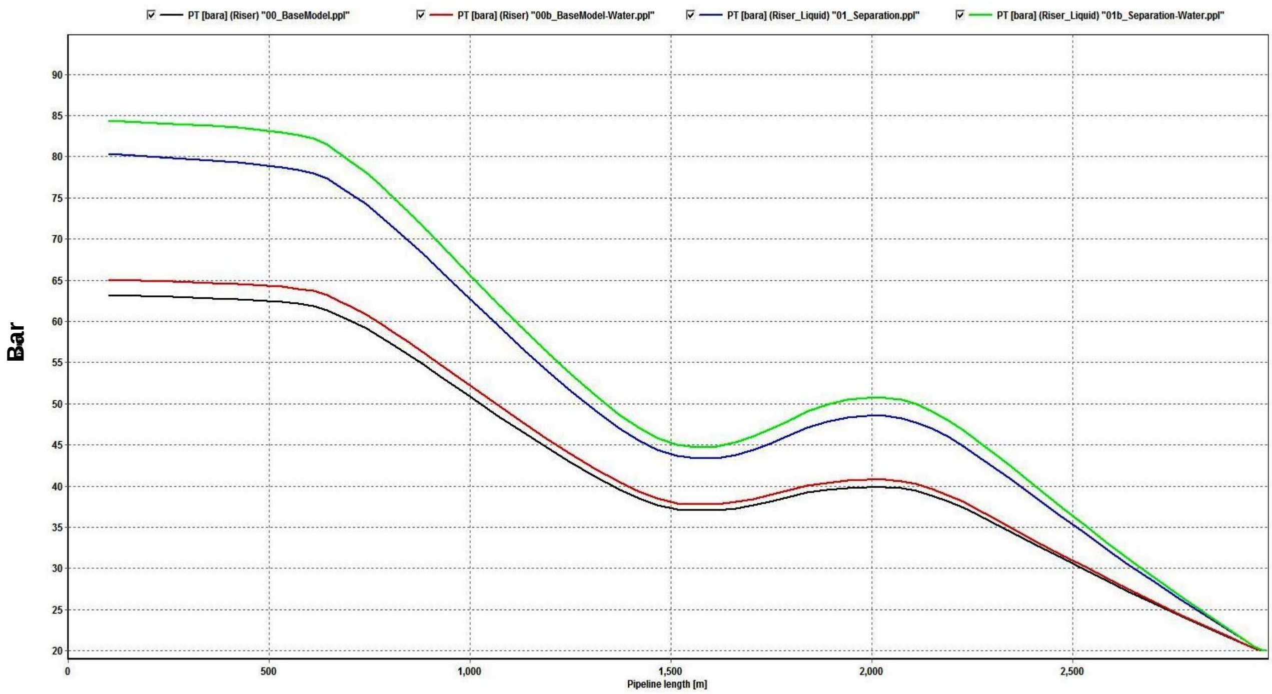

Figure 5-10 Comparison of Pressure Profiles in Risers – 4 Cases

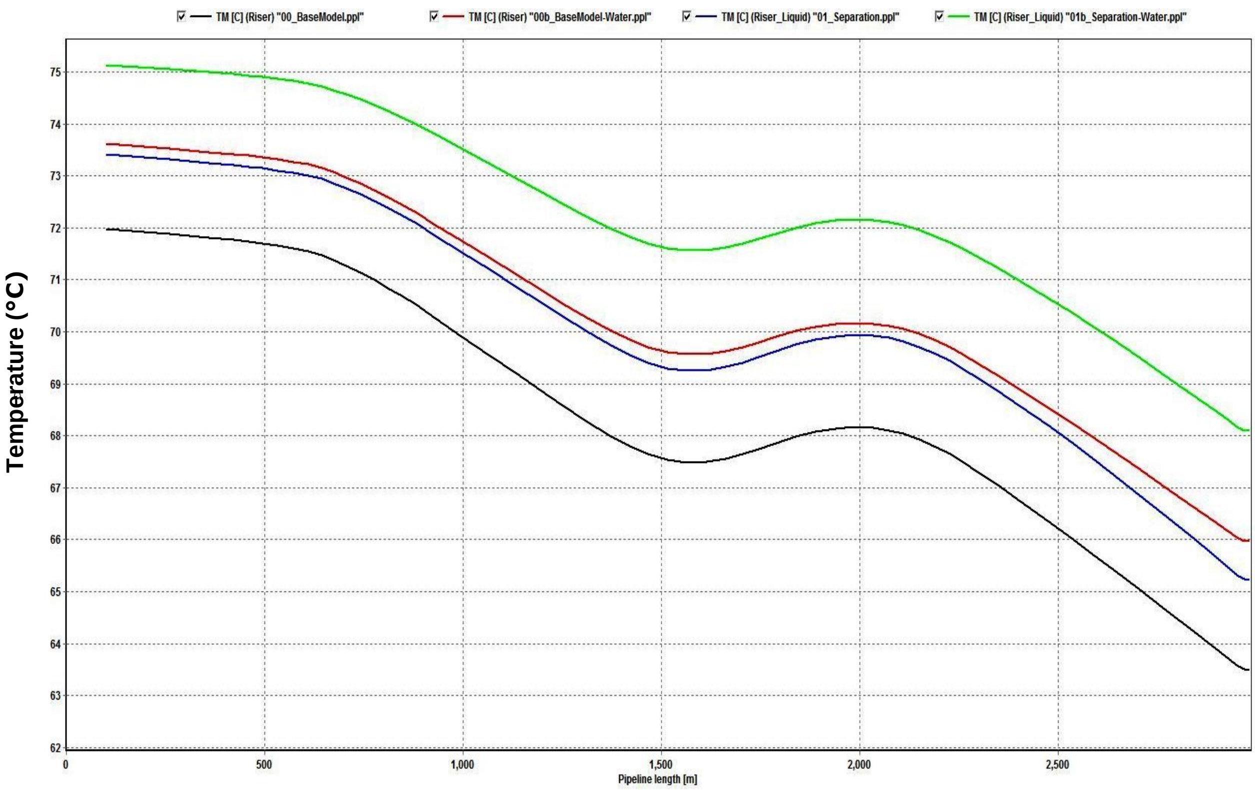

Figure 5-11 Comparison of Temperature Profiles in Risers – 4 Cases

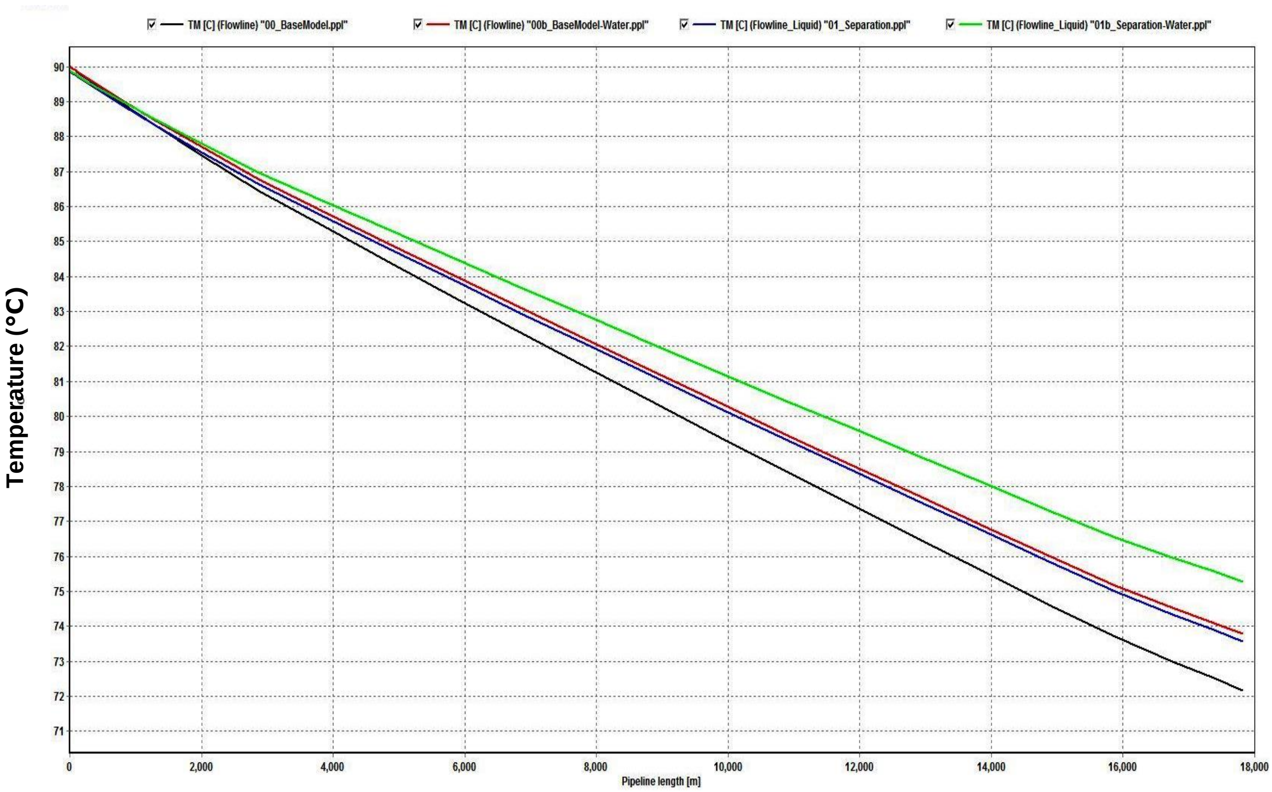

Figure 5-12 Comparison of Temperature Profiles in Flowline – 4 Cases

Examining Figure 5.11, we notice a stable temperature drop along the risers, with the water separation case (green line) at 76°C from the inlet of the riser. The other case in Figure 5.12 also exhibit steady temperature drop along the riser as the GOR is constant with the production. However, in Figure 5.12, there is a drop in the temperature from 90°C along the flowline for all cases with 1.5°C at the flowline end termination for the water separation case. Typically the gas volume decreases in temperature drop with increase in pressure. But when water is present, the temperature increase and the pressure begin to drop along the flowline. This can cause hydrate formation as the gas temperature begin to increase and the pressure drops, forming crystal of hydrate plugs. To mitigate this scenario, methanol injection becomes imperative for such deepwater project, which requires better definition of the dosage for lower CAPEX and OPEX, but it should be kept in mind that methanol contaminates hydrocarbon product and cannot be recovered like monoethylene glycol (MEG) (Pinguet et al., 2014; McMordie et al., 1982; Mantecon and Hollams, 2009). This contamination of hydrocarbon product impact on the OPEX as there would be a need for storage and separate treatment facility. Thus, the acquisition of accurate fluid sampling data with the mechanistic model, a greater percentage of the OPEX could be saved in planning the right injection strategy with methanol.

Furthermore, the presence of water in a gas system induces a risk of hydrate formation since the temperature drop along the system will mainly be driven by the gas expansion, hence the system will cool-down and the increase in pressure due to the presence of water facilitates the flow conditions (P,T) entering the hydrate region. Also the results in Figure 5.12 as depicted in case model of Figure 5.7, demonstrates that an increase in water density is higher in the gas volume than the liquid volume. This is due to the gas flowrate in transient flow of high pressure than liquid flowrate in the flowline. As the water travel along the flowline, the density increases marginally for gas flowline than liquid flowline (McMordie et al., 1982; Mantecon and Hollams, 2009). However, the pressure and temperature conditions along the system have great effects on the density of gas and hydrocarbon liquid, hence the overall 3 phase fluid density.

In summary, water breakthrough in a gas well would increase the back pressure of the well and the well would start backing out. In such scenario, separation becomes imperative at some point during the life of field for reservoir pressure maintenance. For oil production, injection of water is preferred for boosting of reservoir pressure. Having gas will help production to lower the density and hence the back pressure of the well. Therefore, the separation and booting would decrease the back pressure of the well, hence allow for higher production of the well (Baker and Entress, 1991; Davies et al., 2010; Euhemio et al., 2009; Grynning et al., 2009; Ribeiro et al., 2005). Maintaining a low back pressure of the well, allow production for a longer period of time, resulting to increase in asset recovery. However, it is important to note from the outcome of this study using the mechanistic model, that the mass conservation (total mass) across the production system would remain the same (mass balance) fundamentally, but the volume will defer because of phase change due to sensitivity of the temperature and pressure.

5.4.4 **Analysis of Field A, Case 1 (Base Case)**

The mechanistic model simulation for case 1 of field A is described in Figure 5.13. The reservoir characteristics, flow line and pipeline are similar to the case 1 and 2 described in 5.4.1.

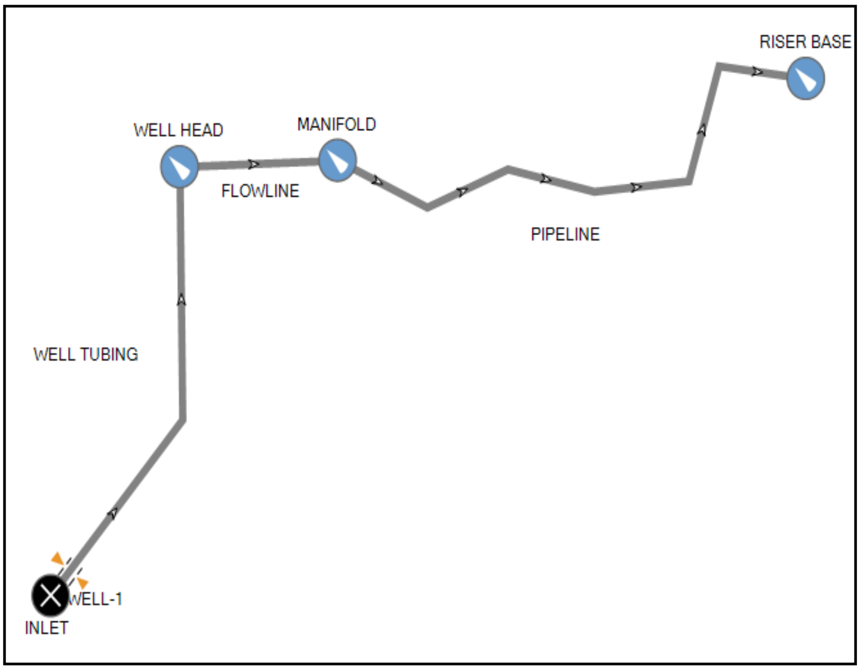

Figure 5-13 Mechanistic Model Representation of Field A, Case 1 (Base Case)

The water cut increase from an initial rate of 0% to 86% at varying years, with varying Production index as shown in Table 5.1. The well positive flow equation is modelled using a linear equation. At the reservoir level, we assume the fluid to be in a single phase. The Table 5.1 shows the additional water cut and production index used for this simulation. Each simulation was modelled for a 12 hour period, to allow for system stability and for accurate prediction.

Table 5-1 Water Cut and Production Index for Selected year over 8 years

year	1	3	6	8
water cut	0	47	79	86
production Index	16.8	7.3	10.3	13.3

A brief description of the graph legends obtained from the simulation is shown below.

- The black line on the graph represents the 1st year of simulation that is water cut =0% and PI= 16.8[-]
- The red line on the graph represents the 3rd year of simulation that is water cut =47% and PI =7.3[-]
- The Blue line on the graph represents the 6th year of simulation that is water cut =79 and PI =10.3[-]
- The Green line on the graph represents the 8th year of simulation that is water cut =86% and PI =13.3[-].

Results

The Figure 5.14 shows the system flowrate over an 8 year period without any form of subsea processing. The 1st year of simulation in Figure 5.14, shown by the black plot on the graph has a very high flowrate of about 4570[m^3/d]. This is as a result of high pressure in the reservoir, high PI and low water cut. The 3rd year of simulation is shown by the red plot on the graph, there is a rapid drop in flowrate of the system to about 2445[m^3/d] as a result of the increase in water cut of the reservoir and fall in production index (PI). The 6th year shown by the blue plot on simulation shows an increase in flowrate of the system to about 2520[m^3/d]. This is as a result of increase in PI despite a higher water cut compared to 3rd year of simulation. The 8th year of simulation shows a decrease in flowrate to about 2245[m^3/d]. This is as a result of increase in PI despite a high water cut and slugging on the system compared to 3rd year of simulation. Therefore, approximately 50% percentage drop in production flowrate is observed from the 1st year to the 8th year with the application of subsea processing.

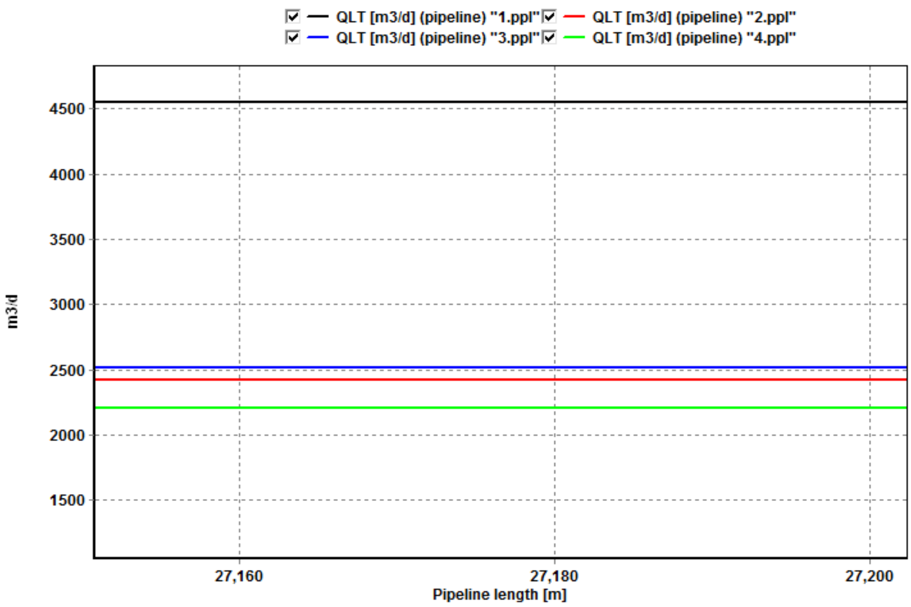

Figure 5-14 Profile Plot of Flowrate against Pipeline for Field A, Case 1

However, the profile plot in Figure 5.15, year 1 and 3 pressure variations showed that slugging was not predominant in the system (a plot of flow regime in the internal diameter not shown here of the pipeline shows that flow at some regions of the pipeline are in the slugging region). It was more or less existent. Plots of pressure from year 1 to 3 showed a decrease in pressure. Increasing the water content of Case 1 led to an increase in slugging frequency within the pipeline, high pressure variations and changes in flow rate. Sensitivity analysis was carried out by varying both the production index and water cut. Results from the analysis showed that slugging developed at production index (PI) of around 79[-] and low water cut above 55[%] for case 1.

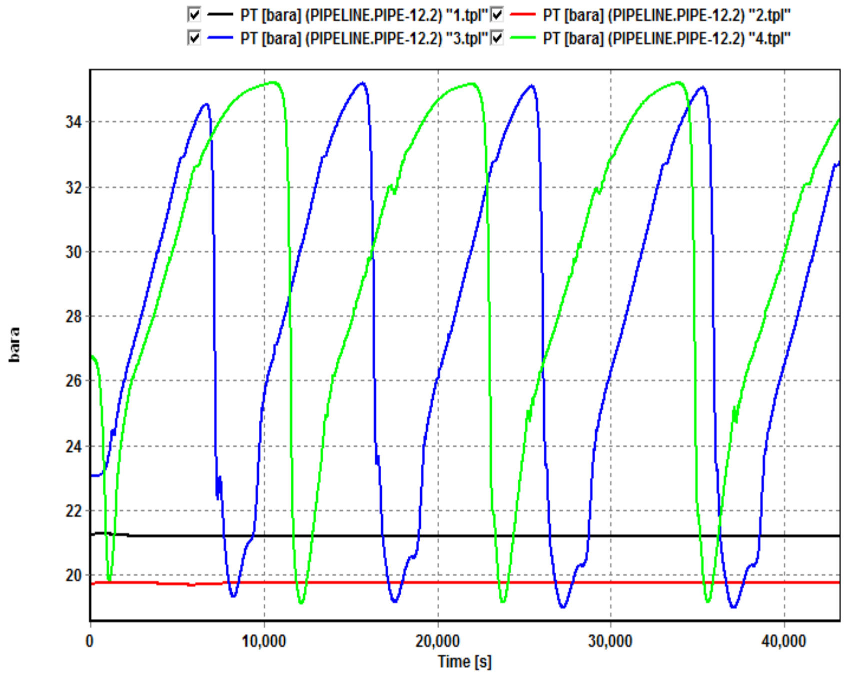

Figure 5-15 Profile Plot of Pressure Variation over Time for Field A, Case 1

Continuous increase in water cut and reduction in production index at year 8, the slug regime leads to back pressure or negative pressure of up to16bars in the pipeline. This leads to an uneven flowrate on the system with a reduction in production and system instabilities and flow assurance issues as shown in Figure 5.15.

Clearly from the mechanistic model simulated, the slugging and production flowrate analysis of the Well in Field A, might prove technical not feasible as well as uneconomical to produce or continue production especial from the 6th year where there is a need to boost production as well as severe slugging on the system. Consequently, from the mechanistic model (transient multiphase flow) employed in the prediction of the well and reservoir production behaviour, the field can’t be exploited effectively and efficiently without some application of subsea processing (separation).

5.4.5 **Analysis of Field A, Case 2 (Boosting)**

The mechanistic model for Case 2 of Field A is described in Figure 5.16 as shown below.

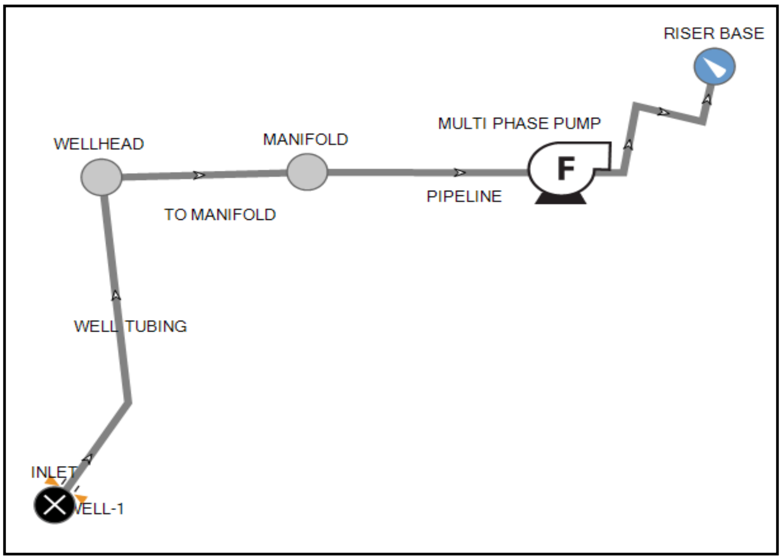

Figure 5-16 Mechanistic Model Representation for Field A, Case 2

Model description

The reservoir characteristics, flow line and pipeline are similar to the case described for the base case in case 1. This model incorporates a multiphase pump along the pipeline very close to the manifold to boost the well pressure after the first year of production as required from the production rate profile in Figure 5.16. The pump characteristic is modelled using the FRAMO-Hx360-1800-38 with a discharge coefficient of 0.84 and pump characteristics already defined. This provision is captured during the early phase conceptual design to accommodate optimisation of the well production for enhances oil recovery.

Results

The 1st year of simulation as shown in Figure 5.17, is a system with a fairly high flowrate of about 4060[m^3/d] close to the riser base of the pipeline explained by the low water cut and high production index from the reservoir. By the 3rd year, there is a steep fall in production rate. The production rate or flowrate falls to about 2300[m^3/d] this can be explained by the rapid increase in water cut of the system from 0% - 47%, drop in PI from 16.8[-] to 7.3[-] and inception of slugs. The 6th year shows a slight increase in flowrate to about 2500 [m^3/d]. This is explained by the increase in PI over the previous year.

The 8th year of simulation shown by the green plot shows an increase of flowrate to about 2700 [m^3/d] as a result of high PI index of about 86%. This is the second highest flowrate on the graph, and this is explained by the application of the multiphase pump and reduction in slugging on the system. Thus, a production index increase of 17% gain is achieved with the application of subsea processing in field A from case 2.

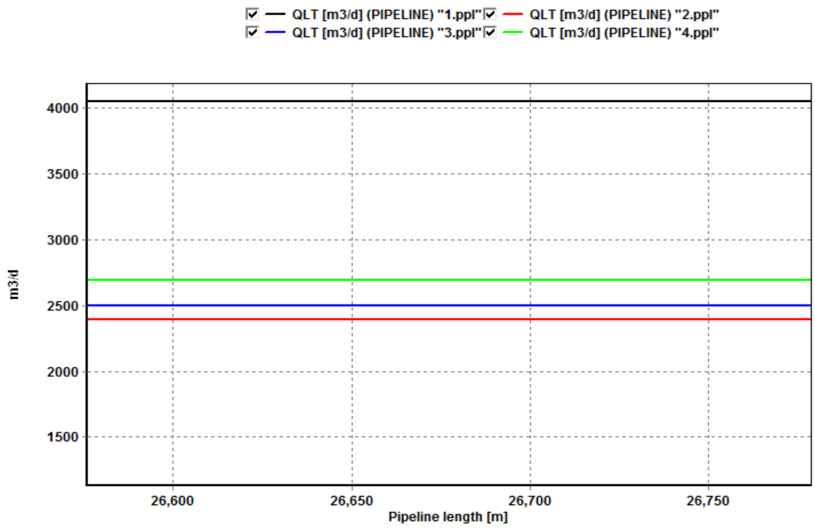

Figure 5-17 Profile Plot of Flow rate over Pipeline for Field A, Case 2

On the 1st year of simulation in Figure 5.18, there is a slight variation in pressure of magnitude 0.2 bar. These variations are as a result of start-up of the multiphase pumping, pipeline topography with regions of undulation and position of the multiphase pump on the pipeline (the longer the length of the fluid flows through the pipeline there is a separation of phases in the system), all these result to regions of instabilities along the pipeline (Manabe, 1997; Henriot, 1999). This variation in pressure completely evens out after about 2-3 hours of operation of the system. By the 3rd year of simulation shown by the red plot, there is a slight increase in pressure variation of the system in the region of 0.3 bar. This slight variation evens out after about 2-3 hours.

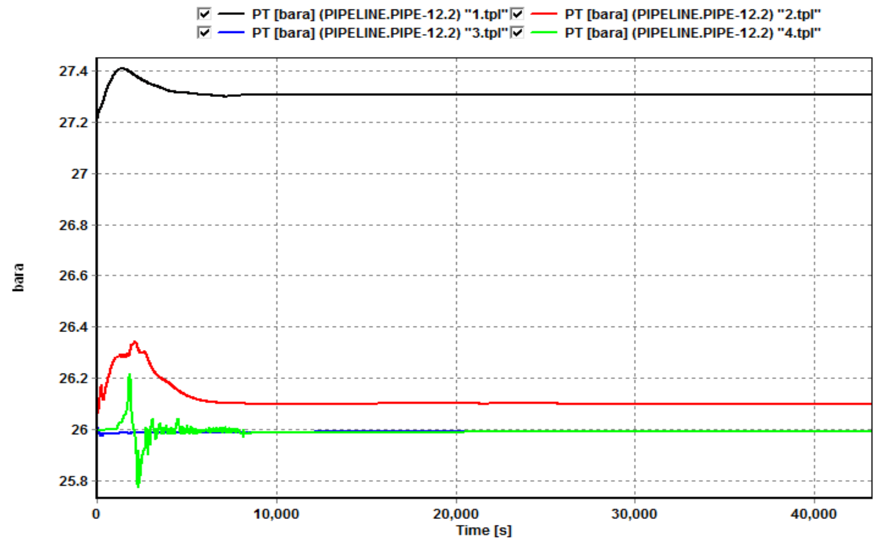

Figure 5-18 A Plot of Pressure Variations in the Pipeline against time for Field A, Case 2

The 6th year of simulation does not show any remarkable variation in flowrate, this can be explained as a result of the high PI in 6th year. The 8th year of simulation results in higher magnitude of variations in pressure compared to the previous years for this case, there is an onset of slugging due to the factors mentioned previously in addition to high water cut of the reservoir (Manabe, 1997; Henriot, 1999). The 8th year is characterized by pressure variations in the region of 0.4bar. After 2- 3 hours of operation this fluctuation evens out to give a fairly stable flow i.e. slight or minimal variation in pressure resulting in a more stable system.

5.4.6 **Summary of Field Case Studies**

In summary, the mechanistic model analysis shows that multiphase pumping in terms of performance offers a relatively high value in maximising production volume. This results in an even production profile, with variable increase in production thereby reducing flow assurance issues, thus extend the fields productive life. It also increases the life of the field's production facilities from the analysis which is best implemented at the later stage of the field's life or when the water cut of the reservoir fluid is above 70%. Multiphase pumps should be kept close to the wellhead as possible so as to prevent separation in fluid phases as they flow through the pipeline, and this contributes in managing flow assurance issues, with increases in productivity. According to

Grynning et al, 2009, multiphase pumps are known to have a maximum step out distance of about 30km for longer distance. The procedure of using multiphase pumps and boosting station are described in available literatures which can be applied (Baker and Entress, 1991; Davies et al., 2010; Euhemio et al., 2009; Grynning et al., 2009; Ribeiro et al., 2005; Abili et al, 2012). Applying this procedure will lead to longer tie backs, reduction in cost as a result of few production facilities on the seabed. Multiphase pumping is also environmentally friendly as it eliminates flaring and produced water re-injection or seabed disposal which results in pollution of the underwater environment. Increase in reliability and availability of multiphase pumping technologies especially in the area of seals improvement and its application across numerous fields in the offshore industry makes it an excellent choice for application in offshore field developments (Baker and Entress, 1991; Davies et al., 2010; Ribeiro et al., 2005).

For deepwater fields though, multiphase pumping offers slight advantage compared to a field without any form of subsea processing technology (SPT). Hence with appropriate application of subsea separation, multiphase pumping will yield high production rate if applied in conjunction with subsea fluid sampling data (water cuts, etc.) and tailored flow assurance strategy.

5.5 Synergy in Deepwater Development

The synergy of the mechanistic model and subsea processing (separation, boosting), to provide insight on the right dosage of chemical injection on subsea facilities, would maximise deepwater asset recovery (Baker and Entress, 1991; Davies et al., 2010; Euhemio et al., 2009; Grynning et al., 2009; Abili et al., 2012).

Prominent is the value subsea fluid sampling (mechanistic model) add in field developments, which is demonstrated in typical application to test the characteristics of different fluid components in merging network. This is applicable for different well streams commingling into a manifold, and tracking individual components of the well, to provide an accurate fluid data measurement and allocation of each well production rate (Mantecon and Hollams, 2009; Sbordone et al., 2012; Abili and Kara, 2015). Also significant is the value it adds in taking decisions on the right time to employ subsea processing during the life-of-field development. The mechanistic model thus provides a valuable predictive tool in detecting and managing water breakthrough as the field matures.

Figure 5-19 – Subsea Separation System for Maximized Recovery (Source: FMC)

Figure 5-20 – Subsea Booster Pump Module (Source: Aker Solutions)

Furthermore, after subsea separation process, water can be re-injected into the reservoir with reduced energy consumption required to deliver the separated hydrocarbon fluid produced to the topside facilities (Abili et al., 2012; Abili et al., 2014; Pinguet et al., 2012; Pinguet et al., 2014; Euphemio et al., 2009). The Figure 5.19 and 5.20 is a typical development of subsea separation system and booster pump module to maximize asset recovery.

However, once the decision to use subsea processing has been made, the next step is to determine which processes are required for the field. Some well fluids require only one or two processes while others require full processing. Equally important to project planning is an understanding of when to introduce subsea processing; not all fields will require major processing at the early phase of production. For example, where initial field studies indicate that water breakthrough is not expected until after the third year of production, it may not be necessary to install water separation equipment from the start. Also, if the natural flow pressure is sufficient until the fourth year, boosting equipment may not need to be installed until the third year of production (Grynning et al., 2009; Ribeiro et al., 2005; Abili et al., 2012). Therefore, a proper field assessment study would be required before making any final investment decisions about employing subsea processing to maximize asset recovery.

5.6 Conclusions

The acquisition of representative subsea fluid samples using the mechanistic model provides the foundation for obtaining accurate fluid properties which are essential for effective reservoir evaluation and management. Retrieving accurate fluid samples is linked to the value creation and realisation in employing subsea processing on field development. The synergy of the mechanistic model and subsea processing has been identified as a viable solution to maximise asset recovery.

However, the mechanistic model uses the fluid properties that are equivalent to the well flow stream been measured to predict reliable reservoir fluid characteristics as demonstrated in the sensitivity analysis in section 5.4.3. This is necessary even under conditions where significant variations in the reservoir fluid composition occur in transient production operations. Thus, the results obtained from subsea fluid sampling periodically would provide the insights to determine an appropriate time to introduce and commission subsea separation and boosting system to manage water breakthrough on well production presented in section 5.4.3 and 5.4.6. This synergy offers the added value to optimise deepwater assets for efficient processing of production fluid with separation and boosting systems to topside facilities for considerable saving on OPEX.

The mechanistic model application is a cost-effective subsea fluid sampling approach to reduce the frequency of retrieving subsea fluid samples on intervention operations presented in section 5.3.4. This synergy offers the added value to optimise deepwater assets for efficient processing of reservoir fluid on the seabed with considerable saving on OPEX, occasioned by contamination of production fluid from over estimate of chemicals (Methanol, Meg, etc.) injection dosage and the recovery process of these injected chemicals.

Therefore, the combination of mechanistic model and subsea processing provides the balanced approach to reservoir and production well performance management. With the synergy of subsea fluid sampling and subsea processing in the life-of-field development, EOR can be realised on deepwater developments.

6 CONCLUSION

6.1 Summary

- The present thesis has developed extensive literatures that cover both hardware technologies and numerical modelling on fluid sampling presented in chapter 2, to provide valuable insights on the applications and benefits of subsea fluid sampling. The process, planning and procedures for carrying out fluid sampling were examined, which leads to safe handling of sample from collection to laboratory. This does prevents contamination and unrepresentative sample capture for data analysis, in optimising production volume in deepwater developments. In addition, chapter 2.19 provide a list of applicable standards that can be used for subsea sampling design and operational planning, as no dedicated standard currently exist for subsea fluid sampling (answer to thesis objective 1).
- Representative subsea fluid samples provide the foundation for obtaining accurate fluid properties which are essential for effective reservoir evaluation and management. A variety of fluid sampling methods, concepts and MCDM have been identified for screening and selection process to obtain the optimal sampling solution, is presented in chapter 3. AHP emerged as the selected MCDM which was applied in the selection of 'ROV deployed fluid sampling' as the optimal solution to retrieve fluid samples close to the wellhead or subsea tree, taken upstream of the MPFM, to provide a source of validation and calibration of MPFMs. A pairwise comparison and Grid analysis were also applied to select the best sampling option 'Fluid Sampling + MPFM on Wellhead' for representative fluid sampling operation (answer to thesis objective 1).
- The mechanistic model has been demonstrated as an additional method to the physical sampling that can be dependent on for reliable measurement data to check and calibrate MPFM with transient multiphase flow metering as presented in chapters 4.5, and 4.6. The

mechanistic compositional fluid tracking model uses the fluid properties that are equivalent to the flow stream being measured to predict reliable reservoir fluid characteristics. This is achieved through validation of simulated result data with experimental data, to justify the accuracy of the mechanistic model measurement data acquired in Figure 4.6, and with further convergence to match experimental data to numerical simulated data in Figure 4.7. This validation became necessary under conditions where significant variations in the reservoir fluid composition occur in transient production operations, which can affect the accuracy of MPFM measurement in the SPS (answer to thesis objective 2).

- The combination of subsea MPFM, ROV deployed fluid sampling and mechanistic compositional fluid tracking model has the potential to provide a balanced approach to reservoir performance monitoring. This provides an accurate method for validating individual production well test. The subsea industry will benefit from the mechanistic compositional fluid tracking model as a complimentary solution, to reduce cost of intervention for subsea sampling operations. With appropriate application of this mechanistic model, EOR can be realised on offshore field developments.

6.2 Contributions

- A significant contribution from this research is the innovative application of subsea sampling hardware to the Subsea Production System (SPS). A dedicated fluid sampling solution packaged in a Flow Control Module (FCM)", was 'conceptualised' from this research to provide 'interchangeability' with the standard Production FCM in chapter 2.10. The FCM (MPFM and choke module) on the SPS is retrievable, so designing a dedicated fluid sampling FCM is a novel approach to make subsea sampling adaptive to the specific design requirement of a subsea production tree, which provide a suitable interface on sampling operations. The new conceptualised "Fluid Sampling FCM Architecture" is significant, as it improve representativeness of sample capture (aid stabilisation of well flowstream without need for shut-in or introduction of external components) and thus enables accurate measurement to check MPFM performance on subsea production system.

- The mechanistic model (using compositional fluid tracking) provides a predictive tool to monitor subsea operational conditions over the life of field. The mechanistic model is attractive as offshore operators would not have to conduct regular subsea sampling intervention operations, with the associated cost of hardware resources required for subsea deployment. However, the failure to obtain representative samples could have considerable impact on the OPEX for subsea production facilities. Hence, the mechanistic model could mitigate the risk of obtaining unrepresentative samples from measurement instruments in the field as presented in chapter 4.5 and 4.6 (answer to thesis objective 2).
- Sensitivity analysis on field case studies in the present research demonstrated that obtaining representative fluid samples depends on sampling in close proximity to the wellhead as presented in chapters 4.5, 5.4.3 and 5.4.6, as this would allow accurate sampling of the reservoir fluid before going into phases along the flowline. This also provides the benefit to test the reliability of MPFMs on subsea wells. The fluid samples acquired can be verified with a full set of fluid properties, using the mechanistic compositional fluid tracking model presented in chapter 4.4 and 4.5. Hence, regular and systematic use of the mechanistic model for field application provides comprehensive knowledge about the formation fluids and resulting productions rate in the subsea facility. This gives a basis for accurate prediction of fluid characteristics (density, PVT, etc.,) over the life of the field (answer to thesis objective 3 and 4).
- Furthermore, an additional contribution is the value of employing mechanistic model in taking fluid sampling, which does proactively enable informed decisions on when to employ subsea processing

during life of field developments as presented in chapter 5.4.3 and 5.4.6. This will assist in managing water breakthrough as the field matures with appropriate mitigation strategy for cost effective chemical injections as presented in chapter 5.4.3 (answer to thesis objective 4). Therefore, water can be separated and re-injected into the reservoir, to enable reduced energy consumption required to boost the hydrocarbon fluid produced to the topside facilities.

However, the present research explored 195 cited references. The contributions of this research are reflected in 6 journals, 9 conference and 2 magazine publications. Table 6.1 and Figure 6.1 provide the publications as an outcome of the research contributions.

Table 6-1 Publication Archive Matrix

Publication Archives	Matrix
Publication References sited	195
Peer reviewed Journal Papers Published	6
Conference Papers Published	9
Research papers Published in Energy Magazines	2

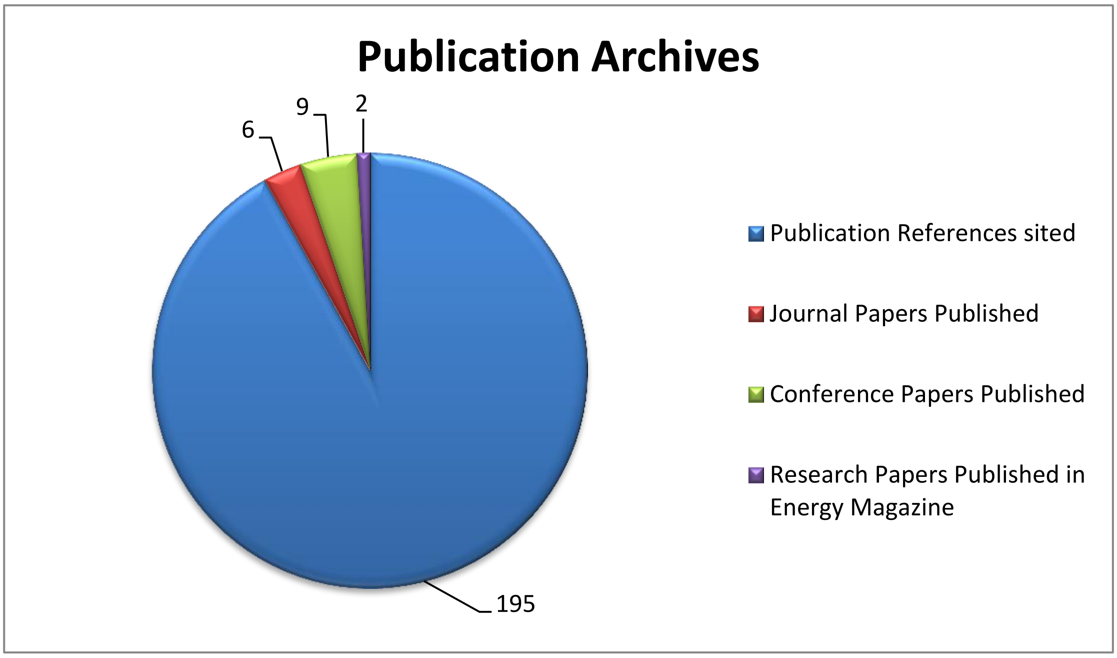

Figure 6-1 Publication Archive Chat

6.3 Recommendations

Further research efforts on subsea fluid sampling should focus on the following recommendations:

- To research the use of redundant meter sensors to measure fluid compositions in order to extend the data range and enable updating of meter algorithms and attenuations used for data analysis. With this improvement, the meter would be able to respond to the changing reservoir conditions during production;

- A methodology should be developed, using the mechanistic model and computational fluid dynamics (CFD) for meter sensor measurements. This would allow the physical property data acquired by the sensor to measure the fluids in multiphase flow. Also this would enable the meter software programme to calibrate the multiphase meter to match actual well or flowline service conditions;

- Furthermore, an intensive cost analysis into the economic impact on subsea fluid sampling applications is recommended for further research studies. The resulting cost analysis and value of capturing subsea fluid sampling in conceptual design on field development would stimulate pre-investment in the sampling technologies and mechanistic model applications for deepwater field developments.

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APPENDENCIES

Appendix I

(a) **Table 1** MPFM Design Specifications

Product	Subsea MPFM
Water depth	3000m
Design Life	25 years
Output	RS 422 / RS 485 MODBUS RTU ;TCP/IP over Ethernet
Accuracy	Contact MPFM Vendors
Installation Method	In-line connection
HP/HT design	Up to 250ºC (482ºF) at 14503psi (1000bar) with design pressure of 15000psi (1034bar)
Maximum Internal Pressure	15000psi (1034bar)
Max. Internal Fluid Temp.	250ºC (482ºF)
Min. Internal Fluid Temp.	- 50ºC (- 56ºF)
Seawater Temp. Range	4 – 25ºC (39 – l77ºF)
Sour service	NACE compliance
Water salinity measurement	0 to 95% water-cut detection
Electronic/Sensor design	ISO 13628-1, 4 and 10423 (API 17D and API 6A).
Qualification	Qualified according to DNV-RP-A203
Repeatability	Better than 1% (total mass rate at line conditions)
Standardization	Available in various sizes for specific applications

(b) **Table 2** ROV Sampler Specification

Parameters	ROV Sampling Skid
Sample Capture	Oil/Gas/Water (Compositions)
Sample Bottle Type	Piston
Sample Flow	Pump Drive
Working Pressure	15,000psi (1034bar)
Supply Fluid	Methanol or glycol
Circulation	Inlet and Outlet Configuration
Isothermal Sampling	Active Heating
Design Temperature	-30 to 200ºC (-22 to 392°F)
Depth Rating	1000-3000m (3281-9843ft)
Sample Volume Bottle	5 liters / 5000cc
No. of Sample Bottle	9 to12
Weight of Sample System	Less than 470kg in air, 40kg in seawater
Deployment	ROV

(c) **Table 3** Typical Time taken for a 5 litre Sample

Wellhead Pressure (Barg)	Time taken to Sample (Minutes)
37	30
50	28
97	22
230	15

(d) First Principle Equations

Conservation of Mass

For the gas phase:

$$\frac{\delta}{\delta t}(V_g\rho_g) = -\frac{1}{A}\frac{\delta}{\delta z}(AV_g\rho_g V_g) + \psi_g + G_g \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(1)$$

For the liquid phase at the wall:

$$\frac{\delta}{\delta t}(V_L\rho_L) = -\frac{1}{A}\frac{\delta}{\delta z}(AV_L\rho_L V_L) - \psi_g\frac{V_L}{V_L+V_D} - \psi_e + \psi_d + G_L \ldots\ldots\ldots\ldots\ldots\ldots(2)$$

For liquid droplets:

$$\frac{\delta}{\delta t}(V_D\rho_L) = -\frac{1}{A}\frac{\delta}{\delta z}(AV_D\rho_L V_D) - \psi_g\frac{V_D}{V_L+V_D} + \psi_e - \psi_d + G_D \ldots\ldots\ldots\ldots\ldots\ldots(.3)$$

From the equation 1 to 3 above,V_g, V_L, $V_D$is gas, liquid-film, and liquid-droplet volume fractions respectively, ρ is density, v is velocity, p is pressure, and A is pipe cross-sectional area. $\psi_g$is mass-transfer rate between the phases, ψ_e ψ_d is the entrainment and deposition rates, and G_f is possible mass source of phase f. The subscripts $g, L, i,$ and D indicate gas, liquid, interface, and droplets respectively (Dhulesia et al., 1996; Bendiksen et al., 1991).

Conservation of Momentum

Considering the conservation of momentum which is demonstrated here, three different fields are examined following equations on the gas, possible liquid droplets, liquid bulk and or film.

For the gas phase:

$$\frac{\delta}{\delta t}(V_g\rho_g v_g = -V_g\left(\frac{\delta p}{\delta z}\right) - \frac{1}{A}\frac{\delta}{\delta z}\left(AV_g\rho_g v_g^2\right) - \lambda_g\frac{1}{2}\rho_g|v_g|v_g\frac{S_g}{4A} - \lambda_i\frac{1}{2}\rho_g|v_r|v_r\frac{S_i}{4A}$$

$$+V_g\rho_g g\cos\alpha + \psi_g v_a - F_D \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots.. (4)$$

For the liquid droplets:

$$\frac{\delta}{\delta t}(V_D\rho_L v_D) = -V_D\left(\frac{\delta p}{\delta z}\right) - \frac{1}{A}\frac{\delta}{\delta z}(AV_D\rho_L v_D^2) + V_D\rho_L g\cos\alpha - \psi_g \frac{V_D}{V_L+V_D}v_a + \psi_e v_i - \psi_d v_D + F_D \text{..(5)}$$

Equation 4 and 5 are combined to yield a combined momentum equation, where the gas/droplet drag terms, F_D, cancel out in equation 6:

$$\frac{\delta}{\delta t}\left(V_g\rho_g v_g + V_D\rho_L v_D\right)$$

$$= -\left(V_g + V_D\right)\left(\frac{\delta p}{\delta z}\right) - \frac{1}{A}\frac{\delta}{\delta z}\left(AV_g\rho_g v_g^2 + AV_D\rho_L v_D^2\right) - \lambda_g\frac{1}{2}\rho_g|v_g|v_g\frac{S_g}{4A} - \lambda_i\frac{1}{2}\rho_g|v_r|v_r\frac{S_i}{4A}$$

$$+(V_g\rho_g + V_D\rho_L)g\cos\alpha + \psi_g\frac{V_L}{V_L+V_D}v_a - \psi_e v_i - \psi_d v_D \text{..........................(6)}$$

For the liquid at the wall:

$$(V_L\rho_L v_L) =$$
$$-V_L\left(\frac{\delta p}{\delta z}\right) - \frac{1}{A}\frac{\delta}{\delta z}(AV_L\rho_L v_L^2) - \lambda_L\frac{1}{2}\rho_L|v_L|v_L\frac{S_L}{4A} - \lambda_i\frac{1}{2}\rho_g|v_r|v_r\frac{S_i}{4A} + V_L\rho_L g\cos\alpha - \psi_g\frac{V_L}{V_L+V_D}v_a -$$
$$\psi_e v_i + \psi_d v_D - V_L d\left(\rho_L - \rho_g\right)g\frac{\delta V_L}{\delta z}\sin\alpha \text{ .... (7)}$$

In the Equation 4 through 7, α is pipe inclination with the vertical S_g, S_L, and S_i is wetted perimeters of the gas, liquid, and interface respectively. The internal source G_f, is assumed to enter at a 90° angle to the pipe wall, carrying no net momentum. So this gives us:

V_a =$V_L$for ψ_e > 0 (For evaporation from the liquid film)………………..(8)

V_a =$V_D$for ψ_g> 0 (For evaporation from the liquid droplets)………..….(9)

V_a =$V_g$for ψ_g<0 (For condensation) …………………………………......(10)

The last three above conservation equations 8, 9 and 10 can be applied for all flow regimes. However, some parameters may drop out for certain flow regimes; e.g., in slug or dispersed bubble flow, all the droplet parameters would disappear (Dhulesia et al., 1996; Bendiksen et al., 1991).

Conservation of Energy

Pressure Equation

Applying the mechanistic model reformulates the problem before discretizing the differential equations to obtain a pressure equation (Bendiksen et al., 1991). This equation, together with the momentum equations, may be solved simultaneously for the pressure and phase velocities and thus allow stepwise time integration.

The conservation of mass equations from Equation 1 to 3 may be expanded with respect to pressure, temperature, and composition, assuming that the densities are given as:

pf=pf(p,T,Rs)..(11)

Where the gas mass fraction, R_s is defined by equation 12

For the gas in equation 1, the left side may be expressed as:

$$\frac{\delta V_g \rho_g}{\delta t} = \rho_g \frac{\delta V_g}{\delta t} + V_g \frac{\delta \rho_g}{\delta t} = \rho_g \frac{\delta V_g}{\delta t} + V_g [(\frac{\delta \rho_g}{\delta P})_{T,R_s} \frac{\delta p}{\delta t} + (\frac{\delta \rho_g}{\delta T})_{p,R_s} \frac{\delta T}{\delta t} + (\frac{\delta \rho_g}{\delta R_s})_{p,T} \frac{\delta R_s}{\delta t}]$$

……………………………………………………………………………(12)

If we divide the expansions in equation 12 for each phase by the densities and adding the three equations yields, a volume-conservation equation is formed (neglecting the last two terms in equation 10 because they normally are negligible in pipeline transport problems due to the slow temperature development):

$$[\frac{V_g}{\rho_g} (\frac{\delta \rho_g}{\delta P})_{T,R_s} \frac{1 - V_g}{\rho_L} \left(\frac{\delta \rho_L}{\delta p}\right)_{T,R_s}] \frac{\delta p}{\delta t} = \frac{1}{\rho_g} \frac{\delta m_g}{\delta t} + \frac{1}{\rho_L} \frac{\delta m_L}{\delta t} + \frac{1}{\rho_L} \frac{\delta m_D}{\delta t}$$

…………………………………………………………………………..…..(13)

Inserting the mass conservation equations for each phase and applying V_g $+V_L + V_D = 1$ which gives:

$$[\frac{V_g}{\rho_g}(\frac{\delta p_g}{\delta P})_{T,R_s} + \frac{1-V_g}{\rho_L}\left(\frac{\delta p_L}{\delta p}\right)_{T,R_s}]\frac{\delta p}{\delta t}$$
$$= -\frac{1}{A\rho_g}\frac{\delta(AV_g\rho_g v_g)}{\delta z} - \frac{1}{A\rho_L}\frac{\delta(AV_L\rho_L v_L)}{\delta z} - \frac{1}{A\rho_L}\frac{\delta(AV_D\rho_L v_D)}{\delta z} + \psi_g\left(\frac{1}{\rho_g} - \frac{1}{\rho_L}\right) + G_g\frac{1}{\rho_g} + G_L\frac{1}{\rho_L} + G_D\frac{1}{\rho_L}$$

…………………………………………………………………..………..(14)

Equation 14 provides a single equation for the pressure and phase fluxes (Dhulesia et al., 1996; Bendiksen et al., 1991). Also note that if the phase transfer term, ψ_g is a function of pressure, temperature, and composition, i.e.:

ψ_g = ψ_g (P, T, s)... (15)

So ψ_g may be expanded by a Taylor series in p, T, and R_s, as shown in equation 15.

Energy Equation

A mixture of energy conservation equation is applied to yield:

$$\frac{\delta}{\delta t}[m_g(E_g+\frac{1}{2}v_g^2+gh)+ m_L(E_L+\frac{1}{2}v_L^2+gh)+ m_D(E_D+\frac{1}{2}v_D^2+gh)] = -\frac{\delta}{\delta z}[m_g v_g\,(H_g+\frac{1}{2}v_g^2+gh)+ m_L v_L(H_L+\frac{1}{2}v_L^2+gh)+ m_D v_D(H_D+\frac{1}{2}v_D^2+gh)]+ H_S+U$$

……………………………………………………………………………………(16)

E is internal energy per unit mass, h is elevation, H_S is enthalpy from mass sources, and U is heat transfer from pipe wall.

Appendix II

(a) Deepwater Field Case Study Molar Compositions of Reservoir Fluid

RESERVOIR		**A**	**B**	**C**	
Appraisal Wells	**units**	**Well 1**	**Well 2**	**Well 3**	**Well 4**
CO_2	mol%	1.2	0.5	0.3	0.3
H_2S	mol%	0	0	0	0
N_2	mol%	0	0	0	0
C_1	mol%	44.8	44.7	60	50.7
C_2	mol%	3.9	6.2	6.2	3.5
C_3	mol%	1.5	8.3	4.4	3.1
i-C_4	mol%	1.3	1.9	1.0	0.7
n-C_4	mol%	1.3	3.5	2.1	1.5
i-C_5	mol%	2.0	1.4	1.0	0.8
n-C_5	mol%	1.9	1.9	0.9	0.7
C_6	mol%	1.5	1.8	1.4	0.6
C_{7+}	mol%	40.6	2897	27.0	38.1
MW Fluid		123	77	69	92
MW C_{7+}		260	201	200	226

(b) Deepwater Field Case Study PVT Data

RESERVOIR	**UNIT**	**A**	**B**	**C**	
Appraisal Wells		**Well 1**	**Well 2**	**Well 3**	**Well 4**
Depth	Ft	8000	8600	9200	9500
Pressure	psia	4300	4601	5302	5490
Temperature	°F	145	159	176	203
Bubble Point Pressure	psia	3550	4190	5015	5000
Initial Solution GOR	Scf /bbl	600	1080	1420	916
API Gravity	°API	29	33	35	30

(c) Deepwater Field Case Study Flowing Wellhead Temperature

RESERVOIR A							**RESERVOIR C**	
	FLOWING WELL HEAD TEMPERATURES (˚F)						**FLOWING WELL HEAD TEMPERATURES (˚F)**	
RATE (MBOPD)	**P15/ PF11**	**P4/P F1**	**P9/P F3**	**P10/P F6**	**P7/PF 11**		**RATE (MBOPD)**	**P1/PF 12**
5	124	144	132	125	113		5	156
10	128	152	136	133	117		10	165
15	130	154	138	135	117		15	169
20	131	155	140	136	117		20	170
25	132	156	142	137	----		25	---
40	132	158	142	137	----		40	---

Appendix III
Industrial Survey

The survey input data were acquired from specific field data taken from a Shell deepwater field development, and vendor design functional specifications on subsea sampling system. The following feedbacks on emailed questionnaires and industrial visits to subsea experts working on subsea fluid sampling are presented in this Appendix.

Questionnaires

The questionnaires emailed out comprise of the available sampling technologies developed from the literature review. The questions were in two sections, Part I – closed-ended and Part II – open-ended. The open-ended questions are used to get the opinion of respondents, as is a qualitative enquiry. This provides information and insights that allow respondents to express their opinions freely, which results in a greater variety of information gathered on subsea fluid sampling technology, and thus, eliminates the possibility of bias on the industrial survey (Kumar, 2005; Patton, 2002).

The questionnaire in section I collects data on demographic information of respondents such as gender, age, level of education, job position and oil & gas working experience. This establishes the characteristics of respondent’s organization. On the other hand, section II in the questionnaire focused on the prevalence of the weighted criteria or factors in the selection of subsea fluid sampling technology, as listed in Appendix IV.

However, the sampling size for quantitative analysis can be statistically determined as shown in Table 1 (Sarantakos, 2005). The samples collected for this research were focused on deepwater project professional working in Nigeria or have business activities in West Africa, who were involved in deepwater development projects. They include, project directors, project manager, project engineers and senior project engineers, etc. About 100 questionnaires were email out using the convenience sampling method. The questionnaire was send to 10 companies (Government regulators, Operators and EPCs), including Department of Petroleum Resources (DPR), Chevron, Exxon Mobil, Shell, TOTAL, Schlumberger, Cameron, FMC, Proserv, and Framo. Table 1 provides details of the sample list of companies from which the respondents participated in the survey. A time period of 6 weeks were given for the data collation. The data were collected before the end of the 6 weeks. The respondent’s population in the research is 100. Thus, from the sample carried out, 86% of the respondent’s population responded to the survey.

Table 4 – List of Companies

Company Listed	Emailed Questionnaire
Department of Petroleum Resource (DPR)	10
CHEVRON	10
EXXON MOBIL	10
Shell Nigeria Exploration and Production Company (SNEPCo)	15
TOTAL E&P	15
Schlumberger	10
Cameron	10
FMC	10
Proserv	5
Framo	5
Total	100

Descriptive Analysis of Respondent Feedbacks

- A visit to Shell was instrumental in acquiring specific field data on a deepwater development. The data are in molar compositions of reservoir fluid, PVT and flowing wellhead temperature, as shown in (a) to (c) of Appendix II. The data was used to characterize the deepwater field fluid compositions in EoS Model and then imported into transient multiphase flow simulation program for the numerical model development.

  Furthermore, an email correspondence with a senior process engineer from Shell Norway, provided insights from Shell perspective. The flow meter industry is continuously developing the multiphase and wet gas flowmeters towards increased accuracy, repeatability and robustness. An example is one JIP run by MPM in Norway, where 6 to 9 oil companies have been involved since 2004. He stressed that the key goal now for the industry is to perform and verify in-situ measurements using the redundant measurements done by the flowmeters various sensors in order to reduce the need for subsea sampling. However, collecting subsea samples would still be needed to verify the performance of the meter and for calibration purposes. He also made reference to Shell involvement in the RPSEA JIP ongoing in the United States, where subsea sampling is one of the work packages. Other information provided through emails contributed to the ranking criterion in assigning a weighted factor on the objective functions for selecting a candidate sampling system.
- A visit to an Engineering Director in MARS production systems, a Cameron company in Scotland Aberdeen, made useful contributions to the sampling system development. He provided subsea sampling design requirements to meet operator’s demand for a representative fluid sampling. He explained that the flow-through method designed by Cameron employs a means of diverting some of the production flow from the subsea tree through sample loop and returning the fluid back downstream. Once the sample bottle for fluid collection is filled and equilibrium reached, it is isolated and can be recovered to surface for

analysis via ROV deployment. Further information provided through emails was useful in assigning a weighted factor on the objective functions for selecting a candidate sampling system.

- A visit to a Vice President from Proserv in Scotland Aberdeen, provided technical requirements for the subsea sampling system design. He said Proserv unique sampling technology is specially designed to provide the best sample possible, at true pressure conditions. This enables laboratories to perform very accurate and high quality PVT and chemical analysis. Apart from providing input to the weighting factors in ranking the subsea sampling technology available in the market, he also supplied the functional design requirements for deepwater development.
- An engagement meeting with a project manager from Framo Engineering in Norway was also useful to the research studies. He provided Framo subsea sampling systems brochure and technical publications on the current development in the subsea industry. Other information provided through emails was useful in assigning a weighted factor on the objective functions for selecting a candidate sampling system.

Appendix IV Fundamental Parameters

The definition of terms includes terms as used in fluid sampling and within the context of this paper (Yasseri, 2012; Letton and Webb, 2012).

Table 5 : Functional Parameters

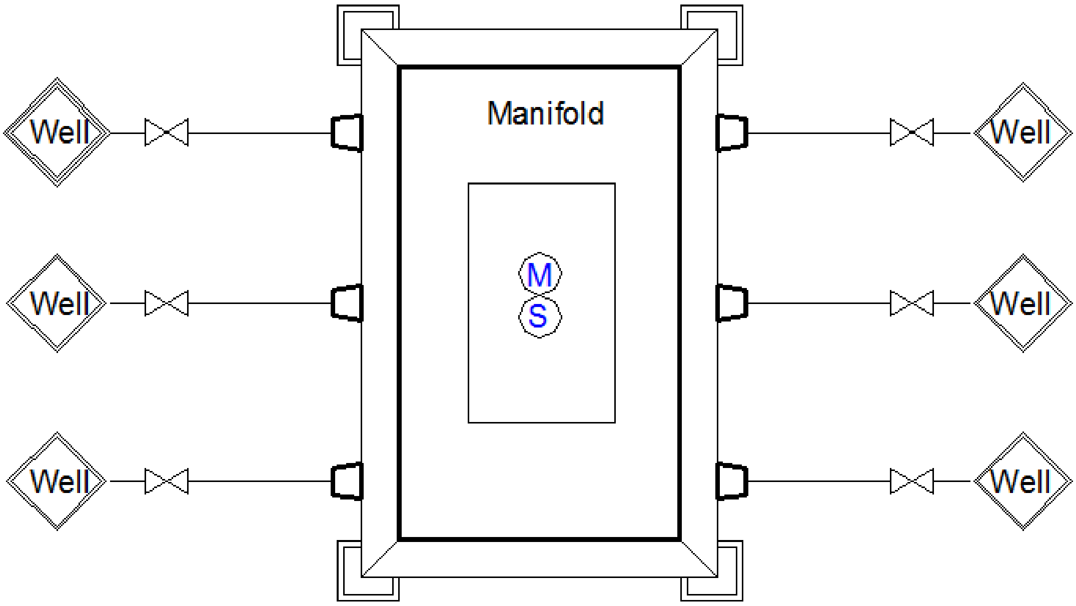
Symbol	Criteria	Sub criteria	Definitions
[1]	Safety and Risk	[A] Minimize leak and emission `	Accident free operation, prevents ingress of water or emission of hydrocarbons during operation, satisfies relevant HSE codes and standards, proper integrity management (ISO 14001).
		[B] Minimize exposure to high pressure fluids	The system should be made to have the same pressure as the produced fluid, not be a source of pressure reduction or loss
		[C] Minimize risk to asset	Enabling accident free operation, risk mitigation routes, robustness of system, identify failure modes, vulnerability to natural hazards adequate redundancy
		[D] Versatility of Design	Standard interface for equipment, reusability, flexibility and adaptability of technology, ease of connection, system with back-up and alternative designs
[2]	Provision of “representative sample”	[A] Is sample Isobaric	The sample should be extracted and stored isobarically without any drop in the reservoir pressure, as this may lead to loss of the single phase of the sample
		[B] Is sample Isothermal	The sample should be extracted and stored by heating to maintain the reservoir temperature, otherwise, it may also jeopardize

			the sample's accuracy
		[C] Prevents Hydrate formation	System should not cause any major flow assurance issue, like Hydrates, wax, asphaltenes or worse still, sampling flow rates should be 'isokinetic', (ISO 3171).
		[D] Is sample free of contaminants	Ingress of water during the operation must be avoided, system should prevent this as leak
		[E] Is sample in a single phase	The sample must be a true representative of the reservoir fluid, which is in a single phase, and it must be maintained during operation
[3]	Sample Verification	[A] Confirm sample acquired	System should have a means of measuring the quantity of acquired fluid to know it has enough sample for its operation
		[B] Confirm phases in the sample	System should also be able to ascertain that the sample taken is still in its single phase hence determine when there is an error in the temperature and pressure drop
[4]	Operation	[A] Acquire multiple sample from a single connection	Requirement of special units for storage, technologies to ensure safe storage kit for the collected sample, power and transportation unit.
		[B] Doesn't interrupt production	The operating interfaces should not stop the production of hydrocarbons, be it partial or whole, the two operations should

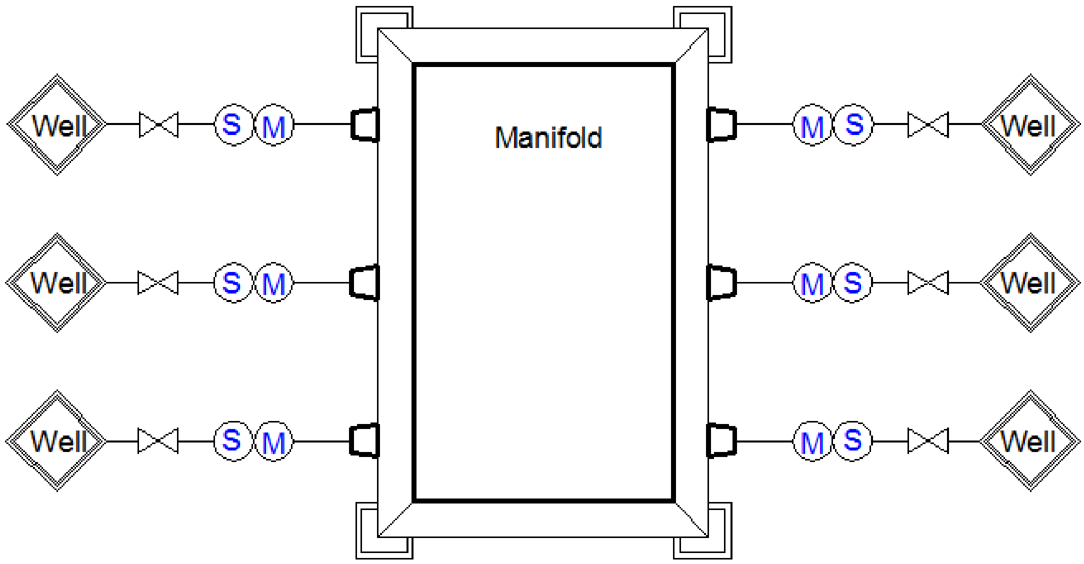
			be able to function simultaneously.
		[C] Simple to operate	The modularity of design, system should be easy to access and monitor, speed and accuracy of control, response time.
		[D] Ability to clean and prepare for next sample	Simplicity and ability to prepare the system for another sampling operation from another well, cleaning, disposal, and sanitizing properly
[5]	Economics	[A] Operational Expenditure	Cost of operating, maintaining, repairs, power consumption, hidden costs of adaption
		[B] Capital Expenditure	Cost of procurement, integration, development
		[C] Lead time	Time spent on operation; delivery, service, staff training, equipment availability
		[D] Integration	Cost of retrofitting, life cost, compatibility with subsea system
[6]	Equipment technology readiness	[A] Technology Readiness Level (TRL)	Maturity of equipment, it’s superiority over others, field tested, technology feasibility, good proven record of robustness, availability of all necessary technologies.
		[B] Size and weight	The system should have units for storage of the collected sample, as well as have components that accommodate the sampling units.
		[C] Survivability	It should be able to function properly Subsea, and survive in

			its field of use
		[D] Maintainability	Easily repaired without much down time.

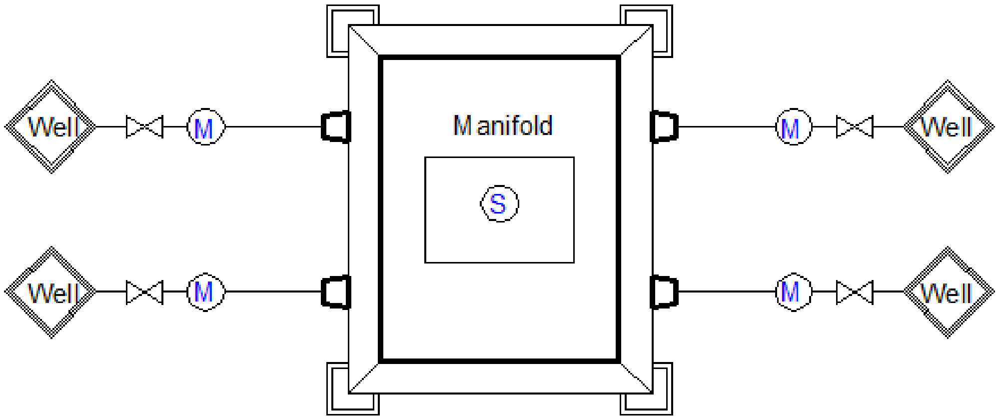
Appendix V Seabed Fluid Sampling Systems Options



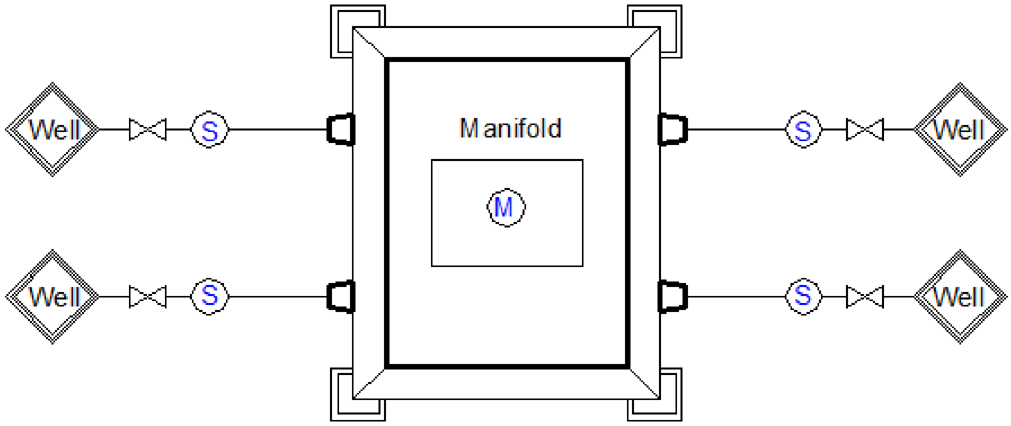
Option B&D



Option A&C



Option E



Option F

Appendix VI Experimental and Simulated CT Data Validation

Pipeline Length (m)	PT [psia] Experimental Results data	PT [psia] Validated CT Results data
38.0929985	731.9782715	732.9782715
114.283997	731.1791382	732.1791382
190.490005	730.3901367	731.3901367
266.722015	729.6011353	730.6011353
342.991516	728.2277222	729.2277222
419.295502	726.4263916	727.4263916
495.616028	724.6265259	725.6265259
571.934998	722.828125	724.828125
648.231995	722.0957031	723.0957031
724.507507	722.3306885	722.6306885
800.786011	722.5627441	722.8627441
877.093018	722.7947998	722.9947998
953.458008	722.46698	722.76698
1029.83899	721.5170288	722.5170288
1106.11902	720.5714111	721.7714111
1182.17847	719.6287231	720.6287231
1257.89148	718.6309204	719.6309204
1334.16895	717.5823364	718.5823364
1413.04395	716.4974365	716.4974365
1496.84155	715.3458862	716.3458862
1588.48291	714.6033325	715.6033325
1688.13	714.3916016	715.3916016
1792.30396	714.1682129	715.1682129
1896.8175	713.9434204	714.9434204
1997.41101	713.727356	713.927356
2090.42456	713.5300903	713.9300903
2173.28662	713.5083618	713.9083618
2249.51611	713.6330566	713.9330566
2327.61133	714.0754395	714.3754395
2412.2019	714.8179932	714.9979932
2504.68506	715.1588135	715.3588135
2602.54688	715.1515503	715.3515503
2698.91504	715.1442871	715.3442871
2787.31836	714.854248	714.954248
2867.01563	714.2146606	714.5146606
2941.74902	713.6171265	713.9171265
3014.45898	713.0355225	713.3355225
3087.78198	712.8063965	712.9963965
3164.03809	712.9847412	712.9847412
3245.5	712.6192627	712.9892627

3332.78052	711.5953369	711.9753369
3424.4126	710.5235596	711.5235596
3518.58008	709.4241943	710.4241943
3613.25635	708.317627	709.317627
3706.36743	707.868042	708.868042
3782.65747	708.097168	709.097168
3828.62402	707.3430176	708.3430176
3859.34106	705.7186279	706.7186279
3901.77197	705.0123291	706.0123291
3973.40723	705.1500854	706.1500854
4059.94312	705.3140259	706.3140259
4144.33887	705.4735107	706.4735107
4228.73535	705.6345215	706.6345215
4298.69043	705.2994995	706.2994995
4354.20557	704.4394531	705.4394531
4430.5835	703.2603149	704.2603149
4523.23828	701.8317871	702.8317871
4608.37305	700.5192261	701.5192261
4688.91992	699.27771	700.27771
4767.25391	699.0761719	700.0761719
4844.41797	699.8564453	700.8564453
4920.31885	700.1827393	700.1827393
4996.51367	700.1450195	701.1450195
5076.36914	700.105896	701.105896
5160.8877	700.0638428	701.0638428
5248.37842	700.0217285	701.0217285

Appendix VII Published Journal and Conference Papers

Integrated approach to maximise deepwater asset value with subsea fluid samplings

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Underwater International Journal
Received 17 November 2013; Accepted 6 January 2015
Abstract

The acquisition of representative subsea fluid samples from offshore field development is crucial for the correct evaluations of oil reserves and for the design of production facilities. Employing a transient multiphase flow simulation program, an 'Integrated Virtual Sampling Model' was developed, capturing the essential building blocks of the subsea production system. With the virtual sampling model, every single fluid component was accounted for throughout the calculation, enabling simulation of scenarios such as start-up and blowdown with a high level of detail and accuracy. Therefore, the model provides a predictive tool to test and monitor subsea operational conditions for the life of field. The application of the model should reduce the frequency of subsea intervention operations required for the offshore oil and gas industry with considerable saving on operational expenditures.

This paper explores the derivable benefits of the integrated virtual sampling application, to maximise value on deepwater field development.

Keywords – Subsea fluid sampling, Compositional tracking, Integrated virtual sampling model, MPFM, EoS Model.

Acronym list	
API	American Petroleum Institutes
EOR	Enhance Oil Recovery
EOS	Equation of State
FEED	Front End Engineering Design
FPSO	Floating Production Storage and Offloading Vessel
GOR	Gas Oil Ratio
MPFM	Multiphase Flow Meter
P	Pressure
PVT	Pressure Volume Temperature
SPS	Subsea Production Systems
T	Temperature

Introduction

Acquiring representative reservoir fluid samples play a key role in the design and optimization of production facilities. Inaccurate and unreliable fluid characterization leads to incorrect production rates, thus negatively impacting reservoir production recoveries. Retrieving reliable pressure, volume and temperature (PVT) properties of reservoir fluids starts with the acquisition of adequate volumes of representative fluid samples, followed by PVT data measurement and phase behaviour modelling. Subsequent laboratory analysis must be monitored through established quality control procedures to provide high quality data (Sbordone et al. 2012; Nagarajan et al., 2007; Joshi and Joshi, 2007). The reservoir fluid characterization methodology must employ best practice to model fluid behaviour as functions of pressure, temperature, and fluid composition.

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Compositional fluid tracking: an optimised approach to subsea fluid sampling

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Abstracts

The complex challenges and cost of intervention in acquiring representative subsea fluid sampling has necessitated an optimised novel approach to compositional fluid tracking to improve estimation of the local fluid properties for facility design optimisation and operations of subsea production systems. This enables computation of the local thermodynamic and hydrodynamic equilibrium in a pipeline flow simulation that accurately takes into account the fluid compositional changes in space and time, and continuously calculates physical properties based on the in-situ hydrocarbon and aqueous compositions.

The present paper demonstrates confidence in the application of compositional fluid tracking with Transient Multiphase Dynamic Flow Model on subsea fluid sampling and allocation of each well production.

Keywords – Compositional fluid tracking, Numerical simulation, Merging network, Confidence, Transient Multiphase Dynamic Flow Model, EoS modelling program.

Introduction

In the present offshore industry, several large oil and gas fields are being developed with metering systems such as multiphase meters and wet-gas meters. These metering systems provides essential data for optimizing production, measuring oil, gas, water fractions and flow rates on a real time (Jernsletten, 2011). However, Multiphase flowmeters (MPFMs) has always been claimed in the industry for using good quality PVT data to assure acceptable metering performance but, rarely have it been able to provide the operators with quantifiable data about this dependency to address these pertinent questions as to ‘what is the percentage effect of a percentage change in the input fluid composition due to improper sampling, recombination or analysis’ (Nagarajan, 2006)?

With the Compositional Tracking model, transient multiphase flow in wellbores and pipeline systems can be analysed using a dynamic two or three-fluid modelling technique (Bendiksen, 1991). In determining pressure drop, temperature changes and flow regime, the model developed essentially solves conservation equations for mass, momentum and energy for the gas and liquid phase or phases as a function of time. Also for water breakthrough, the model can handle water either as an integral part of the hydrocarbon phase or as a separate liquid phase. In this model, some of the important variables or components properties for compositional tracking include phase densities, gas mass fractions, viscosities, surface tension, molar compositions and PVT, etc. (Bendiksen, 1991 ; Rydahl, 2002).

The aim of this paper is to establish a realistic accurate compositional tracking for transient multiphase flow of reservoir fluid properties at the subsea Xmas tree and flowline to guarantee a representative subsea sampling that would inform the design optimisation of subsea facilities and operations in the offshore industry. This will provide a valuable standard on sensitivity analysis for reservoir fluid sampling and meter monitoring (Hall, 2011).

Int. J. Modelling in Operations Management, Vol. 3, Nos. 3/4, 2013 267

A mechanistic model development to overcome the challenges of subsea fluid sampling

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Abstract

Extracting fluid samples from actual flow stream being measured subsea is one of the operational requirements for obtaining sustained accurate measurement for calibration of a subsea multiphase flow meter (MPFM). Samples collected from topside facilities do not represent the fluid being measured due to chemical injection downstream the meter and possible liquid separation / hold-up. However, the issue of subsea intervention and transportation of fluid samples present another challenge with significant cost impact and risk to the subsea environment. To overcome these challenges, a virtual compositional fluid tracking model has being developed as an optimal solution in bridging the gaps in subsea fluid sampling. The virtual model is developed with a compositional fluid tracking module, capturing the essential building blocks of the Subsea Production System (SPS).

Results from the mechanistic model demonstrates the capability in improving understanding of well flow stream, taking into considerations the variations in fluid compositions in real time, and calculating the physical properties in view of matching the hydrocarbons compositions to enable a proactive and cost effective fluid sampling operation. This has also enabled the development of advanced operations monitoring, as operational conditions – we cannot control – changes over the field life.

Key Words: Transient Multiphase Flow Model, Compositional Fluid Tracking, Subsea Fluid Sampling, Multiphase Flow Meter, Well Flow Stream, Optimal Solution, Analytical Techniques, Operational Conditions, Applications.

Introduction

The development of modern electronic flow metering allows flowrate data to be collected and recorded very rapidly in real time. This has become a common practice in subsea applications, providing the opportunities for surface and sub-surface engineers to understand and optimise well performance (Hall et al., 2011). However, the use of modern electronic flow metering and computer equipment for fluid sampling does not mean that wells can be conditioned any more quickly or that gas and liquid flowrate data will automatically become more representative of reservoir fluid. Hence, recent R&D championed by major Operators in the offshore industry have made efforts to improve the performance of the metering systems such as MPFM with the development of subsea fluid sampling technology, deployable toward mid-life of the field to check and calibrate MPFM PVT input data as this field matures (Bruno et al., 2012; Chip et al., 2012; Hall et al., 2011). This has created opportunities to improve understanding of well flow stream for reservoir monitoring with the transient multiphase flow model and redundant metering sensors (Bruno et al., 2012; Andrea et al. 2012). Therefore, obtaining accurate compositional fluid samples is key to the proper characterisation of hydrocarbon reservoirs and the prime factor for the design and advancement of processing facilities.

To achieve subsea fluid sampling set objectives, multiphase flow model has been adopted for development of deepwater fields, employing fluid sampling as a result of significant saving on CAPEX, equally on OPEX in the life of well production (API MPMS., 2013; Chip et al., 2012; Dhulesia et al., 1996; Jaco B., 2012). Previous design approach of multiphase pipeline was by use of an empirical correlation taken from the test loop experimental data. Presently, empirical correlations are no longer reliable due to the fact that it does not take into account the physical phenomena, with measurable uncertainty in the model predictions.

Subsea processing – a holistic approach to marginal field developments

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International journal for Underwater Technology

The application of full subsea processing to develop remotely located marginal fields offshore West Africa is an attractive option for breaking the techno-economic barriers which have long hindered the development of these fields. Some of the fields have remained marginal and unproduced over the years, arguably owing to incorrect estimates in recoveries and economics occasioned by erroneous estimates in basic input parameters. Therefore, the right method of application for developing marginal fields must be sought to ensure that both national and international operating companies partake in the development of these fields. The present paper explores the use of full subsea processing (FSP) technology to develop marginal fields economically.

Keywords: install-produce-retrieve-refurbish, techno-economic barriers, simultaneous method, combinational method, full subsea processing station (FSPS)

Acronym list	
BEP	break-even price
CAPEX	capital expenditure
CPF	central processing facility
ESP	electrical submersible pump
FPSO	floating production, storage and off loading
FSPS	full subsea processing station
FSU	floating storage unit
IPRR	install-produce-retrieve-refurbish
NPV	net present value
OPEX	operating expenditure

Introduction

Subsea processing technology is maturing and is making its way into the toolbox of the oil industries for development of oil and gas fields with huge prospects for developing remotely challenging fields[17]. In the current climate, exploration and production has moved into unlocking reserves in less attractive and difficult environments, requiring innovations and qualified technologies. These marginal fields located offshore or onshore in some cases, requires one form of processing or another before they can be commercially productive.

Today, Operators are interested in the development of oil and gas reserves lying in ultra-deep waters, and the tie-back of remote marginal fields to existing production facilities. Subsea processing is recognized to be an efficient way for oil and gas production enhancement, especially for fields having challenging reservoir characteristics or lying in very deepwater. These marginal fields must be developed with cost efficient solutions and innovative technologies to allow the economic recovery of the reserves, as conventional solutions may not be viable[5]. The subsea separation of associated gas and subsea boosting of liquid through pumping is one of the most interesting solution in deep and ultra-deepwater, allowing longer tie-back distances.

Literature has been published on marginal field developments, the challenging gaps and the applications of subsea processing technology[3, 5, 6, 7, 10, 16]. An evaluation of the technology opportunities available to develop these marginal fields is examined with potential options demonstrated.

Synergy in Maximizing Value on Deepwater Development: Employing Fluid Sampling and Subsea Processing

Abili N., Citi G.; Gassert M., Eni E&P

This paper was prepared for presentation at the Deep Offshore Technology International Conference held in Aberdeen, Scotland, 14-16 October 2014.

Abstract

The acquisition of accurate subsea fluid samples for deep and ultra-deepwater development is crucial for the correct evaluation of oil reserves. This would enable design optimisation of subsea production and processing facilities in order to maximize asset value. Obtaining fluid samples from actual flow stream being measured subsea is one of the operational requirements to acquire accurate measurement for calibration of Subsea Multiphase Flowmeter (SMPFM). To achieve this, sufficient sample volumes are collected through Remote Operated Vehicle (ROV) deployed fluid sampling to ensure statistically valid characterisation of the sampled fluids.

A mechanistic fluid sampling model has been developed, using the fluid properties that are equivalent to the flow stream being measured, to predict reliable reservoir fluid characteristics. This is applicable even under conditions where significant variations in the reservoir fluid composition occur in transient production operations. Another benefit is the value it adds in deciding when to employ subsea processing to manage water breakthrough as the field matures. This can be achieved through efficient processing of the fluid delivered to the topside facilities or for water re-injection to the reservoir. The failure to obtain representative samples can have considerable impact on the Operational Expenditure (OPEX) and consequently the asset value to sustain production volume or enhance financial returns over the life of the field. Hence, the mechanistic model provide a predictive tool to mitigate the risk of obtaining unrepresentative samples from measurement instruments in the field, with considerable cost saving on intervention of subsea sampling operations.

Therefore, the combination of SMPFM, ROV deployed fluid sampling system and the mechanistic fluid sampling model, provides a balanced approach for reservoir performance monitoring. The present paper explores the synergy in successful application of subsea fluid sampling to maximize asset value in implementing subsea processing on deep and ultra-deepwater development.

Key Words: Synergy, SMPFM, ROV, Virtual Fluid Sampling Model, Subsea Processing, OPEX.

Introduction

The increasing world energy demands for oil and gas has driven offshore operators to explore viable solutions to maximize recoverable volume on deep offshore assets with innovative technologies. Industrial forecast from subsea processing game changer report shows that expenditure on subsea processing systems is expected to exceed US$3.4 billion, with deepwater expenditures expected to increase by 130% to $260 billion by 2018 (Douglas-Westwood, 2014; Douglas-Westwood, 2009). A contributing factor driving this expenditure high is the demands to deploy over one thousand additional subsea multiphase flowmeters (SMPFM). This critical component is used to provide well diagnostics to measure individual phases (oil, gas, water) without the need for complex conventional testing operations.

Reassessment of Multiphase Pump on Field Case Studies for Marginal Deepwater Field Developments

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Oil and Gas facility Journal, SPE-165587

Abstract

Subsea Processing Technology (SPT) is one of the Frontier tools currently been explored by the oil and gas industry to open new opportunities and achieve more effective exploitation of offshore oil and gas reserves. Exploration and production has moved into unlocking reserves that are less attractive and in difficult environments like marginal deepwater fields. These marginal field remotely located offshores require one form of processing or another before it can be commercially productive. The present journal paper focuses on the applicability of SPT employing Multiphase Pumps (MPP) to commercially develop marginal fields. This was as a result of the technology selection established due the comparison of performances of several SPTs for effective developments of marginal fields using tools such as Quality Function Deployment (QFD), and further evaluated using Analytical Hierarchal Process (AHP), resulting in the most effective innovative SPT for marginal field development. The result from these tools was further validated in their applications to real life fields and this is achieved by specific field case simulations studies using the OLGA Transient Multiphase Flow Dynamic Model Program to commercially develop marginal fields.

Keywords

Subsea Processing Technology (SPT); Multiphase Pumps (MPP); Analytical Hierarchal Process (AHP); Quality Function Deployment QFD; House Of Quality (HOQ); Voice of Customer (VOC); Production Index (PI); Consistency Index (CI).

Introduction

The challenges faced by the present offshore industry indicates that the era of easy oil is gone with more of the oil and gas reserves being discovered in unconventional and remote fields (Stefano et al., 2011; Liddle, 2012). Majority of the world's exploration and production companies have a significant number of these fields in their portfolio (Nischal et al., 2012). Offshore marginal field is a field that may not produce enough hydrocarbons to make it worth developing at a particular time due to technical, economic, geological and geographical reasons but can become economically viable if the previously stated conditions changes (Nischal et al., 2012; Abili et al., 2012). For successful development of marginal fields economically, optimal production of hydrocarbons is the key (Di Silvestro Stefano et al., 2011). In the development of marginal fields innovative solutions are necessary as conventional solutions are not convenient to make such field developments economically viable. Recent industrial focus has been geared at the accelerated development of subsea processing technology (Khoi Vu et al., 2009). One of the innovative solutions is through the handling and treatment of produced oil and gas at or below the seabed for transport to topside facilities to mitigate flow assurance issues such as hydrate formation, oil and gas conditioning etc. Subsea processing considers effective solution for oil production enhancement for fields having challenging reservoir characteristics (Di Silvestro et al., 2011).

Some of the notable benefits of subsea processing includes, mitigation of hydrate formation, management of pressure related issues resulting from the production of heavy oil, increase in wellhead pressure and increase hydrocarbon production from fields with low pressure profile. In ultra-deepwater and deepwater fields, subsea processing is the most effective solution as such fields are beyond human intervention (divers), and it is used to boost hydrocarbon production from green fields or brown fields, which reduces production cost as well as reducing the need for topside processing, resulting on increases oil recovery rate in fields with declining oil production and fields with high water cuts.

Subsea Processing, a Strategic Approach to Realize Value on Offshore Marginal Field Development

Abili N., Duclocher F., Citi G., Gassert M.; Eni E&P

This paper was prepared for presentation at the Offshore West Africa Conference held in Lagos, Nigeria, 20-22 January 2015.

Abstract

The development of marginal fields in Offshore West Africa poses huge technology challenges. These challenges are further complicated as the field is located offshore with long step-out distance from existing processing facilities. A good number of such fields exist in Nigeria with no concrete plans fully in place to develop them, arguably, due to incorrect estimates in recoveries and economics occasioned by erroneous estimates in basic input parameters. These fields' remotely located offshores require one form of processing or another before it can be commercially productive.

Subsea Processing is maturing to become one of the most innovative technologies at the disposal of the oil and gas industry. As exploration and production is focused on unlocking reserves in difficult environments such as ultra-deepwater, there is impetus for continued innovation and qualified subsea technologies. Subsea processing offers a viable and attractive option in developing these fields.

Qualifications of the different technologies available for subsea processing have been conducted and their various readiness levels determined. A systematic analysis of an existing marginal field has also been done to reveal the economic value of employing subsea processing for growth in volume and cash flows. Increased recovery and reduced Operational Expenditures (OPEX) have been established as vital incentives for developing offshore marginal fields economically. Various methods of overcoming the long distance associated with remote fields are developed and the best method which incorporates a Floating Storage Unit (FSU) identified. A strategic approach which considers developing a group of fields together rather than a single field at a time is adopted to develop the marginal fields in offshore West Africa.

The cumulative effects are significant increases in volume of hydrocarbons recovered while greatly reducing the OPEX – the two most critical drivers in the economic development of offshore fields. The proper equipment for carrying out these processes is incorporated in a Full Subsea Processing Station (FSPS). Application of this strategic approach will enable offshore marginal fields to be developed economically for sustaining the techno-economic growth in offshore West Africa.